HYDRO HAWKESBURY INC.

2014 Cost of Service Application.

Rates Effective: January 1, 2014

EB-2013-0139

Submitted on: May 30, 2013

Revised on: June 13, 2013

Revised on: July 22, 2013

Hydro Hawkesbury Inc.
850 Tupper Street
Hawkesbury, ON

May 30, 2013
Ontario Energy Board P.O.
Box 2319 27th Floor
2300 Yonge Street Toronto,
Ontario M4P 1E4

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

Dear Ms. Walli,

Hydro Hawkesbury Inc. is pleased to submit to the Ontario Energy Board its 2014 Cost of Service Application, in compliance with the OEB letter dated December 11, 2012. This application is being filed pursuant to the Board's e-Filing Services. Two hard copies of the Application will be delivered to the Board over the next few business days.

Excel versions of the following supporting OEB models are being filed pursuant to the Board's e-Filing Services.

EB-2013-0139 HHI 2014 COS Appendices May 30
EB-2013-0139 HHI 2014 COS Cost Allocation Model V3 May 30
EB-2013-0139 HHI 2014 COS PILs Workform May 30
EB-2013-0139 HHI 2014 COS RateDesignModel May 30
EB-2013-0139 HHI 2014 COS RRWF May 30
EB-2013-0139 HHI 2014 COS RTSR Model May 30
EB-2013-0139 HHI COS 2014 EDDVAR May 30
EB-2013-0139 HHI Load Forecast Worksheet May 30

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

Yours truly,

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

Exhibit 1 – Administrative Documents

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EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

The Administrative Documents identified in this section provide the background and summary information to the case as filed. This section consists of four segments.

1) Administration

2) Overview of filing

3) Financial Information

4) Materiality Threshold

Tab 1 - Administration

E1.T1.S1 Legal Application

In the matter of; the Ontario Energy Board Act, 1998;S.O. 1998, c.15, Sched B, as amended; and in the matter of; an Application by HHI for an Order or Orders approving or fixing just and reasonable distribution rates effective January 1, 2014.

Hydro Hawkesbury Inc. ("HHI" or the "Utility" or the "Applicant") is a distributor of electricity pursuant to a distribution license ED-2003-0027 issued by the Ontario Energy Board (the "Board") under the Ontario Energy Board Act, 1998 (the "Act"). HHI hereby applies to the Board pursuant to section 78 of the Act for following Order or Orders:

a) an Order approving HHI's proposed rates for the 2014 rate year, or such other rates as the Board may find to be just and reasonable;
b) an Order approving HHI's proposal to amortize, over a period ending December 31, 2015, the cost of meters included in rate base that have been replaced with Smart Meters;
c) an Order approving clearance of the balances recorded in select deferral and variance accounts by means of rate riders effective January 1, 2014 for a period of 2 years;
d) Approval to charge rates effective January 1, 2014 to recover a service revenue requirement of $1,790,364 which includes a revenue deficiency of $ 303,493;
e) Approval of the proposed loss factor of 1.05;
f) Approval to revise Low Voltage Rates as proposed at Exhibit 8;

g) Approval to revise Retail Transmission Network and Connection rates as proposed at Exhibit 8 ;

h) Approval to continue to charge Wholesale Market and Rural Rate Protection Charges at Exhibit 8;

i) In the event the Board is unable to implement HHI's 2014 rates by January 1, 2014, HHI requests that its current rates be made interim effective January 1, 2014.

j) Approval of its proposed 2014 rate base in the amount of $7,063,936

The 2014 rates proposed by HHI will result in monthly total bill impacts as follows: a) a Residential customer using 800 kWh's: a 3.24% decrease; b) a General Service customer less than 50 kW using 2,000 kWh's: a 6.20% decrease; c) a General Service customer > 50: a -26.56% decrease; d) Unmetered Scattered Load using 4600 kWh's - a 5.25% decrease; e) Sentinel Lighting with a demand of 1.3 kW a 7.70% decrease; Streetlights with a demand of 1kW; a 25.50% decrease. Bill impacts are discussed in detail at Exhibit 8.

Revised June 12, 2013.

The 2014 rates proposed by HHI will result in monthly total bill impacts as follows: a) a Residential customer using 800 kWh's: a 2.91% decrease; b) a General Service customer less than 50 kW using 2,000 kWh's: a 5.97% decrease; c) a General Service customer > 50: a -26.54% decrease; d) Unmetered Scattered Load using 4600 kWh's - a 5.03% decrease; e) Sentinel Lighting with a demand of 1.3 kW a 6.70% decrease; Streetlights with a demand of 1kW; a 25.12% decrease. Bill impacts are discussed in detail at Exhibit 8.

This Application is made in accordance with the Board's Chapter 2 of the Board's Filing Requirements for Transmission and Distribution Applications dated July 12, 2012. The bridge and test year forecast was prepared by management and reviewed by the Board of Director in January of 2013 and March of 2013 respectively.

HHI hereby certifies that the application has been reviewed and approved by the Manager and certifies that the information and evidence presented herein is accurate to the best of The Applicant’s knowledge.

E1.T1.S2 STATEMENT OF PUBLICATION

Upon receiving the Letter of Direction and the Notice of Application and Hearing from the Board, HHI will immediately arrange to have the Notice of Application and Hearing for this proceeding published in the local community “not-paid-for” newspaper which has the highest circulation in its service area;

a) Le Carillon, 1100 Aberdeen, Hawkesbury, ON and/or;
b) Le Régional, 124 Main St. East, Hawkesbury, ON

Once the Notice of Application and Hearing has been published in the above listed newspapers, HHI will immediately file an Affidavit of Publication together with proof.

E1.T1.S3 PROPOSED ISSUES LIST

In establishing the overall appropriateness of the proposed rates, HHI anticipates that the following issues will be addressed by the Board and interveners.

General (Exhibit 1)

- The reasonableness of the overall economic and business planning assumptions for the Test Year.
- The reasonableness of the proposed revenue requirement.
- The appropriateness of HHI's accounting treatment for ratemaking purposes.

Rate Base (Exhibit 2)

- The appropriateness of HHI's asset planning assumptions (e.g. asset knowledge, strategy and conditions, etc.)
- The appropriateness of HHI's capitalization and depreciation policy.
- The reasonableness of overall capital expenditures.
- The reasonableness of the working capital allowance.
- The reasonableness of the proposed rate base for the test year.
- The reasonableness of the accounting for stranded meters.
- The suitability of the Green Energy Plan.

Operating Revenues (Exhibit 3)

- The reasonableness of the load forecast methodology including weather normalization.

- The reasonableness of the proposed customers/connections and load forecasts (both kWh and kW) for the test year
- The appropriate adjustment of CDM in the load forecast.
- The appropriateness of the proposed revenue offsets.

Operating Costs (Exhibit 4)

- The reasonableness of the overall OM&A forecast for the test year.
- The appropriateness of the methodologies used to allocate costs.
- The reasonableness of the proposed level of depreciation/amortization expense for the test year.
- The reasonableness of compensation costs and employee levels.
- The reasonableness of the test year forecast of PILs.
- The suitability of HHI's service-quality results based on the Board specified performance indicators.

Cost of Capital and Rate of Return (Exhibit 5)

- The suitability of the proposed capital structure.
- The appropriateness of the cost of debt.
- The suitability of the proposed return on equity.

Calculation of Revenue Deficiency (Exhibit 6)

- The appropriateness of the calculation of Revenue Deficiency.

Cost Allocation (Exhibit 7)

- The appropriateness of HHI's cost allocation.

- The appropriateness of the proposed revenue-to-cost ratios.

Rate Design (Exhibit 8)

- The appropriateness of the proposed classes of customers.
- The appropriateness of the customer charges and the fixed-variable splits for each class.
- The appropriateness of the proposed Retail Transmission Service Rates.
- The appropriateness of the proposed loss factors.
- The appropriateness of HHI’s proposed Tariff of Rates and Charges.
- The appropriateness of HHI's rate mitigation plan.

9. Deferral and Variance Accounts (Exhibit 9)

- The appropriateness of the account balances, cost allocation methodology and disposition plan.

E1.T1.S4 ALIGNMENT OF RATE YEAR WITH FISCAL YEAR AND RATE ORDER REQUIREMENT FOR IMPLEMENTATION

In this application, HHI is seeking a fiscal rate year alignment. HHI believes that an alignment with its fiscal year will yield benefits such as a reduction in administrative and accounting cost burdens, improved budget planning and improved alignment of rates with costs. Rate increases will be more transparent to consumers since they would occur on dates which differ from the current regulated price plan (RPP) changes.

E1.T1.S4 RATE ORDER REQUIREMENT FOR IMPLEMENTATION

Being a small utility with limited time and resources to effectively update and test changes resulting from the Board's approval of any new Tariff of Rates and Charges, HHI respectfully requests that it receive by December 1, 2013 the Tariff of Rates and Charges effective January 1, 2014. A delay in receiving the new rate information later than mid-December would likely cause the new rates not to be reflected in the initial customer bills and result in corrections having to be made in subsequent bills.

E1.T1.S5 COMPLIANCE WITH CHAPTER 2 OF THE FILING REQUIREMENTS FOR ELECTRICITY TRANSMISSION AND DISTRIBUTION APPLICATIONS

HHI requests an exemption from certain sections of "Chapter 2 of the Filing Requirements for Electricity Transmission and Distribution Applications" as they pertain to the adoption of Modified IFRS ("MIFRS").

On February 14, 2013, the Accounting Standards Board (AcSB) decided to extend the existing deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities by an additional year to January 1, 2015.

In view of this recent development, Hydro Hawkesbury Inc. is seeking certain exemptions as they apply to obligations under Chapter 2 of the Filing Requirements For Electricity Transmission and Distribution Applications, which specify that cost of service applications must be filed on the basis of Modified IFRS ("MIFRS"). Instead, HHI is seeking approval to file their cost of service application on the basis of Modified CGAAP which supports accounting changes for depreciation expense and capitalization policies made mandatory and effective January 1 2013, for all distributors in the letter from the Board issued on July 17, 2012.

HHI believes there are benefits in deferring the use of MIFRS for regulatory reporting, especially for smaller utilities.

The consequences of not aligning the MIFRS date with the adoption of IFRS would create unwarranted burden for both utilities and their auditors, to maintain two sets of books and costs to audit the reconciliation.

As the board is already aware, HHI relies extensively on external resources to compile the evidence required to satisfy the Board's requirements. The exemptions, if granted would ensure that time and cost burdens related to MIFRS are not unnecessarily incurred.

E1.T1.S6 UTILITY OPERATING ENVIRONMENT

HHI's operating environment has not changed since its last rebasing in 2010. HHI is licensed by the Board to distribute electricity to the inhabitants of the Town of Hawkesbury.

The sole Shareholder of The Applicant is the Town of Hawkesbury. The population of the Municipality of Hawkesbury is approximately 10,500. The distribution service area within the Town of Hawkesbury is bounded by the township of Champlain, East Hawkesbury, and the province of Quebec. HHI's customers totals approximately

5,500 and is comprised of over 85% residential customers while 12% are small business or industrial based. The balance of the utility's customer base is comprised of Sentinel Lighting, Street Lights and Unmetered Scattered Load

HHI relies on approximately 67.45 km of circuits deliver approximately 148,212,312 kWh of energy and 10,000 kW of power to approximately 5,500 customers. The circuits can be broken down into roughly 56.65 km of overhead lines and 10.8 km of underground conductor. The distribution system is comprised of 42.85 km of 3-phases circuits and 24.6 km of single phase circuits..

HHI's service territory is surrounded by Hydro One Networks Inc. HHI is directly connected to Hydro One's transmission system at 115 KV and 44KV and is not an embedded LDC that takes delivery of electricity from another LDC.

HHI does not host any utilities within its service area, nor have any embedded utilities within its service area.

HHI is a registered Market Participant dealing directly with the IESO

E1.T1.S7 CORPORATE ORGANISATION

HHI does not conduct any non-utility businesses such as generation and does not have any affiliates.

HHI employs has a workforce of 8 people.

- A General Manager,
- A Director of Finance/Assistant General Manager
- 3 customer service representatives
- 3 linemen

The above relationships are shown in the Utility Organization Chart at the next page.

The General Manager is responsible for designing and planning the utility's distribution system; along with implementing other emerging distribution technologies; ensuring that employees, contractors and public remain safe when interfacing with the distribution system; ensuring the reliable operation – including maintenance and repair – of the distribution system; and ensuring that customer requests for electricity service are provided promptly and according to code. He is responsible for external communications with customers, public and media; providing a single point of contact for customer enquiries;

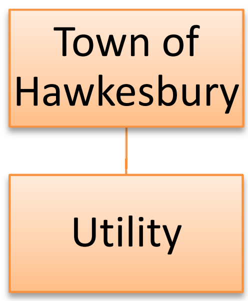
The General Manager is also responsible for providing human resource support including salary and benefit services; maintaining effective communications throughout the company; and ensuring that operations and office staff have access to the highest quality information and training to allow them to perform their work safely and efficiently.

The Assistant General Manager Director of Finance is responsible for all internal and external financial activities of the company including liaison with banks and other financial institutions; providing financial reports to the holding company, Shareholder and the senior management team; guiding the development of budgets and tracking the company's progress towards achieving approved financial targets; metering, information systems and customer billing; liaison with regulatory bodies including the OEB and legal counsel; purchasing and stores; and conservation and demand management.

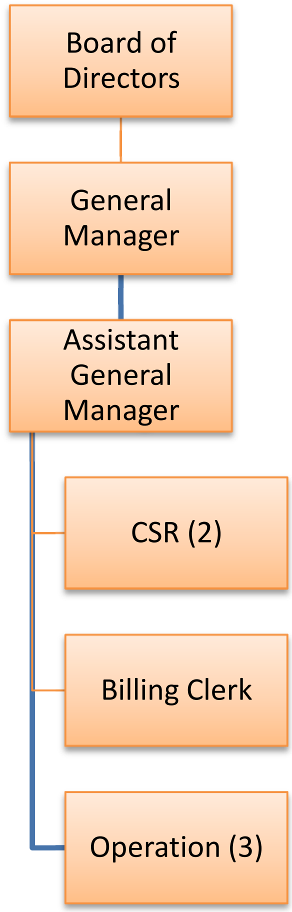
Planned Changes to the Organizational Structure

HHI does not anticipate making any changes to its organizational structure.

Corporate Entities Chart



Corporate Organizational Chart



E1.T1.S8 BOARD DIRECTION FROM PREVIOUS EDR DECISIONS

The only known directive stems from Decision and Order, EB-2009-0186, May 10, 2010 which states: "*The Board therefore directs Hawkesbury to perform an outage review and determine whether there is an economical means to be more proactive to lower outages and further increase safety and reliability of its system. . The Board directs Hawkesbury to file a report in its next COS application. In performing this study, the Board does not expect Hawkesbury to incur any significant additional costs.*" As directed, this matter is specifically addressed at Exhibit 2 of this application. There are no other outstanding directives from the Board resulting from previous EDR decisions.

E1.T1.S9 PROCEDURAL ORDER, MOTIONS AND CORRESPONDENCE

In a letter dated December 11, 2012, the OEB identified HHI as one of the LDCs expected to file a cost of service application in respect of its 2014 rates. In a letter dated January 24, 2013 HHI notified the OEB of its intent move to a January 1 rate year and of its intent to file its cost of service application on April 26, 2013

No further Procedural Orders have been issued by the OEB to the date of filing this application.

E1.T1.S10 ACCOUNTING ORDERS

HHI is not requesting any Accounting Orders in this proceeding and has not knowingly made any departure from the Uniform System of Accounts. HHI has complied with accounting changes as directed by the OEB.

E1.T1.S11 ACCOUNTING TREATMENT OF NON-UTILITY RELATED BUSINESS

Ottawa Hydro conducts conservation and demand management (CDM) activities on behalf of HHI in order to meet the CDM targets that are a condition of HHI's license. Apart from the above and the sale of electricity to its customers, HHI engages in no other business activities.

E1.T1.S12 COMPLIANCE ORDERS

No Compliance Orders have been issued by the OEB to the date of filing this application

E1.T1.S13 OTHER BOARD DIRECTIONS

No Other Orders have been issued by the OEB to the date of filing this application

E1.T1.S14 CONDITIONS OF SERVICE

HHI is in the process of updating its conditions of services. Amongst the proposed revisions are the following subjects.

- Time of Use (consumption data retrieval and billing alignment with applicable regulations and directions from the Smart Meter Entity)
- Customer Service issues such as Low- Income customers and deposit policy
- Connection of renewable generation / customer owned generation and
- connection of renewable generation

- Review and revisions to rate classes such as MicroFIT Generator Rate Classification.

Once the 2014 Cost of Service Application is filed, HHI will focus its efforts on updating its Conditions of Service. The expected effective date of the revised document is January 1, 2014.

Tab 2 - Overview of Filing

E1.T2.S1 SUMMARY OF APPLICATION AND APPROVAL REQUESTED

In preparing this Application, HHI has considered the impact on its customers, with the goal of minimizing those impacts. Customer impacts including percentage average Total Bill Impact are set out at Exhibit 8 Section E8.T8.S1. Embedded in this monthly bill impact is the effect of revised distribution rates (monthly service charge and volumetric rate), revised Loss Factors, Stranded Meter Rate Rider and Deferral and Variance

The current rates will result in actual a Return on Equity in 2014 below the level currently approved by the OEB. The increase in rates is required to:

1. Maintain current capital investment levels in infrastructure to ensure a safe, reliable distribution system.
2. Manage human and financial resources at a level which will ensure regulatory compliance, ESA compliance, promote conservation programs and effectively support its customer’s needs.
3. Ensure that the utility as able to accommodate new connections and that new assets related to the new development are included in the utility’s rate base.
4. Earn reasonable rate of return.

In this proceeding, HHI is seeking the following approvals:

- Approval to charge rates effective January 1, 2014 to recover a service revenue requirement of $1,790,364, as set out in Exhibit 6.
- Approval of proposed rates as set out in Exhibit 8.
- Approval of the proposed capital structure, with a deemed common equity component of 40% and a deemed debt component of 60%, as set out in Exhibit 5 consistent with the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors dated December 20, 2006.
- Approval of the proposed loss factor of 1.05 as set out in Exhibit 8
- Approval to continue to charge Rural Rate Protection Charges and Wholesale Market Service rate as set out in Exhibit 8.
- Approval of the Retail Transmission – Network Service and Retail Transmission – Connection rates, in accordance with the Guideline for Electricity Distribution Retail Transmission Service (G-2008-0001), Revision 1.0 issued July 22, 2009 and models issued July 7, 2011.

HHI is in a debit position as far as its Deferral and Variance Accounts is concerned. HHI is requesting the disposition of the amounts specified in Exhibit 9 over a two year period, via a rate rider, allocated to all classes. HHI is also requesting a Stranded Meter Rate Rider over one year to recover the stranded meter assets as a result of the implementation of the smart metering infrastructure. HHI has included the Smart Meter Entity charge of 0.79 per customer per month to recover the costs of the IESO relating to the smart meter infrastructure.

- Approval to dispose of Deferral and Variance Account balances as at December 31, 2012 with interest to December 31, 2013, over a two-year period using the method of recovery described in Exhibit 9.
- Approval to dispose of the 1589-RSVA/Power variance account, sub-account Global Adjustment, by way of a distinct rate rider charged to customers not subject to the Regulated Price Plan, as calculated in Exhibit 9.
- Approval to use the Board Approved 1595 account – Disposition and Recovery of Regulatory Balances and sub-accounts to record the disposition and recoveries of Deferral and Variance account balances.
- Approval to use the Board Approved accounts to collect costs in connection with the Green Energy and Green Economy Act (GEGEA) described as:
    - 1531 – Renewable Connection Capital Deferral Account
    - 1532 – Renewable Connection OM&A Deferral Account
    - 1534 – Smart Grid Capital Deferral Account
    - 1535 – Smart Grid OM&A Deferral Account

- Approval of transfer of Smart Meter related capital expenses to Rate Base. Further information can be found at Exhibit 2.
- Approval to transfer Smart Meter related operating expenses to the utility's test year OM&A. Further information can be found at Exhibit 4.

E1.T2.S2 ACCOUNTING STANDARD FOR FINANCIAL REPORTING

In 2008, the Accounting Standards Board of Canada ("AcSB") prescribed that publicly accountable entities were required to transition to IFRS by 2012. On March 30, 2012, the AcSB issued the Accounting Standards Board – Decision Summary, March 20-21, 2012, which indicated the AcSB's decision to allow an additional one-year deferral of the mandatory adoption of IFRS to January 1, 2013 for Canadian utilities with qualifying rate-regulated activities for financial reporting purposes.

Further to the AcSB's decision, the Board issued a letter dated April 30, 2012 re: Impact of the Decision to Defer the Mandatory Date for the Implementation of International Financial Reporting Standards to January 1, 2013 by the Canadian Accounting Standards Board. The letter states the following:

"The Board notes that by virtue of the existing AcSB standard the rate-regulated utilities are required to adopt IFRS by January 1, 2013. The Board therefore expects that all 2013 cost of service applications will be filed on the basis of MIFRS."

In February 2013, the Accounting Standards Board (AcSB) decided to extend the existing deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities by an additional year to January 1, 2015. Discussions at the International Accounting Standards Board's (IASB) January 2013 meeting indicate that the IASB is on track to:

- publish an exposure draft proposing the interim IFRS described under "December 2012 News" (below) in March 2013; and

- issue an interim standard by the end of the year.

The end of 2013 is also when the AcSB's IFRS deferral for this sector would have ended absent an extension. The AcSB stated that it wished to provide first-time adopters of IFRSs adequate time to prepare comparative figures based on a new interim IFRS.

In the absence of further updates or revision to the Board's views stated in its letter of April 30, 2012, HHI has filed its rate application using Modified Canadian Generally Accepted Accounting Principle ("Modified CGAAP") for the years 2013 to 2014.

HHI plans to file both its pro-formas and audited financial statements for 2013 and 2014 in Modified CGAAP.

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E1.T2.S3 BUDGET DIRECTIVES AND ASSUMPTIONS

HHI compiles budget information for the three major components of the budgeting process: (1) revenue forecasts; (2) operating, maintenance and administration ("OM&A"); and (3) capital costs. This budget information is compiled for 2013 Bridge Year and 2014 Test Year.

Revenue Forecast

The revenue forecasts are based on throughput volume and existing rates for the 2013 Bridge Year and HHI's proposed rates for the 2014 Test Year. The forecasted volumes have been weather normalized and consider such factors as new customer additions and load for all classes of customers. Details are presented at E3.T1.S4. The forecast has been adjusted to reflect the CDM initiatives currently undertaken by HHI. The CDM adjusted forecast can be found in E3.T1.S6

OM&A Costs

OM&A costs in Exhibit 4 represent HHI'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 HHI's distribution system, and meeting the requirements of the OEB's Standard Supply Code and Retail Settlement Code.

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

Capital Costs

In managing its capital assets, HHI's primary objectives are to optimize asset performance in a cost-effective manner, enhance safety, protect the environment, improve operational efficiency, maintain high standards of reliability, adhere to regulation and meet customer demand. HHI develops capital programs on both a short and longer-term basis, and prepares annual budgets and forecasts as the basis for capital investments. HHI's approach to managing its distribution system is comprised of the following two key strategies:

System Planning; add new assets and/or replace assets that are at or nearing the end of their useful life. This includes consideration for:

- Capital Investment
- Contingency Planning

Managing and Sustaining Existing Assets; maintain and operate existing distribution assets to prevent failures and maximize equipment useful life. HHI's approach to managing its distribution assets is described in more detail in HHI's Distribution Asset Management Program (DAMP).

- Asset Knowledge
- Asset Condition.
- Operating and Maintaining Assets

Capital costs in Exhibit 2 have been developed with the key strategies above in mind.

Overall Budgeting Process

The capital and operating budgets are prepared annually by management and reviewed and approved by the Board of Directors. The General Manager and the Assistant General Manager are responsible for the preparation of their departmental budget. This includes identifying resources, including labour, materials and other third party costs that are required to execute the work plans. HHI ensures that departmental responsibilities are met and that anticipated works will be completed during the fiscal year. Once approved, the budget is only revised if a material change in plan is required. In such cases, the revised budget is approved by the Board of Directors.

E1.T2.S4 CHANGE IN METHODOLOGY

In compliance with the Board's letter issued July 17, 2012 which state that utilities must changes change their depreciation expense and capitalization policies, HHI has adopted these mandatory changes effective on January 1, 2013.

The Applicant is proposing to change the estimated useful lives of its assets to be consistent with the guidelines in the Board-commissioned Kinectrics Report dated June 15, 2010. The Applicant is also proposing to change its accounting policy for the accounting of overhead costs associated with capital work as clarified by the Board in its letter dated February 24, 2010.

Consistent with recent applications to the Board, The Applicant no longer includes PST in its OM&A cost estimates.

Changes in revenue requirement and rate base as a result of the change in accounting are explained throughout this application but more specifically at Exhibit 2 and Exhibit 4.

E1.T2.S5 REVENUE SUFFICIENCY/DEFICIENCY

Revenue deficiency/sufficiency of $303,493 is determined as the difference between revenue at current rates (before rates are adjusted to recover the required revenue), and service revenue requirement for 2014. The detailed calculations are presented in E6.T2.S2 and summarized in Table 1 below.

Table 1 – Summary of Revenue Deficit

Revenue Deficiency from Below		$297,828.00
Distribution Revenue	$1,363,660.00	$1,031,905.00
Other Operating Revenue Offsets - net	$157,139.00	$157,139.00
Total Revenue	**$1,520,799.00**	**$1,486,871.00**
Operating Expenses	$1,349,519.00	$1,349,519.00
Deemed Interest Expense	$168,828.00	$168,828.00
Total Cost and Expenses	**$1,518,347.00**	**$1,518,347.00**
Utility Income Before Income Taxes	**$2,452.00**	**-$31,476.00**
Utility Rate Base	**$7,063,936.00**	**$7,063,936.00**
Deemed Equity Portion of Rate Base	**$2,825,574.00**	**$2,825,574.00**
Income/(Equity Portion of Rate Base)	$0.00	-$0.02
Target Return - Equity on Rate Base	$0.09	$0.09
Deficiency/Sufficiency in Return on Equity	-$0.09	-$0.11
Indicated Rate of Return	$0.02	$0.02
Requested Rate of Return on Rate Base	$0.06	$0.06
Deficiency/Sufficiency in Rate of Return	-$0.04	-$0.04
Target Return on Equity	**$253,737.00**	**$253,737.00**
Revenue Deficiency/(Sufficiency)	**$251,664.00**	**-$303,493.00**
Gross Revenue Deficiency/(Sufficiency)	**$297,828.00**	

E1.T2.S6 APPROVED REVENUE REQUIREMENT VS PROPOSED REVENUE REQUIREMENT

Table 2 below shows a comparison of the last Board Approved Revenue Requirement versus the 2014 proposed Revenue Requirement.

Table 2 comparison of revenue requirements

Particular	CGAAP	CGAAP
	2014 Test Year	**Last Board Approved**
OM&A Expenses	$1,126,665	$973,854
Amortization Expense	$222,854	$169,798
Total Distribution Expenses	$1,349,519	$1,143,652
Regulated Return On Capital	$422,565	$311,549
IFRS Adjustment	$0	
Grossed up PILs	$18,820	$37,164
Service Revenue Requirement	**$1,790.364**	**$1,492,365**
Less: Revenue Offsets	$157,139	$173,420
Base Revenue Requirement	**$1,633,225**	**$1,318945**

E1.T2.S7 REVENUE REQUIREMENT WORKFORM OF PROPOSED RATES

The Revenue Requirement Workform is presented at the next page.

Revenue Requirement Workform

Data Input [1]

		Initial Application	(2)		(6)	Per Board Decision	
1	**Rate Base**						
	Gross Fixed Assets (average)	$7,102,782		$ 7,102,782		$7,102,782	
	Accumulated Depreciation (average)	($2,255,831)	(5)	($2,255,831)		($2,255,831)	
	Allowance for Working Capital:						
	Controllable Expenses	$1,126,665		$ 1,126,665		$1,126,665	
	Cost of Power	$15,927,063		$ 15,927,063		$15,927,063	
	Working Capital Rate (%)	13.00%	(9)	13.00%	(9)	13.00%	(9)
2	**Utility Income**						
	Operating Revenues:						
	Distribution Revenue at Current Rates	$1,363,660					
	Distribution Revenue at Proposed Rates	$1,329,732					
	Other Revenue:						
	Specific Service Charges	$70,000					
	Late Payment Charges	$30,000					
	Other Distribution Revenue	$32,139					
	Other Income and Deductions	$25,000					
	Total Revenue Offsets	$157,139	(7)				
	Operating Expenses:						
	OM+A Expenses	$1,126,665		$ 1,126,665		$1,126,665	
	Depreciation/Amortization	$222,854	(10)	$ 222,854		$222,854	
	Property taxes						
	Other expenses						
3	**Taxes/PILs**						
	Taxable Income:						
	Adjustments required to arrive at taxable income		(3)				
	Utility Income Taxes and Rates:						
	Income taxes (not grossed up)	$15,447					
	Income taxes (grossed up)	$18,280					
	Federal tax (%)	11.00%					
	Provincial tax (%)	4.50%					
	Income Tax Credits						
4	**Capitalization/Cost of Capital**						
	Capital Structure:						
	Long-term debt Capitalization Ratio (%)	56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		(8)		(8)
	Common Equity Capitalization Ratio (%)	40.0%					
	Prefered Shares Capitalization Ratio (%)						
		100.0%					
	Cost of Capital						
	Long-term debt Cost Rate (%)	4.12%					
	Short-term debt Cost Rate (%)	2.07%					
	Common Equity Cost Rate (%)	8.98%					
	Prefered Shares Cost Rate (%)						
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS ($)		(11)		(11)		(11)

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

(10) Depreciation Expense should include the adjustment resulting from the amortization of the deferred PP&E balance as shown on Appendix 2-EA or Appendix 2-EB of the Chapter 2 Appendices to the Filing Requirements.

(11) Adjustment should include the adjustment to the return on rate base associated with deferred PP&E balance as shown on Appendix 2-EA or Appendix 2-EB of the Chapter 2 Appendices to the Filing Requirements.

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(3)	$7,102,782	$ -	$7,102,782	$ -	$7,102,782
2	Accumulated Depreciation (average)	(3)	($2,255,831)	$ -	($2,255,831)	$ -	($2,255,831)
3	Net Fixed Assets (average)	(3)	$4,846,951	$ -	$4,846,951	$ -	$4,846,951
4	Allowance for Working Capital	(1)	$2,216,985	$ -	$2,216,985	$ -	$2,216,985
5	**Total Rate Base**		$7,063,936	$ -	$7,063,936	$ -	$7,063,936

Allowance for Working Capital - Derivation

(1)

Line No.	Particulars		Initial Application				Per Board Decision
6	Controllable Expenses		$1,126,665	$ -	$1,126,665	$ -	$1,126,665
7	Cost of Power		$15,927,063	$ -	$15,927,063	$ -	$15,927,063
8	Working Capital Base		$17,053,728	$ -	$17,053,728	$ -	$17,053,728
9	Working Capital Rate %	(2)	13.00%	0.00%	13.00%	0.00%	13.00%
10	Working Capital Allowance		$2,216,985	$ -	$2,216,985	$ -	$2,216,985

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. Default rate for 2013 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$1,329,732	($1,329,732)	$ -	$ -	$ -
2	Other Revenue	(1)	$157,139	($157,139)	$ -	$ -	$ -
3	Total Operating Revenues		$1,486,871	($1,486,871)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$1,126,665	$ -	$1,126,665	$ -	$1,126,665
5	Depreciation/Amortization		$222,854	$ -	$222,854	$ -	$222,854
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$1,349,519	$ -	$1,349,519	$ -	$1,349,519
10	Deemed Interest Expense		$168,828	($168,828)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)		$1,518,347	($168,828)	$1,349,519	$ -	$1,349,519
12	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS		$ -	$ -	$ -	$ -	$ -
13	**Utility income before income taxes**		($31,476)	($1,318,043)	($1,349,519)	$ -	($1,349,519)
14	Income taxes (grossed-up)		$18,280	$ -	$18,280	$ -	$18,280
15	**Utility net income**		($49,756)	($1,318,043)	($1,367,799)	$ -	($1,367,799)

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application				Per Board Decision
(1)	Specific Service Charges	$70,000		$ -		$ -
	Late Payment Charges	$30,000		$ -		$ -
	Other Distribution Revenue	$32,139		$ -		$ -
	Other Income and Deductions	$25,000		$ -		$ -
	Total Revenue Offsets	$157,139	$ -	$ -	$ -	$ -

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$253,737	$ -	$ -
2	Adjustments required to arrive at taxable utility income	$ -	$ -	$ -
3	Taxable income	$253,737	$ -	$ -
	Calculation of Utility income Taxes			
4	Income taxes	$15,447	$15,447	$15,447
6	Total taxes	$15,447	$15,447	$15,447
7	Gross-up of Income Taxes	$2,833	$2,833	$2,833
8	Grossed-up Income Taxes	$18,280	$18,280	$18,280
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$18,280	$18,280	$18,280
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	11.00%	11.00%	11.00%
12	Provincial tax (%)	4.50%	4.50%	4.50%
13	Total tax rate (%)	15.50%	15.50%	15.50%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Initial Application

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	$3,955,804	4.12%	$162,979
2	Short-term Debt	4.00%	$282,557	2.07%	$5,849
3	**Total Debt**	60.00%	$4,238,361	3.98%	$168,828
	Equity				
4	Common Equity	40.00%	$2,825,574	8.98%	$253,737
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$2,825,574	8.98%	$253,737
7	**Total**	100.00%	$7,063,936	5.98%	$422,565

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$ -
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
4	Common Equity	0.00%	$ -	0.00%	$ -
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	$ -
7	**Total**	0.00%	$7,063,936	0.00%	$ -

Per Board Decision

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
8	Long-term Debt	0.00%	$ -	4.12%	$ -
9	Short-term Debt	0.00%	$ -	2.07%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	8.98%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$7,063,936	0.00%	$ -

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	At Current Approved Rates	At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$297,828		($14,141)		$1,349,519
2	Distribution Revenue	$1,363,660	$1,031,905	$1,363,660	$1,343,874	$ -	($1,349,519)
3	Other Operating Revenue Offsets - net	$157,139	$157,139	$ -	$ -	$ -	$ -
4	**Total Revenue**	$1,520,799	$1,486,871	$1,363,660	$1,329,732	$ -	$ -
5	Operating Expenses	$1,349,519	$1,349,519	$1,349,519	$1,349,519	$1,349,519	$1,349,519
6	Deemed Interest Expense	$168,828	$168,828	$ -	$ -	$ -	$ -
7	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	$ - (2)	$ -	$ - (2)	$ -	$ - (2)	$ -
8	**Total Cost and Expenses**	$1,518,347	$1,518,347	$1,349,519	$1,349,519	$1,349,519	$1,349,519
9	**Utility Income Before Income Taxes**	$2,452	($31,476)	$14,141	($19,787)	($1,349,519)	($1,349,519)
10	Tax Adjustments to Accounting Income per 2013 PILs model	$ -	$ -	$ -	$ -	$ -	$ -
11	**Taxable Income**	$2,452	($31,476)	$14,141	($19,787)	($1,349,519)	($1,349,519)
12	Income Tax Rate	15.50%	15.50%	15.50%	15.50%	15.50%	15.50%
13	**Income Tax on Taxable Income**	$380	($4,879)	$2,192	($3,067)	($209,175)	($209,175)
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$2,072	($49,756)	$11,950	($1,367,799)	($1,140,344)	($1,367,799)
16	**Utility Rate Base**	$7,063,936	$7,063,936	$7,063,936	$7,063,936	$7,063,936	$7,063,936
17	Deemed Equity Portion of Rate Base	$2,825,574	$2,825,574	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	0.07%	-1.76%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.98%	8.98%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-8.91%	-10.74%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	2.42%	1.69%	0.17%	0.00%	-16.14%	0.00%
22	Requested Rate of Return on Rate Base	5.98%	5.98%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-3.56%	-4.30%	0.17%	0.00%	-16.14%	0.00%
24	Target Return on Equity	$253,737	$253,737	$ -	$ -	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$251,664	($303,493)	($11,950)	$ -	$1,140,344	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$297,828 (1)		($14,141) (1)		$1,349,519 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

(2) Treated as an adjustment pre-tax to avoid an impact on taxes/PILs and hence on revenue sufficiency deficiency

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$1,126,665		$1,126,665		$1,126,665	
2	Amortization/Depreciation	$222,854		$222,854		$222,854	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$18,280		$18,280		$18,280	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$168,828		$ -		$ -	
	Return on Deemed Equity	$253,737		$ -		$ -	
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	$ -		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$1,790,364		$1,367,799		$1,367,799	
9	Revenue Offsets	$157,139		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$1,633,225		$1,367,799		$1,367,799	
11	Distribution revenue	$1,329,732		$ -		$ -	
12	Other revenue	$157,139		$ -		$ -	
13	**Total revenue**	$1,486,871		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($303,493)	(1)	($1,367,799)	(1)	($1,367,799)	(1)

Notes

(1) Line 11 - Line 8

E1.T2.S8 ANNUAL REPORTS

HHI does not publish any annual reports.

E1.T2.S9 AFFILIATE TRANSACTIONS AND SERVICE LEVEL AGREEMENT

HHI does not have affiliates and therefore does not need any service level agreement

Tab 3 – Financial Information

E1.T3.S1 HISTORICAL FINANCIAL STATEMENTS

The Administrative Documents identified in this section provide the background and summary information to the case as filed. The following section consists of the 3 following attachments.

1) 2012 Audited Statements
2) 2011 Audited Statements
3) 2010 Audited Statements

Hydro Hawkesbury

Financial statements of
États financiers de

Hawkesbury Hydro Inc.
Hydro Hawkesbury Inc.

December 31, 2010
31 décembre 2010

Hawkesbury Hydro Inc.
December 31, 2010

Hydro Hawkesbury Inc.
31 décembre 2010

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Deloitte & Touche LLP
300 McGill Street
Hawkesbury, Ontario K6A 1P8
Canada

Tel: (613) 632-4178
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Independent Auditor's Report

To the Directors of Hawkesbury Hydro Inc.

We have audited the accompanying financial statements of Hawkesbury Hydro Inc., which comprise the balance sheet as at December 31, 2010, and the statements of earnings, retained earnings 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.

Auditor's 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 judgment, 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 overall 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 Hawkesbury Hydro Inc. as at December 31, 2010, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants
Licensed Public Accountants

April 19, 2011

Deloitte.

Deloitte & Touche, s.r.l.
300, rue McGill
Hawkesbury, Ontario K6A 1P8
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Rapport de l'auditeur indépendant

Aux administrateurs de Hydro Hawkesbury Inc.

Nous avons effectué l'audit des états financiers ci-joints de Hydro Hawkesbury Inc. qui comprennent le bilan au 31 décembre 2010, les états des résultats, des bénéfices non répartis et des flux de trésorerie pour l'exercice clos à cette date, ainsi qu'un résumé des principales méthodes comptables et d'autres informations explicatives.

Responsabilité de la direction pour les états financiers

La direction est responsable de la préparation et de la présentation fidèle de ces états financiers conformément aux principes comptables généralement reconnus du Canada, ainsi que du contrôle interne qu'elle considère comme nécessaire pour permettre la préparation d'états financiers exempts d'anomalies significatives, que celles-ci résultent de fraudes ou d'erreurs.

Responsabilité de l'auditeur

Notre responsabilité consiste à exprimer une opinion sur les états financiers, sur la base de notre audit. Nous avons effectué notre audit selon les normes d'audit généralement reconnues du Canada. Ces normes requièrent que nous nous conformions aux règles de déontologie et que nous planifiions et réalisions l'audit de façon à obtenir l'assurance raisonnable que les états financiers ne comportent pas d'anomalies significatives.

Un audit implique la mise en œuvre de procédures en vue de recueillir des éléments probants concernant les montants et les informations fournis dans les états financiers. Le choix des procédures relève du jugement de l'auditeur, et notamment de son évaluation des risques que les états financiers comportent des anomalies significatives, que celles-ci résultent de fraudes ou d'erreurs. Dans l'évaluation de ces risques, l'auditeur prend en considération le contrôle interne de l'entité portant sur la préparation et la présentation fidèle des états financiers afin de concevoir des procédures d'audit appropriées aux circonstances, et non dans le but d'exprimer une opinion sur l'efficacité du contrôle interne de l'entité. Un audit comporte également l'appréciation du caractère approprié des méthodes comptables retenues et du caractère raisonnable des estimations comptables faites par la direction, de même que l'appréciation de la présentation d'ensemble des états financiers.

Nous estimons que les éléments probants que nous avons obtenus sont suffisants et appropriés pour fonder notre opinion d'audit.

Opinion

À notre avis, les états financiers donnent, dans tous leurs aspects significatifs, une image fidèle de la situation financière de Hydro Hawkesbury Inc. au 31 décembre 2010, ainsi que de ses résultats d'exploitation et de ses flux de trésorerie pour l'exercice clos à cette date, conformément aux principes comptables généralement reconnus du Canada.

Deloitte & Touche s.r.l.

Comptables agréés
Experts-comptables autorisés

Le 19 avril 2011

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

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

	2010	2009	
	$	$	
Revenues (Note 11)			**Revenus (note 11)**
Energy	**10,221,319**	10,647,223	Énergie
Distribution	**1,210,348**	1,090,418	Distribution
	11,431,667	11,737,641	
Cost of power	**10,221,319**	10,647,223	Coût de l’énergie
	1,210,348	1,090,418	
Other operating revenues	**199,285**	219,165	Autres revenus d’exploitation
	1,409,633	1,309,583	
Expenses			Charges
Distribution	**206,613**	209,879	Distribution
Billing and collection	**325,519**	312,763	Facturation et perception
Community relations	**100**	1,305	Relations publiques
Administration	**335,458**	264,013	Administration
Amortization of capital assets	**158,511**	153,992	Amortissement des immobilisations corporelles
Interest	**64,737**	92,866	Intérêts
Property taxes	**15,678**	15,766	Impôts fonciers
Others	**29,321**	60,828	Autres
	1,135,937	1,111,412	
Earnings before income taxes	**273,696**	198,171	Bénéfice avant impôts sur les bénéfices
Income taxes			Impôts sur les bénéfices
Recovered	**(161,142)**	(59,831)	Recouvrés
Future	**288,402**	89,664	Futurs
	127,260	29,833	
Net earnings	**146,436**	168,338	**Bénéfice net**

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

Hydro Hawkesbury Inc.
État des bénéfices non répartis
de l'exercice terminé le 31 décembre 2010

	2010	2009	
	$	$	
Balance, beginning of year	**953,460**	869,589	**Solde au début**
Net earnings	**146,436**	168,338	Bénéfice net
Dividends on common shares	**(84,467)**	(84,467)	Dividendes sur les actions ordinaires
Balance, end of year	**1,015,429**	953,460	**Solde à la fin**

Hawkesbury Hydro Inc.
Balance sheet
as at December 31, 2010

Hydro Hawkesbury Inc.
Bilan
au 31 décembre 2010

	2010	2009	
	$	$	
Assets			**Actif**
Current assets			Actif à court terme
Cash and term deposits	**1,167,332**	2,384,441	Encaisse et dépôts à terme
Accounts receivable (Note 5)	**1,787,553**	1,551,811	Débiteurs (note 5)
Inventories	**125,669**	126,957	Stocks
Unbilled revenues	**1,275,333**	1,318,771	Revenus non facturés
Prepaid expenses	**211,464**	182,425	Charges payées d'avance
Income taxes receivable	**282,900**	274,051	Impôts sur les benefices à recevoir
	4,850,251	5,838,456	
Future income taxes	**167,484**	455,886	Impôts futurs
Other assets (Note 6)	**1,047,432**	675,660	Autres actifs (note 6)
Capital assets (Note 7)	**1,956,741**	1,962,897	Immobilisations corporelles (note 7)
	8,021,908	8,932,899	
Liabilities			**Passif**
Current liabilities			Passif à court terme
Accounts payable and accrued liabilities	**2,286,853**	2,390,023	Créditeurs et charges à payer
Other current liabilities	**129,283**	203,688	Autres passifs à court terme
Current portion of other long-term liabilities (Note 8)	**326,573**	198,086	Tranche des autres passifs à long terme échéant à moins d'un an (note 8)
Current portion of note payable (Note 9)	**231,425**	216,899	Tranche échéant à moins d'un an du billet à payer (note 9)
	2,974,134	3,008,696	
Provision for sick leave benefits	**78,563**	70,748	Provision pour congés de maladie
Other long-term liabilities (Note 8)	**1,764,146**	2,478,934	Autres passifs à long terme (note 8)
Note payable (Note 9)	**500,290**	731,715	Billet à payer (note 9)
	5,317,133	6,290,093	
Contingencies (Note 14)			Éventualités (note 14)
Shareholder's equity			**Capitaux propres**
Share capital (Note 10)	**1,689,346**	1,689,346	Capital-actions (note 10)
Retained earnings	**1,015,429**	953,460	Bénéfices non répartis
	2,704,775	2,642,806	
	8,021,908	8,932,899	

On behalf of the Board — Au nom du conseil

Director ______________________ administrateur

Director ______________________ administrateur

Hawkesbury Hydro Inc.

Statement cash flows
year ended December 31, 2010

Hydro Hawkesbury Inc.

État des flux de trésorerie
de l'exercice terminé le 31 décembre 2010

	2010	2009	
	$	$	
Operating activities			**Activités d'exploitation**
Net earnings	**146,436**	168,338	Bénéfice net
Items not affecting cash:			Éléments sans effet sur la trésorerie :
Amortization of capital assets	**158,511**	153,992	Amortissement des immobilisations corporelles
Future income taxes	**288,402**	89,664	Impôts futurs
Changes in non-cash operating working capital items (Note 12)	**(398,664)**	47,562	Variation des éléments hors caisse du fonds de roulement d'exploitation (note 12)
	194,685	459,556	
Investing activities			**Activités d'investissement**
Purchase of capital assets	**(226,655)**	(209,226)	Acquisition d'immobilisations corporelles
Increase of other assets	**(371,772)**	(201,755)	Augmentation des autres actifs
	(598,427)	(410,981)	
Financing activities			**Activités de financement**
Decrease other long-term liabilities	**(586,301)**	(418,380)	Diminution des autres passifs à long terme
Increase of contribution for capital assets	**74,300**	14,307	Augmentation des apports pour immobilisations corporelles
Repayment of note payable	**(216,899)**	(203,284)	Remboursement du billet à payer
Dividends paid	**(84,467)**	(84,467)	Dividendes payés
	(813,367)	(691,824)	
Net decrease in cash and term deposits	**(1,217,109)**	(643,249)	Diminution nette de l'encaisse et dépôts à terme
Cash and term deposits, beginning of year	**2,384,441**	3,027,690	Encaisse et dépôts à terme au début
Cash and term deposits, end of year	**1,167,332**	2,384,441	**Encaisse et dépôts à terme à la fin**

Additional information is presented in Note 12.

Des renseignements complémentaires sont présentés à la note 12.

1. Description of business

The Corporation, incorporated under the Ontario Business Corporations Act, is engaged in the distribution of electricity.

2. Future in accounting changes

New accounting framework

The Corporation, qualifying entity with rate-regulated activities, selected the option proposed by the Canadian Accounting Standards Board to defer its adoption of International Financial Reporting Standards for the first time until its period beginning on January 1, 2012. The impact of this transition has not yet been determined.

3. Accounting policies

The financial statements have been prepared in accordance with Canadian generally accepted accounting principles with rate regulation specifications described under the other assets heading for electricity distributors as required by the Ontario Energy Board and set forth in the Accounting Procedures Handbook:

Financial instruments

Financial assets and financial liabilities are initially recognized at fair value and their subsequent measurement is dependent on their classification as described below. Their classification depends on the purpose, for which the financial instruments were acquired or issued, their characteristics and the Corporation's designation of such instruments. Settlement date accounting is used.

Classification

Cash and term deposits/Held for trading
Accounts receivable/Loans and receivables
Unbilled revenues/Loans and receivables
Other assets/Loans and receivables
Accounts payable and accrued liabilities/Other liabilities
Other current liabilities/Other liabilities
Long-term liabilities/Other liabilities
Other long-term liabilities/Other liabilities
Note payable/Other liabilities

Held for trading

Held for trading financial assets are financial assets typically acquired for resale prior to maturity or that are designated as held for trading. They are measured at fair value at the balance sheet date. Fair value fluctuations including interest earned, interest accrued, gains and losses realized on disposal and unrealized gains and losses are included in other operating revenues.

1. Description de l'entreprise

La Société, constituée en vertu de la Loi sur les sociétés par actions de l'Ontario, se spécialise dans la distribution de l'électricité.

2. Modifications comptables futures

Nouveau référentiel comptable

La Société, une entité admissible exerçant des activités à tarifs réglementés, a choisi l'option offerte par le Conseil des normes comptables du Canada de reporter la première application des normes internationales d'information financières jusqu'à son exercice ouvert à compter du 1er janvier 2012. Les incidences de ce changement n'ont pas encore été évaluées.

3. Conventions comptables

Les états financiers ont été préparés conformément aux principes comptables généralement reconnus du Canada et tiennent compte des particularités énumérées sous la rubrique des autres actifs pour les distributeurs d'électricité tel que requis par la Commission de l'énergie de l'Ontario et établis dans le "Accounting Procedures Handbook" :

Instruments financiers

Les actifs financiers et les passifs financiers sont constatés initialement à la juste valeur et leur évaluation ultérieure dépend de leur classement, comme il est décrit ci-après. Leur classement dépend de l'objet visé lorsque les instruments financiers ont été acquis ou émis, de leurs caractéristiques et de leur désignation par la Société. La comptabilisation à la date de règlement est utilisée.

Classification

Encaisse et dépôts à terme/Détenus à des fins de transaction
Débiteurs/Prêts et créances
Revenus non facturés/Prêts et créances
Autres actifs/Prêts et créances
Créditeurs et charges à payer/Autres passifs
Autres passifs à court terme/Autres passifs
Passifs à long terme/Autres passifs
Autres passifs à long terme/Autres passifs
Billet à payer/Autres passifs

Détenus à des fins de transaction

Les actifs financiers détenus à des fins de transaction sont des actifs financiers qui sont généralement acquis en vue d'être revendus avant leur échéance ou qui ont été désignés comme étant détenus à des fins de transaction. Ils sont mesurés à la juste valeur à la date de clôture. Les fluctuations de la juste valeur qui incluent les intérêts gagnés, les intérêts courus, les gains et pertes réalisés sur cession et les gains et pertes non réalisés sont inclus dans les autres revenus d'exploitation.

3. Accounting policies (continued)

Financial instruments (continued)

Loans and receivables

Loans and receivables are accounted for at amortized cost using the effective interest method.

Other liabilities

Other liabilities are recorded at amortized cost using the effective interest method and include all financial liabilities, other than derivative instruments.

Transaction costs

Transaction costs related to held for trading financial assets are expensed as incurred. Transaction costs related to other liabilities and loans and receivables are netted against the carrying value of the asset or liability and are then recognized over the expected life of the instrument using the effective interest method.

Cash and term deposits

Cash and term deposits are redeemable anytime.

Inventories

Inventories are valued at the lower of cost and net realizable value.

Capital assets and amortization

Capital assets are recorded at cost. Amortization is calculated on the basis of the straight-line method with reference to estimated useful lives of the assets in accordance with Ontario Energy Board policy at the following terms:

	Years
Building	50
Transmission equipment	30 to 40
Distribution equipment	25
Office equipment	5 to 10
Rolling stock and equipment	8 to 10
Capital contribution	25

Acquisitions made during the year are amortized at half the normal rate.

Capital contribution is the portion assumed by the owners or the developers for capital assets owned by the Corporation.

3. Conventions comptables (suite)

Instruments financiers (suite)

Prêts et créances

Les prêts et créances sont comptabilisés au coût après amortissement selon la méthode du taux d'intérêt effectif.

Autres passifs

Les autres passifs sont comptabilisés au coût après amortissement selon la méthode du taux d'intérêt effectif et comprennent tous les passifs financiers autres que les instruments dérivés.

Coûts de transaction

Les coûts de transaction liés aux actifs financiers détenus à des fins de transaction sont passés en charge au moment où ils sont engagés. Les coûts de transaction liés aux autres passifs et aux prêts et créances sont comptabilisés en diminution de la valeur comptable de l'actif ou du passif et sont ensuite constatés sur la durée de vie prévue de l'instrument selon la méthode du taux d'intérêt effectif.

Encaisse et dépôts à terme

L'encaisse et les dépôts à terme sont encaissables en tout temps.

Stocks

Les stocks sont évalués au moindre du coût de la valeur nette de réalisation.

Immobilisations corporelles et amortissement

Les immobilisations corporelles sont comptabilisées au coût. L'amortissement est calculé selon la méthode de l'amortissement linéaire répartit sur la durée estimative de vie utile de l'immobilisation selon les politiques de la Commission de l'énergie de l'Ontario aux termes suivants:

	Années
Immeuble	50
Équipement de transmission	30 à 40
Équipement de distribution	25
Équipement de bureau	5 à 10
Matériel roulant et équipement	8 à 10
Apports en immobilisations	25

Les acquisitions de l'année sont amorties à la moitié du taux normal.

Les apports en immobilisations sont la portion qui est assumée par les propriétaires ou les développeurs sur les immobilisations appartenant à la Société.

3. Accounting policies (continued)

Customers' deposits

Deposits are taken to guarantee the payment of power bills or contract performance.

Impairment of long-lived assets

Long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. An impairment loss is recognized when their carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. The amount of the impairment loss is determined as the excess of the carrying value of the asset over its fair value.

Other assets

Purchased power costs are included in allowed rates on a forecast basis. For rate-setting purposes, differences between forecast and actual purchased power costs in the rate year are held until the following year, when their final disposition is decided. The Corporation recognizes purchased power cost variances as a regulatory asset or liability, based on the expectation that amounts held from one year to the next for rate-setting purposes will be approved for collection from, or refund to, customers. In the absence of rate regulation, generally accepted accounting principles would require that actual purchased power costs be recognized as an expense when incurred.

The assets, other than variances, are recorded at cost in accordance with accounting principles as required by the Ontario Energy Board.

For certain of the regulatory items identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate-setting purposes. Any disallowed costs will be expensed in the year that they are disallowed.

Recoveries for these assets are presented in a separate account until the Ontario Energy Board approves the recoveries. At that time, recoveries will be applied against the regulated assets.

The financial statements effects of rate regulation are presented in Note 16.

3. Conventions comptables (suite)

Dépôts de clients

Des dépôts sont pris en garantie de paiement de la facturation ou de contrat.

Dépréciation d'actifs à long terme

Les actifs à long terme sont soumis à un test de recouvrabilité lorsque des événements ou des changements de situation indiquent que leur valeur comptable pourrait ne pas être recouvrable. Une perte de valeur est constatée lorsque leur valeur comptable excède les flux de trésorerie non actualisés découlant de leur utilisation et de leur sortie éventuelle. La perte de valeur constatée est mesurée comme étant l'excédent de la valeur comptable de l'actif sur sa juste valeur.

Autres actifs

Les coûts associés à l'énergie achetée sont pris en compte dans les tarifs autorisés, sur une base prévisionnelle. Aux fins de l'établissement des tarifs, les écarts entre les coûts prévus et les coûts réels associés à l'énergie achetée au cours de l'année de tarification sont laissés en suspens jusqu'à l'année suivante, au cours de laquelle leur traitement définitif est déterminé. La Société comptabilise les écarts de coûts associés à l'énergie achetée à titre d'actif ou de passif réglementaire, parce que la Société s'attend à obtenir l'autorisation de recouvrer auprès des clients futurs les montants laissés en suspens d'une année à l'autre aux fins de l'établissement des tarifs, ou à devoir rembourser les montants à ces clients. Si les tarifs n'étaient pas réglementés, les coûts réels associés à l'énergie achetée devraient être passés en charges au moment où ils sont engagés, selon les principes comptables généralement reconnus.

Les actifs autres que les écarts de prix ont été comptabilisés au coût selon les règles de la Commission de l'énergie de l'Ontario.

Dans le cas de certains des éléments réglementaires mentionnés ci-dessus, les risques et incertitudes découlant du pouvoir ultime de l'autorité de réglementation de déterminer le traitement de l'élément aux fins de la tarification influent sur la période prévue de recouvrement ou de règlement, ou sur la probabilité de recouvrement ou de règlement. Les montants refusés seront imputés aux résultats dans l'année où ils seront refusés.

Les recouvrements pour tous ces frais sont identifiés dans un compte distinct et seront appliqués contre les actifs suite à l'approbation par la Commission de l'énergie de l'Ontario.

Les effets de la règlementation des tarifs sur les états financiers sont décrits à la note 16.

3. Accounting policies (continued)

Revenue recognition

The Corporation recognizes energy and distribution revenues when billed to customers. Other revenues are recognized when persuasive evidence of an arrangement exists, delivery has occurred, the price to the buyer is fixed or determinable and collection is reasonably assured.

Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent 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 these estimates.

3. Conventions comptables (suite)

Constatation des produits

La Société constate ses revenus d'énergie et de distribution lorsqu'ils sont facturés aux clients alors que les autres revenus sont constatés lorsqu'il existe des preuves convaincantes de l'existence d'un accord, que les marchandises sont expédiées aux clients, que le prix est déterminé ou déterminable et que l'encaissement est raisonnablement assuré.

Utilisation d'estimations

Dans le cadre de la préparation des états financiers, la direction doit établir des estimations et des hypothèses qui ont une incidence sur les montants des actifs et des passifs présentés et sur la présentation des actifs et des passifs éventuels à la date des états financiers, ainsi que sur les montants des revenus et des charges constatés au cours de la période visée par les états financiers. Les résultats réels pourraient varier par rapport à ces estimations.

4. Term deposits

Temporary investments consist of guaranteed investments with an interest of 1%.

4. Dépôts à terme

Les placements temporaires sont constitués de placements garantis avec un taux d'intérêt de 1%.

5. Accounts receivable / 5. Débiteurs

	2010	2009	
	$	$	
Electrical energy	**1,613,377**	1,518,210	Énergie électrique
Other	**195,278**	47,678	Autres
	1,808,655	1,565,888	
Allowance for doubtful accounts	**(21,102)**	(14,077)	Provision pour mauvaises créances
	1,787,553	1,551,811	

6. Other assets / 6. Autres actifs

	2010	2009	
	$	$	
Transition costs	**22,611**	22,611	Frais de transition
Smart meters	**326,600**	93,338	Compteurs intelligents
Low voltage charges	**47,960**	162,637	Distribution à faible tension
Retail settlement variance account	**591,438**	-	Écarts de prix avec les détaillants
Other regulatory assets	**58,823**	333,651	Autres actifs réglementaires
Amounts to recover	**-**	63,423	Montants à récupérer
	1,047,432	675,660	

7. Capital assets / 7. Immobilisations corporelles

			2010	2009	
	Cost/ Coût	**Accumulated amortization/ Amortisse-ment cumulé**	**Net book value/ Valeur nette**	Net book value/ Valeur nette	
	$	$	$	$	
Land and land rights	**56,888**	**2,608**	**54,280**	54,280	Terrain et droit de passage
Building	**824,124**	**186,572**	**637,552**	654,551	Immeuble
Transmission equipment	**587,272**	**177,191**	**410,081**	368,009	Équipement de transmission
Distribution equipment	**1,798,516**	**916,264**	**882,252**	834,735	Équipement de distribution
Office equipment	**210,925**	**128,012**	**82,913**	93,203	Équipement de bureau
Rolling stock and equipment	**229,675**	**203,466**	**26,209**	24,656	Matériel roulant et équipement
Capital contribution	**(144,474)**	**(7,928)**	**(136,546)**	(66,537)	Apports en immobilisations
	3,562,926	**1,606,185**	**1,956,741**	1,962,897	

8. Other long-term liabilities / 8. Autres passifs à long terme

	2010	2009	
	$	$	
Pre-market opening energy variance	**10,682**	10,682	Écarts de prix avant l'ouverture du marché
Retail settlement variance account	**-**	1,967,998	Écarts de prix avec les détaillants
Amounts to reimburse	**1,370,458**	-	Montants à rembourser
Customers' deposits	**709,579**	692,536	Dépôts de clients
Hydro One	**-**	5,804	Hydro One
	2,090,719	2,677,020	
Current portion	**326,573**	198,086	Tranche échéant à moins d'un an
	1,764,146	2,478,934	

9. Note payable / 9. Billet à payer

	2010	2009	
	$	$	
Note payable to the Corporation of the Town of Hawkesbury, sole shareholder of the Corporation, 6.5%, payable in monthly instalments of $ 22,681 including interest	**731,715**	948,614	Billet à payer à la Corporation de la Ville de Hawkesbury, l'unique actionnaire de la Société, 6,5%, remboursable par versements mensuels de 22 681 $ incluant les intérêts
Current portion	**231,425**	216,899	Tranche échéant à moins d'un an
	500,290	731,715	

Principal repayments to be made during the next three years are as follows: 2011, $ 231,425; 2012, $ 246,924 and 2013, $ 253,366.

Les versements en capital requis au cours des trois prochains exercices sont les suivants : 2011, 231 425 $; 2012, 246 924 $ et 2013, 253 366 $.

No restrictive covenant has been imposed by the Corporation of the Town of Hawkesbury.

Aucune clause restrictive n'a été imposée par la Corporation de la Ville de Hawkesbury.

10. Share capital / 10. Capital-actions

Authorized / *Autorisé*

Unlimited number of common shares / Nombre illimité d'actions ordinaires

Issued / *Émis*

	2010	2009	
	$	$	
1 000 common shares	**1,689,346**	1,689,346	1 000 actions ordinaires

11. Revenues / 11. Revenus

	2010	2009	
	$	$	
Energy			*Énergie*
Residential	**3,107,821**	2,949,767	Résidentiel
General < 50 KW	**1,296,430**	1,175,206	Général < 50 KW
General > 50 KW	**2,572,023**	2,540,650	Général > 50 KW
Large users	**-**	408,533	Consommation significative
Street light	**40,735**	71,284	Éclairage des rues
Sentinel	**6,692**	6,723	Sentinelle
Retailers	**868,199**	952,210	Détaillants
Regulatory charges	**2,329,419**	2,542,850	Frais réglementés
	10,221,319	10,647,223	

11. Revenues (continued) / **11. Revenus (suite)**

	2010	2009	
	$	$	
Distribution			*Distribution*
Residential	**742,598**	743,111	Résidentiel
General < 50 KW	**193,055**	163,275	Général < 50 KW
General > 50 KW	**233,371**	31,230	Général > 50 KW
Large users	**-**	120,611	Consommation significative
Street light	**24,602**	15,442	Éclairage des rues
Sentinel	**2,321**	2,393	Sentinelle
Regulatory charges	**14,401**	14,356	Frais réglementés
	1,210,348	1,090,418	

12. Additional information relating to the statement of cash flows / **12. Renseignements complémentaires à l'état des flux de trésorerie**

	2010	2009	
	$	$	
Changes in non-cash operating working capital items			*Variation des éléments hors caisse du fonds de roulement d'exploitation*
Accounts receivable	**(235,742)**	(46,456)	Débiteurs
Inventories	**1,288**	91,270	Stocks
Unbilled revenues	**43,438**	159,820	Revenus non facturés
Prepaid expenses	**(29,039)**	(129,793)	Charges payées d'avance
Income taxes receivable	**(8,849)**	(255,519)	Impôts sur les bénéfices à recevoir
Accounts payable and accrued liabilities	**(103,170)**	178,090	Créditeurs et charges à payer
Other current liabilities	**(74,405)**	47,028	Autres passifs à court terme
Provision for sick leave benefits	**7,815**	3,122	Provision pour congés de maladie
	(398,664)	47,562	
Other information			*Autres renseignements*
Interest paid	**61,477**	73,706	Intérêts payés
Income taxes (recovered) paid	**(152,293)**	195,688	Impôts sur les bénéfices (recouvrés) payés

13. Pension plan

The Corporation makes contributions to the Ontario Municipal Employees Retirement Fund ("OMERS"), which is a multi-employer plan, on behalf of 8 members of its staff. The plan is a defined benefit plan, which specifies the amount or the retirement benefit to be received by the employees based on the length of service and rates of pay.

The amount contributed to OMERS for 2010 is $ 29,943 (2009 - $ 28,249) for current service and is included as an expense in the statement of earnings.

13. Régime de retraite

La Société contribue au régime de retraite des employés municipaux de l'Ontario ("RREMO"), qui est un régime à employeurs multiples, pour 8 membres de son personnel. Il s'agit d'un régime à prestations déterminées qui prévoit le niveau de pension à être reçu par les employés en se basant sur les années de service et le niveau salarial.

Le montant contribué à RREMO en 2010 est de 29 943 $ (2009 - 28 249 $) pour services courants et est inclus dans les charges à l'état des résultats.

14. Contingencies

Letter of guarantee

A letter of guarantee in the amount of $ 399,528 was issued in favour of the Independent Electricity System Operator and is renewable in February 2011. The Corporation of the Town of Hawkesbury endorsed this letter of guarantee.

14. Éventualités

Lettre de garantie

Une lettre de garantie au montant de 399 528 $ a été émise en faveur de "Independent Electricity System Operator" est renouvelable en février 2011. La Corporation de la Ville de Hawkesbury a endossé cette lettre de garantie.

15. Related party transactions

During the year, the Company purchased and sold services to the Corporation of the Town of Hawkesbury, its sole shareholder. These transactions were made in the normal course of business and have been recorded at the exchange amounts.

15. Opérations entre apparentées

Au cours de l'exercice, la Société a achetée et vendue des services à la Corporation de la Ville de Hawkesbury, son unique actionnaire. Ces opérations ont été effectuées dans le cours normal des activités et ont été comptabilisées à la valeur d'échange.

	2010	2009	
	$	$	
Note payable to the shareholder			Billet à payer à l'actionnaire
Interest paid	**55,273**	68,888	Intérêts versés
Principal paid	**216,899**	203,284	Capital versé
Dividends on common shares	**84,467**	84,467	Dividendes sur actions ordinaires
Other operating revenues	**7,724**	14,210	Autres revenus d'exploitation
Distribution expenses	**4,960**	4,846	Charges de distribution
Property taxes	**15,678**	15,766	Impôts fonciers

16. Financial statements' effects of rate regulation

16. Effets de la réglementation des tarifs sur les états financiers

	2010	2009	
	$	$	
Earnings before income taxes established in accordance with accounting principles for electricity distributers as required by the Ontario Energy Board	**273,696**	198,171	Bénéfice avant impôts sur les bénéfices établis conformément aux principes comptables pour les distributeurs d'électricité tels que requis par la Commission de l'énergie de l'Ontario
Variances/expenses included in other assets/ liabilities	**(251,405)**	(486,274)	Variances/charges incluses dans les autres actifs/passifs
Carrying charges on other assets/liabilities	**3,260**	19,160	Frais d'intérêts sur les autres actifs/passifs
Amortization of capital assets included in other assets	**(24,415)**	(3,556)	Amortissement des immobilisations corporelles inclus dans les autres actifs
(Remitted) recovered	**(414,421)**	44,007	(Remboursés) recouvrés
Loss before income taxes and before the effect of the regulation on the financial statements	**(413,285)**	(228,492)	Perte ajustée avant impôts sur les bénéfices et avant l'effet de la réglementation sur les états financiers

17. Financial instruments and risk management

The Corporation, through its financial assets and liabilities, has exposure to the following risks from its use of financial instruments: credit risk, market risk, and liquidity risk. The following analysis provides a measurement of risk as at December 31, 2010.

Credit risk

The Corporation’s principal financial assets are cash and term deposits and accounts receivable, which are subject to credit risk. The carrying amounts of financial assets on the balance sheet represent the Corporation's maximum credit exposure at the balance sheet date.

The Corporation's credit risk is primarily attributable to its accounts receivable. The amounts disclosed in the balance sheet are net of allowance for doubtful accounts, estimated by the management of the Corporation based on previous experience and its assessment of the current economic environment. In order to reduce its risk, management has adopted credit policies that include regular review of credit limits. The Corporation does not have significant exposure to any individual customer and has not incurred any significant bad debts during the year. The credit risk on cash and term deposits is limited because the counterparties are chartered banks with high credit-ratings assigned by national credit-rating agencies.

As at December 31, 2010, the aging of accounts receivable was:

17. Instruments financiers et gestion des risques

En raison de ses actifs et de ses passifs financiers, la Société est exposée aux risques suivants relatifs à l'utilisation d'instruments financiers: le risque de crédit, le risque de marché et le risque de liquidité. L'analyse suivante permet d'évaluer les risques au 31 décembre 2010.

Risque de crédit

Les principaux actifs financiers de la Société comprennent l'encaisse et dépôts à terme et les débiteurs, lesquels sont assujettis au risque de crédit. La valeur comptable des actifs financiers au bilan représente le risque de crédit maximal à la date du bilan.

Le risque de crédit de la Société est principale-ment imputable à ses débiteurs. Les montants sont présentés dans le bilan déduction faite de la provision pour créances douteuses, laquelle a fait l'objet d'une estimation par la direction de la Société en fonction de l'expérience antérieure et de son évaluation de la conjoncture économique actuelle. Afin de réduire le risque, la direction a adopté des politiques de crédit qui comprennent une révision régulière des limites de crédit. La Société n'est exposée à aucun risque important à l'égard d'un client particulier et n'a eu aucune créance irrécouvrable importante au cours de l'exercice. Le risque de crédit lié à l'encaisse et dépôts à terme est limité puisque les contreparties sont des banques à charte jouissant de cotes de solvabilité élevées attribuées par des agences de notation nationales.

Au 31 décembre 2010, le classement par échéance des débiteurs était le suivant :

	2010	2009	
	$	$	
Current	**1,645,631**	1,520,764	Courant
Aged between 31 and 90 days	**14,803**	18,466	Entre 31 et 90 jours
Aged greater than 90 days	**148,221**	26,658	Plus de 90 jours
	1,808,655	1,565,888	
Allowance for doubtful accounts	**(21,102)**	(14,077)	Provision pour créances douteuses
	1,787,553	1,551,811	

17. Financial instruments and risk management (continued)

Credit risk (continued)

Reconciliation of allowance for doubtful accounts:

	2010	2009	
	$	$	
Balance, beginning of year	**14,077**	8,280	Solde au début
Increase during the year	**19,528**	13,021	Augmentation au cours de l'exercice
Bad debts recovery during the year	**3,093**	2,356	Créances douteuses recouvrées au cours de l'exercice
Bad debts written off during the year	**(15,596)**	(9,580)	Créances douteuses radiées au cours de l'exercice
Balance, end of year	**21,102**	14,077	Solde à la fin

Interest rate risk

The note payable bears interest at a fixed rate. Consequently, the cash flow exposure is not significant. However, the fair value of loans having fixed rates of interest, could fluctuate because of changes in market interest rates.

Liquidity risk

The Corporation's objective is to have sufficient liquidity to meet its liabilities when due. The Corporation monitors its cash balances and cash flows generated from operations to meet its requirements. The Corporation has the following financial liabilities as at December 31, 2010:

17. Instruments financiers et gestion des risques (suite)

Risque de crédit (suite)

Rapprochement de la provision pour créances douteuses :

Risque de taux d'intérêt

Le billet à payer porte intérêts à taux fixe. Par conséquent, les risques de trésorerie sont minimes. Toutefois, la juste valeur des emprunts dont le taux d'intérêt est fixe pourrait fluctuer en fonction des variations des taux d'intérêt du marché.

Risque de liquidité

Le risque de liquidité est le risque que la Société ne soit pas en mesure de remplir ses obligations financières à leur échéance. La Société surveille le solde de son encaisse et ses flux de trésorerie qui découlent de son exploitation pour être en mesure de respecter ses engagements. Au 31 décembre 2010, les passifs financiers de la Société étaient les suivants :

	Net book value/ Valeur comptable nette	2011	2012	2013 and after/ 2013 et après	
	$	$	$	$	
Accounts payable and accrued liabilities	**2,286,853**	2,260,300	-	26,553	Créditeurs et charges à payer
Other current liabilities	**129,283**	129,283	-	-	Autres passifs à court terme
Note payable	**731,715**	231,425	246,924	253,366	Billet à payer
Other long-term liabilities	**2,090,719**	791,276	541,304	758,139	Autres passifs à long terme
	5,238,570	3,412,284	788,228	1,038,058	

17. Financial instruments and risk management (continued)

Fair value

Establishing fair value

The fair value of cash and term deposits, accounts receivable unbilled revenues, accounts payable and accrued liabilities and other current liabilities approximates their carrying values due to their short-term maturity.

The fair value of note payable approximates its carrying value as it has financing conditions similar to those currently available to the Corporation.

Fair value hierarchy

Financial instruments recorded at fair value on the balance sheet are classified using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1 - valuation based on unadjusted prices for identical assets or liabilities;

Level 2 - valuation techniques based on inputs other than prices included in Level 1 that are observable for the asset or liability, either directly or indirectly;

Level 3 - valuation techniques using inputs for the asset or liability that are not based on observable market data.

The fair value hierarchy requires the use of observable market inputs whenever such inputs exist. A financial instrument is classified to the lowest level of the hierarchy for which a significant input has been considered in measuring fair value.

17. Instruments financiers et gestion des risques (suite)

Juste valeur

Détermination de la juste valeur

Les justes valeurs de l'encaisse et dépôts à terme, des débiteurs des revenus non facturés, des créditeurs et charges à payer et autres passifs à court terme correspondent approximativement à leur valeur comptable en raison de leur échéance à court terme.

La juste valeur du billet à payer correspond approximativement à sa valeur comptable étant donné que la dette comporte des conditions de financement que la Société pourrait obtenir actuellement.

Hiérarchie des évaluations à la juste valeur

Les instruments financiers comptabilisés à la juste valeur au bilan sont classés selon une hiérarchie qui reflète l'importance des données utilisées pour effectuer les évaluations. La hiérarchie des évaluations à la juste valeur se compose des niveaux suivants :

Niveau 1 - évaluation fondée sur les prix non rajustés pour des actifs ou passifs identiques;

Niveau 2 - techniques d'évaluation fondées sur des données autres que les prix visés au niveau 1, qui sont observables pour l'actif ou le passif, directement ou indirectement;

Niveau 3 - techniques d'évaluation fondées sur une part importante de données relatives à l'actif ou au passif qui ne sont pas fondées sur des données de marché observables.

La hiérarchie qui s'applique dans le cadre de la détermination de la juste valeur exige l'utilisation de données observables sur le marché chaque fois que de telles données existent. Un instrument financier est classé au niveau le plus bas de la hiérarchie pour lequel une donnée importante a été prise en compte dans l'évaluation de la juste valeur.

17. Financial instruments and risk management (continued)

Fair value (continued)

The following table presents the financial instruments recorded at fair value in the balance sheet, classified using the fair value hierarchy described above:

17. Instruments financiers et gestion des risques (suite)

Juste valeur (suite)

Le tableau suivant présente les instruments financiers comptabilisés à la juste valeur au bilan, classés selon la hiérarchie d'évaluation décrite ci-dessus :

	Level 1/ Niveau 1	Level 2/ Niveau 2	Level 3/ Niveau 3	Total financial assets at fair value/ Total des actifs financiers à la juste valeur	
	$	$	$	$	
2010					*2010*
Financial assets					Actifs financiers
Cash and term deposits	1,167,332	-	-	1,167,332	Encaisse et dépôts à terme
2009					*2009*
Financial assets					Actifs financiers
Cash and term deposits	2,384,441	-	-	2,384,441	Encaisse et dépôts à terme

During the year, there has been no significant transfer of amounts between levels.

Au cours de l'exercice, il n'y a eu aucun transfert important de montants entre les niveaux.

18. Comparative figures

Certain of the comparative figures have been reclassified to conform to the current year's presentation.

18. Chiffres de l'exercice précédent

Certains chiffres de l'exercice précédent ont été reclassés afin que leur présentation soit conforme à celle adoptée pour l'exercice courant.

Financial statements of the
États financiers de l'

Hawkesbury Hydro Inc.
Hydro Hawkesbury Inc.

December 31, 2011
31 décembre 2011

Hawkesbury Hydro Inc.
December 31, 2011

Hydro Hawkesbury Inc.
31 décembre 2011

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Independent Auditor's Report

To the Directors of the Hawkesbury Hydro Inc.

Report on the Financial Statements

We have audited the accompanying financial statements of the Hawkesbury Hydro Inc., which comprise the balance sheet as at December 31, 2011, and the statements of earnings, retained earnings 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.

Auditor's 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 judgment, 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 overall 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 the Hawkesbury Hydro Inc. as at December 31, 2011, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants
Licensed Public Accountants

April 17, 2012

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Rapport de l'auditeur indépendant

Aux administrateurs de l'Hydro Hawkesbury Inc.

Rapport sur les états financiers

Nous avons effectué l'audit des états financiers ci-joints de l'Hydro Hawkesbury Inc. qui comprennent le bilan au 31 décembre 2011, les états des résultats, des bénéfices non répartis et des flux de trésorerie pour l'exercice clos à cette date, ainsi qu'un résumé des principales méthodes comptables et d'autres informations explicatives.

Responsabilité de la direction pour les états financiers

La direction est responsable de la préparation et de la présentation fidèle de ces états financiers conformément aux principes comptables généralement reconnus du Canada, ainsi que du contrôle interne qu'elle considère comme nécessaire pour permettre la préparation d'états financiers exempts d'anomalies significatives, que celles-ci résultent de fraudes ou d'erreurs.

Responsabilité de l'auditeur

Notre responsabilité consiste à exprimer une opinion sur les états financiers, sur la base de notre audit. Nous avons effectué notre audit selon les normes d'audit généralement reconnues du Canada. Ces normes requièrent que nous nous conformions aux règles de déontologie et que nous planifiions et réalisions l'audit de façon à obtenir l'assurance raisonnable que les états financiers ne comportent pas d'anomalies significatives.

Un audit implique la mise en œuvre de procédures en vue de recueillir des éléments probants concernant les montants et les informations fournis dans les états financiers. Le choix des procédures relève du jugement de l'auditeur, et notamment de son évaluation des risques que les états financiers comportent des anomalies significatives, que celles-ci résultent de fraudes ou d'erreurs. Dans l'évaluation de ces risques, l'auditeur prend en considération le contrôle interne de l'entité portant sur la préparation et la présentation fidèle des états financiers afin de concevoir des procédures d'audit appropriées aux circonstances, et non dans le but d'exprimer une opinion sur l'efficacité du contrôle interne de l'entité. Un audit comporte également l'appréciation du caractère approprié des méthodes comptables retenues et du caractère raisonnable des estimations comptables faites par la direction, de même que l'appréciation de la présentation d'ensemble des états financiers.

Nous estimons que les éléments probants que nous avons obtenus sont suffisants et appropriés pour fonder notre opinion d'audit.

Opinion

À notre avis, les états financiers donnent, dans tous leurs aspects significatifs, une image fidèle de la situation financière de l'Hydro Hawkesbury Inc. au 31 décembre 2011, ainsi que de ses résultats d'exploitation et de ses flux de trésorerie pour l'exercice clos à cette date, conformément aux principes comptables généralement reconnus du Canada.

Deloitte & Touche s.r.l.

Comptables agréés
Experts-comptables autorisés

Le 17 avril 2012

Hawkesbury Hydro Inc.

Statement of earnings
year ended December 31, 2011

Hydro Hawkesbury Inc.

État des résultats
de l'exercice clos le 31 décembre 2011

	2011	2010	
	$	$	
Revenues			**Revenus**
Energy (Note 12)	**9,895,593**	10,221,319	Énergie (note 12)
Distribution (Note 12)	**1,328,430**	1,210,348	Distribution (note 12)
Other operating revenues	**173,830**	199,285	Autres revenus d'exploitation
	11,397,853	11,630,952	
Cost of power	**9,895,593**	10,221,319	Coût de l'énergie
	1,502,260	1,409,633	
Expenses			Charges
Distribution	**218,665**	206,613	Distribution
Billing and collection	**339,942**	325,519	Facturation et perception
Community relations	**225**	100	Relations publiques
Administration	**350,658**	335,458	Administration
Amortization of capital assets	**159,561**	158,511	Amortissement des immobilisations corporelles
Interest	**75,347**	64,737	Intérêts
Property taxes	**14,987**	15,678	Impôts fonciers
Other	**19,500**	29,321	Autres
	1,178,885	1,135,937	
Earnings before income taxes	**323,375**	273,696	Bénéfice avant impôts sur les bénéfices
Income taxes			Impôts sur les bénéfices
Recovered	**(214,218)**	(161,142)	Recouvrés
Future	**178,217**	288,402	Futurs
	(36,001)	127,260	
Net earnings	**359,376**	146,436	**Bénéfice net**

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

Hydro Hawkesbury Inc.
État des bénéfices non répartis
de l'exercice clos le 31 décembre 2011

	2011	2010	
	$	$	
Balance, beginning of year	**1,015,429**	953,460	**Solde au début**
Net earnings	**359,376**	146,436	Bénéfice net
Dividends on common shares	**(84,467)**	(84,467)	Dividendes sur les actions ordinaires
Balance, end of year	**1,290,338**	1,015,429	**Solde à la fin**

Hawkesbury Hydro Inc.
Balance sheet
as at December 31, 2011

Hydro Hawkesbury Inc.
Bilan
au 31 décembre 2011

	2011	2010	
	$	$	
Assets			**Actif**
Current assets			Actif à court terme
Cash	**1,003,165**	1,167,332	Encaisse
Accounts receivable (Note 5)	**1,245,614**	1,787,553	Débiteurs (note 5)
Inventories	**118,434**	125,669	Stocks
Unbilled revenues	**1,095,308**	1,275,333	Revenus non facturés
Prepaid expenses	**171,653**	211,464	Charges payées d’avance
Income taxes	**383,289**	282,900	Impôts sur les bénéfices
	4,017,463	4,850,251	
Future income taxes	**-**	167,484	Impôts futurs
Other assets (Note 6)	**1,587,188**	1,047,432	Autres actifs (note 6)
Capital assets (Note 7)	**1,985,359**	1,956,741	Immobilisations corporelles (note 7)
	7,590,010	8,021,908	
Liabilities			**Passif**
Current liabilities			Passif à court terme
Accounts payable and accrued liabilities	**3,020,796**	2,286,853	Créditeurs et charges à payer
Other current liabilities	**148,440**	129,283	Autres passifs à court terme
Current portion of other long-term liabilities (Note 9)	**569,669**	326,573	Tranche des autres passifs à long terme échéant à moins d’un an (note 9)
Current portion of note payable (Note 10)	**246,924**	231,425	Tranche échéant à moins d’un an du billet à payer (note 10)
	3,985,829	2,974,134	
Future income taxes	**10,733**	-	Impôt futurs
Provision for sick leave benefits	**82,169**	78,563	Provision pour congés de maladie
Other long-term liabilities (Note 9)	**278,229**	1,764,146	Autres passifs à long terme (note 9)
Note payable (Note 10)	**253,366**	500,290	Billet à payer (note 10)
	4,610,326	5,317,133	
Contingencies and commitments (Note 15 and 16)			Éventualités et engagementst (notes 15 et 16)
Shareholder’s equity			**Capitaux propres**
Share capital (Note 11)	**1,689,346**	1,689,346	Capital-actions (note 11)
Retained earnings	**1,290,338**	1,015,429	Bénéfices non répartis
	2,979,684	2,704,775	
	7,590,010	8,021,908	

Approved by the Board — Au nom du conseil

Director ______________________ administrateur

Director ______________________ administrateur

Hawkesbury Hydro Inc.
Statement cash flows
year ended December 31, 2011

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

	2011	2010	
	$	$	
Operating activities			**Activités d'exploitation**
Net earnings	**359,376**	146,436	Bénéfice net
Items not affecting cash:			Éléments sans effet sur la trésorerie :
Amortization of capital assets	**159,561**	158,511	Amortissement des immobilisations corporelles
Future income taxes	**178,217**	288,402	Impôts futurs
Changes in non-cash operating working capital items (Note 13)	**1,425,327**	(398,664)	Variation des éléments hors caisse du fonds de roulement d'exploitation (note 13)
	2,122,481	194,685	
Investing activities			**Activités d'investissement**
Purchase of capital assets	**(188,179)**	(226,655)	Acquisition d'immobilisations corporelles
Increase of other assets	**(539,756)**	(371,772)	Augmentation des autres actifs
	(727,935)	(598,427)	
Financing activities			**Activités de financement**
Decrease in other long-term liabilities	**(1,242,821)**	(586,301)	Diminution des autres passifs à long terme
Increase in contribution for capital assets	**-**	74,300	Augmentation des apports pour immobilisations corporelles
Repayment of note payable	**(231,425)**	(216,899)	Remboursement du billet à payer
Dividends paid	**(84,467)**	(84,467)	Dividendes payés
	(1,558,713)	(813,367)	
Net decrease in cash and term deposits	**(164,167)**	(1,217,109)	Diminution nette de l'encaisse et dépôts à terme
Cash and term deposits, beginning of year	**1,167,332**	2,384,441	Encaisse et dépôts à terme au début
Cash, end of year	**1,003,165**	1,167,332	**Encaisse à la fin**

Additional information is presented in Note 13.

Des renseignements complémentaires sont présentés à la note 13.

1. Description of business

The Corporation, incorporated under the Ontario Business Corporations Act, is engaged in the distribution of electricity.

1. Description de l'entreprise

La Société, constituée en vertu de la Loi sur les sociétés par actions de l'Ontario, se spécialise dans la distribution de l'électricité.

2. Future in accounting changes

New accounting framework

The Corporation, a qualifying entity with rate-regulated activities, selected the option proposed by the Canadian Accounting Standards Board to defer its adoption of International Financial Reporting Standards for the first time until its fiscal period beginning on January 1, 2012. The impact of this transition has not yet been determined.

2. Modifications comptables futures

Nouveau référentiel comptable

La Société, une entité admissible exerçant des activités à tarifs réglementés, a choisi l'option offerte par le Conseil des normes comptables du Canada de reporter la première application des normes internationales d'information financières jusqu'à son exercice ouvert à compter du 1er janvier 2012. Les incidences de ce changement n'ont pas encore été évaluées.

3. Accounting policies

The financial statements have been prepared in accordance with Canadian generally accepted accounting principles for rate regulated entities as required by the Ontario Energy Board and set forth in the Accounting Procedures Handbook:

Financial instruments

Financial assets and financial liabilities are initially recognized at fair value and their subsequent measurement is dependent on their classification as described below. Their classification depends on the purpose, for which the financial instruments were acquired or issued, their characteristics and the Corporation's designation of such instruments. Settlement date accounting is used.

Classification

Cash	Held for trading
Accounts receivable	Loans and receivables
Unbilled revenues	Loans and receivables
Accounts payable and accrued liabilities	Other liabilities
Other current liabilities	Other liabilities
Other long-term liabilities	Other liabilities
Note payable	Other liabilities

Held for trading

Held for trading financial assets are financial assets typically acquired for resale prior to maturity or that are designated as held for trading. They are measured at fair value at the balance sheet date. Fair value fluctuations including interest earned, interest accrued, gains and losses realized on disposal and unrealized gains and losses are included in other operating revenues.

3. Méthodes comptables

Les états financiers ont été préparés conformément aux principes comptables généralement reconnus du Canada pour les entités à taux règlementés tel que requis par la Commission de l'énergie de l'Ontario et établis dans le "Accounting Procedures Handbook" :

Instruments financiers

Les actifs financiers et les passifs financiers sont constatés initialement à la juste valeur et leur évaluation ultérieure dépend de leur classement, comme il est décrit ci-après. Leur classement dépend de l'objet visé lorsque les instruments financiers ont été acquis ou émis, de leurs caractéristiques et de leur désignation par la Société. La comptabilisation à la date de règlement est utilisée.

Classification

Encaisse	Détenus à des fins de transaction
Débiteurs	Prêts et créances
Revenus non facturés	Prêts et créances
Créditeurs et charges à payer	Autres passifs
Autres passifs à court terme	Autres passifs
Autres passifs à long terme	Autres passifs
Billet à payer	Autres passifs

Détenus à des fins de transaction

Les actifs financiers détenus à des fins de transaction sont des actifs financiers qui sont généralement acquis en vue d'être revendus avant leur échéance ou qui ont été désignés comme étant détenus à des fins de transaction. Ils sont mesurés à la juste valeur à la date de clôture. Les fluctuations de la juste valeur qui incluent les intérêts gagnés, les intérêts courus, les gains et pertes réalisés sur cession et les gains et pertes non réalisés sont inclus dans les autres revenus d'exploitation.

3. Accounting policies (continued)

Financial instruments (continued)

Loans and receivables

Loans and receivables are accounted for at amortized cost using the effective interest method.

Other liabilities

Other liabilities are recorded at amortized cost using the effective interest method and include all financial liabilities, other than derivative instruments.

Transaction costs

Transaction costs related to held for trading financial assets are expensed as incurred. Transaction costs related to other liabilities and loans and receivables are netted against the carrying value of the asset or liability and are then recognized over the expected life of the instrument using the effective interest method.

Inventories

Inventories are valued at the lower of cost and net realizable value.

Capital assets and amortization

Capital assets are recorded at cost. Amortization is calculated on the basis of the straight-line method with reference to estimated useful lives of the assets in accordance with Ontario Energy Board policy at the following rates:

	Years
Office equipment	5 to 10
Rolling stock and equipment	8 to 10
Capital contribution	25
Distribution equipment	25
Transmission equipment	30 to 40
Building	50

Acquisitions made during the year are amortized at half the normal rate.

Capital contribution is the portion funded by the owners or the developers for capital assets owned by the Corporation.

3. Méthodes comptables (suite)

Instruments financiers (suite)

Prêts et créances

Les prêts et créances sont comptabilisés au coût après amortissement selon la méthode du taux d’intérêt effectif.

Autres passifs

Les autres passifs sont comptabilisés au coût après amortissement selon la méthode du taux d’intérêt effectif et comprennent tous les passifs financiers autres que les instruments dérivés.

Coûts de transaction

Les coûts de transaction liés aux actifs financiers détenus à des fins de transaction sont passés en charge au moment où ils sont engagés. Les coûts de transaction liés aux autres passifs et aux prêts et créances sont comptabilisés en diminution de la valeur comptable de l’actif ou du passif et sont ensuite constatés sur la durée de vie prévue de l’instrument selon la méthode du taux d’intérêt effectif.

Stocks

Les stocks sont évalués au moindre du coût de la valeur nette de réalisation.

Immobilisations corporelles et amortissement

Les immobilisations corporelles sont comptabilisées au coût. L'amortissement est calculé selon la méthode de l'amortissement linéaire répartit sur la durée estimative de vie utile de l'immobilisation selon les politiques de la Commission de l’énergie de l’Ontario aux taux suivants:

	Années
Équipement de bureau	5 à 10
Matériel roulant et équipement	8 à 10
Apports en immobilisations	25
Équipement de distribution	25
Équipement de transmission	30 à 40
Immeuble	50

Les acquisitions de l’année sont amorties à la moitié du taux normal.

Les apports en immobilisations sont la portion qui est financée par les propriétaires ou les développeurs sur les immobilisations appartenant à la Société.

3. Accounting policies (continued)

Other assets/Long-term liabilities

Purchased power costs are included in allowed rates on a forecast basis. For rate-setting purposes, differences between energy revenues and purchased power costs in the rate year are held until the following year, when their final disposition is decided. The Corporation recognizes purchased power cost variances as a regulatory asset or liability, based on the expectation that amounts held from one year to the next for rate-setting purposes will be approved for collection from, or refund to, customers. In the absence of rate regulation, generally accepted accounting principles would require that actual purchased power costs be recognized as an expense when incurred.

The other assets/long-term liabilities, other than variances, are recorded at cost in accordance with accounting principles as required by the Ontario Energy Board.

For certain of the regulatory items identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate-setting purposes. Any disallowed costs will be expensed in the year that they are disallowed.

Recoveries of these assets are presented in a separate account until the Ontario Energy Board approves the recoveries. At that time, recoveries are applied against the regulated assets.

The financial statements effects of rate regulation are presented in Note 18.

Impairment of long-lived assets

Long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. An impairment loss is recognized when their carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. The amount of the impairment loss is determined as the excess of the carrying value of the asset over its fair value.

Provision for sick leave benefits

Employees earns one day of sick leave benefit for every month worked. Unused benefits, which can accrue to a maximum of 130 days, are payable at 50% upon retirement. Accrued benefits above 130 days are payable at 50% at the beginning of the following year.

3. Méthodes comptables (suite)

Autres actifs/Autres passifs à long terme

Les coûts associés à l'énergie achetée sont pris en compte dans les tarifs autorisés, sur une base prévisionnelle. Aux fins de l'établissement des tarifs, les écarts entre les revenus d'énergie et les coûts de l'énergie achetée au cours de l'année de tarification sont laissés en suspens jusqu'à l'année suivante, au cours de laquelle leur traitement définitif est déterminé. La Société comptabilise les écarts de coûts associés à l'énergie achetée à titre d'actif ou de passif réglementaire, parce que la Société s'attend à obtenir l'autorisation de recouvrer auprès des clients futurs les montants laissés en suspens d'une année à l'autre aux fins de l'établissement des tarifs, ou à devoir rembourser les montants à ces clients. Si les tarifs n'étaient pas réglementés, les coûts réels associés à l'énergie achetée devraient être passés en charges au moment où ils sont engagés, selon les principes comptables généralement reconnus.

Les autres actifs/passifs à long terme autres que les écarts de prix ont été comptabilisés au coût selon les règles de la Commission de l'énergie de l'Ontario.

Dans le cas de certains des éléments réglementaires mentionnés ci-dessus, les risques et incertitudes découlant du pouvoir ultime de l'autorité de réglementation de déterminer le traitement de l'élément aux fins de la tarification influent sur la période prévue de recouvrement ou de règlement, ou sur la probabilité de recouvrement ou de règlement. Les montants refusés seront imputés aux résultats dans l'année où ils seront refusés.

Les recouvrements de tous ces frais sont identifiés dans un compte distinct et sont appliqués contre les actifs suite à l'approbation par la Commission de l'énergie de l'Ontario.

Les effets de la règlementation des tarifs sur les états financiers sont décrits à la note 18.

Dépréciation d'actifs à long terme

Les actifs à long terme sont soumis à un test de recouvrabilité lorsque des événements ou des changements de situation indiquent que leur valeur comptable pourrait ne pas être recouvrable. Une perte de valeur est constatée lorsque leur valeur comptable excède les flux de trésorerie non actualisés découlant de leur utilisation et de leur sortie éventuelle. La perte de valeur constatée est mesurée comme étant l'excédent de la valeur comptable de l'actif sur sa juste valeur.

Provision au titre des congés de maladie

Les employé(e)s accumulent une journée de maladie pour chaque mois travaillé. Les journées non utilisées, qui peuvent être accumulées jusqu'à un maximum de 130 jours, sont payables à la retraite à 50%. Les journées accumulées au-delà de 130 jours, est payable à 50% au début de l'exercice suivant.

3. Accounting policies (continued)

Customers' deposits

Deposits are taken to guarantee the payment of utility bills or ensure contract performance by the counter-party.

Revenue recognition

The Corporation recognizes energy and distribution revenues when billed to customers. Other revenues are recognized when persuasive evidence of an arrangement exists, delivery has occurred, the price to the buyer is fixed or determinable and collection is reasonably assured.

Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Key components of the financial statements requiring management to make estimates include the provision for doubtful accounts in respect of receivables, the cost and net realizable value of inventories, the useful lives of capital assets, the recoverability of regulatory assets, income taxes and the fair value of certain financial instruments. Actual results could differ from these estimates.

3. Méthodes comptables (suite)

Dépôts de clients

Des dépôts sont pris en garantie de paiement des factures de services publics ou veiller à l'exécution du contrat par la contrepartie.

Constatation des produits

La Société constate ses revenus d'énergie et de distribution lorsqu'ils sont facturés aux clients alors que les autres revenus sont constatés lorsqu'il existe des preuves convaincantes de l'existence d'un accord, que les marchandises sont expédiées aux clients, que le prix est déterminé ou déterminable et que l'encaissement est raisonnablement assuré.

Utilisation d'estimations

Dans le cadre de la préparation des états financiers, conformément aux principes comptables généralement reconnus du Canada, la direction doit établir des estimations et des hypothèses qui ont une incidence sur les montants des actifs et des passifs présentés et sur la présentation des actifs et des passifs éventuels à la date des états financiers, ainsi que sur les montants des revenus et des charges constatés au cours de la période visée par les états financiers. Parmi les principales composantes des états financiers non consolidés exigeant de la direction qu'elle établisse des estimations figurent la provision pour créances douteuses à l'égard des débiteurs, le coût et la valeur de réalisation nette des stocks, les durées de vie utiles des immobilisations corporelles, la recouvrabilité des actifs règlementés, les impôts et la juste valeur de certains instruments financiers. Les résultats réels pourraient varier par rapport à ces estimations.

4. Term deposits

Temporary investments were cashed during the year.

4. Dépôts à terme

Les placements temporaires ont été encaissés en cours de l'exercice.

5. Accounts receivable / **5. Débiteurs**

	2011	2010	
	$	$	
Electrical energy	**1,213,921**	1,613,377	Énergie électrique
Other	**48,294**	195,278	Autres
	1,262,215	1,808,655	
Allowance for doubtful accounts	**(16,601)**	(21,102)	Provision pour mauvaises créances
	1,245,614	1,787,553	

6. Other assets / 6. Autres actifs

	2011	2010	
	$	$	
Transition costs	**22,611**	22,611	Frais de transition
Smart meters	**394,234**	326,600	Compteurs intelligents
Low voltage charges	**70,504**	47,960	Distribution à faible tension
Retail settlement variance account	**808,374**	591,438	Écarts de prix avec les détaillants
Other regulatory assets	**291,465**	58,823	Autres actifs réglementaires
	1,587,188	1,047,432	

7. Capital assets / 7. Immobilisations corporelles

			2011	2010	
	Cost/ Coût	**Accumulated amortization/ Amortissement cumulé**	**Net book value/ Valeur nette**	Net book value/ Valeur nette	
	$	**$**	**$**	$	
Land and land rights	**56,888**	**2,608**	**54,280**	54,280	Terrain et droit de passage
Office equipment	**222,798**	**158,582**	**64,216**	82,913	Équipement de bureau
Rolling stock and equipment	**234,739**	**208,444**	**26,295**	26,209	Matériel roulant et équipement
Capital contribution	**(144,474)**	**(13,705)**	**(130,769)**	(136,546)	Apports en immobilisations
Distribution equipment	**1,847,567**	**1,007,451**	**840,116**	882,252	Équipement de distribution
Transmission equipment	**709,463**	**198,795**	**510,668**	410,081	Équipement de transmission
Building	**824,124**	**203,571**	**620,553**	637,552	Immeuble
	3,751,105	**1,765,746**	**1,985,359**	1,956,741	

8. Bank loan

The Corporation has an authorized line of credit of $ 1,000,000, at preferred rate, renewable annually, which remained unused at year-end.

There are no covenants to be met.

8. Emprunt bancaire

La Société dispose d'une marge de crédit autorisée de 1 000 000 $, au taux préférentiel, renégociable annuellement, dont la totalité n'était pas utilisée en fin d'exercice.

Il n'y a pas de ratios à respecter.

9. Other long-term liabilities / 9. Autres passifs à long terme

	2011	2010	
	$	$	
Pre-market opening energy variance	**10,682**	10,682	Écarts de prix avant l'ouverture du marché
Amounts to reimburse	**174,423**	1,370,458	Montants à rembourser
Customers' deposits	**662,793**	709,579	Dépôts de clients
	847,898	2,090,719	
Current portion	**569,669**	326,573	Tranche échéant à moins d'un an
	278,229	1,764,146	

10. Note payable / 10. Billet à payer

	2011	2010	
	$	$	
Note payable to the Corporation of the Town of Hawkesbury, sole shareholder of the Corporation, 6.5%, negociated annually, payable in monthly instalments of $ 22,681 including interest	**500,290**	**731,715**	Billet à payer à la Corporation de la Ville de Hawkesbury, l'unique actionnaire de la Société, 6,5%, négocié annuellement, remboursable par versements mensuels de 22 681 $ incluant les intérêts
Current portion	**246,924**	**231,425**	Tranche échéant à moins d'un an
	253,366	**500,290**	

Principal payments required in each of the next two years are as follows: 2012, $ 246,924 and 2013, $ 253,366.

Les versements de capital requis au cours des deux prochains exercices sont les suivants : 2012, 246 924 $ et 2013, 253 366 $.

No restrictive covenant has been imposed by the Corporation of the Town of Hawkesbury.

Aucune clause restrictive n'a été imposée par la Corporation de la Ville de Hawkesbury.

11. Share capital / 11. Capital-actions

Issued share capital:

Informations sur le capital-actions émis :

An unlimited number of common shares

Un nombre illimité d'actions ordinaires

Issued / *Émis*

	2011	2010	
	$	$	
1,000 common shares	**1,689,346**	1,689,346	1 000 actions ordinaires

12. Revenues / 12. Revenus

	2011	2010	
	$	$	
Energy			*Énergie*
Residential	**3,383,069**	3,107,821	Résidentiel
General < 50 KW	**1,263,664**	1,296,430	Général < 50 KW
General > 50 KW	**2,264,913**	2,572,023	Général > 50 KW
Street light	**38,916**	40,735	Éclairage des rues
Sentinel	**6,612**	6,692	Sentinelle
Retailers	**682,613**	868,199	Détaillants
Regulatory charges	**2,255,806**	2,329,419	Frais réglementés
	9,895,593	10,221,319	

12. Revenues (continued) / **12. Revenus (suite)**

	2011	2010	
	$	$	
Distribution			*Distribution*
Residential	**747,170**	742,598	Résidentiel
General < 50 KW	**198,496**	193,055	Général < 50 KW
General > 50 KW	**331,827**	233,371	Général > 50 KW
Street light	**34,056**	24,602	Éclairage des rues
Sentinel	**2,300**	2,321	Sentinelle
Regulatory charges	**14,581**	14,401	Frais réglementés
	1,328,430	1,210,348	

13. Additional information relating to the statement of cash flows / **13. Renseignements complémentaires à l'état des flux de trésorerie**

	2011	2010	
	$	$	
Changes in non-cash operating working capital items			*Variation des éléments hors caisse du fonds de roulement d'exploitation*
Accounts receivable	**541,939**	(235,742)	Débiteurs
Inventories	**7,235**	1,288	Stocks
Unbilled revenues	**180,025**	43,438	Revenus non facturés
Prepaid expenses	**39,811**	(29,039)	Charges payées d'avance
Income taxes receivable	**(100,389)**	(8,849)	Impôts sur les bénéfices à recevoir
Accounts payable and accrued liabilities	**733,943**	(103,170)	Créditeurs et charges à payer
Other current liabilities	**19,157**	(74,405)	Autres passifs à court terme
Provision for sick leave benefits	**3,606**	7,815	Provision pour congés de maladie
	1,425,327	(398,664)	
Other information			*Autres renseignements*
Interest paid	**53,826**	59,861	Intérêts payés
Income taxes recovered	**(113,829)**	(152,293)	Impôts sur les bénéfices recouvrés

14. Pension plan

The Corporation makes contributions to the Ontario Municipal Employees Retirement Fund ("OMERS"), which is a multi-employer plan, on behalf of 8 members of its staff. The plan is a defined benefit plan, which specifies the amount or the retirement benefit to be received by the employees based on the length of service and rates of pay.

The amount contributed to OMERS for 2011 is $ 35,078 (2010 - $ 29,943) for current service and is included as an expense in the statement of earnings.

14. Régime de retraite

La Société contribue au régime de retraite des employés municipaux de l'Ontario ("RREMO"), qui est un régime interemployeurs, pour 8 membres de son personnel. Il s'agit d'un régime à prestations déterminées qui prévoit le niveau de pension à être reçu par les employés en se basant sur les années de service et le niveau salarial.

Le montant contribué à RREMO en 2011 est de 35 078 $ (2010 - 29 943 $) pour services courants et est inclus dans les charges à l'état des résultats.

15. Contingencies

Letter of guarantee

A letter of guarantee in the amount of $ 399,528 was issued in favour of the Independent Electricity System Operator and is renewable in September 2012. The Corporation of the Town of Hawkesbury endorsed this letter of guarantee.

15. Éventualités

Lettre de garantie

Une lettre de garantie au montant de 399 528 $ a été émise en faveur de "Independent Electricity System Operator" est renouvelable en septembre 2012. La Corporation de la Ville de Hawkesbury a endossé cette lettre de garantie.

16. Commitments

The Corporation committed to purchase transmission equipment for an amount of $ 527,110. It also entered into a loan agreement in the amount of $ 750,000 with Ontario Infrastructure and Lands Corporation. Once disbursed it will be repayable over 25 years, with an interest rate of 4.36% for a monthly payment of $ 4,109.

16. Engagements

La Société s'est engagée à faire l'acquisition d'équipements de transmission pour un montant de 527 110 $. Elle a également signée une entente pour un emprunt de 750 000 $ avec Ontario Infrastructure and Lands Corporation. Une fois en place, l'emprunt sera remboursable sur une période de 25 ans à un taux d'intérêt de 4,36% avec un versement mensuel de 4 109 $.

17. Related party transactions

During the year, the Corporation entered into transactions with the Corporation of the Town of Hawkesbury, its sole shareholder. These transactions were made in the normal course of business and have been recorded at the exchange amounts.

17. Opérations entre apparentées

Au cours de l'exercice, la Société a effectué des transactions avec la Corporation de la Ville de Hawkesbury, son unique actionnaire. Ces opérations ont été effectuées dans le cours normal des activités et ont été comptabilisées à la valeur d'échange.

	2011	2010	
	$	$	
Note payable to the shareholder			Billet à payer à l'actionnaire
Interest paid	**40,747**	55,273	Intérêts versés
Principal paid	**231,425**	216,899	Capital versé
Dividends paid on common shares	**84,467**	84,467	Dividendes versés sur actions ordinaires
Other operating revenues	**-**	7,724	Autres revenus d'exploitation
Distribution expenses	**100**	4,960	Charges de distribution
Property taxes	**14,987**	15,678	Impôts fonciers

18. Financial statements' effects of rate regulation

18. Effets de la réglementation des tarifs sur les états financiers

	2011	2010	
	$	$	
Earnings before income taxes established in accordance with accounting principles for electricity distributers as required by the Ontario Energy Board	**323,375**	273,696	Bénéfice avant impôts sur les bénéfices établis conformément aux principes comptables pour les distributeurs d'électricité tels que requis par la Commission de l'énergie de l'Ontario
Variances/expenses included in other assets/ liabilities	**(919,238)**	(251,405)	Variances/charges incluses dans les autres actifs/passifs
Carrying charges on other assets/liabilities	**(7,903)**	3,260	Frais d'intérêts sur les autres actifs/passifs
Amortization of capital assets included in other assets	**(42,688)**	(24,415)	Amortissement des immobilisations corporelles inclus dans les autres actifs
Remitted to clients	**(653,365)**	(414,421)	Remboursés aux clients
Loss before income taxes and before the effect of the regulation on the financial statements	**(1,299,819)**	(413,285)	Perte ajustée avant impôts sur les bénéfices et avant l'effet de la réglementation sur les états financiers

19. Financial instruments and risk management

The Corporation, through its financial assets and liabilities, has exposure to the following risks from its use of financial instruments: credit risk, market risk, and liquidity risk. The following analysis provides a measurement of risk as at December 31, 2011.

Credit risk

The Corporation's principal financial assets are cash and accounts receivable, which are subject to credit risk. The carrying amounts of financial assets on the balance sheet represent the Corporation's maximum credit exposure at the balance sheet date.

19. Instruments financiers et gestion des risques

En raison de ses actifs et de ses passifs financiers, la Société est exposée aux risques suivants relatifs à l'utilisation d'instruments financiers: le risque de crédit, le risque de marché et le risque de liquidité. L'analyse suivante permet d'évaluer les risques au 31 décembre 2011.

Risque de crédit

Les principaux actifs financiers de la Société comprennent l'encaisse et les débiteurs, lesquels sont assujettis au risque de crédit. La valeur comptable des actifs financiers au bilan représente le risque de crédit maximal à la date du bilan.

19. Financial instruments and risk management (continued)

Credit risk (continued)

The Corporation's credit risk is primarily attributable to its accounts receivable. The amounts disclosed in the balance sheet are net of allowance for doubtful accounts, estimated by the management of the Corporation based on previous experience and its assessment of the current economic environment. In order to reduce its risk, management has adopted credit policies that include regular review of credit limits. The Corporation does not have significant exposure to any individual customer and has not incurred any significant bad debts during the year. The credit risk on cash is limited because the counterparties are chartered banks with high credit-ratings assigned by national credit-rating agencies.

19. Instruments financiers et gestion des risques (suite)

Risque de crédit (suite)

Le risque de crédit de la Société est principalement imputable à ses débiteurs. Les montants sont présentés dans le bilan déduction faite de la provision pour créances douteuses, laquelle a fait l'objet d'une estimation par la direction de la Société en fonction de l'expérience antérieure et de son évaluation de la conjoncture économique actuelle. Afin de réduire le risque, la direction a adopté des politiques de crédit qui comprennent une révision régulière des limites de crédit. La Société n'est exposée à aucun risque important à l'égard d'un client particulier et n'a eu aucune créance irrécouvrable importante au cours de l'exercice. Le risque de crédit lié à l'encaisse est limité puisque les contreparties sont des banques à charte jouissant de cotes de solvabilité élevées attribuées par des agences de notation nationales.

As at December 31, 2011, the aging of accounts receivable was as follow:

Au 31 décembre 2011, le classement par échéance des débiteurs était le suivant :

	2011	2010	
	$	$	
Current	**1,225,247**	1,645,631	Courant
Aged between 31 and 90 days	**7,263**	14,803	Entre 31 et 90 jours
Aged greater than 90 days	**29,705**	148,221	Plus de 90 jours
	1,262,215	1,808,655	
Allowance for doubtful accounts	**(16,601)**	(21,102)	Provision pour créances douteuses
	1,245,614	1,787,553	

Reconciliation of allowance for doubtful accounts:

Rapprochement de la provision pour créances douteuses :

	2011	2010	
	$	$	
Balance, beginning of year	**21,102**	14,077	Solde au début
Increase during the year	**17,497**	19,528	Augmentation au cours de l'exercice
Bad debts recovered during the year	**146**	3,093	Créances douteuses recouvrées au cours de l'exercice
Bad debts written off during the year	**(22,144)**	(15,596)	Créances douteuses radiées au cours de l'exercice
Balance, end of year	**16,601**	21,102	Solde à la fin

19. Financial instruments and risk management (continued)

Interest rate risk

The note payable bears interest at a fixed rate. Consequently, there is no cash flow exposure. However, the fair value of loans having fixed rates of interest, could fluctuate because of changes in market interest rates.

Liquidity risk

The Corporation's objective is to have sufficient liquidity to meet its liabilities when due. The Corporation monitors its cash balances and cash flows generated from operations to meet its requirements. The Corporation has the following financial liabilities as at December 31, 2011:

19. Instruments financiers et gestion des risques (suite)

Risque de taux d'intérêt

Le billet à payer porte intérêts à taux fixe. Par conséquent, il n'y a pas de risques de trésorerie. Toutefois, la juste valeur des emprunts dont le taux d'intérêt est fixe pourrait fluctuer en fonction des variations des taux d'intérêt du marché.

Risque de liquidité

Le risque de liquidité est le risque que la Société ne soit pas en mesure de remplir ses obligations financières à leur échéance. La Société surveille le solde de son encaisse et ses flux de trésorerie qui découlent de son exploitation pour être en mesure de respecter ses engagements. Au 31 décembre 2011, les passifs financiers de la Société étaient les suivants :

	Net book value/ Valeur comptable nette	2011	2012	2013 and after/ 2013 et après	
	$	$	$	$	
Accounts payable and accrued liabilities	**3,020,796**	3,020,796	-	-	Créditeurs et charges à payer
Other current liabilities	**148,440**	148,440	-	-	Autres passifs à court terme
Note payable	**500,290**	246,924	253,366	-	Billet à payer
Other long-term liabilities	**847,898**	569,669	(9,219)	287,448	Autres passifs à long terme
	4,517,424	3,985,829	244,147	287,448	

Fair value

Establishing fair value

The fair value of cash, accounts receivable, accounts payable and accrued liabilities and other current liabilities approximates their carrying values due to their short-term maturity.

Commodity price risk

The price of energy varies with the market. There is no impact for the Corporation because actual costs are recovered from customers.

Juste valeur

Détermination de la juste valeur

Les justes valeurs de l'encaisse, des débiteurs, des créditeurs et charges à payer et autres passifs à court terme correspondent approximativement à leur valeur comptable en raison de leur échéance à court terme.

Risque de prix de marchandises

Le prix de l'énergie fluctue selon le marché. Il n'y a pas d'impact pour la Société puisque les coûts réels sont récupérés des clients.

19. Financial instruments and risk management (continued)

Fair value (continued)

Fair value hierarchy

Financial instruments recorded at fair value on the balance sheet are classified using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1 - valuation based on unadjusted prices for identical assets or liabilities;

Level 2 - valuation techniques based on inputs other than prices included in Level 1 that are observable for the asset or liability, either directly or indirectly;

Level 3 - valuation techniques using inputs for the asset or liability that are not based on observable market data.

The fair value hierarchy requires the use of observable market inputs whenever such inputs exist. A financial instrument is classified to the lowest level of the hierarchy for which a significant input has been considered in measuring fair value.

The following table presents the financial instruments recorded at fair value in the balance sheet, classified using the fair value hierarchy described above:

19. Instruments financiers et gestion des risques (suite)

Juste valeur (suite)

Hiérarchie des évaluations à la juste valeur

Les instruments financiers comptabilisés à la juste valeur au bilan sont classés selon une hiérarchie qui reflète l'importance des données utilisées pour effectuer les évaluations. La hiérarchie des évaluations à la juste valeur se compose des niveaux suivants :

Niveau 1 - évaluation fondée sur les prix non rajustés pour des actifs ou passifs identiques;

Niveau 2 - techniques d'évaluation fon-dées sur des données autres que les prix visés au niveau 1, qui sont observables pour l'actif ou le passif, directement ou indirectement;

Niveau 3 - techniques d'évaluation fon-dées sur une part importante de données relatives à l'actif ou au passif qui ne sont pas fondées sur des données de marché observables.

La hiérarchie qui s'applique dans le cadre de la détermination de la juste valeur exige l'utilisation de données observables sur le marché chaque fois que de telles données existent. Un instrument financier est classé au niveau le plus bas de la hiérarchie pour lequel une donnée importante a été prise en compte dans l'évaluation de la juste valeur.

Le tableau suivant présente les instru-ments financiers comptabilisés à la juste valeur au bilan, classés selon la hiérarchie d'évaluation décrite ci-dessus :

	Level 1/ Niveau 1	Level 2/ Niveau 2	Level 3/ Niveau 3	Total financial assets at fair value/Total des actifs financiers à la juste valeur	
	$	$	$	$	
2011					*2011*
Financial assets					Actifs financiers
Cash	1,003,165	-	-	1,003,165	Encaisse
2010					*2010*
Financial assets					Actifs financiers
Cash	1,167,332	-	-	1,167,332	Encaisse

During the year, there has been no significant transfer of amounts between levels.

Au cours de l'exercice, il n'y a eu aucun transfert important de montants entre les niveaux.

Financial statements of
États financiers de

Hawkesbury Hydro Inc.
Hydro Hawkesbury Inc.

December 31, 2012
31 décembre 2012

Hawkesbury Hydro Inc.
December 31, 2012

Hydro Hawkesbury Inc.
31 décembre 2012

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Independent Auditor's Report

To the Directors of Hawkesbury Hydro Inc.

Report on the Financial Statements

We have audited the accompanying financial statements of Hawkesbury Hydro Inc., which comprise the balance sheet as at December 31, 2012, and the statements of earnings, retained earnings 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.

Auditor's 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 judgment, 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 overall 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 Hawkesbury Hydro Inc. as at December 31, 2012, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Deloitte LLP

Chartered Professional Accountants, Chartered Accountants
Licensed Public Accountants

May 14, 2013

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Rapport de l'auditeur indépendant

Aux administrateurs de Hydro Hawkesbury Inc.

Rapport sur les états financiers

Nous avons effectué l'audit des états financiers ci-joints de Hydro Hawkesbury Inc. qui comprennent le bilan au 31 décembre 2012, les états des résultats, des bénéfices non répartis et des flux de trésorerie pour l'exercice clos à cette date, ainsi qu'un résumé des principales méthodes comptables et d'autres informations explicatives.

Responsabilité de la direction pour les états financiers

La direction est responsable de la préparation et de la présentation fidèle de ces états financiers conformément aux principes comptables généralement reconnus du Canada, ainsi que du contrôle interne qu'elle considère comme nécessaire pour permettre la préparation d'états financiers exempts d'anomalies significatives, que celles-ci résultent de fraudes ou d'erreurs.

Responsabilité de l'auditeur

Notre responsabilité consiste à exprimer une opinion sur les états financiers, sur la base de notre audit. Nous avons effectué notre audit selon les normes d'audit généralement reconnues du Canada. Ces normes requièrent que nous nous conformions aux règles de déontologie et que nous planifiions et réalisions l'audit de façon à obtenir l'assurance raisonnable que les états financiers ne comportent pas d'anomalies significatives.

Un audit implique la mise en œuvre de procédures en vue de recueillir des éléments probants concernant les montants et les informations fournis dans les états financiers. Le choix des procédures relève du jugement de l'auditeur, et notamment de son évaluation des risques que les états financiers comportent des anomalies significatives, que celles-ci résultent de fraudes ou d'erreurs. Dans l'évaluation de ces risques, l'auditeur prend en considération le contrôle interne de l'entité portant sur la préparation et la présentation fidèle des états financiers afin de concevoir des procédures d'audit appropriées aux circonstances, et non dans le but d'exprimer une opinion sur l'efficacité du contrôle interne de l'entité. Un audit comporte également l'appréciation du caractère approprié des méthodes comptables retenues et du caractère raisonnable des estimations comptables faites par la direction, de même que l'appréciation de la présentation d'ensemble des états financiers.

Nous estimons que les éléments probants que nous avons obtenus sont suffisants et appropriés pour fonder notre opinion d'audit.

Opinion

À notre avis, les états financiers donnent, dans tous leurs aspects significatifs, une image fidèle de la situation financière de Hydro Hawkesbury Inc. au 31 décembre 2012, ainsi que de ses résultats d'exploitation et de ses flux de trésorerie pour l'exercice clos à cette date, conformément aux principes comptables généralement reconnus du Canada.

Deloitte s.r.l.

Comptables professionnels agréés, Comptables agréés
Experts-comptables autorisés

Le 14 mai 2013

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

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

	2012	2011	
	$	$	
Revenues			**Revenus**
Energy (Note 11)	**9,546,720**	9,895,593	Énergie (note 11)
Distribution (Note 11)	**1,648,714**	1,328,430	Distribution (note 11)
Other operating revenues	**183,270**	173,830	Autres revenus d'exploitation
	11,378,704	11,397,853	
Cost of power	**9,546,720**	9,895,593	Coût de l'énergie
	1,831,984	1,502,260	
Expenses			Charges
Distribution	**253,130**	218,665	Distribution
Billing and collection	**347,731**	339,942	Facturation et perception
Community relations	**-**	225	Relations publiques
Administration	**403,559**	350,658	Administration
Amortization of capital assets	**274,433**	159,561	Amortissement des immobilisations corporelles
Interest	**88,612**	75,347	Intérêts
Property taxes	**14,768**	14,987	Impôts fonciers
Others	**24,546**	19,500	Autres
	1,406,779	1,178,885	
Earnings before income taxes	**425,205**	323,375	Bénéfice avant impôts sur les bénéfices
Income taxes			Impôts sur les bénéfices
Recovered	**-**	(214,218)	Recouvrés
Future	**65,907**	178,217	Futurs
	65,907	(36,001)	
Net earnings	**359,298**	359,376	**Bénéfice net**

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

Hydro Hawkesbury Inc.
État des bénéfices non répartis
de l'exercice clos le 31 décembre 2012

	2012	2011	
	$	$	
Balance, beginning of year	**1,290,338**	1,015,429	**Solde au début**
Net earnings	**359,298**	359,376	Bénéfice net
Dividends on common shares	**(84,467)**	(84,467)	Dividendes sur les actions ordinaires
Balance, end of year	**1,565,169**	1,290,338	**Solde à la fin**

Hawkesbury Hydro Inc.
Balance sheet
as at December 31, 2012

Hydro Hawkesbury Inc.
Bilan
au 31 décembre 2012

	2012	2011	
	$	$	
Assets			**Actif**
Current assets			Actif à court terme
Cash	**216,704**	1,003,165	Encaisse
Accounts receivable (Note 4)	**1,386,514**	1,245,614	Débiteurs (note 4)
Inventories	**111,022**	118,434	Stocks
Unbilled revenues	**1,151,703**	1,095,308	Revenus non facturés
Income taxes	**222,147**	383,289	Impôts sur les bénéfices
Prepaid expenses	**97,256**	171,653	Frais payés d'avance
	3,185,346	4,017,463	
Capital assets (Note 5)	**2,462,875**	1,985,359	Immobilisations corporelles (note 5)
Regulatory assets (Note 6)	**1,785,641**	1,587,188	Actifs réglementaires (note 6)
	7,433,862	7,590,010	
Liabilities			**Passif**
Current liabilities			Passif à court terme
Accounts payable and accrued liabilities	**2,342,183**	3,020,796	Créditeurs et charges à payer
Other current liabilities	**55,411**	148,440	Autres passifs à court terme
Current portion of long-term debt (Note 8)	**271,703**	246,924	Tranche de la dette à long terme échéant à moins d'un an (note 8)
Current portion of regulatory and other long-term financial liabilities (Note 9)	**270,160**	569,669	Tranche des passifs réglementaires et autres passifs financiers à long terme échéant à moins d'un an (note 9)
	2,939,457	3,985,829	
Provision for sick leave benefits	**86,171**	82,169	Provision pour congés de maladie
Long-term debt (Note 8)	**722,761**	253,366	Dette à long terme (note 8)
Regulatory and other long-term financial liabilities (Note 9)	**354,318**	278,229	Passifs réglementaires et autres passifs financiers à long terme (note 9)
Future income taxes	**76,640**	10,733	Impôt futurs
	4,179,347	4,610,326	
Contingencies (Note 14)			Éventualités (note 14)
Shareholder's equity			**Capitaux propres**
Share capital (Note 10)	**1,689,346**	1,689,346	Capital-actions (note 10)
Retained earnings	**1,565,169**	1,290,338	Bénéfices non répartis
	3,254,515	2,979,684	
	7,433,862	7,590,010	

Approved by the Board — Au nom du conseil

Director ________________________ administrateur

Director ________________________ administrateur

Hawkesbury Hydro Inc.
Statement cash flows
year ended December 31, 2012

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

	2012	2011	
	$	$	
Operating activities			**Activités d'exploitation**
Net earnings	**359,298**	359,376	Bénéfice net
Items not affecting cash:			Éléments sans effet sur la trésorerie :
Amortization of capital assets	**274,433**	159,561	Amortissement des immobilisations corporelles
Future income taxes	**65,907**	178,217	Impôts futurs
Changes in non-cash operating working capital items (Note 12)	**(721,984)**	1,425,327	Variation des éléments hors caisse du fonds de roulement d'exploitation (note 12)
	(22,346)	2,122,481	
Investing activities			**Activités d'investissement**
Purchase of capital assets	**(216,451)**	(188,179)	Acquisition d'immobilisations corporelles
Increase of regulatory assets	**(843,992)**	(539,756)	Augmentation des actifs réglementaires
	(1,060,443)	(727,935)	
Financing activities			**Activités de financement**
Increase in contribution for capital assets	**110,041**	-	Augmentation des apports pour immobilisations corporelles
Proceeds from long-term debt	**750,000**	-	Produit d'emprunts à long terme
Repayment of long-term debt	**(255,826)**	(231,425)	Remboursement de la dette à long terme
Decrease in regulatory and other long-term financial liabilities	**(223,420)**	(1,242,821)	Diminution des passifs réglementaires et autres passifs financiers à long terme
Dividends paid	**(84,467)**	(84,467)	Dividendes payés
	296,328	(1,558,713)	
Net decrease in cash	**(786,461)**	(164,167)	Diminution nette de l'encaisse
Cash, beginning of year	**1,003,165**	1,167,332	Encaisse au début
Cash, end of year	**216,704**	1,003,165	**Encaisse à la fin**

Additional information is presented in Note 12.

Des renseignements complémentaires sont présentés à la note 12.

1. Description of business

Hawkesbury Hydro Inc. (the "Corporation"), incorporated under the Ontario Business Corporations Act, is engaged in the distribution of electricity.

2. Future in accounting changes

New accounting framework

The Corporation, a qualifying entity with rate-regulated activities, selected the option proposed by the Canadian Accounting Standards Board to defer its adoption of International Financial Reporting Standards for the first time until its fiscal period beginning on January 1, 2015. The impact of this transition has not yet been determined.

3. Accounting policies

The financial statements have been prepared in accordance with Canadian generally accepted accounting principles for rate regulated entities as required by the Ontario Energy Board and set forth in the Accounting Procedures Handbook.

Financial instruments

Financial assets and financial liabilities are initially recognized at fair value and their subsequent measurement is dependent on their classification as described below. Their classification depends on the purpose, for which the financial instruments were acquired or issued, their characteristics and the Corporation's designation of such instruments. Settlement date accounting is used.

Classification

Cash	Held for trading
Accounts receivable	Loans and receivables
Unbilled revenues	Loans and receivables
Accounts payable and accrued liabilities	Other liabilities
Other current liabilities	Other liabilities
Long-term debt	Other liabilities
Other long-term financial liabilities	Other liabilities

Held for trading

Held for trading financial assets are financial assets typically acquired for resale prior to maturity or that are designated as held for trading. They are measured at fair value at the balance sheet date. Fair value fluctuations including interest earned, interest accrued, gains and losses realized on disposal and unrealized gains and losses are included in other operating revenues.

1. Description de l'entreprise

Hydro Hawkesbury Inc. (la « Société »), constituée en vertu de la Loi sur les sociétés par actions de l'Ontario, se spécialise dans la distribution de l'électricité.

2. Modifications comptables futures

Nouveau référentiel comptable

La Société, une entité admissible exerçant des activités à tarifs réglementés, a choisi l'option offerte par le Conseil des normes comptables du Canada de reporter la première application des normes internationales d'information financières jusqu'à son exercice ouvert à compter du 1er janvier 2015. Les incidences de ce changement n'ont pas encore été évaluées.

3. Méthodes comptables

Les états financiers ont été préparés conformément aux principes comptables généralement reconnus du Canada pour les entités à taux règlementés tel que requis par la Commission de l'énergie de l'Ontario et établis dans le « Accounting Procedures Handbook » :

Instruments financiers

Les actifs financiers et les passifs financiers sont constatés initialement à la juste valeur et leur évaluation ultérieure dépend de leur classement, comme il est décrit ci-après. Leur classement dépend de l'objet visé lorsque les instruments financiers ont été acquis ou émis, de leurs caractéristiques et de leur désignation par la Société. La comptabilisation à la date de règlement est utilisée.

Classification

Encaisse	Détenus à des fins de transaction
Débiteurs	Prêts et créances
Revenus non facturés	Prêts et créances
Créditeurs et charges à payer	Autres passifs
Autres passifs à court terme	Autres passifs
Dette à long terme	Autres passifs
Autres passifs financiers à long terme	Autres passifs

Détenus à des fins de transaction

Les actifs financiers détenus à des fins de transaction sont des actifs financiers qui sont généralement acquis en vue d'être revendus avant leur échéance ou qui ont été désignés comme étant détenus à des fins de transaction. Ils sont mesurés à la juste valeur à la date de clôture. Les fluctuations de la juste valeur qui incluent les intérêts gagnés, les intérêts courus, les gains et pertes réalisés sur cession et les gains et pertes non réalisés sont inclus dans les autres revenus d'exploitation.

3. Accounting policies (continued)

Financial instruments (continued)

Loans and receivables

Loans and receivables are accounted for at amortized cost using the effective interest method.

Other liabilities

Other liabilities are recorded at amortized cost using the effective interest method and include all financial liabilities, other than derivative instruments.

Transaction costs

Transaction costs related to held for trading financial assets are expensed as incurred. Transaction costs related to other liabilities and loans and receivables are netted against the carrying value of the asset or liability and are then recognized over the expected life of the instrument using the effective interest method.

Inventories

Inventories are valued at the lower of cost and net realizable value.

Capital assets and amortization

Capital assets are recorded at cost. Amortization is calculated on the basis of the straight-line method with reference to estimated useful lives of the assets in accordance with Ontario Energy Board policy at the following terms:

	Years
Office equipment	5 to 10
Rolling stock and equipment	8 to 10
Capital contribution	25
Distribution equipment	25
Transmission equipment	30 to 40
Building	50

Acquisitions made during the year are amortized at half the normal rate.

Capital contribution is the portion funded by the owners or the developers for capital assets owned by the Corporation.

3. Méthodes comptables (suite)

Instruments financiers (suite)

Prêts et créances

Les prêts et créances sont comptabilisés au coût après amortissement selon la méthode du taux d'intérêt effectif.

Autres passifs

Les autres passifs sont comptabilisés au coût après amortissement selon la méthode du taux d'intérêt effectif et comprennent tous les passifs financiers autres que les instruments dérivés.

Coûts de transaction

Les coûts de transaction liés aux actifs financiers détenus à des fins de transaction sont passés en charge au moment où ils sont engagés. Les coûts de transaction liés aux autres passifs et aux prêts et créances sont comptabilisés en diminution de la valeur comptable de l'actif ou du passif et sont ensuite constatés sur la durée de vie prévue de l'instrument selon la méthode du taux d'intérêt effectif.

Stocks

Les stocks sont évalués au moindre du coût de la valeur nette de réalisation.

Immobilisations corporelles et amortissement

Les immobilisations corporelles sont comptabilisées au coût. L'amortissement est calculé selon la méthode de l'amortissement linéaire répartit sur la durée estimative de vie utile de l'immobilisation selon les politiques de la Commission de l'énergie de l'Ontario aux termes suivants :

	Années
Équipement de bureau	5 à 10
Matériel roulant et équipement	8 à 10
Apports en immobilisations	25
Équipement de distribution	25
Équipement de transmission	30 à 40
Immeuble	50

Les acquisitions de l'année sont amorties à la moitié du taux normal.

Les apports en immobilisations sont la portion qui est financée par les propriétaires ou les développeurs sur les immobilisations appartenant à la Société.

3. Accounting policies (continued)

Regulatory assets/liabilities

Purchased power costs are included in allowed rates on a forecast basis. For rate-setting purposes, differences between energy revenues and purchased power costs in the rate year are held until the following year, when their final disposition is decided. The Corporation recognizes purchased power cost variances as a regulatory asset or liability, based on the expectation that amounts held from one year to the next for rate-setting purposes will be approved for collection from, or refund to, customers. In the absence of rate regulation, generally accepted accounting principles would require that actual purchased power costs be recognized as an expense when incurred.

The other assets/long-term liabilities, other than variances, are recorded at cost in accordance with accounting principles as required by the Ontario Energy Board.

For certain of the regulatory items identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate-setting purposes. Any disallowed costs will be expensed in the year that they are disallowed.

Recoveries of these assets are presented in a separate account until the Ontario Energy Board approves the recoveries. At that time, recoveries are applied against the regulated assets.

The financial statements effects of rate regulation are presented in Note 16.

Impairment of long-lived assets

Long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. An impairment loss is recognized when their carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. The amount of the impairment loss is determined as the excess of the carrying value of the asset over its fair value.

Provision for sick leave benefits

Employees earns one day of sick leave benefit for every month worked. Unused benefits, which can accrue to a maximum of 130 days, are payable at 50% upon retirement. Accrued benefits above 130 days are payable at 50% at the beginning of the following year.

3. Méthodes comptables (suite)

Actifs/passifs réglementaires

Les coûts associés à l'énergie achetée sont pris en compte dans les tarifs autorisés, sur une base prévisionnelle. Aux fins de l'établissement des tarifs, les écarts entre les revenus d’énergie et les coûts de l'énergie achetée au cours de l'année de tarification sont laissés en suspens jusqu'à l'année suivante, au cours de laquelle leur traitement définitif est déterminé. La Société comptabilise les écarts de coûts associés à l'énergie achetée à titre d'actif ou de passif réglementaire, parce que la Société s'attend à obtenir l'autorisation de recouvrer auprès des clients futurs les montants laissés en suspens d'une année à l'autre aux fins de l'établissement des tarifs, ou à devoir rembourser les montants à ces clients. Si les tarifs n'étaient pas réglementés, les coûts réels associés à l'énergie achetée devraient être passés en charges au moment où ils sont engagés, selon les principes comptables généralement reconnus.

Les autres actifs/passifs à long terme autres que les écarts de prix ont été comptabilisés au coût selon les règles de la Commission de l’énergie de l’Ontario.

Dans le cas de certains des éléments réglementaires mentionnés ci-dessus, les risques et incertitudes découlant du pouvoir ultime de l'autorité de réglementation de déterminer le traitement de l'élément aux fins de la tarification influent sur la période prévue de recouvrement ou de règlement, ou sur la probabilité de recouvrement ou de règlement. Les montants refusés seront imputés aux résultats dans l’année où ils seront refusés.

Les recouvrements de tous ces frais sont identifiés dans un compte distinct et sont appliqués contre les actifs suite à l’approbation par la Commission de l’énergie de l’Ontario.

Les effets de la règlementation des tarifs sur les états financiers sont décris à la note 16.

Dépréciation d’actifs à long terme

Les actifs à long terme sont soumis à un test de recouvrabilité lorsque des événements ou des changements de situation indiquent que leur valeur comptable pourrait ne pas être recouvrable. Une perte de valeur est constatée lorsque leur valeur comptable excède les flux de trésorerie non actualisés découlant de leur utilisation et de leur sortie éventuelle. La perte de valeur constatée est mesurée comme étant l'excédent de la valeur comptable de l'actif sur sa juste valeur.

Provision pour congés de maladie

Les employé(e)s accumulent une journée de maladie pour chaque mois travaillé. Les journées non utilisées, qui peuvent être accumulées jusqu’à un maximum de 130 jours, sont payables à la retraite à 50%. Les journées accumulées au-delà de 130 jours, est payable à 50% au début de l’exercice suivant.

3. Accounting policies (continued)

Customers' deposits

Deposits are taken to guarantee the payment of utility bills or ensure contract performance by the counter-party.

Revenue recognition

The Corporation recognizes energy and distribution revenues when billed to customers. Other revenues are recognized when persuasive evidence of an arrangement exists, delivery has occurred, the price to the buyer is fixed or determinable and collection is reasonably assured.

Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Key components of the financial statements requiring management to make estimates include the provision for doubtful accounts in respect of receivables, the cost and net realizable value of inventories, the recoverability of regulatory assets, income taxes and the fair value of certain financial instruments. Actual results could differ from these estimates.

3. Méthodes comptables (suite)

Dépôts de clients

Des dépôts sont pris en garantie de paiement des factures de services publics ou veiller à l'exécution du contrat par la contrepartie.

Constatation des produits

La Société constate ses revenus d'énergie et de distribution lorsqu'ils sont facturés aux clients alors que les autres revenus sont constatés lorsqu'il existe des preuves convaincantes de l'existence d'un accord, que les marchandises sont expédiées aux clients, que le prix est déterminé ou déterminable et que l'encaissement est raisonnablement assuré.

Utilisation d'estimations

Dans le cadre de la préparation des états financiers, conformément aux principes comptables généralement reconnus du Canada, la direction doit établir des estimations et des hypothèses qui ont une incidence sur les montants des actifs et des passifs présentés et sur la présentation des actifs et des passifs éventuels à la date des états financiers, ainsi que sur les montants des revenus et des charges constatés au cours de la période visée par les états financiers. Parmi les principales composantes des états financiers, exigeant de la direction qu'elle établisse des estimations, figurent la provision pour créances douteuses à l'égard des débiteurs, le coût et la valeur de réalisation nette des stocks, la recouvrabilité des actifs règlementés, les impôts sur les bénéfices et la juste valeur de certains instruments financiers. Les résultats réels pourraient varier par rapport à ces estimations.

4. Accounts receivable / 4. Débiteurs

	2012	2011	
	$	$	
Electrical energy customers	**1,375,289**	1,213,921	Énergie électrique des clients
Others	**27,834**	48,294	Autres
	1,403,123	1,262,215	
Allowance for doubtful accounts (Note 17)	**(16,609)**	(16,601)	Provision pour créances douteuses (Note 17)
	1,386,514	1,245,614	

5. Capital assets / 5. Immobilisations corporelles

	Cost/ Coût	Accumulated amortization/ Amortissement cumulé	2012 Net book value/ Valeur comptable nette	2011 Net book value/ Valeur comptable nette	
	$	**$**	**$**	$	
Land and land rights	**56,888**	**2,608**	**54,280**	54,280	Terrain et droit de passage
Office equipment	**269,686**	**198,075**	**71,611**	64,216	Équipement de bureau
Rolling stock and equipment	**237,154**	**213,581**	**23,573**	26,295	Matériel roulant et équipement
Capital contribution	**(254,514)**	**(21,682)**	**(232,832)**	(130,769)	Apports en immobilisations
Distribution equipment	**2,630,180**	**1,203,884**	**1,426,296**	840,116	Équipement de distribution
Transmission equipment	**738,985**	**222,592**	**516,393**	510,668	Équipement de transmission
Building	**824,124**	**220,570**	**603,554**	620,553	Immeuble
	4,502,503	**2,039,628**	**2,462,875**	1,985,359	

6. Regulatory assets / 6. Actifs réglementaires

	2012	2011	
	$	$	
Transition costs	**-**	22,611	Frais de transition
Smart meters	**-**	394,234	Compteurs intelligents
Low voltage charges	**87,149**	70,504	Distribution à faible tension
Retail settlement variance account	**902,060**	808,374	Écarts de prix avec les détaillants
Payments in lien of income taxes	**2,916**	-	Paiements versés en remplacement d’impôts sur les bénéfices
Amounts to recover from clients	**13,506**	-	Montants à récupérer des clients
Other regulatory assets	**780,010**	291,465	Autres actifs réglementaires
	1,785,641	1,587,188	

7. Bank loan

The Corporation has an authorized line of credit of $ 1,000,000, at preferred rate, renewable annually, which remained unused at year-end.

There are no covenants to be met.

7. Emprunt bancaire

La Société dispose d’une marge de crédit autorisée de 1 000 000 $, au taux préférentiel, renouvelable annuellement, dont la totalité n’était pas utilisée en fin d’exercice.

Il n’y a pas de ratios à respecter.

8. Long-term debt / 8. Dette à long terme

	2012	2011	
	$	$	
Note payable to the Corporation of the Town of Hawkesbury, sole shareholder of the Corporation, 6.5%, negociated annually, payable in monthly instalments of $ 22,681 including interest	**253,366**	500,290	Billet à payer à la Corporation de la Ville de Hawkesbury, l'unique actionnaire de la Société, 6,5%, négocié annuellement, remboursable par versements mensuels de 22 681 $ incluant les intérêts
Loan, 3.94%, payable until June 2037 in monthly instalments of $ 3,934 including interest, secured by a general security agreement over all the assets of the Corporation	**741,098**	-	Emprunt, 3,94%, remboursable jusqu'en juin 2037 par versements mensuels de 3 934 $ incluant les intérêts, garanti par un contrat de garantie générale sur tous les actifs de la Société
	994,464	500,290	
Current portion	**271,703**	246,924	Tranche échéant à moins d'un an
	722,761	253,366	

Principal payments required in each of the next five years are as follows:

Les versements de capital requis au cours des cinq prochains exercices sont les suivants :

	$
2013	271,703
2014	19,073
2015	19,838
2016	20,634
2017	21,462

Under the terms of the loan agreement, the Corporation must satisfy certain restrictive covenants as to minimum financial ratios, regarding the disposal of capital assets, must not increase the line of credit and the letter of guarantee, must not invest in subsidiary and must not distribute to the shareholder more than the permitted annual distribution limit. The Corporation is in default regarding a financial ratio.

Selon les conditions rattachées à l'emprunt, la Société est soumise à certaines clauses restrictives en ce qui concerne le maintien de ratios financiers minimums, au sujet de la disposition d'immobilisations corporelles, ne doit pas augmenter sa marge de crédit ou sa lettre de garantie, ne doit pas investir dans des filiales, et ne doit pas distribuer à l'actionnaire plus que la limite annuelle permise. La Société est en défaut concernant un ratio financier.

The debt in the amount of $ 741,098 is still presented as long-term because of a waiver obtained from the lender in regards to the covenant breach.

La dette au montant de 741 098 $ est encore présentée à long terme étant donné la renonciation obtenue du prêteur concernant le non-respect d'une clause restrictive.

9. Regulatory and other long-term financial liabilities / 9. Passifs réglementaires et autres passifs financiers à long terme

	2012	2011	
	$	$	
Pre-market opening energy variance	**-**	10,682	Écarts de prix avant l'ouverture du marché
Amounts to reimburse	**-**	174,423	Montants à rembourser
Customers' deposits	**624,478**	662,793	Dépôts de clients
	624,478	847,898	
Current portion	**270,160**	569,669	Tranche échéant à moins d'un an
	354,318	278,229	

10. Share capital / 10. Capital-actions

Issued share capital: / *Informations sur le capital-actions émis :*

An unlimited number of common shares / Un nombre illimité d'actions ordinaires

Issued / *Émis*

	2012	2011	
	$	$	
1,000 common shares	**1,689,346**	1,689,346	1 000 actions ordinaires

11. Revenues / 11. Revenus

	2012	2011	
	$	$	
Energy			*Énergie*
Residential	**3,814,623**	3,383,069	Résidentiel
General < 50 KW	**1,350,881**	1,263,664	Général < 50 KW
General > 50 KW	**1,653,275**	2,264,913	Général > 50 KW
Street light	**29,115**	38,916	Éclairage des rues
Sentinel	**6,958**	6,612	Sentinelle
Retailers	**392,782**	682,613	Détaillants
Regulatory charges	**2,299,086**	2,255,806	Frais réglementés
	9,546,720	9,895,593	
Distribution			*Distribution*
Residential	**1,024,351**	747,170	Résidentiel
General < 50 KW	**255,740**	198,496	Général < 50 KW
General > 50 KW	**316,720**	331,827	Général > 50 KW
Street light	**34,031**	34,056	Éclairage des rues
Sentinel	**2,288**	2,300	Sentinelle
Regulatory charges	**15,584**	14,581	Frais réglementés
	1,648,714	1,328,430	

12. Additional information relating to the statement of cash flows

12. Renseignements complémentaires à l'état des flux de trésorerie

	2012	2011	
	$	$	
Changes in non-cash operating working capital items			*Variation des éléments hors caisse du fonds de roulement d'exploitation*
Accounts receivable	**(140,900)**	541,939	Débiteurs
Inventories	**7,412**	7,235	Stocks
Unbilled revenues	**(56,395)**	180,025	Revenus non facturés
Income taxes receivable	**161,142**	(100,389)	Impôts sur les bénéfices à recevoir
Prepaid expenses	**74,397**	39,811	Frais payés d'avance
Accounts payable and accrued liabilities	**(678,613)**	733,943	Créditeurs et charges à payer
Other current liabilities	**(93,029)**	19,157	Autres passifs à court terme
Provision for sick leave benefits	**4,002**	3,606	Provision pour congés de maladie
	(721,984)	1,425,327	
Other information			*Autres renseignements*
Interest paid	**57,145**	53,826	Intérêts payés
Income taxes recovered	**(161,142)**	(113,829)	Impôts sur les bénéfices recouvrés

During the year, an amount of $ 645,539 was transferred from regulatory assets to capital assets for the smart meters.

Au cours de l'exercice, un montant de 645 539 $ a été transféré des actifs réglementaires aux immobilisations corporelles pour les compteurs intelligents.

13. Pension plan

The Corporation makes contributions to the Ontario Municipal Employees Retirement System ("OMERS"), which is a multi-employer plan, on behalf of 8 members of its staff. The plan is a defined benefit plan, which specifies the amount or the retirement benefit to be received by the employees based on the length of service and rates of pay.

The amount contributed to OMERS for 2012 is $ 39,885 ($ 35,078 in 2011) for current service and is included as an expense in the statement of earnings.

13. Régime de retraite

La Société contribue au régime de retraite des employés municipaux de l'Ontario (« RREMO »), qui est un régime interemployeurs, pour 8 membres de son personnel. Il s'agit d'un régime à prestations déterminées qui prévoit le niveau de pension à être reçu par les employés en se basant sur les années de service et le niveau salarial.

Le montant contribué à RREMO en 2012 est de 39 885 $ (35 078 $ en 2011) pour services courants et est inclus dans les charges à l'état des résultats.

14. Contingencies

Letter of guarantee

A letter of guarantee in the amount of $ 399,528 was issued in favour of the Independent Electricity System Operator and is renewable in September 2013. The Corporation of the Town of Hawkesbury endorsed this letter of guarantee.

14. Éventualités

Lettre de garantie

Une lettre de garantie au montant de 399 528 $ a été émise en faveur de « Independent Electricity System Operator » est renouvelable en septembre 2013. La Corporation de la Ville de Hawkesbury a endossé cette lettre de garantie.

15. Related party transactions

During the year, the Corporation entered into transactions with the Corporation of the Town of Hawkesbury, its sole shareholder. These transactions were made in the normal course of business and have been recorded at the exchange amounts.

15. Opérations entre apparentées

Au cours de l'exercice, la Société a effectué des transactions avec la Corporation de la Ville de Hawkesbury, son unique actionnaire. Ces opérations ont été effectuées dans le cours normal des activités et ont été comptabilisées à la valeur d'échange.

	2012	2011	
	$	$	
Note payable to the shareholder			Billet à payer à l'actionnaire
Interest paid	**25,248**	40,747	Intérêts payés
Principal paid	**246,924**	231,425	Capital payé
Dividends paid on common shares	**84,467**	84,467	Dividendes payés sur actions ordinaires
Distribution expenses	**644**	100	Charges de distribution
Property taxes	**14,768**	14,987	Impôts fonciers

16. Financial statements' effects of rate regulation

16. Effets de la réglementation des tarifs sur les états financiers

	2012	2011	
	$	$	
Earnings before income taxes established in accordance with accounting principles for electricity distributers as required by the Ontario Energy Board	**425,205**	323,375	Bénéfice avant impôts sur les bénéfices établis conformément aux principes comptables pour les distributeurs d'électricité tels que requis par la Commission de l'énergie de l'Ontario
Variances/expenses included in other assets/ liabilities	**(28,770)**	(919,238)	Variances/charges incluses dans les autres actifs/passifs
Carrying charges on other assets/liabilities	**(5,509)**	(7,903)	Frais d'intérêts sur les autres actifs/passifs
Adjustments for smart meters	**(227,593)**	-	Ajustements pour compteurs intelligents
Amortization of capital assets included in other assets	**(22,715)**	(42,688)	Amortissement des immobilisations corporelles inclus dans les autres actifs
Recovered from (remitted to) clients	**172,372**	(653,365)	Recouvrés des (remboursés aux) clients
Earnings (loss) before income taxes and before the effect of the regulation on the financial statements	**312,990**	(1,299,819)	Bénéfice ajusté (perte ajustée) avant impôts sur les bénéfices et avant l'effet de la réglementation sur les états financiers

17. Financial instruments and risk management

The Corporation, through its financial assets and liabilities, has exposure to the following risks from its use of financial instruments: credit risk, market risk, and liquidity risk. The following analysis provides a measurement of risk as at December 31, 2012.

17. Instruments financiers et gestion des risques

En raison de ses actifs et de ses passifs financiers, la Société est exposée aux risques suivants relatifs à l'utilisation d'instruments financiers: le risque de crédit, le risque de marché et le risque de liquidité. L'analyse suivante permet d'évaluer les risques au 31 décembre 2012.

17. Financial instruments and risk management (continued)

Credit risk

The Corporation's principal financial assets are cash and accounts receivable, which are subject to credit risk. The carrying amounts of financial assets on the balance sheet represent the Corporation's maximum credit exposure at the balance sheet date.

The Corporation's credit risk is primarily attributable to its accounts receivable. The amounts disclosed in the balance sheet are net of allowance for doubtful accounts, estimated by the management of the Corporation based on previous experience and its assessment of the current economic environment. In order to reduce its risk, management has adopted credit policies that include regular review of credit limits. The Corporation does not have significant exposure to any individual customer and has not incurred any significant bad debts during the year. The credit risk on cash is limited because the counterparties are chartered banks with high credit-ratings assigned by national credit-rating agencies.

As at December 31, 2012, the aging of accounts receivable was as follow:

17. Instruments financiers et gestion des risques (suite)

Risque de crédit

Les principaux actifs financiers de la Société comprennent l'encaisse et les débiteurs, lesquels sont assujettis au risque de crédit. La valeur comptable des actifs financiers au bilan représente le risque de crédit maximal à la date du bilan

Le risque de crédit de la Société est principalement imputable à ses débiteurs. Les montants sont présentés dans le bilan déduction faite de la provision pour créances douteuses, laquelle a fait l'objet d'une estimation par la direction de la Société en fonction de l'expérience antérieure et de son évaluation de la conjoncture économique actuelle. Afin de réduire le risque, la direction a adopté des politiques de crédit qui comprennent une révision régulière des limites de crédit. La Société n'est exposée à aucun risque important à l'égard d'un client particulier et n'a eu aucune créance irrécouvrable importante au cours de l'exercice. Le risque de crédit lié à l'encaisse est limité puisque les contreparties sont des banques à charte jouissant de cotes de solvabilité élevées attribuées par des agences de notation nationales.

Au 31 décembre 2012, le classement par échéance des débiteurs était le suivant :

	2012	2011	
	$	$	
Current	**1,358,023**	1,225,247	Courant
Aged between 31 and 90 days	**20,138**	7,263	Entre 31 et 90 jours
Aged greater than 90 days	**24,962**	29,705	Plus de 90 jours
	1,403,123	1,262,215	
Allowance for doubtful accounts	**(16,609)**	(16,601)	Provision pour créances douteuses
	1,386,514	1,245,614	

Reconciliation of allowance for doubtful accounts:			Rapprochement de la provision pour créances douteuses :
Balance, beginning of year	**16,601**	21,102	Solde au début
Increase during the year	**2,800**	17,497	Augmentation au cours de l'exercice
Bad debts recovered during the year	**241**	146	Créances douteuses recouvrées au cours de l'exercice
Bad debts written off during the year	**(3,033)**	(22,144)	Créances douteuses radiées au cours de l'exercice
Balance, end of year	**16,609**	16,601	Solde à la fin

17. Financial instruments and risk management (continued)

17. Instruments financiers et gestion des risques (suite)

Interest rate risk

The long-term debt bears interest at a fixed rate. Consequently, there is no cash flow exposure. However, the fair value of loans having fixed rates of interest, could fluctuate because of changes in market interest rates.

Risque de taux d'intérêt

La dette à long terme porte intérêts à taux fixe. Par conséquent, il n'y a pas de risques de trésorerie. Toutefois, la juste valeur des emprunts dont le taux d'intérêt est fixe pourrait fluctuer en fonction des variations des taux d'intérêt du marché.

Liquidity risk

The Corporation's objective is to have sufficient liquidity to meet its liabilities when due. The Corporation monitors its cash balances and cash flows generated from operations to meet its requirements. The Corporation has the following financial liabilities as at December 31, 2012:

Risque de liquidité

Le risque de liquidité est le risque que la Société ne soit pas en mesure de remplir ses obligations financières à leur échéance. La Société surveille le solde de son encaisse et ses flux de trésorerie qui découlent de son exploitation pour être en mesure de respecter ses engagements. Au 31 décembre 2012, les passifs financiers de la Société étaient les suivants :

	Net book value/ Valeur comptable nette	2013	2014	2015 and after/ 2015 et après	
	$	$	$	$	
Accounts payable and accrued liabilities	**2,342,184**	2,342,184	-	-	Créditeurs et charges à payer
Other current liabilities	**55,411**	55,411	-	-	Autres passifs à court terme
Long-term debt	**994,464**	271,703	19,073	703,688	Dette à long terme
Other long-term financial liabilities	**624,478**	270,160	70,864	283,454	Autres passifs financiers à long terme
	4,016,537	2,939,458	89,937	987,142	

Fair value

Establishing fair value

The fair value of cash, accounts receivable, accounts payable and accrued liabilities and other current liabilities approximates their carrying values due to their short-term maturity.

Juste valeur

Détermination de la juste valeur

Les justes valeurs de l'encaisse, des débiteurs, des créditeurs et charges à payer et autres passifs à court terme correspondent approximativement à leur valeur comptable en raison de leur échéance à court terme.

Commodity price risk

The price of energy varies with the market. There is no impact for the Corporation because actual costs are recovered from customers.

Risque de prix de marchandises

Le prix de l'énergie fluctue selon le marché. Il n'y a pas d'impact pour la Société puisque les coûts réels sont récupérés des clients.

17. Financial instruments and risk management (continued)

Fair value (continued)

Fair value hierarchy

Financial instruments recorded at fair value on the balance sheet are classified using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1 - valuation based on unadjusted prices for identical assets or liabilities;

Level 2 - valuation techniques based on inputs other than prices included in Level 1 that are observable for the asset or liability, either directly or indirectly;

Level 3 - valuation techniques using inputs for the asset or liability that are not based on observable market data.

The fair value hierarchy requires the use of observable market inputs whenever such inputs exist. A financial instrument is classified to the lowest level of the hierarchy for which a significant input has been considered in measuring fair value.

The following table presents the financial instruments recorded at fair value in the balance sheet, classified using the fair value hierarchy described above:

17. Instruments financiers et gestion des risques (suite)

Juste valeur (suite)

Hiérarchie des évaluations à la juste valeur

Les instruments financiers comptabilisés à la juste valeur au bilan sont classés selon une hiérarchie qui reflète l'importance des données utilisées pour effectuer les évaluations. La hiérarchie des évaluations à la juste valeur se compose des niveaux suivants :

Niveau 1 - évaluation fondée sur les prix non rajustés pour des actifs ou passifs identiques;

Niveau 2 - techniques d'évaluation fon-dées sur des données autres que les prix visés au niveau 1, qui sont observables pour l'actif ou le passif, directement ou indirectement;

Niveau 3 - techniques d'évaluation fon-dées sur une part importante de données relatives à l'actif ou au passif qui ne sont pas fondées sur des données de marché observables.

La hiérarchie qui s'applique dans le cadre de la détermination de la juste valeur exige l'utilisation de données observables sur le marché chaque fois que de telles données existent. Un instrument financier est classé au niveau le plus bas de la hiérarchie pour lequel une donnée importante a été prise en compte dans l'évaluation de la juste valeur.

Le tableau suivant présente les instru-ments financiers comptabilisés à la juste valeur au bilan, classés selon la hiérarchie d'évaluation décrite ci-dessus :

	Level 1/ Niveau 1	Level 2/ Niveau 2	Level 3/ Niveau 3	Total financial assets at fair value/Total des actifs financiers à la juste valeur	
	$	$	$	$	
2012					*2012*
Financial assets					Actifs financiers
Cash	216,704	-	-	216,704	Encaisse
2011					*2011*
Financial assets					Actifs financiers
Cash	1,003,165	-	-	1,003,165	Encaisse

During the year, there has been no significant transfer of amounts between levels.

Au cours de l'exercice, il n'y a eu aucun transfert important de montants entre les niveaux.

E1.T3.S2 HISTORICAL TRIAL BALANCE FILINGS

The Administrative Documents identified in this section provide the background and summary information to the case as filed. The following section consists of the 3 following attachments.

1) 2012 2.1.7 RRR Filings
2) 2011 2.1.7 RRR Filings
3) 2010 2.1.7 RRR Filings

Trial Balance (E217)

January 09, 2013

Filing Year
2010

Filing Name
2.1.7

RRR Filing Number
1,232

Reporting Period and Company Name
April-2010Hydro Hawkesbury Inc.

Licence Type
Distributor

Status
Submitted

Report Version
0

Extension Granted

Extension Deadline

Filing Due Date
April 30, 2010

Reporting From

Reporting To

Submitted On
April 28, 2010

Submitter Name
Linda Parisien

Expiry Date
May 01, 2010

Color Legend: **Assets** **Liabilities and Equity** **Income Statement**

Account Description	Account Number	Amount
Cash	1005	381,885.70
Cash Advances and Working Funds	1010	1,200.00
Interest Special Deposits	1020	
Dividend Special Deposits	1030	
Other Special Deposits	1040	
Term Deposits	1060	2,001,355.39
Current Investments	1070	
Customer Accounts Receivable	1100	1,518,210.46
Accounts Receivable - Services	1102	21,124.61
Accounts Receivable - Recoverable Work	1104	
Accounts Receivable - Merchandise, Jobbing, etc.	1105	
Other Accounts Receivable	1110	
Accrued Utility Revenues	1120	1,318,771.21
Accumulated Provision for Uncollectible Accounts--Credit	1130	-14,077.34
Interest and Dividends Receivable	1140	
Rents Receivable	1150	
Notes Receivable	1170	
Prepayments	1180	24,770.52
Miscellaneous Current and Accrued Assets	1190	26,633.20
Accounts Receivable from Associated Companies	1200	
Notes Receivable from Associated Companies	1210	
Fuel Stock	1305	
Plant Materials and Operating Supplies	1330	126,956.68
Merchandise	1340	

Account Description	Account Number	Amount
Other Materials and Supplies	1350	
Long Term Investments in Non-Associated Companies	1405	
Long Term Receivable - Street Lighting Transfer	1408	
Other Special or Collateral Funds	1410	
Sinking Funds	1415	
Unamortized Debt Expense	1425	
Unamortized Discount on Long-Term Debt--Debit	1445	
Unamortized Deferred Foreign Currency Translation Gains and Losses	1455	
Other Non-Current Assets	1460	157,654.17
O.M.E.R.S. Past Service Costs	1465	
Past Service Costs - Employee Future Benefits	1470	
Past Service Costs - Other Pension Plans	1475	
Portfolio Investments - Associated Companies	1480	
Investment in Associated Companies - Significant Influence	1485	
Investment in Subsidiary Companies	1490	
Unrecovered Plant and Regulatory Study Costs	1505	
Other Regulatory Assets	1508	46,619.01
Preliminary Survey and Investigation Charges	1510	
Emission Allowance Inventory	1515	
Emission Allowances Withheld	1516	
RCVARetail	1518	1,686.26
Power Purchase Variance Account	1520	
Miscellaneous Deferred Debits	1525	272,374.19
Deferred Losses from Disposition of Utility Plant	1530	
Renewable Connection Capital Deferral Account	1531	
Renewable Connection OM&A Deferral Account	1532	
Smart Grid Capital Deferral Account	1534	
Smart Grid Capital OM&A Account	1535	
Unamortized Loss on Reacquired Debt	1540	
Development Charge Deposits/ Receivables	1545	
RCVASTR	1548	12,971.55
LV Variance Account	1550	162,637.30
Smart Meter Capital and Recovery Offset Variance	1555	89,781.38
Smart Meter OM&A Variance	1556	3,556.43
Deferred Development Costs	1560	
Deferred Payments in Lieu of Taxes	1562	-59,433.94
Deferred PILs Contra Account	1563	59,433.94
Conservation and Demand Management Expenditures and Recoveries	1565	

Account Description	Account Number	Amount
CDM Contra	1566	
Qualifying Transition Costs	1570	22,611.10
Pre-market Opening Energy Variance	1571	-10,682.28
Extraordinary Event Costs	1572	
Deferred Rate Impact Amounts	1574	
RSVAWMS	1580	-449,774.55
RSVAONE-TIME	1582	13,416.06
RSVANW	1584	-239,448.71
RSVACN	1586	-1,517,536.62
RSVAPOWER	1588	225,345.67
Recovery of regulatory asset balances	1590	63,422.66
2006 PILs & Taxes Variance	1592	
Disposition and Recovery of Regulatory Balances Control Account	1595	
Sub-Account Disposition of Account Balances Approved in 2008	1595	
Sub-Account Disposition of Account Balances Approved in 2009	1595	
Electric Plant in Service - Control Account	1605	
Organization	1606	
Franchises and Consents	1608	
Miscellaneous Intangible Plant	1610	
Land	1615	
Land Rights	1616	
Buildings and Fixtures	1620	
Leasehold Improvements	1630	
Boiler Plant Equipment	1635	
Engines and Engine-Driven Generators	1640	
Turbogenerator Units	1645	
Reservoirs, Dams and Waterways	1650	
Water Wheels, Turbines and Generators	1655	
Roads, Railroads and Bridges	1660	
Fuel Holders, Producers and Accessories	1665	
Prime Movers	1670	
Generators	1675	
Accessory Electric Equipment	1680	
Miscellaneous Power Plant Equipment	1685	
Land	1705	10,000.00
Land Rights	1706	
Buildings and Fixtures	1708	
Leasehold Improvements	1710	

Account Description	Account Number	Amount
Station Equipment	1715	
Towers and Fixtures	1720	
Poles and Fixtures	1725	
Overhead Conductors and Devices	1730	
Underground Conduit	1735	
Underground Conductors and Devices	1740	
Roads and Trails	1745	
Land	1805	10,000.00
Land Rights	1806	8,588.00
Buildings and Fixtures	1808	
Leasehold Improvements	1810	
Transformer Station Equipment - Normally Primary above 50 kV	1815	349,916.94
Distribution Station Equipment - Normally Primary below 50 kV	1820	175,800.99
Storage Battery Equipment	1825	
Poles, Towers and Fixtures	1830	322,655.88
Overhead Conductors and Devices	1835	367,500.19
Underground Conduit	1840	113,707.70
Underground Conductors and Devices	1845	212,731.50
Line Transformers	1850	372,827.19
Services	1855	23,261.26
Meters	1860	246,912.13
Other Installations on Customer's Premises	1865	
Leased Property on Customer Premises	1870	
Street Lighting and Signal Systems	1875	
Land	1905	28,299.70
Land Rights	1906	
Buildings and Fixtures	1908	824,123.77
Leasehold Improvements	1910	
Office Furniture and Equipment	1915	30,527.53
Computer Equipment - Hardware	1920	46,427.21
Computer Software	1925	113,795.64
Transportation Equipment	1930	205,345.80
Stores Equipment	1935	
Tools, Shop and Garage Equipment	1940	13,959.53
Measurement and Testing Equipment	1945	
Power Operated Equipment	1950	4,363.29
Communication Equipment	1955	
Miscellaneous Equipment	1960	

Account Description	Account Number	Amount
Water Heater Rental Units	1965	
Load Management Controls - Customer Premises	1970	
Load Management Controls - Utility Premises	1975	
System Supervisory Equipment	1980	
Sentinel Lighting Rental Units	1985	
Other Tangible Property	1990	
Contributions and Grants - Credit	1995	-66,537.00
Property Under Capital Leases	2005	
Electric Plant Purchased or Sold	2010	
Experimental Electric Plant Unclassified	2020	
Electric Plant and Equipment Leased to Others	2030	
Electric Plant Held for Future Use	2040	
Completed Construction Not Classified--Electric	2050	
Construction Work in Progress--Electric	2055	
Electric Plant Acquisition Adjustment	2060	
Other Electric Plant Adjustment	2065	
Other Utility Plant	2070	
Non-Utility Property Owned or Under Capital Leases	2075	
Accumulated Amortization of Electric Utility Plan - PP&E	2105	-1,451,310.55
Accumulated Amortization of Electric Utility Plant - Intangibles	2120	
Accumulated Amortization of Electric Plant Acquisition Adjustment	2140	
Accumulated Amortization of Other Utility Plant	2160	
Accumulated Amortization of Non-Utility Property	2180	
Accounts Payable	2205	-2,325,266.88
Customer Credit Balances	2208	-203,687.97
Current Portion of Customer Deposits	2210	-192,282.00
Dividends Declared	2215	
Miscellaneous Current and Accrued Liabilities	2220	-69,611.63
Notes and Loans Payable	2225	
Accounts Payable to Associated Companies	2240	
Notes Payable to Associated Companies	2242	
Debt Retirement Charges(DRC) Payable	2250	
Transmission Charges Payable	2252	
Electrical Safety Authority Fees Payable	2254	
Independent Market Operator Fees and Penalties Payable	2256	
Current Portion of Long Term Debt	2260	
Ontario Hydro Debt - Current Portion	2262	
Pensions and Employee Benefits - Current Portion	2264	

Account Description	Account Number	Amount
Accrued Interest on Long Term Debt	2268	
Matured Long Term Debt	2270	
Matured Interest on Long Term Debt	2272	
Obligations Under Capital Leases--Current	2285	
Commodity Taxes	2290	
Payroll Deductions / Expenses Payable	2292	
Accrual for Taxes Payments in Lieu of Taxes, Etc.	2294	274,051.00
Future Income Taxes - Current	2296	455,886.00
Accumulated Provision for Injuries and Damages	2305	
Employee Future Benefits	2306	
Other Pensions - Past Service Liability	2308	
Vested Sick Leave Liability	2310	-71,776.14
Accumulated Provision for Rate Refunds	2315	
Other Miscellaneous Non-Current Liabilities	2320	
Obligations Under Capital Lease--Non-Current	2325	
Development Charge Fund	2330	
Long Term Customer Deposits	2335	-500,254.07
Collateral Funds Liability	2340	
Unamortized Premium on Long Term Debt	2345	
O.M.E.R.S. - Past Service Liability - Long Term Portion	2348	
Future Income Tax - Non-Current	2350	
Other Regulatory Liabilities	2405	
Deferred Gains from Disposition of Utility Plant	2410	
Unamortized Gain on Reacquired Debt	2415	
Other Deferred Credits	2425	
Accrued Rate-Payer Benefit	2435	
Debentures Outstanding - Long Term Portion	2505	
Debenture Advances	2510	
Reacquired Bonds	2515	
Other Long Term Debt	2520	-948,613.35
Term Bank Loans - Long Term Portion	2525	
Ontario Hydro Debt Outstanding - Long Term Portion	2530	
Advances from Associated Companies	2550	
Common Shares Issued	3005	-1,689,346.00
Preference Shares Issued	3008	
Contributed Surplus	3010	
Donations Received	3020	
Development Charges Transferred to Equity	3022	

Account Description	Account Number	Amount
Capital Stock Held in Treasury	3026	
Miscellaneous Paid-In Capital	3030	
Installments Received on Capital Stock	3035	
Appropriated Retained Earnings	3040	
Unappropriated Retained Earnings	3045	-869,588.96
Balance Transferred From Income	3046	-168,338.05
Appropriations of Retained Earnings - Current Period	3047	
Dividends Payable-Preference Shares	3048	
Dividends Payable-Common Shares	3049	84,467.30
Adjustment to Retained Earnings	3055	
Unappropriated Undistributed Subsidiary Earnings	3065	
Residential Energy Sales	4006	-2,949,767.69
Commercial Energy Sales	4010	
Industrial Energy Sales	4015	
Energy Sales to Large Users	4020	-408,532.52
Street Lighting Energy Sales	4025	-71,283.68
Sentinel Lighting Energy Sales	4030	-6,722.52
General Energy Sales	4035	-3,715,856.73
Other Energy Sales to Public Authorities	4040	
Energy Sales to Railroads and Railways	4045	
Revenue Adjustment	4050	
Energy Sales for Resale	4055	-952,209.82
Interdepartmental Energy Sales	4060	
Billed WMS	4062	-1,142,321.63
Billed One-Time	4064	
Billed NW	4066	-818,909.01
Billed CN	4068	-529,329.49
Billed - LV	4075	-52,290.22
Distribution Services Revenue	4080	-1,090,417.99
Retail Services Revenues	4082	
Service Transaction Requests (STR) Revenues	4084	
Electric Services Incidental to Energy Sales	4090	
Transmission Charges Revenue	4105	
Transmission Services Revenue	4110	
Interdepartmental Rents	4205	
Rent from Electric Property	4210	-16,544.48
Other Utility Operating Income	4215	
Other Electric Revenues	4220	

Account Description	Account Number	Amount
Late Payment Charges	4225	-37,616.82
Sales of Water and Water Power	4230	
Miscellaneous Service Revenues	4235	-78,123.32
Provision for Rate Refunds	4240	
Government Assistance Directly Credited to Income	4245	
Regulatory Debits	4305	
Regulatory Credits	4310	
Revenues from Electric Plant Leased to Others	4315	
Expenses of Electric Plant Leased to Others	4320	
Revenues from Merchandise, Jobbing, Etc.	4325	-64,902.73
Costs and Expenses of Merchandising, Jobbing, Etc.	4330	51,480.84
Profits and Losses from Financial Instrument Hedges	4335	
Profits and Losses from Financial Instrument Investments	4340	
Gains from Disposition of Future Use Utility Plant	4345	
Losses from Disposition of Future Use Utility Plant	4350	
Gain on Disposition of Utility and Other Property	4355	
Loss on Disposition of Utility and Other Property	4360	
Gains from Disposition of Allowances for Emission	4365	
Losses from Disposition of Allowances for Emission	4370	
Revenues from Non-Utility Operations	4375	
Expenses of Non-Utility Operations	4380	
Non-Utility Rental Income	4385	
Miscellaneous Non-Operating Income	4390	-1,800.00
Rate-Payer Benefit Including Interest	4395	
Foreign Exchange Gains and Losses, Including Amortization	4398	
Interest and Dividend Income	4405	-10,829.71
Equity in Earnings of Subsidiary Companies	4415	
Operation Supervision and Engineering	4505	
Fuel	4510	
Steam Expense	4515	
Steam From Other Sources	4520	
Steam Transferred--Credit	4525	
Electric Expense	4530	
Water For Power	4535	
Water Power Taxes	4540	
Hydraulic Expenses	4545	
Generation Expense	4550	
Miscellaneous Power Generation Expenses	4555	

Account Description	Account Number	Amount
Rents	4560	
Allowances for Emissions	4565	
Maintenance Supervision and Engineering	4605	
Maintenance of Structures	4610	
Maintenance of Boiler Plant	4615	
Maintenance of Electric Plant	4620	
Maintenance of Reservoirs, Dams and Waterways	4625	
Maintenance of Water Wheels, Turbines and Generators	4630	
Maintenance of Generating and Electric Plant	4635	
Maintenance of Miscellaneous Power Generation Plant	4640	
Power Purchased	4705	8,104,372.96
Charges-WMS	4708	1,142,321.63
Cost of Power Adjustments	4710	
Charges-One-Time	4712	
Charges-NW	4714	818,909.01
System Control and Load Dispatching	4715	
Charges-CN	4716	529,329.49
Other Expenses	4720	
Competition Transition Expense	4725	
Rural Rate Assistance Expense	4730	
Charges - LV	4750	52,290.22
Operation Supervision and Engineering	4805	
Load Dispatching	4810	
Station Buildings and Fixtures Expenses	4815	
Transformer Station Equipment - Operating Labour	4820	
Transformer Station Equipment - Operating Supplies and Expense	4825	
Overhead Line Expenses	4830	
Underground Line Expenses	4835	
Transmission of Electricity by Others	4840	
Miscellaneous Transmission Expense	4845	
Rents	4850	
Maintenance Supervision and Engineering	4905	
Maintenance of Transformer Station Buildings and Fixtures	4910	
Maintenance of Transformer Station Equipment	4916	
Maintenance of Towers, Poles and Fixtures	4930	
Maintenance of Overhead Conductors and Devices	4935	
Maintenance of Overhead Lines - Right of Way	4940	
Maintenance of Overhead Lines - Roads and Trails Repairs	4945	

Account Description	Account Number	Amount
Maintenance of Overhead Lines - Snow Removal from Roads and Trails	4950	
Maintenance of Underground Lines	4960	
Maintenance of Miscellaneous Transmission Plant	4965	
Operation Supervision and Engineering	5005	
Load Dispatching	5010	
Station Buildings and Fixtures Expense	5012	
Transformer Station Equipment - Operation Labour	5014	5,396.29
Transformer Station Equipment - Operation Supplies and Expenses	5015	6,707.90
Distribution Station Equipment - Operation Labour	5016	9,147.45
Distribution Station Equipment - Operation Supplies and Expenses	5017	1,679.98
Overhead Distribution Lines and Feeders - Operation Labour	5020	8,284.31
Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	5025	1,232.44
Overhead Subtransmission Feeders - Operation	5030	
Overhead Distribution Transformers- Operation	5035	3,743.93
Underground Distribution Lines and Feeders - Operation Labour	5040	992.66
Underground Distribution Lines and Feeders - Operation Supplies and Expenses	5045	10.80
Underground Subtransmission Feeders - Operation	5050	
Underground Distribution Transformers - Operation	5055	365.34
Street Lighting and Signal System Expense	5060	
Meter Expense	5065	11,635.67
Customer Premises - Operation Labour	5070	
Customer Premises - Materials and Expenses	5075	
Miscellaneous Distribution Expense	5085	
Underground Distribution Lines and Feeders - Rental Paid	5090	
Overhead Distribution Lines and Feeders - Rental Paid	5095	1,029.96
Other Rent	5096	
Maintenance Supervision and Engineering	5105	4,720.00
Maintenance of Buildings and Fixtures - Distribution Stations	5110	
Maintenance of Transformer Station Equipment	5112	
Maintenance of Distribution Station Equipment	5114	
Maintenance of Poles, Towers and Fixtures	5120	7,058.73
Maintenance of Overhead Conductors and Devices	5125	32,631.16
Maintenance of Overhead Services	5130	30,998.92
Overhead Distribution Lines and Feeders - Right of Way	5135	58,977.85
Maintenance of Underground Conduit	5145	449.58
Maintenance of Underground Conductors and Devices	5150	3,684.76
Maintenance of Underground Services	5155	4,441.56
Maintenance of Line Transformers	5160	12,022.75

Account Description	Account Number	Amount
Maintenance of Street Lighting and Signal Systems	5165	
Sentinel Lights - Labour	5170	
Sentinel Lights - Materials and Expenses	5172	
Maintenance of Meters	5175	4,666.60
Customer Installations Expenses- Leased Property	5178	
Water Heater Rentals - Labour	5185	
Water Heater Rentals - Materials and Expenses	5186	
Water Heater Controls - Labour	5190	
Water Heater Controls - Materials and Expenses	5192	
Maintenance of Other Installations on Customer Premises	5195	
Purchase of Transmission and System Services	5205	
Transmission Charges	5210	
Transmission Charges Recovered	5215	
Supervision	5305	
Meter Reading Expense	5310	27,809.57
Customer Billing	5315	170,150.96
Collecting	5320	101,678.44
Collecting- Cash Over and Short	5325	102.78
Collection Charges	5330	
Bad Debt Expense	5335	13,021.36
Miscellaneous Customer Accounts Expenses	5340	
Supervision	5405	
Community Relations - Sundry	5410	500.00
Energy Conservation	5415	805.44
Community Safety Program	5420	
Miscellaneous Customer Service and Informational Expenses	5425	
Supervision	5505	
Demonstrating and Selling Expense	5510	
Advertising Expense	5515	
Miscellaneous Sales Expense	5520	
Executive Salaries and Expenses	5605	96,303.19
Management Salaries and Expenses	5610	61,156.22
General Administrative Salaries and Expenses	5615	
Office Supplies and Expenses	5620	20,291.84
Administrative Expense Transferred/Credit	5625	
Outside Services Employed	5630	11,137.50
Property Insurance	5635	4,469.58
Injuries and Damages	5640	11,603.52

Account Description	Account Number	Amount
Employee Pensions and Benefits	5645	3,106.80
Franchise Requirements	5650	
Regulatory Expenses	5655	12,411.47
General Advertising Expenses	5660	
Miscellaneous General Expenses	5665	12,917.57
Rent	5670	
Maintenance of General Plant	5675	25,826.52
Electrical Safety Authority Fees	5680	4,787.49
Independent Market Operator Fees and Penalties	5685	
OM&A Contra	5695	
Amortization Expense - Property, Plant, and Equipment	5705	153,992.36
Amortization of Limited Term Electric Plant	5710	
Amortization of Intangibles and Other Electric Plant	5715	
Amortization of Electric Plant Acquisition Adjustments	5720	
Miscellaneous Amortization	5725	
Amortization of Unrecovered Plant and Regulatory Study Costs	5730	
Amortization of Deferred Development Costs	5735	
Amortization of Deferred Charges	5740	
Interest on Long Term Debt	6005	
Amortization of Debt Discount and Expense	6010	
Amortization of Premium on Debt/Credit	6015	
Amortization of Loss on Reacquired Debt	6020	
Amortization of Gain on Reacquired Debt--Credit	6025	
Interest on Debt to Associated Companies	6030	
Other Interest Expense	6035	92,866.35
Allowance for Borrowed Funds Used During Construction--Credit	6040	
Allowance For Other Funds Used During Construction	6042	
Interest Expense on Capital Lease Obligations	6045	
Taxes Other Than Income Taxes	6105	15,765.56
Income Taxes	6110	-59,831.00
Provision for Future Income Taxes	6115	89,664.00
Donations	6205	
Life Insurance	6210	
Penalties	6215	
Other Deductions	6225	
Extraordinary Income	6305	
Extraordinary Deductions	6310	
Income Taxes: Extraordinary Item	6315	

Account Description	Account Number	Amount
Discontinues Operations - Income/ Gains	6405	
Discontinued Operations - Deductions/ Losses	6410	
Income Taxes, Discontinued Operations	6415	

Trial Balance Summary

Assets

Current Assets:	5,279,873.75
Inventory:	126,956.68
Non-Current Assets:	157,654.17
Other Assets and Deferred Charges:	-1,303,020.55
Other Capital Assets:	3,414,207.25
Accumulated Amortization:	-1,451,310.55
Net Assets:	6,224,360.75

Liabilities And Equity

Non-Current Liabilities:	-572,030.21
Current Liabilities:	-2,060,911.48
Other Liabilities Deferred Credit:	-948,613.35
Shareholders' Equity:	-2,642,805.71
Net Liabilities and Equity:	-6,224,360.75

Revenues

Sales of Electricity:	-10,647,223.31
Revenues from Services:	-1,090,417.99
Other Operating Revenues:	-132,284.62
Other Income / Deductions:	-15,221.89
Investment Income:	-10,829.71
Total Revenues:	-11,895,977.52

Expenses

Generation Expenses:	0.00
Other Power Supply Expenses:	10,647,223.31
Transmission Expenses:	0.00
Distribution Expenses:	209,878.64
Other Expenses:	
Billing Collecting:	312,763.11
Community Relations:	1,305.44
Sales Expenses:	
Administration General Expenses:	264,011.70
Amortization Expenses:	153,992.36
Interest Expenses:	92,866.35
Taxes:	45,598.56
Other Deductions:	
Extraordinary Items:	
Discontinued Operations:	
Total Expenses:	11,727,639.47
Profit/Loss:	-168,338.05

Final Total/Balancing Factor

Trial balance Total Excluding accounts 1605 and 3046:	**0.00**

Trial Balance (E217)

January 09, 2013

Filing Year	Filing Name	RRR Filing Number
2011	2.1.7	536
Reporting Period and Company Name	**Licence Type**	**Status**
April-2011Hydro Hawkesbury Inc.	Distributor	Submitted
Report Version	**Extension Granted**	**Extension Deadline**
0		
Filing Due Date	**Reporting From**	**Reporting To**
May 02, 2011	01/01/2010	31/12/2010
Submitted On	**Submitter Name**	**Expiry Date**
April 18, 2011	Linda Parisien	May 03, 2011

Color Legend: **Assets** **Liabilities and Equity** **Income Statement**

Account Description	Account Number	Amount
Cash	1005	92,785.99
Cash Advances and Working Funds	1010	1,200.00
Interest Special Deposits	1020	0.00
Dividend Special Deposits	1030	0.00
Other Special Deposits	1040	0.00
Term Deposits	1060	1,012,190.49
Current Investments	1070	0.00
Customer Accounts Receivable	1100	1,674,532.06
Accounts Receivable - Services	1102	168,724.45
Accounts Receivable - Recoverable Work	1104	0.00
Accounts Receivable - Merchandise, Jobbing, etc.	1105	0.00
Other Accounts Receivable	1110	0.00
Accrued Utility Revenues	1120	1,275,333.18
Accumulated Provision for Uncollectible Accounts--Credit	1130	-21,101.49
Interest and Dividends Receivable	1140	0.00
Rents Receivable	1150	0.00
Notes Receivable	1170	0.00
Prepayments	1180	27,904.86
Miscellaneous Current and Accrued Assets	1190	27,333.01
Accounts Receivable from Associated Companies	1200	0.00
Notes Receivable from Associated Companies	1210	0.00
Fuel Stock	1305	0.00
Plant Materials and Operating Supplies	1330	125,668.58
Merchandise	1340	0.00

Account Description	Account Number	Amount
Other Materials and Supplies	1350	0.00
Long Term Investments in Non-Associated Companies	1405	0.00
Long Term Receivable - Street Lighting Transfer	1408	0.00
Other Special or Collateral Funds	1410	0.00
Sinking Funds	1415	0.00
Unamortized Debt Expense	1425	0.00
Unamortized Discount on Long-Term Debt--Debit	1445	0.00
Unamortized Deferred Foreign Currency Translation Gains and Losses	1455	0.00
Other Non-Current Assets	1460	183,559.50
O.M.E.R.S. Past Service Costs	1465	0.00
Past Service Costs - Employee Future Benefits	1470	0.00
Past Service Costs - Other Pension Plans	1475	0.00
Portfolio Investments - Associated Companies	1480	0.00
Investment in Associated Companies - Significant Influence	1485	0.00
Investment in Subsidiary Companies	1490	0.00
Unrecovered Plant and Regulatory Study Costs	1505	0.00
Other Regulatory Assets	1508	3,218.25
Preliminary Survey and Investigation Charges	1510	9,400.00
Emission Allowance Inventory	1515	0.00
Emission Allowances Withheld	1516	0.00
RCVARetail	1518	-685.82
Power Purchase Variance Account	1520	0.00
Special Purpose Charge Assessment Variance	1521	50,683.09
Miscellaneous Deferred Debits	1525	4.09
Deferred Losses from Disposition of Utility Plant	1530	0.00
Renewable Connection Capital Deferral Account	1531	0.00
Renewable Connection OM&A Deferral Account	1532	0.00
Smart Grid Capital Deferral Account	1534	0.00
Smart Grid Capital OM&A Account	1535	-8,161.66
Unamortized Loss on Reacquired Debt	1540	0.00
Development Charge Deposits/ Receivables	1545	0.00
RCVASTR	1548	4,365.00
LV Variance Account	1550	47,960.11
Smart Meter Capital and Recovery Offset Variance	1555	293,197.29
Smart Meter OM&A Variance	1556	33,402.90
Deferred Development Costs	1560	0.00
Deferred Payments in Lieu of Taxes	1562	-59,857.75
Deferred PILs Contra Account	1563	59,857.75

Account Description	Account Number	Amount
Conservation and Demand Management Expenditures and Recoveries	1565	0.00
CDM Contra	1566	0.00
Qualifying Transition Costs	1570	22,611.10
Pre-market Opening Energy Variance	1571	-10,682.28
Extraordinary Event Costs	1572	0.00
Deferred Rate Impact Amounts	1574	0.00
RSVAWMS	1580	-336,755.40
RSVAONE-TIME	1582	0.00
RSVANW	1584	53,444.42
RSVACN	1586	-89,395.03
RSVAPOWER	1588	964,143.37
Recovery of regulatory asset balances	1590	495.63
2006 PILs & Taxes Variance	1592	0.00
Disposition and Recovery of Regulatory Balances Control Account	1595	-1,370,954.21
Sub-Account Disposition of Account Balances Approved in 2008	1595	0.00
Sub-Account Disposition of Account Balances Approved in 2009	1595	0.00
Electric Plant in Service - Control Account	1605	
Organization	1606	0.00
Franchises and Consents	1608	0.00
Miscellaneous Intangible Plant	1610	0.00
Land	1615	0.00
Land Rights	1616	0.00
Buildings and Fixtures	1620	0.00
Leasehold Improvements	1630	0.00
Boiler Plant Equipment	1635	0.00
Engines and Engine-Driven Generators	1640	0.00
Turbogenerator Units	1645	0.00
Reservoirs, Dams and Waterways	1650	0.00
Water Wheels, Turbines and Generators	1655	0.00
Roads, Railroads and Bridges	1660	0.00
Fuel Holders, Producers and Accessories	1665	0.00
Prime Movers	1670	0.00
Generators	1675	0.00
Accessory Electric Equipment	1680	0.00
Miscellaneous Power Plant Equipment	1685	0.00
Land	1705	10,000.00
Land Rights	1706	0.00
Buildings and Fixtures	1708	0.00

Account Description	Account Number	Amount
Leasehold Improvements	1710	0.00
Station Equipment	1715	0.00
Towers and Fixtures	1720	0.00
Poles and Fixtures	1725	0.00
Overhead Conductors and Devices	1730	0.00
Underground Conduit	1735	0.00
Underground Conductors and Devices	1740	0.00
Roads and Trails	1745	0.00
Land	1805	10,000.00
Land Rights	1806	8,588.00
Buildings and Fixtures	1808	0.00
Leasehold Improvements	1810	0.00
Transformer Station Equipment - Normally Primary above 50 kV	1815	402,411.74
Distribution Station Equipment - Normally Primary below 50 kV	1820	184,860.00
Storage Battery Equipment	1825	0.00
Poles, Towers and Fixtures	1830	351,066.63
Overhead Conductors and Devices	1835	402,306.23
Underground Conduit	1840	113,855.12
Underground Conductors and Devices	1845	260,391.60
Line Transformers	1850	397,148.41
Services	1855	26,835.48
Meters	1860	246,912.13
Other Installations on Customer's Premises	1865	0.00
Leased Property on Customer Premises	1870	0.00
Street Lighting and Signal Systems	1875	0.00
Land	1905	28,299.70
Land Rights	1906	0.00
Buildings and Fixtures	1908	824,123.77
Leasehold Improvements	1910	0.00
Office Furniture and Equipment	1915	32,653.73
Computer Equipment - Hardware	1920	50,118.41
Computer Software	1925	128,153.27
Transportation Equipment	1930	205,345.80
Stores Equipment	1935	0.00
Tools, Shop and Garage Equipment	1940	19,966.20
Measurement and Testing Equipment	1945	0.00
Power Operated Equipment	1950	4,363.29
Communication Equipment	1955	0.00

Account Description	Account Number	Amount
Miscellaneous Equipment	1960	0.00
Water Heater Rental Units	1965	0.00
Load Management Controls - Customer Premises	1970	0.00
Load Management Controls - Utility Premises	1975	0.00
System Supervisory Equipment	1980	0.00
Sentinel Lighting Rental Units	1985	0.00
Other Tangible Property	1990	0.00
Contributions and Grants - Credit	1995	-136,546.00
Property Under Capital Leases	2005	0.00
Electric Plant Purchased or Sold	2010	0.00
Experimental Electric Plant Unclassified	2020	0.00
Electric Plant and Equipment Leased to Others	2030	0.00
Electric Plant Held for Future Use	2040	0.00
Completed Construction Not Classified--Electric	2050	0.00
Construction Work in Progress--Electric	2055	0.00
Electric Plant Acquisition Adjustment	2060	0.00
Other Electric Plant Adjustment	2065	0.00
Other Utility Plant	2070	0.00
Non-Utility Property Owned or Under Capital Leases	2075	0.00
Accumulated Amortization of Electric Utility Plan - PP&E	2105	-1,614,112.81
Accumulated Amortization of Electric Utility Plant - Intangibles	2120	0.00
Accumulated Amortization of Electric Plant Acquisition Adjustment	2140	0.00
Accumulated Amortization of Other Utility Plant	2160	0.00
Accumulated Amortization of Non-Utility Property	2180	0.00
Accounts Payable	2205	-2,229,071.54
Customer Credit Balances	2208	-129,283.39
Current Portion of Customer Deposits	2210	-326,572.92
Dividends Declared	2215	0.00
Miscellaneous Current and Accrued Liabilities	2220	-58,560.57
Notes and Loans Payable	2225	0.00
Accounts Payable to Associated Companies	2240	0.00
Notes Payable to Associated Companies	2242	0.00
Debt Retirement Charges(DRC) Payable	2250	0.00
Transmission Charges Payable	2252	0.00
Electrical Safety Authority Fees Payable	2254	0.00
Independent Market Operator Fees and Penalties Payable	2256	0.00
Current Portion of Long Term Debt	2260	0.00
Ontario Hydro Debt - Current Portion	2262	0.00

Account Description	Account Number	Amount
Pensions and Employee Benefits - Current Portion	2264	0.00
Accrued Interest on Long Term Debt	2268	0.00
Matured Long Term Debt	2270	0.00
Matured Interest on Long Term Debt	2272	0.00
Obligations Under Capital Leases--Current	2285	0.00
Commodity Taxes	2290	0.00
Payroll Deductions / Expenses Payable	2292	0.00
Accrual for Taxes Payments in Lieu of Taxes, Etc.	2294	282,900.00
Future Income Taxes - Current	2296	167,484.00
Accumulated Provision for Injuries and Damages	2305	0.00
Employee Future Benefits	2306	0.00
Other Pensions - Past Service Liability	2308	0.00
Vested Sick Leave Liability	2310	-78,562.95
Accumulated Provision for Rate Refunds	2315	0.00
Other Miscellaneous Non-Current Liabilities	2320	0.00
Obligations Under Capital Lease--Non-Current	2325	0.00
Development Charge Fund	2330	0.00
Long Term Customer Deposits	2335	-383,005.34
Collateral Funds Liability	2340	0.00
Unamortized Premium on Long Term Debt	2345	0.00
O.M.E.R.S. - Past Service Liability - Long Term Portion	2348	0.00
Future Income Tax - Non-Current	2350	0.00
Other Regulatory Liabilities	2405	0.00
Deferred Gains from Disposition of Utility Plant	2410	0.00
Unamortized Gain on Reacquired Debt	2415	0.00
Other Deferred Credits	2425	0.00
Accrued Rate-Payer Benefit	2435	0.00
Debentures Outstanding - Long Term Portion	2505	0.00
Debenture Advances	2510	0.00
Reacquired Bonds	2515	0.00
Other Long Term Debt	2520	-731,714.70
Term Bank Loans - Long Term Portion	2525	0.00
Ontario Hydro Debt Outstanding - Long Term Portion	2530	0.00
Advances from Associated Companies	2550	0.00
Common Shares Issued	3005	-1,689,346.00
Preference Shares Issued	3008	0.00
Contributed Surplus	3010	0.00
Donations Received	3020	0.00

Account Description	Account Number	Amount
Development Charges Transferred to Equity	3022	0.00
Capital Stock Held in Treasury	3026	0.00
Miscellaneous Paid-In Capital	3030	0.00
Installments Received on Capital Stock	3035	0.00
Appropriated Retained Earnings	3040	0.00
Unappropriated Retained Earnings	3045	-953,459.71
Balance Transferred From Income	3046	-146,436.36
Appropriations of Retained Earnings - Current Period	3047	0.00
Dividends Payable-Preference Shares	3048	0.00
Dividends Payable-Common Shares	3049	84,467.30
Adjustment to Retained Earnings	3055	0.00
Unappropriated Undistributed Subsidiary Earnings	3065	0.00
Non-Utility Shareholders¿ Equity	3075	0.00
Residential Energy Sales	4006	-3,107,821.13
Commercial Energy Sales	4010	0.00
Industrial Energy Sales	4015	0.00
Energy Sales to Large Users	4020	0.00
Street Lighting Energy Sales	4025	-40,735.07
Sentinel Lighting Energy Sales	4030	-6,692.08
General Energy Sales	4035	-3,868,453.29
Other Energy Sales to Public Authorities	4040	0.00
Energy Sales to Railroads and Railways	4045	0.00
Revenue Adjustment	4050	0.00
Energy Sales for Resale	4055	-868,199.20
Interdepartmental Energy Sales	4060	0.00
Billed WMS	4062	-1,041,785.51
Billed One-Time	4064	0.00
Billed NW	4066	-792,091.05
Billed CN	4068	-461,614.33
Billed - LV	4075	-33,927.80
Distribution Services Revenue	4080	-1,210,347.70
Retail Services Revenues	4082	0.00
Service Transaction Requests (STR) Revenues	4084	0.00
Electric Services Incidental to Energy Sales	4090	0.00
Transmission Charges Revenue	4105	0.00
Transmission Services Revenue	4110	0.00
Interdepartmental Rents	4205	0.00
Rent from Electric Property	4210	-16,394.48

Account Description	Account Number	Amount
Other Utility Operating Income	4215	0.00
Other Electric Revenues	4220	0.00
Late Payment Charges	4225	-28,329.26
Sales of Water and Water Power	4230	0.00
Miscellaneous Service Revenues	4235	-72,825.59
Provision for Rate Refunds	4240	0.00
Government Assistance Directly Credited to Income	4245	0.00
Regulatory Debits	4305	0.00
Regulatory Credits	4310	0.00
Revenues from Electric Plant Leased to Others	4315	0.00
Expenses of Electric Plant Leased to Others	4320	0.00
Special Purpose Charge Recovery	4324	-22,101.26
Revenues from Merchandise, Jobbing, Etc.	4325	-34,415.03
Costs and Expenses of Merchandising, Jobbing, Etc.	4330	19,817.12
Profits and Losses from Financial Instrument Hedges	4335	0.00
Profits and Losses from Financial Instrument Investments	4340	0.00
Gains from Disposition of Future Use Utility Plant	4345	0.00
Losses from Disposition of Future Use Utility Plant	4350	0.00
Gain on Disposition of Utility and Other Property	4355	0.00
Loss on Disposition of Utility and Other Property	4360	0.00
Gains from Disposition of Allowances for Emission	4365	0.00
Losses from Disposition of Allowances for Emission	4370	0.00
Revenues from Non-Utility Operations	4375	0.00
Expenses of Non-Utility Operations	4380	0.00
Non-Utility Rental Income	4385	0.00
Miscellaneous Non-Operating Income	4390	-3,655.22
Rate-Payer Benefit Including Interest	4395	0.00
Foreign Exchange Gains and Losses, Including Amortization	4398	0.00
Interest and Dividend Income	4405	-12,059.97
Equity in Earnings of Subsidiary Companies	4415	0.00
Operation Supervision and Engineering	4505	0.00
Fuel	4510	0.00
Steam Expense	4515	0.00
Steam From Other Sources	4520	0.00
Steam Transferred--Credit	4525	0.00
Electric Expense	4530	0.00
Water For Power	4535	0.00
Water Power Taxes	4540	0.00

Account Description	Account Number	Amount
Hydraulic Expenses	4545	0.00
Generation Expense	4550	0.00
Miscellaneous Power Generation Expenses	4555	0.00
Rents	4560	0.00
Allowances for Emissions	4565	0.00
Maintenance Supervision and Engineering	4605	0.00
Maintenance of Structures	4610	0.00
Maintenance of Boiler Plant	4615	0.00
Maintenance of Electric Plant	4620	0.00
Maintenance of Reservoirs, Dams and Waterways	4625	0.00
Maintenance of Water Wheels, Turbines and Generators	4630	0.00
Maintenance of Generating and Electric Plant	4635	0.00
Maintenance of Miscellaneous Power Generation Plant	4640	0.00
Power Purchased	4705	7,891,900.77
Charges-WMS	4708	1,041,785.51
Cost of Power Adjustments	4710	0.00
Charges-One-Time	4712	0.00
Charges-NW	4714	792,091.05
System Control and Load Dispatching	4715	0.00
Charges-CN	4716	461,614.33
Other Expenses	4720	0.00
Competition Transition Expense	4725	0.00
Rural Rate Assistance Expense	4730	0.00
Charges - LV	4750	33,927.80
Operation Supervision and Engineering	4805	0.00
Load Dispatching	4810	0.00
Station Buildings and Fixtures Expenses	4815	0.00
Transformer Station Equipment - Operating Labour	4820	0.00
Transformer Station Equipment - Operating Supplies and Expense	4825	0.00
Overhead Line Expenses	4830	0.00
Underground Line Expenses	4835	0.00
Transmission of Electricity by Others	4840	0.00
Miscellaneous Transmission Expense	4845	0.00
Rents	4850	0.00
Maintenance Supervision and Engineering	4905	0.00
Maintenance of Transformer Station Buildings and Fixtures	4910	0.00
Maintenance of Transformer Station Equipment	4916	0.00
Maintenance of Towers, Poles and Fixtures	4930	0.00

Account Description	Account Number	Amount
Maintenance of Overhead Conductors and Devices	4935	0.00
Maintenance of Overhead Lines - Right of Way	4940	0.00
Maintenance of Overhead Lines - Roads and Trails Repairs	4945	0.00
Maintenance of Overhead Lines - Snow Removal from Roads and Trails	4950	0.00
Maintenance of Underground Lines	4960	0.00
Maintenance of Miscellaneous Transmission Plant	4965	0.00
Operation Supervision and Engineering	5005	0.00
Load Dispatching	5010	0.00
Station Buildings and Fixtures Expense	5012	0.00
Transformer Station Equipment - Operation Labour	5014	3,289.90
Transformer Station Equipment - Operation Supplies and Expenses	5015	8,023.04
Distribution Station Equipment - Operation Labour	5016	4,358.85
Distribution Station Equipment - Operation Supplies and Expenses	5017	4,905.24
Overhead Distribution Lines and Feeders - Operation Labour	5020	9,936.49
Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	5025	1,171.07
Overhead Subtransmission Feeders - Operation	5030	0.00
Overhead Distribution Transformers- Operation	5035	7,628.04
Underground Distribution Lines and Feeders - Operation Labour	5040	911.05
Underground Distribution Lines and Feeders - Operation Supplies and Expenses	5045	31.74
Underground Subtransmission Feeders - Operation	5050	0.00
Underground Distribution Transformers - Operation	5055	316.59
Street Lighting and Signal System Expense	5060	0.00
Meter Expense	5065	33,645.26
Customer Premises - Operation Labour	5070	0.00
Customer Premises - Materials and Expenses	5075	0.00
Miscellaneous Distribution Expense	5085	0.00
Underground Distribution Lines and Feeders - Rental Paid	5090	0.00
Overhead Distribution Lines and Feeders - Rental Paid	5095	886.91
Other Rent	5096	0.00
Maintenance Supervision and Engineering	5105	720.00
Maintenance of Buildings and Fixtures - Distribution Stations	5110	0.00
Maintenance of Transformer Station Equipment	5112	0.00
Maintenance of Distribution Station Equipment	5114	0.00
Maintenance of Poles, Towers and Fixtures	5120	5,216.54
Maintenance of Overhead Conductors and Devices	5125	36,894.46
Maintenance of Overhead Services	5130	28,277.95
Overhead Distribution Lines and Feeders - Right of Way	5135	40,522.91
Maintenance of Underground Conduit	5145	333.17

Account Description	Account Number	Amount
Maintenance of Underground Conductors and Devices	5150	5,407.59
Maintenance of Underground Services	5155	7,402.01
Maintenance of Line Transformers	5160	7,716.53
Maintenance of Street Lighting and Signal Systems	5165	0.00
Sentinel Lights - Labour	5170	0.00
Sentinel Lights - Materials and Expenses	5172	0.00
Maintenance of Meters	5175	-981.88
Customer Installations Expenses- Leased Property	5178	0.00
Water Heater Rentals - Labour	5185	0.00
Water Heater Rentals - Materials and Expenses	5186	0.00
Water Heater Controls - Labour	5190	0.00
Water Heater Controls - Materials and Expenses	5192	0.00
Maintenance of Other Installations on Customer Premises	5195	0.00
Purchase of Transmission and System Services	5205	0.00
Transmission Charges	5210	0.00
Transmission Charges Recovered	5215	0.00
Supervision	5305	0.00
Meter Reading Expense	5310	29,863.73
Customer Billing	5315	175,731.13
Collecting	5320	100,396.13
Collecting- Cash Over and Short	5325	0.00
Collection Charges	5330	0.00
Bad Debt Expense	5335	19,528.13
Miscellaneous Customer Accounts Expenses	5340	0.00
Supervision	5405	0.00
Community Relations - Sundry	5410	100.00
Energy Conservation	5415	0.00
Community Safety Program	5420	0.00
Miscellaneous Customer Service and Informational Expenses	5425	0.00
Supervision	5505	0.00
Demonstrating and Selling Expense	5510	0.00
Advertising Expense	5515	0.00
Miscellaneous Sales Expense	5520	0.00
Executive Salaries and Expenses	5605	105,990.16
Management Salaries and Expenses	5610	69,180.62
General Administrative Salaries and Expenses	5615	0.00
Office Supplies and Expenses	5620	21,409.29
Administrative Expense Transferred/Credit	5625	0.00

Account Description	Account Number	Amount
Outside Services Employed	5630	11,212.50
Property Insurance	5635	4,566.42
Injuries and Damages	5640	6,177.60
Employee Pensions and Benefits	5645	3,249.72
Franchise Requirements	5650	0.00
Regulatory Expenses	5655	47,004.25
General Advertising Expenses	5660	0.00
Miscellaneous General Expenses	5665	13,817.39
Rent	5670	0.00
Maintenance of General Plant	5675	25,832.76
Electrical Safety Authority Fees	5680	4,914.05
Special Purpose Charge Expense	5681	22,101.26
Independent Market Operator Fees and Penalties	5685	0.00
OM&A Contra	5695	0.00
Amortization Expense - Property, Plant, and Equipment	5705	158,511.29
Amortization of Limited Term Electric Plant	5710	0.00
Amortization of Intangibles and Other Electric Plant	5715	0.00
Amortization of Electric Plant Acquisition Adjustments	5720	0.00
Miscellaneous Amortization	5725	0.00
Amortization of Unrecovered Plant and Regulatory Study Costs	5730	0.00
Amortization of Deferred Development Costs	5735	0.00
Amortization of Deferred Charges	5740	0.00
Interest on Long Term Debt	6005	0.00
Amortization of Debt Discount and Expense	6010	0.00
Amortization of Premium on Debt/Credit	6015	0.00
Amortization of Loss on Reacquired Debt	6020	0.00
Amortization of Gain on Reacquired Debt--Credit	6025	0.00
Interest on Debt to Associated Companies	6030	0.00
Other Interest Expense	6035	64,736.83
Allowance for Borrowed Funds Used During Construction--Credit	6040	0.00
Allowance For Other Funds Used During Construction	6042	0.00
Interest Expense on Capital Lease Obligations	6045	0.00
Taxes Other Than Income Taxes	6105	15,678.31
Income Taxes	6110	-161,142.00
Provision for Future Income Taxes	6115	288,402.00
Donations	6205	0.00
Life Insurance	6210	0.00
Penalties	6215	0.00

Account Description	Account Number	Amount
Other Deductions	6225	0.00
Extraordinary Income	6305	0.00
Extraordinary Deductions	6310	0.00
Income Taxes: Extraordinary Item	6315	0.00
Discontinues Operations - Income/ Gains	6405	0.00
Discontinued Operations - Deductions/ Losses	6410	0.00
Income Taxes, Discontinued Operations	6415	0.00

Account Description	Account Number	Amount

Trial Balance Summary

Assets

Current Assets:	4,258,902.55
Inventory:	125,668.58
Non-Current Assets:	183,559.50
Other Assets and Deferred Charges:	-333,709.15
Other Capital Assets:	3,570,853.51
Accumulated Amortization:	-1,614,112.81
Net Assets:	6,191,162.18

Liabilities And Equity

Non-Current Liabilities:	-461,568.29
Current Liabilities:	-2,293,104.42
Other Liabilities Deferred Credit:	-731,714.70
Shareholders' Equity:	-2,704,774.77
Net Liabilities and Equity:	-6,191,162.18

Revenues

Sales of Electricity:	-10,221,319.46
Revenues from Services:	-1,210,347.70
Other Operating Revenues:	-117,549.33
Other Income / Deductions:	-40,354.39
Investment Income:	-12,059.97
Total Revenues:	-11,601,630.85

Expenses

Generation Expenses:	0.00
Other Power Supply Expenses:	10,221,319.46
Transmission Expenses:	0.00
Distribution Expenses:	206,613.46
Other Expenses:	
Billing Collecting:	325,519.12
Community Relations:	100.00
Sales Expenses:	
Administration General Expenses:	335,456.02
Amortization Expenses:	158,511.29
Interest Expenses:	64,736.83
Taxes:	142,938.31
Other Deductions:	
Extraordinary Items:	
Discontinued Operations:	
Total Expenses:	11,455,194.49
Profit/Loss:	-146,436.36

Final Total/Balancing Factor

Trial balance Total Excluding accounts 1605 and 3046:	**0.00**

Report Name: E217_Trial_Balance, Last Version March 4, 2011

Trial Balance (E217)

January 09, 2013

Filing Year
2012

Filing Name
2.1.7

RRR Filing Number
1,299

Reporting Period and Company Name
April-2012Hydro Hawkesbury Inc.

Licence Type
Distributor

Status
Submitted

Report Version
0

Extension Granted

Extension Deadline

Filing Due Date
April 30, 2012

Reporting From
01/01/2011

Reporting To
31/12/2011

Submitted On
April 12, 2012

Submitter Name
Linda Parisien

Expiry Date
May 01, 2012

Color Legend: **Assets** **Liabilities and Equity** **Income Statement**

Account Description	Account Number	Amount
Cash	1005	1,001,965.25
Cash Advances and Working Funds	1010	1,200.00
Interest Special Deposits	1020	
Dividend Special Deposits	1030	
Other Special Deposits	1040	
Term Deposits	1060	
Current Investments	1070	
Customer Accounts Receivable	1100	1,211,800.99
Accounts Receivable - Services	1102	38,602.50
Accounts Receivable - Recoverable Work	1104	
Accounts Receivable - Merchandise, Jobbing, etc.	1105	
Other Accounts Receivable	1110	
Accrued Utility Revenues	1120	1,095,307.57
Accumulated Provision for Uncollectible Accounts--Credit	1130	-16,601.17
Interest and Dividends Receivable	1140	
Rents Receivable	1150	
Notes Receivable	1170	
Prepayments	1180	23,232.08
Miscellaneous Current and Accrued Assets	1190	11,811.29
Accounts Receivable from Associated Companies	1200	
Notes Receivable from Associated Companies	1210	
Fuel Stock	1305	
Plant Materials and Operating Supplies	1330	118,433.87
Merchandise	1340	

Account Description	Account Number	Amount
Other Materials and Supplies	1350	
Long Term Investments in Non-Associated Companies	1405	
Long Term Receivable - Street Lighting Transfer	1408	
Other Special or Collateral Funds	1410	
Sinking Funds	1415	
Unamortized Debt Expense	1425	
Unamortized Discount on Long-Term Debt--Debit	1445	
Unamortized Deferred Foreign Currency Translation Gains and Losses	1455	
Other Non-Current Assets	1460	148,421.06
O.M.E.R.S. Past Service Costs	1465	
Past Service Costs - Employee Future Benefits	1470	
Past Service Costs - Other Pension Plans	1475	
Portfolio Investments - Associated Companies	1480	
Investment in Associated Companies - Significant Influence	1485	
Investment in Subsidiary Companies	1490	
Unrecovered Plant and Regulatory Study Costs	1505	
Other Regulatory Assets	1508	4,308.84
Preliminary Survey and Investigation Charges	1510	265,449.94
Emission Allowance Inventory	1515	
Emission Allowances Withheld	1516	
RCVARetail	1518	-114.62
Power Purchase Variance Account	1520	
Special Purpose Charge Assessment Variance	1521	13,143.90
Miscellaneous Deferred Debits	1525	4.09
Deferred Losses from Disposition of Utility Plant	1530	
Renewable Connection Capital Deferral Account	1531	
Renewable Connection OM&A Deferral Account	1532	
Smart Grid Capital Deferral Account	1534	
Smart Grid Capital OM&A Account	1535	1,847.27
Unamortized Loss on Reacquired Debt	1540	
Development Charge Deposits/ Receivables	1545	
RCVASTR	1548	6,825.77
LV Variance Account	1550	70,504.17
Smart Meter Capital and Recovery Offset Variance	1555	313,842.47
Smart Meter OM&A Variance	1556	80,391.30
Deferred Development Costs	1560	
Deferred Payments in Lieu of Taxes	1562	-6,299.00
Deferred PILs Contra Account	1563	6,299.00

Account Description	Account Number	Amount
Conservation and Demand Management Expenditures and Recoveries	1565	
CDM Contra	1566	
Board-Approval CDM Variance Account	1567	
Qualifying Transition Costs	1570	22,611.10
Pre-market Opening Energy Variance	1571	-10,682.28
Extraordinary Event Costs	1572	
Deferred Rate Impact Amounts	1574	
IFRS-CGAAP Transitional PP&E Amounts	1575	
RSVAWMS	1580	-381,988.43
RSVAONE-TIME	1582	
RSVANW	1584	55,163.97
RSVACN	1586	-69,429.83
RSVAPOWER	1588	1,204,628.32
Recovery of regulatory asset balances	1590	75.81
2006 PILs & Taxes Variance	1592	
Disposition and Recovery of Regulatory Balances Control Account	1595	-174,499.43
Electric Plant in Service - Control Account	1605	
Organization	1606	
Franchises and Consents	1608	
Miscellaneous Intangible Plant	1610	
Land	1615	
Land Rights	1616	
Buildings and Fixtures	1620	
Leasehold Improvements	1630	
Boiler Plant Equipment	1635	
Engines and Engine-Driven Generators	1640	
Turbogenerator Units	1645	
Reservoirs, Dams and Waterways	1650	
Water Wheels, Turbines and Generators	1655	
Roads, Railroads and Bridges	1660	
Fuel Holders, Producers and Accessories	1665	
Prime Movers	1670	
Generators	1675	
Accessory Electric Equipment	1680	
Miscellaneous Power Plant Equipment	1685	
Land	1705	10,000.00
Land Rights	1706	
Buildings and Fixtures	1708	

Account Description	Account Number	Amount
Leasehold Improvements	1710	
Station Equipment	1715	
Towers and Fixtures	1720	
Poles and Fixtures	1725	
Overhead Conductors and Devices	1730	
Underground Conduit	1735	
Underground Conductors and Devices	1740	
Roads and Trails	1745	
Land	1805	10,000.00
Land Rights	1806	8,588.00
Buildings and Fixtures	1808	
Leasehold Improvements	1810	
Transformer Station Equipment - Normally Primary above 50 kV	1815	457,911.74
Distribution Station Equipment - Normally Primary below 50 kV	1820	251,550.82
Storage Battery Equipment	1825	
Poles, Towers and Fixtures	1830	378,725.15
Overhead Conductors and Devices	1835	405,942.53
Underground Conduit	1840	113,855.12
Underground Conductors and Devices	1845	260,976.91
Line Transformers	1850	403,173.06
Services	1855	30,185.70
Meters	1860	254,708.77
Other Installations on Customer's Premises	1865	
Leased Property on Customer Premises	1870	
Street Lighting and Signal Systems	1875	
Land	1905	28,299.70
Land Rights	1906	
Buildings and Fixtures	1908	824,123.77
Leasehold Improvements	1910	
Office Furniture and Equipment	1915	33,783.96
Computer Equipment - Hardware	1920	52,221.79
Computer Software	1925	136,792.61
Transportation Equipment	1930	205,345.80
Stores Equipment	1935	
Tools, Shop and Garage Equipment	1940	25,029.47
Measurement and Testing Equipment	1945	
Power Operated Equipment	1950	4,363.29
Communication Equipment	1955	

Account Description	Account Number	Amount
Miscellaneous Equipment	1960	
Water Heater Rental Units	1965	
Load Management Controls - Customer Premises	1970	
Load Management Controls - Utility Premises	1975	
System Supervisory Equipment	1980	
Sentinel Lighting Rental Units	1985	
Other Tangible Property	1990	
Contributions and Grants - Credit	1995	-130,769.00
Property Under Capital Leases	2005	
Electric Plant Purchased or Sold	2010	
Experimental Electric Plant Unclassified	2020	
Electric Plant and Equipment Leased to Others	2030	
Electric Plant Held for Future Use	2040	
Completed Construction Not Classified--Electric	2050	
Construction Work in Progress--Electric	2055	
Electric Plant Acquisition Adjustment	2060	
Other Electric Plant Adjustment	2065	
Other Utility Plant	2070	
Non-Utility Property Owned or Under Capital Leases	2075	
Accumulated Amortization of Electric Utility Plan - PP&E	2105	-1,779,449.81
Accumulated Amortization of Electric Utility Plant - Intangibles	2120	
Accumulated Amortization of Electric Plant Acquisition Adjustment	2140	
Accumulated Amortization of Other Utility Plant	2160	
Accumulated Amortization of Non-Utility Property	2180	
Accounts Payable	2205	-2,956,289.23
Customer Credit Balances	2208	-148,439.89
Current Portion of Customer Deposits	2210	-303,483.39
Dividends Declared	2215	
Miscellaneous Current and Accrued Liabilities	2220	-64,507.11
Notes and Loans Payable	2225	
Accounts Payable to Associated Companies	2240	
Notes Payable to Associated Companies	2242	
Debt Retirement Charges(DRC) Payable	2250	
Transmission Charges Payable	2252	
Electrical Safety Authority Fees Payable	2254	
Independent Market Operator Fees and Penalties Payable	2256	
Current Portion of Long Term Debt	2260	
Ontario Hydro Debt - Current Portion	2262	

Account Description	Account Number	Amount
Pensions and Employee Benefits - Current Portion	2264	
Accrued Interest on Long Term Debt	2268	
Matured Long Term Debt	2270	
Matured Interest on Long Term Debt	2272	
Obligations Under Capital Leases--Current	2285	
Commodity Taxes	2290	
Payroll Deductions / Expenses Payable	2292	
Accrual for Taxes Payments in Lieu of Taxes, Etc.	2294	383,289.00
Future Income Taxes - Current	2296	-10,733.00
Accumulated Provision for Injuries and Damages	2305	
Employee Future Benefits	2306	
Other Pensions - Past Service Liability	2308	
Vested Sick Leave Liability	2310	-82,168.88
Accumulated Provision for Rate Refunds	2315	
Other Miscellaneous Non-Current Liabilities	2320	
Obligations Under Capital Lease--Non-Current	2325	
Development Charge Fund	2330	
Long Term Customer Deposits	2335	-359,309.34
Collateral Funds Liability	2340	
Unamortized Premium on Long Term Debt	2345	
O.M.E.R.S. - Past Service Liability - Long Term Portion	2348	
Future Income Tax - Non-Current	2350	
Other Regulatory Liabilities	2405	
Deferred Gains from Disposition of Utility Plant	2410	
Unamortized Gain on Reacquired Debt	2415	
Other Deferred Credits	2425	
Accrued Rate-Payer Benefit	2435	
Debentures Outstanding - Long Term Portion	2505	
Debenture Advances	2510	
Reacquired Bonds	2515	
Other Long Term Debt	2520	-500,289.76
Term Bank Loans - Long Term Portion	2525	
Ontario Hydro Debt Outstanding - Long Term Portion	2530	
Advances from Associated Companies	2550	
Common Shares Issued	3005	-1,689,346.00
Preference Shares Issued	3008	
Contributed Surplus	3010	
Donations Received	3020	

Account Description	Account Number	Amount
Development Charges Transferred to Equity	3022	
Capital Stock Held in Treasury	3026	
Miscellaneous Paid-In Capital	3030	
Installments Received on Capital Stock	3035	
Appropriated Retained Earnings	3040	
Unappropriated Retained Earnings	3045	-1,015,428.77
Balance Transferred From Income	3046	-359,376.11
Appropriations of Retained Earnings - Current Period	3047	
Dividends Payable-Preference Shares	3048	
Dividends Payable-Common Shares	3049	84,467.30
Adjustment to Retained Earnings	3055	
Unappropriated Undistributed Subsidiary Earnings	3065	
Non-Utility Shareholders¿ Equity	3075	
Residential Energy Sales	4006	-3,383,067.89
Commercial Energy Sales	4010	
Industrial Energy Sales	4015	
Energy Sales to Large Users	4020	
Street Lighting Energy Sales	4025	-38,916.09
Sentinel Lighting Energy Sales	4030	-6,612.10
General Energy Sales	4035	-3,528,577.91
Other Energy Sales to Public Authorities	4040	
Energy Sales to Railroads and Railways	4045	
Revenue Adjustment	4050	
Energy Sales for Resale	4055	-682,613.25
Interdepartmental Energy Sales	4060	
Billed WMS	4062	-897,527.67
Billed One-Time	4064	
Billed NW	4066	-865,147.61
Billed CN	4068	-434,995.13
Billed - LV	4075	-58,135.98
Distribution Services Revenue	4080	-1,328,429.79
Retail Services Revenues	4082	
Service Transaction Requests (STR) Revenues	4084	
Electric Services Incidental to Energy Sales	4090	
Transmission Charges Revenue	4105	
Transmission Services Revenue	4110	
Interdepartmental Rents	4205	
Rent from Electric Property	4210	-16,389.44

Account Description	Account Number	Amount
Other Utility Operating Income	4215	
Other Electric Revenues	4220	
Late Payment Charges	4225	-27,264.73
Sales of Water and Water Power	4230	
Miscellaneous Service Revenues	4235	-75,517.97
Provision for Rate Refunds	4240	
Government Assistance Directly Credited to Income	4245	
Regulatory Debits	4305	
Regulatory Credits	4310	
Revenues from Electric Plant Leased to Others	4315	
Expenses of Electric Plant Leased to Others	4320	
Special Purpose Charge Recovery	4324	
Revenues from Merchandise, Jobbing, Etc.	4325	-8,159.10
Costs and Expenses of Merchandising, Jobbing, Etc.	4330	8,159.10
Profits and Losses from Financial Instrument Hedges	4335	
Profits and Losses from Financial Instrument Investments	4340	
Gains from Disposition of Future Use Utility Plant	4345	
Losses from Disposition of Future Use Utility Plant	4350	
Gain on Disposition of Utility and Other Property	4355	
Loss on Disposition of Utility and Other Property	4360	
Gains from Disposition of Allowances for Emission	4365	
Losses from Disposition of Allowances for Emission	4370	
Revenues from Non-Utility Operations	4375	
Expenses of Non-Utility Operations	4380	
Non-Utility Rental Income	4385	
Miscellaneous Non-Operating Income	4390	-902.68
Rate-Payer Benefit Including Interest	4395	
Foreign Exchange Gains and Losses, Including Amortization	4398	
Interest and Dividend Income	4405	-36,255.44
Equity in Earnings of Subsidiary Companies	4415	
Operation Supervision and Engineering	4505	
Fuel	4510	
Steam Expense	4515	
Steam From Other Sources	4520	
Steam Transferred--Credit	4525	
Electric Expense	4530	
Water For Power	4535	
Water Power Taxes	4540	

Account Description	Account Number	Amount
Hydraulic Expenses	4545	
Generation Expense	4550	
Miscellaneous Power Generation Expenses	4555	
Rents	4560	
Allowances for Emissions	4565	
Maintenance Supervision and Engineering	4605	
Maintenance of Structures	4610	
Maintenance of Boiler Plant	4615	
Maintenance of Electric Plant	4620	
Maintenance of Reservoirs, Dams and Waterways	4625	
Maintenance of Water Wheels, Turbines and Generators	4630	
Maintenance of Generating and Electric Plant	4635	
Maintenance of Miscellaneous Power Generation Plant	4640	
Power Purchased	4705	7,639,787.24
Charges-WMS	4708	897,527.67
Cost of Power Adjustments	4710	
Charges-One-Time	4712	
Charges-NW	4714	865,147.61
System Control and Load Dispatching	4715	
Charges-CN	4716	434,995.13
Other Expenses	4720	
Competition Transition Expense	4725	
Rural Rate Assistance Expense	4730	
Charges - LV	4750	58,135.98
Operation Supervision and Engineering	4805	
Load Dispatching	4810	
Station Buildings and Fixtures Expenses	4815	
Transformer Station Equipment - Operating Labour	4820	
Transformer Station Equipment - Operating Supplies and Expense	4825	
Overhead Line Expenses	4830	
Underground Line Expenses	4835	
Transmission of Electricity by Others	4840	
Miscellaneous Transmission Expense	4845	
Rents	4850	
Maintenance Supervision and Engineering	4905	
Maintenance of Transformer Station Buildings and Fixtures	4910	
Maintenance of Transformer Station Equipment	4916	
Maintenance of Towers, Poles and Fixtures	4930	

Account Description	Account Number	Amount
Maintenance of Overhead Conductors and Devices	4935	
Maintenance of Overhead Lines - Right of Way	4940	
Maintenance of Overhead Lines - Roads and Trails Repairs	4945	
Maintenance of Overhead Lines - Snow Removal from Roads and Trails	4950	
Maintenance of Underground Lines	4960	
Maintenance of Miscellaneous Transmission Plant	4965	
Operation Supervision and Engineering	5005	
Load Dispatching	5010	
Station Buildings and Fixtures Expense	5012	
Transformer Station Equipment - Operation Labour	5014	11,350.91
Transformer Station Equipment - Operation Supplies and Expenses	5015	3,779.67
Distribution Station Equipment - Operation Labour	5016	10,381.08
Distribution Station Equipment - Operation Supplies and Expenses	5017	2,053.11
Overhead Distribution Lines and Feeders - Operation Labour	5020	9,930.66
Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	5025	1,750.80
Overhead Subtransmission Feeders - Operation	5030	
Overhead Distribution Transformers- Operation	5035	4,195.49
Underground Distribution Lines and Feeders - Operation Labour	5040	3,095.89
Underground Distribution Lines and Feeders - Operation Supplies and Expenses	5045	31.74
Underground Subtransmission Feeders - Operation	5050	
Underground Distribution Transformers - Operation	5055	1,836.82
Street Lighting and Signal System Expense	5060	
Meter Expense	5065	21,738.16
Customer Premises - Operation Labour	5070	
Customer Premises - Materials and Expenses	5075	
Miscellaneous Distribution Expense	5085	
Underground Distribution Lines and Feeders - Rental Paid	5090	
Overhead Distribution Lines and Feeders - Rental Paid	5095	886.91
Other Rent	5096	
Maintenance Supervision and Engineering	5105	
Maintenance of Buildings and Fixtures - Distribution Stations	5110	
Maintenance of Transformer Station Equipment	5112	
Maintenance of Distribution Station Equipment	5114	
Maintenance of Poles, Towers and Fixtures	5120	3,986.57
Maintenance of Overhead Conductors and Devices	5125	28,090.02
Maintenance of Overhead Services	5130	34,875.10
Overhead Distribution Lines and Feeders - Right of Way	5135	44,239.08
Maintenance of Underground Conduit	5145	545.37

Account Description	Account Number	Amount
Maintenance of Underground Conductors and Devices	5150	15,280.20
Maintenance of Underground Services	5155	7,581.97
Maintenance of Line Transformers	5160	11,805.91
Maintenance of Street Lighting and Signal Systems	5165	
Sentinel Lights - Labour	5170	
Sentinel Lights - Materials and Expenses	5172	
Maintenance of Meters	5175	1,229.42
Customer Installations Expenses- Leased Property	5178	
Water Heater Rentals - Labour	5185	
Water Heater Rentals - Materials and Expenses	5186	
Water Heater Controls - Labour	5190	
Water Heater Controls - Materials and Expenses	5192	
Maintenance of Other Installations on Customer Premises	5195	
Purchase of Transmission and System Services	5205	
Transmission Charges	5210	
Transmission Charges Recovered	5215	
Supervision	5305	
Meter Reading Expense	5310	42,061.58
Customer Billing	5315	185,552.18
Collecting	5320	94,826.84
Collecting- Cash Over and Short	5325	4.99
Collection Charges	5330	
Bad Debt Expense	5335	17,496.83
Miscellaneous Customer Accounts Expenses	5340	
Supervision	5405	
Community Relations - Sundry	5410	225.00
Energy Conservation	5415	
Community Safety Program	5420	
Miscellaneous Customer Service and Informational Expenses	5425	
Supervision	5505	
Demonstrating and Selling Expense	5510	
Advertising Expense	5515	
Miscellaneous Sales Expense	5520	
Executive Salaries and Expenses	5605	105,071.87
Management Salaries and Expenses	5610	72,506.75
General Administrative Salaries and Expenses	5615	
Office Supplies and Expenses	5620	24,654.78
Administrative Expense Transferred/Credit	5625	

Account Description	Account Number	Amount
Outside Services Employed	5630	19,494.95
Property Insurance	5635	4,657.86
Injuries and Damages	5640	9,018.00
Employee Pensions and Benefits	5645	3,687.72
Franchise Requirements	5650	
Regulatory Expenses	5655	66,083.48
General Advertising Expenses	5660	
Miscellaneous General Expenses	5665	13,850.00
Rent	5670	
Maintenance of General Plant	5675	26,746.30
Electrical Safety Authority Fees	5680	4,887.12
Special Purpose Charge Expense	5681	
Independent Market Operator Fees and Penalties	5685	
OM&A Contra	5695	
Amortization Expense - Property, Plant, and Equipment	5705	159,560.00
Amortization of Limited Term Electric Plant	5710	
Amortization of Intangibles and Other Electric Plant	5715	
Amortization of Electric Plant Acquisition Adjustments	5720	
Miscellaneous Amortization	5725	
Amortization of Unrecovered Plant and Regulatory Study Costs	5730	
Amortization of Deferred Development Costs	5735	
Amortization of Deferred Charges	5740	
Interest on Long Term Debt	6005	
Amortization of Debt Discount and Expense	6010	
Amortization of Premium on Debt/Credit	6015	
Amortization of Loss on Reacquired Debt	6020	
Amortization of Gain on Reacquired Debt--Credit	6025	
Interest on Debt to Associated Companies	6030	
Other Interest Expense	6035	75,346.43
Allowance for Borrowed Funds Used During Construction--Credit	6040	
Allowance For Other Funds Used During Construction	6042	
Interest Expense on Capital Lease Obligations	6045	
Taxes Other Than Income Taxes	6105	14,987.38
Income Taxes	6110	-214,218.00
Provision for Future Income Taxes	6115	178,217.00
Donations	6205	2,000.00
Life Insurance	6210	
Penalties	6215	

Account Description	Account Number	Amount
Other Deductions	6225	
Extraordinary Income	6305	
Extraordinary Deductions	6310	
Income Taxes: Extraordinary Item	6315	
Discontinues Operations - Income/ Gains	6405	
Discontinued Operations - Deductions/ Losses	6410	
Income Taxes, Discontinued Operations	6415	

Account Description	Account Number	Amount

Trial Balance Summary

Assets

Current Assets:	3,367,318.51
Inventory:	118,433.87
Non-Current Assets:	148,421.06
Other Assets and Deferred Charges:	1,402,082.36
Other Capital Assets:	3,764,809.19
Accumulated Amortization:	-1,779,449.81
Net Assets:	7,021,615.18

Liabilities And Equity

Non-Current Liabilities:	-441,478.22
Current Liabilities:	-3,100,163.62
Other Liabilities Deferred Credit:	-500,289.76
Shareholders' Equity:	-2,979,683.58
Net Liabilities and Equity:	-7,021,615.18

Revenues

Sales of Electricity:	-9,895,593.63
Revenues from Services:	-1,328,429.79
Other Operating Revenues:	-119,172.14
Other Income / Deductions:	-902.68
Investment Income:	-36,255.44
Total Revenues:	-11,380,353.68

Expenses

Generation Expenses:	0.00
Other Power Supply Expenses:	9,895,593.63
Transmission Expenses:	0.00
Distribution Expenses:	218,664.88
Other Expenses:	
Billing Collecting:	339,942.42
Community Relations:	225.00
Sales Expenses:	
Administration General Expenses:	350,658.83
Amortization Expenses:	159,560.00
Interest Expenses:	75,346.43
Taxes:	-21,013.62
Other Deductions:	2,000.00
Extraordinary Items:	
Discontinued Operations:	
Total Expenses:	11,020,977.57
Profit/Loss:	-359,376.11

Final Total/Balancing Factor

Trial balance Total Excluding accounts 1605 and 3046:	**0.00**

Report Name: E217_Trial_Balance, Last Version March 4, 2011

E1.T3.S3 RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND RRR FILINGS

A detailed reconciliation between the financial results shown in HHI's RRR filings, Audited Financial Statements and with the regulatory financial results filed in the application is presented at the next page. Changes include revisions to various USoA accounts as instructed in the Board communication dated December 20, 2011.

Hydro Hawkesbury Inc.

2010 Trial Balance mapped to Audited Financial Statements

Statement of earnings		Trial Balance		
Revenues				
Energy	**10,221,319**	(3,107,821)	4006-000	RESIDENTIAL Energy Sales
		(3,868,453)	4035-000	GENERAL <50kW Energy Sales
		(40,735)	4025-000	STREETLIGHTS Energy Sales
		(6,692)	4030-000	SENTINEL LIGHTS Energy Sales
		(868,199)	4055-000	RETAILER Energy Sales
		(1,041,786)	4062-000	Billed - WMS
		(792,091)	4066-000	Transmission Network Services
		(461,614)	4068-000	Transmission Connection Serv.
		(33,928)	4075-000	Billed - Low Voltage (LV) Chrg
		(10,221,319)		
Distribution	**1,210,348**	(1,210,348)	4080-100	Distribution & Service Charge Revenues
		(1,210,348)		
Cost of power	**10,221,319**	7,891,901	4705-000	Power Purchased
		1,041,786	4708-000	Charges - WMS
		792,091	4714-000	Retail Transmission Network Ch
		461,614	4716-000	Retail Transmission Connection
		33,928	4750-000	Charges - Low Voltage (LV)
		10,221,319		
Other operating revenues	**199,285**	(9,015)	4082-000	Retail Services Revenue
		(489)	4084-000	STR Revenues
		(16,394)	4210-000	Rent from Electric Property
		(28,329)	4225-100	Late Payment Charges
		(72,826)	4235-001	Misc. Service Revenues
		(22,101)	4324-001	Special Purpose Charge - Recovery
		(34,415)	4325-001	Revenues from Jobbing
		(3,655)	4390-000	Misc. Non-Operating Income
		(12,060)	4405-000	Interest and Dividend Income
		(199,285)		
Expenses				
Distribution	**206,613**	3,290	5014-000	Transformer Station Equipment - 115KV
		8,023	5015-000	Transformer Station Equipment - 115KV
		4,359	5016-000	Distribution Station Equipment - 44KV
		4,905	5017-000	Distribution Station Equipment - 44KV
		9,936	5020-000	O/H Distribution Lines & Feede
		1,171	5025-000	O/H Distribution Lines & Feede
		7,628	5035-000	O/H Distribution Transformers
		911	5040-000	U/G Distribution Lines & Feede
		32	5045-000	U/G Distribution Lines & Feede
		317	5055-000	U/G Dist Transformers-Operatio
		33,645	5065-000	Meter Expense
		887	5095-000	O/H Distribution Lines & Feede
		720	5105-000	Maintenance Supervision & Eng.
		5,217	5120-000	Maint of Poles, Towers & Fixtu
		36,894	5125-000	Maintenance of Overhead Conduc
		28,278	5130-000	Maintenance of O/H Services
		40,523	5135-000	Maintenance of Right of Ways
		333	5145-000	Maintenance of U/G Conduit
		5,408	5150-000	Maintenance of U/G Conductors
		7,402	5155-000	Maintenance of U/G Services
		7,717	5160-000	Maintenance of Line Transfor.
		(982)	5175-000	Maintenance of Meters
		206,613		

Billing and collection	**325,519**	29,864	5310-000	Meter Reading Expense
		175,731	5315-000	Customer Billing
		100,396	5320-001	Collecting
		19,528	5335-000	Bad Debts Expense (W-Offs)
		325,519		
Community relations	**100**	**100**	5410-000	Community Relations - Sundry
Administration	**335,458**	105,990	5605-000	Executive Salaries and Expense
		69,181	5610-000	Management Salaries & Expenses
		21,409	5620-000	Office Supplies and Expenses
		11,213	5630-000	Outside Services Employed
		4,566	5635-000	Property Insurance
		6,178	5640-000	Injuries and Damages
		3,250	5645-000	Employee Pensions & Benefits
		47,004	5655-000	Regulatory Expenses
		13,817	5665-000	Miscellaneous General Expenses
		25,833	5675-000	Maintenance of General Plant
		4,914	5680-000	Elect. Safety Authority Fees
		22,101	5681-001	Special Purpose Charge - Expense
		335,458		
Amortization of capital assets	**158,511**	**158,511**	5705-000	Amortization Expense
Interest	**64,737**	64,737	6035-000	Other Interest Expense
		64,737		
Property taxes	**15,678**	**15,678**	6105-001	Property Taxes
Others	**29,321**	9,015	4083-000	Retail Services Expenses
		489	4085-000	STR Expenses
		19,817	4330-001	Costs & Expenses from Jobbing
		29,321		

Income Taxes

Recovered	**(161,142)**	**(161,142)**	6110-001	Income Tax Expense
Future	**288,402**	**288,402**	6115-000	FUTURE INCOME TAXES PROVISION

Balance Sheet	**Trial Balance**

Assets

Current Assets

Cash and term deposits	**1,167,332**	92,786	1005-201	Cash in Bank #351-23
		61,155	1100-000	Customer Accounts Receivable
		1,200	1010-000	Cash Advances and Working Fund
		1,012,190	1060-000	Term Deposits
		1,167,332		
Accounts receivable	**1,787,553**	1,613,377	1100-000	Customer Accounts Receivable
		168,724	1102-000	Accounts Receivable - Services
		26,553	1190-000	Misc Current & Accrued Assets
		(21,101)	1130-000	Acc Provision for Uncoll Acc't
		1,787,553		

Acct 1190 Split in AFS Balance Sheet			
Under Accts receivable	26,553.20	**27,333**	Acct 1190 in RRR Trial Bal. 2.1.7
Under Accts pay. & accrued liabilities (1191 gst)	779.81		
	Total:	**27,333**	

Acct 1100 Split in AFS Balance Sheet			
Under Accts receivable	1,613,376.66	**1,674,532**	Acct 1100 in RRR Trial Bal. 2.1.7
Under cash and term deposits	61,155.40		
	Total:	**1,674,532**	

Inventories	**125,669**	**125,669**	1330-000	Plant Materials & Op. Supplies
Unbilled revenue	**1,275,333**	**1,275,333**	1120-000	Accrued Utility Revenues
Prepaid charges	**211,464**	27,905	1180-000	Prepaid Expenses
		183,560	1460-000	Other Non-Current Assets
		211,464		
Income taxes receivable	**282,900**	**282,900**	2294-000	Accrual for Taxes (Pil's)
Future income taxes	**167,484**	**167,484**	2296-000	Future Income Tax - Current
Other assets	**1,047,432**	22,611	1570-010	Transition Costs - Carrying Charges
		293,197	1555-000	Smart Meter Capital & Recovery
		33,403	1556-000	Smart Meter - OM&A Variance
		47,960	1550-000	Low Voltage (LV) Variance Acct
		(336,755)	1580-000	RSVA WMS
		53,444	1584-000	RSVA Network Service
		(89,395)	1586-000	RSVA Connection Service
		964,143	1588-001	RSVA POWER
		3,218	1508-004	Other Reg. Assets
		9,400	1510-000	Preliminary Survey & Investigation Charges
		(686)	1518-000	RCVA Retail
		50,683	1521-001	Special Purpose Charge Variance Account
		4	1525-010	Miscelleneous Debits - Carrying Charges
		(8,162)	1535-000	Smart Grid OM&A Deferral Account
		4,365	1548-000	RCVA STR
		1,047,432		
Capital assets	**1,956,741**	10,000	1705-000	Land Transmission Plant 115Kv
		10,000	1805-000	Land Distribution Plant 44Kv
		8,588	1806-000	Land Rights Distribution Plant
		28,300	1905-000	Land General Plant
		824,124	1908-000	Buildings and Fixtures
		402,412	1815-000	Transformer Station Equipment
		184,860	1820-000	Distribution Station Equipment
		351,067	1830-000	Poles, Towers and Fixtures
		402,306	1835-000	Overhead Conductors and Device
		113,855	1840-000	Underground Conduit
		260,392	1845-000	Underground Conductors & Devic
		397,148	1850-000	Line Transformers
		26,835	1855-000	Services
		246,912	1860-000	Meters
		32,654	1915-000	Office Furniture and Equipment
		50,118	1920-000	Computer Equipment - Hardware
		128,153	1925-000	Computer Software
		205,346	1930-000	Transportation Equipment
		19,966	1940-000	Tools, Shop and Garage Equip.
		4,363	1950-000	Power Operated Equipment
		(136,546)	1995-000	Contributions and Grants - Credit
		(1,614,113)	2105-000	Acc Amort of Electric Plant
		1,956,741		

Liabilities

Current liabilities

Accounts payable and accrued liabilities	**2,286,853**	780	1191-000	G.S.T. Paid
		(2,229,072)	2205-000	Accounts Payable
		(58,561)	2220-000	Misc Current & Accrued Liab.
		(2,286,853)		
Other current liabilities	**129,283**	**(129,283)**	2208-000	Customer Credit Balances
Current portion of other long-term liabilities	**326,573**	**(326,573)**	2210-000	Current Portion of Cust. Dep.
Current portion of note payable	**231,425**	(231,425)	2520-000A	Other Long Term Debt - CURRENT PORTION
		(500,290)	2520-000	Other Long Term Debt

		(731,715)	2520-000	**TOTAL in RRR Trial Balance**
Provision for sick leave benefits	**78,563**	**(78,563)**	2310-000	Vested Sick Leave Liability
Other long-term liabilities	**1,764,146**	(10,682)	1571-010	Pre-Market Opening - Carrying Charges
		496	1590-010	Rate Rider - Carrying Charges
		(1,370,954)	1595-001	Principle RSVA's Bal. Approved for Disposition in 2010
		(383,005)	2335-000	Long Term Customer Deposits
		(1,764,146)		
Note payable	**500,290**	(500,290)	2520-000	Other Long Term Debt
		(231,425)	2520-000A	Other Long Term Debt - CURRENT PORTION
		(731,715)	2520-000	**TOTAL in RRR Trial Balance**

Shareholder's equity

Share capital	**1,689,346**	**(1,689,346)**	3005-000	Common Shares Issued
Retained earnings	**1,015,429**	(953,460)	3045-000	Retained Earnings
		(146,436)	3046-000	Net earnings
		84,467	3049-000	Dividends Payable
		(1,015,429)		

Hydro Hawkesbury Inc.

2011 Trial Balance mapped to Audited Financial Statements

Statement of earnings		Trial Balance		
Revenues				
Energy	**9,895,593**	(3,383,068)	4006-000	RESIDENTIAL Energy Sales
		(3,528,578)	4035-000	GENERAL <50kW Energy Sales
		(38,916)	4025-000	STREETLIGHTS Energy Sales
		(6,612)	4030-000	SENTINEL LIGHTS Energy Sales
		(682,613)	4055-000	RETAILER Energy Sales
		(897,528)	4062-000	Billed - WMS
		(865,148)	4066-000	Transmission Network Services
		(434,995)	4068-000	Transmission Connection Serv.
		(58,136)	4075-000	Billed - Low Voltage (LV) Chrg
		(9,895,594)		
Distribution	**1,328,430**	(1,328,430)	4080-100	Distribution & Service Charge Revenues
		(1,328,430)		
Cost of power	**9,895,593**	7,639,787	4705-000	Power Purchased
		897,528	4708-000	Charges - WMS
		865,148	4714-000	Retail Transmission Network Ch
		434,995	4716-000	Retail Transmission Connection
		58,136	4750-000	Charges - Low Voltage (LV)
		9,895,594		
Other operating revenues	**173,830**	(9,201)	4082-000	Retail Services Revenue
		(140)	4084-000	STR Revenues
		(16,389)	4210-000	Rent from Electric Property
		(27,265)	4225-100	Late Payment Charges
		(75,518)	4235-001	Misc. Service Revenues
		-	4324-001	Special Purpose Charge - Recovery
		(8,159)	4325-001	Revenues from Jobbing
		(903)	4390-000	Misc. Non-Operating Income
		(36,255)	4405-000	Interest and Dividend Income
		(173,830)		
Expenses				
Distribution	**218,665**	11,351	5014-000	Transformer Station Equipment - 115KV
		3,780	5015-000	Transformer Station Equipment - 115KV
		10,381	5016-000	Distribution Station Equipment - 44KV
		2,053	5017-000	Distribution Station Equipment - 44KV
		9,931	5020-000	O/H Distribution Lines & Feede
		1,751	5025-000	O/H Distribution Lines & Feede
		4,195	5035-000	O/H Distribution Transformers
		3,096	5040-000	U/G Distribution Lines & Feede
		32	5045-000	U/G Distribution Lines & Feede
		1,837	5055-000	U/G Dist Transformers-Operatio
		21,738	5065-000	Meter Expense
		887	5095-000	O/H Distribution Lines & Feede
		-	5105-000	Maintenance Supervision & Eng.
		3,987	5120-000	Maint of Poles, Towers & Fixtu
		28,090	5125-000	Maintenance of Overhead Conduc
		34,875	5130-000	Maintenance of O/H Services
		44,239	5135-000	Maintenance of Right of Ways
		545	5145-000	Maintenance of U/G Conduit
		15,280	5150-000	Maintenance of U/G Conductors
		7,582	5155-000	Maintenance of U/G Services
		11,806	5160-000	Maintenance of Line Transfor.
		1,229	5175-000	Maintenance of Meters
		218,665		

Billing and collection	**339,942**	42,062	5310-000	Meter Reading Expense
		185,552	5315-000	Customer Billing
		94,827	5320-001	Collecting
		5	5325-000	Collecting - Cash Over & Short
		17,497	5335-000	Bad Debts Expense (W-Offs)
		339,942		
Community relations	**225**	**225**	5410-000	Community Relations - Sundry
Administration	**350,658**	105,072	5605-000	Executive Salaries and Expense
		72,507	5610-000	Management Salaries & Expenses
		24,655	5620-000	Office Supplies and Expenses
		19,495	5630-000	Outside Services Employed
		4,658	5635-000	Property Insurance
		9,018	5640-000	Injuries and Damages
		3,688	5645-000	Employee Pensions & Benefits
		66,083	5655-000	Regulatory Expenses
		13,850	5665-000	Miscellaneous General Expenses
		26,746	5675-000	Maintenance of General Plant
		4,887	5680-000	Elect. Safety Authority Fees
		-	5681-001	Special Purpose Charge - Expense
		350,659		
Amortization of capital assets	**159,561**	**159,560**	5705-000	Amortization Expense
Interest	**75,347**	75,346	6035-000	Other Interest Expense
		75,346		
Property taxes	**14,987**	**14,987**	6105-001	Property Taxes
Others	**19,500**	9,201	4083-000	Retail Services Expenses
		140	4085-000	STR Expenses
		8,159	4330-001	Costs & Expenses from Jobbing
		2,000	6205-001	Donations - LEAP Funding
		19,500		

Income Taxes

Recovered	**(214,218)**	**(214,218)**	6110-001	Income Tax Expense
Future	**178,217**	**178,217**	6115-000	FUTURE INCOME TAXES PROVISION

Balance Sheet	**Trial Balance**

Assets

Current Assets

Cash and term deposits	**1,003,165**	1,001,965	1005-201	Cash in Bank #351-23
		1,200	1010-000	Cash Advances and Working Fund
		-	1060-000	Term Deposits
		1,003,165		
Accounts receivable	**1,245,614**	1,211,801	1100-000	Customer Accounts Receivable
		38,603	1102-000	Accounts Receivable - Services
		11,811	1190-000	Misc Current & Accrued Assets
		(16,601)	1130-000	Acc Provision for Uncoll Acc't
		1,245,614		

Acct 1190 Split in AFS Balance Sheet			
Under Accts receivable	9,691.46	**11,811**	Acct 1190 in RRR Trial Bal. 2.1.7
Under Accts pay. & accrued liabilities (1191 gst)	2,119.83		
	Total:	**11,811**	

Inventories	**118,434**	**118,434**	1330-000	Plant Materials & Op. Supplies

Unbilled revenue	**1,095,308**	**1,095,308**	1120-000	Accrued Utility Revenues
Prepaid charges	**171,653**	23,232	1180-000	Prepaid Expenses
		148,421	1460-000	Other Non-Current Assets
		171,653		
Income taxes receivable	**383,289**	**383,289**	2294-000	Accrual for Taxes (Pil's)
Future income taxes	-	-	2296-000	Future Income Tax - Current
Other assets	**1,587,188**	22,611	1570-010	Transition Costs - Carrying Charges
		313,842	1555-000	Smart Meter Capital & Recovery
		80,391	1556-000	Smart Meter - OM&A Variance
		70,504	1550-000	Low Voltage (LV) Variance Acct
		(381,988)	1580-000	RSVA WMS
		55,164	1584-000	RSVA Network Service
		(69,430)	1586-000	RSVA Connection Service
		1,204,628	1588-001	RSVA POWER
		4,309	1508-004	Other Reg. Assets
		265,450	1510-000	Preliminary Survey & Investigation Charges
		(115)	1518-000	RCVA Retail
		13,144	1521-001	Special Purpose Charge Variance Account
		4	1525-010	Miscelleneous Debits - Carrying Charges
		1,847	1535-000	Smart Grid OM&A Deferral Account
		6,826	1548-000	RCVA STR
		1,587,188		
Capital assets	**1,985,359**	10,000	1705-000	Land Transmission Plant 115Kv
		10,000	1805-000	Land Distribution Plant 44Kv
		8,588	1806-000	Land Rights Distribution Plant
		457,912	1815-000	Transformer Station Equipment
		251,551	1820-000	Distribution Station Equipment
		378,725	1830-000	Poles, Towers and Fixtures
		405,943	1835-000	Overhead Conductors and Device
		113,855	1840-000	Underground Conduit
		260,977	1845-000	Underground Conductors & Devic
		403,173	1850-000	Line Transformers
		30,186	1855-000	Services
		254,709	1860-000	Meters
		28,300	1905-000	Land General Plant
		824,124	1908-000	Buildings and Fixtures
		33,784	1915-000	Office Furniture and Equipment
		52,222	1920-000	Computer Equipment - Hardware
		136,793	1925-000	Computer Software
		205,346	1930-000	Transportation Equipment
		25,029	1940-000	Tools, Shop and Garage Equip.
		4,363	1950-000	Power Operated Equipment
		(130,769)	1995-000	Contributions and Grants - Credit
		(1,779,450)	2105-000	Acc Amort of Electric Plant
		1,985,359		

Liabilities

Current liabilities

Accounts payable and accrued liabilities	**3,020,796**	-	1191-000	G.S.T. Paid
		(2,956,289)	2205-000	Accounts Payable
		(64,507)	2220-000	Misc Current & Accrued Liab.
		(3,020,796)		
Other current liabilities	**148,440**	**(148,440)**	2208-000	Customer Credit Balances
Current portion of other long-term liabilities	**569,669**			
Current portion of note payable	**246,924**	(246,924)	2520-000A	Other Long Term Debt - CURRENT PORTION
		(253,366)	2520-000	Other Long Term Debt
		(500,290)	2520-000	**TOTAL in RRR Trial Balance**

Future income taxes	**10,733**	**(10,733)**	2296-000	Future Income Tax - Current
Provision for sick leave benefits	**82,169**	**82,169**	2310-000	Vested Sick Leave Liability
Other long-term liabilities	**278,229**	(10,682)	1571-010	Pre-Market Opening - Carrying Charges
		76	1590-010	Rate Rider - Carrying Charges
Other long-term liabilities: TOTAL	**847,898**	(174,499)	1595-001	Principle RSVA's Bal. Approved for Disposition in 2010/2011
		(303,483)	2210-000	Current Portion of Cust. Dep.
		(359,309)	2335-000	Long Term Customer Deposits
		(847,899)		
Note payable	**253,366**	(253,366)	2520-000	Other Long Term Debt
		(246,924)	2520-000A	Other Long Term Debt - CURRENT PORTION
		(500,290)	2520-000	**TOTAL in RRR Trial Balance**

Shareholder's equity

Share capital	**1,689,346**	**(1,689,346)**	3005-000	Common Shares Issued
Retained earnings	**1,290,338**	(1,015,429)	3045-000	Retained Earnings
		(359,376)	3046-000	Net earnings
		84,467	3049-000	Dividends Payable
		(1,290,338)		

Hydro Hawkesbury Inc.

2012 Trial Balance mapped to Audited Financial Statements

Statement of earnings		Trial Balance		
Revenues				
Energy	**9,546,720**	(3,814,623)	4006-000	RESIDENTIAL Energy Sales
		(3,004,157)	4035-000	GENERAL <50kW Energy Sales
		(29,115)	4025-000	STREETLIGHTS Energy Sales
		(6,958)	4030-000	SENTINEL LIGHTS Energy Sales
		(392,782)	4055-000	RETAILER Energy Sales
		(880,494)	4062-000	Billed - WMS
		(931,292)	4066-000	Transmission Network Services
		(430,694)	4068-000	Transmission Connection Serv.
		(56,607)	4075-000	Billed - Low Voltage (LV) Chrg
		(9,546,720)		
Distribution	**1,648,714**	(1,648,714)	4080-100	Distribution & Service Charge Revenues
		(1,648,714)		
Cost of power	**9,546,720**	7,247,634	4705-000	Power Purchased
		880,494	4708-000	Charges - WMS
		931,292	4714-000	Retail Transmission Network Ch
		430,694	4716-000	Retail Transmission Connection
		56,607	4750-000	Charges - Low Voltage (LV)
		9,546,720		
Other operating revenues	**183,270**	(7,845)	4082-000	Retail Services Revenue
		(83)	4084-000	STR Revenues
		(16,739)	4210-000	Rent from Electric Property
		(31,973)	4225-100	Late Payment Charges
		(64,162)	4235-001	Misc. Service Revenues
		-	4324-001	Special Purpose Charge - Recovery
		(22,937)	4325-001	Revenues from Jobbing
		-	4390-000	Misc. Non-Operating Income
		(39,530)	4405-000	Interest and Dividend Income
		(183,270)		
Expenses				
Distribution	**253,130**	6,356	5014-000	Transformer Station Equipment - 115KV
		5,261	5015-000	Transformer Station Equipment - 115KV
		8,507	5016-000	Distribution Station Equipment - 44KV
		6,400	5017-000	Distribution Station Equipment - 44KV
		11,028	5020-000	O/H Distribution Lines & Feede
		1,404	5025-000	O/H Distribution Lines & Feede
		5,585	5035-000	O/H Distribution Transformers
		1,920	5040-000	U/G Distribution Lines & Feede
		50	5045-000	U/G Distribution Lines & Feede
		1,274	5055-000	U/G Dist Transformers-Operatio
		25,715	5065-000	Meter Expense
		887	5095-000	O/H Distribution Lines & Feede
		-	5105-000	Maintenance Supervision & Eng.
		11,552	5120-000	Maint of Poles, Towers & Fixtu
		35,188	5125-000	Maintenance of Overhead Conduc
		42,724	5130-000	Maintenance of O/H Services
		62,172	5135-000	Maintenance of Right of Ways
		1,606	5145-000	Maintenance of U/G Conduit
		4,084	5150-000	Maintenance of U/G Conductors
		7,468	5155-000	Maintenance of U/G Services
		11,988	5160-000	Maintenance of Line Transfor.
		1,963	5175-000	Maintenance of Meters
		253,130		
Billing and collection	**347,731**	35,200	5310-000	Meter Reading Expense
		211,800	5315-000	Customer Billing
		97,931	5320-001	Collecting
		-	5325-000	Collecting - Cash Over & Short
		2,800	5335-000	Bad Debts Expense (W-Offs)

		347,731		
Community relations	-	-	5410-000	Community Relations - Sundry
Administration	**403,559**	105,734	5605-000	Executive Salaries and Expense
		74,249	5610-000	Management Salaries & Expenses
		22,744	5620-000	Office Supplies and Expenses
		17,784	5630-000	Outside Services Employed
		4,798	5635-000	Property Insurance
		3,509	5640-000	Injuries and Damages
		3,627	5645-000	Employee Pensions & Benefits
		128,606	5655-000	Regulatory Expenses
		14,600	5665-000	Miscellaneous General Expenses
		23,003	5675-000	Maintenance of General Plant
		4,904	5680-000	Elect. Safety Authority Fees
		-	5681-001	Special Purpose Charge - Expense
		403,559		
Amortization of capital assets	**274,433**	**274,433**	5705-000	Amortization Expense
Interest	**88,612**	17,742	6005-001	Interest on Long Term Debt
		70,870	6035-000	Other Interest Expense
		88,612		
Property taxes	**14,768**	**14,768**	6105-001	Property Taxes
Others	**24,546**	7,845	4083-000	Retail Services Expenses
		83	4085-000	STR Expenses
		14,619	4330-001	Costs & Expenses from Jobbing
		2,000	6205-001	Donations - LEAP Funding
		24,546		

Income Taxes

Recovered	-	-	6110-001	Income Tax Expense
Future	**65,907**	**65,907**	6115-000	FUTURE INCOME TAXES PROVISION

Balance Sheet		**Trial Balance**		

Assets

Current Assets

Cash and term deposits	**216,704**	215,504	1005-201	Cash in Bank #351-23
		1,200	1010-000	Cash Advances and Working Fund
		-	1060-000	Term Deposits
		216,704		
Accounts receivable	**1,386,514**	1,375,289	1100-000	Customer Accounts Receivable
		18,142	1102-000	Accounts Receivable - Services
		9,691	1190-000	Misc Current & Accrued Assets
		(16,609)	1130-000	Acc Provision for Uncoll Acc't
		1,386,514		
Inventories	**111,022**	**111,022**	1330-000	Plant Materials & Op. Supplies
Unbilled revenue	**1,151,703**	**1,151,703**	1120-000	Accrued Utility Revenues
Prepaid charges	**97,256**	28,054	1180-000	Prepaid Expenses
		69,202	1460-000	Other Non-Current Assets
		97,256		
Income taxes receivable	**222,147**	**222,147**	2294-000	Accrual for Taxes (Pil's)
Future income taxes	-	-	2296-000	Future Income Tax - Current
Other assets	**1,785,641**	766,850	1508-004/10	Other Reg. Assets
		1,830	1518-000	RCVA Retail
		1,874	1535-000	Smart Grid OM&A Deferral Account
		9,455	1548-000	RCVA STR

		87,149	1550-000	Low Voltage (LV) Variance Acct
		2,916	1563-000	Deferred PILs Contra Account
		(291,714)	1580-000	RSVA WMS
		(11,724)	1584-000	RSVA Network Service
		(56,170)	1586-000	RSVA Connection Service
		458,677	1588-001	RSVA POWER
		802,991	1589-001	RSVA GLOBAL ADJUSTMENT
		(193,536)	1595	Disposition and Recovery of Regulatory Balances (2010)
		127,934	1595	Disposition and Recovery of Regulatory Balances (2011)
		79,109	1595	Disposition and Recovery of Regulatory Balances (2012)
		1,785,641		
Capital assets	**2,462,875**	181,024	1611-000	Computer Software
		8,588	1612-000	Land Rights Distribution Plant
		10,000	1705-000	Land Transmission Plant 115Kv
		10,000	1805-000	Land Distribution Plant 44Kv
		482,802	1815-000	Transformer Station Equipment
		256,183	1820-000	Distribution Station Equipment
		459,627	1830-000	Poles, Towers and Fixtures
		475,830	1835-000	Overhead Conductors and Device
		113,855	1840-000	Underground Conduit
		265,913	1845-000	Underground Conductors & Devic
		408,793	1850-000	Line Transformers
		32,420	1855-000	Services
		254,843	1860-000	Meters
		618,899	1860-001	Smart Meters
		28,300	1905-000	Land General Plant
		824,124	1908-000	Buildings and Fixtures
		33,784	1915-000	Office Furniture and Equipment
		54,878	1920-000	Computer Equipment - Hardware
		204,794	1930-000	Transportation Equipment
		27,996	1940-000	Tools, Shop and Garage Equip.
		4,363	1950-000	Power Operated Equipment
		(232,832)	1995-000	Contributions and Grants - Credit
		(2,061,309)	2105-000	Acc Amort of Electric Plant
		2,462,875		

Liabilities

Current liabilities

Accounts payable and accrued liabilities	**2,342,183**	-	1191-000	G.S.T. Paid
		(2,264,509)	2205-000	Accounts Payable
		(77,675)	2220-000	Misc Current & Accrued Liab.
		(2,342,183)		
Other current liabilities	**55,411**	**55,411**	2208-000	Customer Credit Balances
Current portion of other long-term liabilities	**270,160**	**(270,160)**	2210-000	Current Portion of Customer Deposits
Current portion of long term debt	**271,703**	(253,366)	2520-000A	Other Long Term Debt - CURRENT PORTION (Town of Hawkesbury)
		(18,337)	2520-000	Other Long Term Debt (IO Loan SUB 44KV)
		(271,703)	2520-000	**TOTAL in RRR Trial Balance**
Future income taxes	**76,640**	**(76,640)**	2350-000	Future Income Tax - Non-Current
Provision for sick leave benefits	**86,171**	**(86,171)**	2310-000	Vested Sick Leave Liability
Other long-term liabilities	**354,318**	(354,318)	2335-000	Long Term Portion of Customer Deposits
		(354,318)		
Other long-term liabilities: TOTAL	**624,478**			
Long term debt	**722,761**	(722,761)	2520-000	Other Long Term Debt - IO Loan SUB 44KV
		(722,761)	2520-000	**TOTAL in RRR Trial Balance**

Shareholder's equity

Share capital	**1,689,346**	**(1,689,346)**	3005-000	Common Shares Issued
Retained earnings	**1,565,169**	(1,290,338)	3045-000	Retained Earnings
		(359,298)	3046-000	Net earnings
		84,467	3049-000	Dividends Payable
		(1,565,169)		

E1.T3.S4 PRO-FORMAS

Pro-Formas for both the 2013 Bridge Year and 2014 Test Year are presented at the next page.

File Number:	EB-2013-0139
Exhibit:	1
Tab:	4
Schedule:	5
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Date:	

TESI-14
Net Income Trends

Account Grouping		CGAAP Test Year 2014	Bridge Year 2013	Actual 2012	Actual 2011	Actual 2010	Board Appr 2010
Balance Sheet							
1050-Current Assets		2,892,200	3,126,715	2,782,975	3,367,319	4,258,903	3,520,562
1100-Inventory		111,000	111,000	111,022	118,434	125,669	218
1150-Non-Current Assets		0	0	69,202	148,421	183,560	21,200
1200-Other Assets and Deferred Charges		994,783	497,247	1,785,641	1,402,082	-333,709	-545,248
1300-Intangible Plant		226,024	209,024	181,024	136,793	128,153	129,242
1450-Distribution Plant		5,886,361	5,910,104	3,387,752	2,575,618	2,404,375	2,536,572
1500-General Plant		1,253,639	1,229,439	1,178,239	1,173,168	1,164,871	1,264,406
1550-Other Capital Assets		-254,514	-254,514	-254,514	-144,474	-144,474	-55,867
1600-Accumulated Amortization		-2,270,587	-2,241,075	-2,039,627	-1,765,745	-1,606,185	-1,620,320
Total Assets		**8,838,906**	**8,587,941**	**7,201,715**	**7,011,615**	**6,181,162**	**5,250,765**
1650-Current Liabilities		-2,281,729	-2,284,991	-2,445,608	-3,100,164	-2,293,104	-3,191,382
1700-Non-Current Liabilities		-555,000	-550,000	-517,129	-441,478	-461,568	-517,411
1800-Long-Term Debt		-2,200,000	-2,217,000	-994,464	-500,290	-731,715	-850,364
Total Liabilities		**-5,036,729**	**-5,051,991**	**-3,957,202**	**-4,041,932**	**-3,486,387**	**-4,559,157**
1850-Shareholders' Equity		-3,812,177	-3,545,949	-3,254,514	-2,979,684	-2,704,775	-1,021,077
Total Liabilities & Shareholders' Equity		**-8,848,906**	**-8,597,940**	**-7,211,716**	**-7,021,615**	**-6,191,162**	**-5,580,234**
Net Liability and Equity	**	**-10,000**	**-10,000**	**-10,000**	**-10,000**	**-10,000**	

Account Grouping	CGAAP Test Year 2014	Bridge Year 2013	Actual 2012	Actual 2011	Actual 2010	Board Appr 2010
Profit and Loss						
3000-Sales of Electricity	-15,927,063	-16,062,015	-9,546,720	-9,895,594	-10,221,319	-13,066,984
3050-Revenues From Services - Distribution	-1,648,624	-1,648,624	-1,648,714	-1,328,430	-1,210,348	-943,552
3100-Other Operating Revenues	-116,739	-116,739	-112,875	-119,172	-117,549	-119,952
3150-Other Income & Deductions	-5,000	-5,000	-8,319	-903	-40,354	-20,500
3200-Investment Income	-20,000	-20,000	-39,530	-36,255	-12,060	-17,000
Net Revenues	**-17,717,427**	**-17,852,379**	**-11,356,159**	**-11,380,354**	**-11,601,631**	**-14,167,988**
3350-Power Supply Expenses	15,927,063	16,062,015	9,546,720	9,895,594	10,221,319	13,066,985
3500-Distribution Expenses - Operation	96,550	85,250	74,387	71,031	75,104	75,463
3550-Distribution Expenses - Maintenance	205,700	189,700	178,745	147,634	131,509	171,887
3650-Billing and Collecting	426,315	390,190	347,731	339,942	325,519	327,572
3700-Community Relations	200	200	0	225	100	108
3800-Administrative and General Expenses	397,900	467,400	405,557	352,659	335,456	370,562
OM&A and Power Supply Expenses	**17,053,728**	**17,194,755**	**10,553,140**	**10,807,085**	**11,089,008**	**14,012,577**
3850-Amortization Expense	222,854	202,997	274,433	159,560	158,511	169,798
Earnings Before Interest & Taxes	**-440,845**	**-454,627**	**-528,585**	**-413,708**	**-354,112**	**14,387**
3900-Interest Expense	114,500	95,744	88,612	75,346	64,737	57,943
Earnings Before Tax	**-326,345**	**-358,883**	**-439,973**	**-338,362**	**-289,375**	**72,330**
4000-Income Taxes	45,117	52,447	65,907	-36,001	127,260	0
Net Income excluding Extraordinary Items	**-281,228**	**-306,436**	**-374,066**	**-374,363**	**-162,115**	**72,330**
4100-Unusual & Other Items	15,000	15,000	14,768	14,987	15,678	28,262
Net Income	**-266,228**	**-291,436**	**-359,299**	**-359,376**	**-146,436**	**100,592**

** The variance is explained by the amount of $10,000 recorded in account 1705-Land.

E1.T3.S5 PROSPECTUS AND RECENT DEBT/SHARE ISSUANCE UPDATE

This Applicant does not issue any type of prospectus, debt/share issuance update.

Tab 4 – Materiality Threshold

E1.T4.S1 UTILITY MATERIALITY THRESHOLD

HHI has determined the materiality threshold in accordance with the Filing Requirements. These state that for a utility with a distribution revenue requirement less than or equal to $10 million; the materiality threshold is set at $50,000. HHI has used this value for both operating variances and capital projects.

Exhibit 2 – Rate Base

EXHIBIT 2 – RATE BASE

The evidence presented in this exhibit provides information supporting the value of assets, on which a public utility is permitted to earn a specified rate of return, in accordance with rules set by the Ontario Energy Board. The evidence is organized according to the following topics;

1) Overview of Rate Base
2) Capital Expenditures
3) Service Quality and Reliability Performance

Tab 1 – Overview Rate Base

E2.T1.S1 OVERVIEW

HHI's Rate Base is determined by taking the average of the balances at the beginning and the end of the 2014 Test Year, plus a working capital allowance of 13% of the sum of the cost of power and controllable expenses. The use of a 13% rate is consistent with the Board's letter of April 12, 2012.

The net fixed assets include those distribution assets associated with activities that enable the conveyance of electricity for distribution purposes. HHI does not have non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

Table 1 below presents HHI's Rate Base calculations for all required years including the 2014 Test Year. HHI has calculated its 2014 rate base to be $7,063,936. This rate base is also used to determine the proposed revenue requirement found at E6.T1.S2.

Table 1- Rate Base Trend Table

Particulars	Modified CGAAP Test Year 2014	Modified CGAAP Bridge Year 2013	CGAAP Actual 2012	CGAAP Actual 2011	CGAAP Actual 2010	CGAAP Board Appr 2010
Net Capital Assets in Service:						
Opening Balance	4,852,979	2,452,875	1,975,359	1,946,741	1,952,897	2,057,629
Ending Balance	4,840,923	4,852,979	2,452,875	1,975,359	1,946,741	2,254,031
Average Balance	4,846,951	3,652,927	2,214,117	1,961,050	1,949,819	2,155,830
Working Capital Allowance	2,216,985	2,579,213	1,582,971	1,621,063	1,663,351	2,106,126
Total Rate Base	**7,063,936**	**6,232,140**	**3,797,088**	**3,582,113**	**3,613,170**	**4,261,956**

Expenses for Working Capital	CGAAP					
Eligible Distribution Expenses:						
3500-Distribution Expenses - Operation	96,550	85,250	74,387	71,031	75,104	75,463
3550-Distribution Expenses - Maintenance	205,700	189,700	178,745	147,634	131,509	171,887
3650-Billing and Collecting	426,315	390,190	347,731	339,942	325,519	327,572
3700-Community Relations	200	200	-	225	100	108
3800-Administrative and General Expenses	397,900	467,400	405,557	352,659	335,456	398,824
Total Eligible Distribution Expenses	1,126,665	1,132,740	1,006,420	911,491	867,689	973,854
3350-Power Supply Expenses	15,927,063	16,062,015	9,546,720	9,895,594	10,221,319	13,066,985
Total Expenses for Working Capital	17,053,728	17,194,755	10,553,140	10,807,085	11,089,008	14,040,839
Working Capital factor	13%	15%	15%	15%	15%	15%
Total Working Capital	**2,216,985**	**2,579,213**	**1,582,971**	**1,621,063**	**1,663,351**	**2,106,126**

The Rate Base for 2014 has increased by $832K over 2013 and $2.8MK over the 2010 Board Approved Rate Base. The reason for the considerable increase in 2014 is mainly attributed to the inclusion of capital expenditures previously approved in an ICM application in the test year rate base. The capital assets added in 2013 total 2.3M. Details of these additions are discussed in detail at E2.T2.S4 and E2.T2.S7. Another significant reason for the increase is the inclusion of $600K in Smart Meter Related Capital expenditures into the Test Year's Rate Base. Further details on the topic of Smart Meters can also be found at E2.T1.S7 and E2.T2.S4.

The Working Capital Allowance has decreased by $362K over 2013 and increased by $110,000 over the 2010 Board Approved Working Capital Allowance. The reason for the decrease from 2014 to 2013 is due to the change in Working Capital Allowance rate from 15% to 13%.

E2.T1.S2 RATE BASE VARIANCE DRIVERS

The following paragraphs provide a narrative on the changes that have driven the increase in rate base since HHI's 2010 cost of service.

Table 2- 2014-2013 Rate Base Variance

	Modified CGAAP			
Particulars	**Test Year 2014**	**Bridge Year 2013**	**Var**	**%**
Net Capital Assets in Service:				
Opening Balance	4,852,979	2,452,875	2,400,104	98%
Ending Balance	4,840,923	4,852,979	(12,055)	0%
Average Balance	4,846,951	3,652,927	1,194,024	33%
Working Capital Allowance	2,216,985	2,579,213	(474,363)	-18%
Total Rate Base	7,063,936	6,232,140	719,661	12%

2014 Test Year vs. 2013 Bridge Year:

The total projected average balance in 2014 of $4.8 million is $1.2M or 33% greater than 2013. The main reason for the variance is the use of an average opening and closing balance for 2013 which saw significant capital additions. In 2014, the utility's investment in its distribution system is required in order to keep the system running in a safe and reliable manner. This increase is offset by the removal of stranded conventional meters from Rate Base and other cost savings and deferrals during 2014. The utility is also planning on replacing deteriorated poles as a result of its asset assessment. Details regarding pole replacements can be found in the Asset Management Plan at E2.T2.S7. The rest of the increase can be attributed to regular maintenance of the distribution system. The working capital allowance saw a decrease due to the reduction in rate from 15% to 13%.

Table 3 - 2013-2012 Rate Base Variance

	CGAAP			
Particulars	**Bridge Year 2013**	**Actual 2012**	**Var**	**%**
Net Capital Assets in Service:				
Opening Balance	2,452,875	1,975,359	477,515	24%
Ending Balance	4,852,979	2,452,875	2,400,104	98%
Average Balance	3,652,927	2,214,117	1,438,810	65%
Working Capital Allowance	2,579,213	1,582,971	996,242	63%
Total Rate Base	**6,232,140**	**3,797,088**	**2,435,052**	**64%**

2013 Bridge Year vs. 2012 Actual:

The total projected average balance in 2013 of $3.6 million is $1.4 million or 65% greater than 2012. The increase is primarily due to the inclusion of previously approved ICM expenditures into rate base. Similarly to 2014, the utility is planning to replace deteriorated poles as a result of its asset assessment. Details regarding pole replacements can be found in the Asset Management Plan at E2.T2.S7. The rest of the increase can be attributed to regular maintenance of the distribution system. The working capital allowance saw an increase proportional to the increase in OM&A. Details of the OM&A expenditures are presented at Exhibit 4.

Table 4 - 2012-2011 Rate Base Variance

	CGAAP			
Particulars	**Actual 2012**	**Actual 2011**	**Var**	**%**
Net Capital Assets in Service:				
Opening Balance	1,975,359	1,946,741	28,619	1%
Ending Balance	2,452,875	1,975,359	477,515	24%
Average Balance	2,214,117	1,961,050	253,067	13%
Working Capital Allowance	1,582,971	1,621,063	(38,092)	-2%
Total Rate Base	**3,797,088**	**3,582,113**	**214,975**	**6%**

2012 Actual vs. 2011 Actual:

The total projected average balance in 2012 of $2.2 million is $253K or 13% greater than 2011. The increase is primarily due to the inclusion of Smart Meters in Rate Base in the amount of 601K. The rest of the increase can be attributed to regular maintenance of the distribution system. The working capital allowance saw an increase proportional to the increase in OM&A. Details of the OM&A expenditures are presented at Exhibit 4.

Table 5 - 2011-2010 Rate Base Variance

	CGAAP			
Particulars	**Actual 2011**	**Actual 2010**	**Var**	**%**
Net Capital Assets in Service:				
Opening Balance	1,946,741	1,952,897	(6,156)	0%
Ending Balance	1,975,359	1,946,741	28,619	1%
Average Balance	1,961,050	1,949,819	11,231	1%
Working Capital Allowance	1,621,063	1,663,351	(42,288)	-3%
Total Rate Base	**3,582,113**	**3,613,170**	**(31,057)**	**-1%**

2011Actual vs. 2010 Actual:

2011 shows a marginal increase average net fixed assets and is more reflective of a typical year with additions related to typical maintenance of the distribution system. The working capital allowance mirrors the increase in OM&A as detailed at Exhibit 4

Table 6 - 2011-2010 Board Approved Rate Base Variance

	CGAAP			
Particulars	**Actual 2010**	**Board Appr. 2010**	**Var**	**%**
Net Capital Assets in Service:				
Opening Balance	1,952,897	2,057,629	(104,733)	-5%
Ending Balance	1,946,741	2,254,031	(307,291)	-14%
Average Balance	1,949,819	2,155,830	(206,012)	-10%
Working Capital Allowance	1,663,351	2,106,126	(442,775)	-21%
Total Rate Base	**3,613,170**	**4,261,956**	**(648,786)**	**-15%**

2010 Actual vs. 2010 Board-Approved:

The total projected average balance in 2010 Actual of $2 million is $443K lesser or -10% lesser than the 2010 Board Approved. The underspending can be attributed to the fact that rates were not approved until mid-year. The utility, like many others, tend to put capital investments on hold until the cost of service application is approved. This caused delays in HHI investing time in maintaining and upgrading its system.

E2.T1.S3 GROSS ASSET – PROPERTY PLAN AND EQUIPMENT

HHI's Assets are broken down by the following functions.

Table 7 – Asset Breakdown

	Modified CGAAP	**CGAAP**					
OEB	**2014 Test Year**	**2013 Bridge Year**	**2012 Actual**	**2011 Actual**	**2010 Actual**	**2010 Board Approved**	**2009 Actual**
1300-Intangible Plant	$226,024.11	$209,024.11	$181,024.11	$136,792.61	$128,153.27	$129,242.00	$113,795.64
1450-Distribution Plant	$5,886,360.99	$5,910,104.37	$3,387,752.37	$2,575,617.80	$2,404,375.34	$2,536,572.00	$2,203,901.78
1500-General Plant	$1,253,639.30	$1,229,439.30	$1,178,239.10	$1,173,167.78	$1,164,870.90	$1,264,406.00	$1,153,046.83
1550-Other Capital Assets	-$254,514.18	-$254,514.18	-$254,514.18	-$144,473.61	-$144,473.61	-$55,867.00	-$66,537.00
	$7,111,510.22	**$7,094,053.60**	**$4,492,501.40**	**$3,741,104.58**	**$3,552,925.90**	**$3,874,353.00**	**$3,404,207.25**

E2.T1.S4 SUMMARY OF ICM ADJUSTMENT FROM IRM

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

The new 25 MVA would have the capability to support the entire service area. The Board found that the need, prudence and materiality for each for the two applied-for projects had been established and that Hydro Hawkesbury had also adequately demonstrated that its 2012 capital budget for both the 44kV and the 25 MVA both projects) was of non-discretionary nature. The Board then accepted HHI's incremental capital module of $2,230,722.

The decision related to the HHI's 2012 IRM is presented at Appendix A

HHI has included the value of these assets in its Rate Base.

E2.T1.S5 CONTINUITY STATEMENTS – APPENDIX 2-B

The Continuity Schedule calculates the cost, accumulated amortization, and net book value (NBV) for each Capital USoA. The information is presented for all relevant years at the next pages.

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Appendix 2-B
Fixed Asset Continuity Schedule

Year **2010**

				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)		$ 113,796	$ 14,358		$ 128,153	$ (50,289)	$ (23,124)		$ (73,412)	$ 54,741
CEC	1612	Land Rights (Formally known as Account 1906)		$ 8,588	$ -		$ 8,588	$ (2,608)	$ -		$ (2,608)	$ 5,980
N/A	1805	Land		$ 10,000			$ 10,000	$ -	$ -		$ -	$ 10,000
47	1808	Buildings					$ -				$ -	$ -
13	1810	Leasehold Improvements					$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 349,917	$ 52,495		$ 402,412	$ (68,848)	$ (8,885)		$ (77,733)	$ 324,679
47	1820	Distribution Station Equipment <50 kV		$ 175,801	$ 9,059		$ 184,860	$ (88,861)	$ (10,597)		$ (99,458)	$ 85,402
47	1825	Storage Battery Equipment					$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 322,656	$ 28,411		$ 351,067	$ (171,009)	$ (18,316)		$ (189,325)	$ 161,742
47	1835	Overhead Conductors & Devices		$ 367,500	$ 34,806		$ 402,306	$ (198,824)	$ (22,294)		$ (221,118)	$ 181,188
47	1840	Underground Conduit		$ 113,708	$ 147		$ 113,855	$ (54,221)	$ (5,937)		$ (60,158)	$ 53,697
47	1845	Underground Conductors & Devices		$ 212,732	$ 47,660		$ 260,392	$ (84,447)	$ (11,544)		$ (95,991)	$ 164,401
47	1850	Line Transformers		$ 372,827	$ 24,321		$ 397,148	$ (170,766)	$ (16,654)		$ (187,420)	$ 209,728
47	1855	Services (Overhead & Underground)		$ 23,261	$ 3,574		$ 26,835	$ (5,121)	$ (1,001)		$ (6,122)	$ 20,713
47	1860	Meters		$ 246,912			$ 246,912	$ (140,473)	$ (15,656)		$ (156,129)	$ 90,783
47	1860	Meters (Smart Meters)					$ -				$ -	$ -
N/A	1905	Land		$ 28,300			$ 28,300	$ -	$ -		$ -	$ 28,300
47	1908	Buildings & Fixtures		$ 824,124			$ 824,124	$ (169,573)	$ (16,999)		$ (186,572)	$ 637,552
13	1910	Leasehold Improvements					$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 30,528	$ 2,126		$ 32,654	$ (12,211)	$ (2,616)		$ (14,827)	$ 17,827
8	1915	Office Furniture & Equipment (5 years)					$ -				$ -	$ -
10	1920	Computer Equipment - Hardware		$ 46,427	$ 3,691		$ 50,118	$ (35,048)	$ (4,725)		$ (39,773)	$ 10,345
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)					$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)					$ -				$ -	$ -
10	1930	Transportation Equipment		$ 205,346			$ 205,346	$ (188,730)	$ (2,556)		$ (191,286)	$ 14,060
8	1935	Stores Equipment					$ -				$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 13,960	$ 6,007		$ 19,966	$ (7,830)	$ (1,353)		$ (9,182)	$ 10,784
8	1945	Measurement & Testing Equipment					$ -				$ -	$ -
8	1950	Power Operated Equipment		$ 4,363			$ 4,363	$ (2,453)	$ (545)		$ (2,998)	$ 1,365
8	1955	Communications Equipment					$ -				$ -	$ -
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					$ -				$ -	$ -
47	1995	Contributions & Grants		$ (70,174)	$ (74,300)		$ (144,474)	$ 3,637	$ 4,291		$ 7,928	$ (136,546)
	etc.						$ -				$ -	$ -
		Total		**$ 3,400,571**	**$ 152,355**	**$ -**	**$ 3,552,926**	**$ (1,447,674)**	**$ (158,511)**	**$ -**	**$ (1,606,185)**	**$ 1,946,741**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ -

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Appendix 2-B
Fixed Asset Continuity Schedule

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	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 128,153	$ 8,639		$ 136,793	$ (73,412)	$ (23,439)		$ (96,851)	$ 39,941
CEC	1612	Land Rights (Formally known as Account 1906)		$ 8,588	$ -		$ 8,588	$ (2,608)	$ -		$ (2,608)	$ 5,980
N/A	1805	Land		$ 10,000			$ 10,000	$ -	$ -		$ -	$ 10,000
47	1808	Buildings		$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 402,412	$ 55,500		$ 457,912	$ (77,733)	$ (9,744)		$ (87,477)	$ 370,435
47	1820	Distribution Station Equipment <50 kV		$ 184,860	$ 66,691		$ 251,551	$ (99,458)	$ (11,860)		$ (111,318)	$ 140,233
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 351,067	$ 27,659		$ 378,725	$ (189,325)	$ (18,599)		$ (207,924)	$ 170,802
47	1835	Overhead Conductors & Devices		$ 402,306	$ 3,636		$ 405,943	$ (221,118)	$ (22,027)		$ (243,145)	$ 162,797
47	1840	Underground Conduit		$ 113,855	$ -		$ 113,855	$ (60,158)	$ (5,942)		$ (66,100)	$ 47,755
47	1845	Underground Conductors & Devices		$ 260,392	$ 585		$ 260,977	$ (95,991)	$ (12,507)		$ (108,498)	$ 152,479
47	1850	Line Transformers		$ 397,148	$ 6,025		$ 403,173	$ (187,420)	$ (15,567)		$ (202,987)	$ 200,186
47	1855	Services (Overhead & Underground)		$ 26,835	$ 3,350		$ 30,186	$ (6,122)	$ (1,140)		$ (7,262)	$ 22,923
47	1860	Meters		$ 246,912	$ 7,797		$ 254,709	$ (156,129)	$ (15,406)		$ (171,535)	$ 83,174
47	1860	Meters (Smart Meters)		$ -			$ -	$ -			$ -	$ -
N/A	1905	Land		$ 28,300	$ -		$ 28,300	$ -	$ -		$ -	$ 28,300
47	1908	Buildings & Fixtures		$ 824,124	$ -		$ 824,124	$ (186,572)	$ (16,999)		$ (203,571)	$ 620,553
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 32,654	$ 1,130		$ 33,784	$ (14,827)	$ (2,738)		$ (17,565)	$ 16,219
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 50,118	$ 2,103		$ 52,222	$ (39,773)	$ (4,392)		$ (44,165)	$ 8,056
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 205,346	$ -		$ 205,346	$ (191,286)	$ (2,556)		$ (193,842)	$ 11,504
8	1935	Stores Equipment		$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 19,966	$ 5,063		$ 25,029	$ (9,182)	$ (1,876)		$ (11,058)	$ 13,971
8	1945	Measurement & Testing Equipment		$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment		$ 4,363	$ -		$ 4,363	$ (2,998)	$ (545)		$ (3,543)	$ 820
8	1955	Communications Equipment		$ -			$ -	$ -			$ -	$ -
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		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		$ (144,474)	$ -		$ (144,474)	$ 7,928	$ 5,777		$ 13,705	$ (130,769)
	etc.			$ -			$ -	$ -			$ -	$ -
		Total		**$ 3,552,926**	**$ 188,179**	**$ -**	**$ 3,741,105**	**$ (1,606,185)**	**$ (159,560)**	**$ -**	**$ (1,765,745)**	**$ 1,975,359**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ -

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Appendix 2-B
Fixed Asset Continuity Schedule

Year **2012**

				Cost					Accumulated Depreciation					
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Smart Meter Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Smart Meter Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)		$ 136,793	$ 2,683	$ 41,549		$ 181,024	$ (96,851)	$ (28,739)	$ (4,361)		$ (129,951)	$ 51,073
CEC	1612	Land Rights (Formally known as Account 1906)		$ 8,588	$ -			$ 8,588	$ (2,608)	$ -			$ (2,608)	$ 5,980
N/A	1805	Land		$ 10,000	$ -			$ 10,000	$ -	$ -			$ -	$ 10,000
47	1808	Buildings		$ -				$ -	$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements		$ -				$ -	$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 457,912	$ 24,890			$ 482,802	$ (87,477)	$ (10,749)			$ (98,226)	$ 384,576
47	1820	Distribution Station Equipment <50 kV		$ 251,551	$ 4,632			$ 256,183	$ (111,318)	$ (13,048)			$ (124,366)	$ 131,817
47	1825	Storage Battery Equipment		$ -				$ -	$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 378,725	$ 80,902			$ 459,627	$ (207,924)	$ (20,770)			$ (228,694)	$ 230,934
47	1835	Overhead Conductors & Devices		$ 405,943	$ 69,888			$ 475,830	$ (243,145)	$ (22,615)			$ (265,760)	$ 210,070
47	1840	Underground Conduit		$ 113,855	$ -			$ 113,855	$ (66,100)	$ (5,735)			$ (71,835)	$ 42,020
47	1845	Underground Conductors & Devices		$ 260,977	$ 4,936			$ 265,913	$ (108,498)	$ (12,310)			$ (120,808)	$ 145,105
47	1850	Line Transformers		$ 403,173	$ 5,620			$ 408,793	$ (202,987)	$ (15,664)			$ (218,651)	$ 190,141
47	1855	Services (Overhead & Underground)		$ 30,186	$ 2,234			$ 32,420	$ (7,262)	$ (1,252)			$ (8,514)	$ 23,905
47	1860	Meters		$ 254,709	$ 135			$ 254,843	$ (171,535)	$ (12,753)			$ (184,288)	$ 70,555
47	1860	Meters (Smart Meters)		$ -	$ 17,082	$ 601,817		$ 618,899	$ -	$ (40,690)	$ (64,643)		$ (105,333)	$ 513,566
N/A	1905	Land		$ 28,300	$ -			$ 28,300	$ -	$ -			$ -	$ 28,300
47	1908	Buildings & Fixtures		$ 824,124	$ -			$ 824,124	$ (203,571)	$ (16,999)			$ (220,570)	$ 603,554
13	1910	Leasehold Improvements		$ -				$ -	$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 33,784	$ -			$ 33,784	$ (17,565)	$ (2,755)			$ (20,320)	$ 13,464
8	1915	Office Furniture & Equipment (5 years)		$ -				$ -	$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 52,222	$ 2,656			$ 54,878	$ (44,165)	$ (3,639)			$ (47,804)	$ 7,074
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -				$ -	$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -				$ -	$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 205,346	$ -		$ (552)	$ 204,794	$ (193,842)	$ (2,556)		$ 552	$ (195,846)	$ 8,948
8	1935	Stores Equipment		$ -				$ -	$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 25,029	$ 794	$ 2,173		$ 27,996	$ (11,058)	$ (2,281)	$ (307)		$ (13,647)	$ 14,350
8	1945	Measurement & Testing Equipment		$ -				$ -	$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment		$ 4,363	$ -			$ 4,363	$ (3,543)	$ (545)			$ (4,089)	$ 275
8	1955	Communications Equipment		$ -				$ -	$ -	$ -			$ -	$ -
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		$ -				$ -	$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		$ (144,474)	$ (110,041)			$ (254,514)	$ 13,705	$ 7,978			$ 21,682	$ (232,832)
				$ -				$ -	$ -				$ -	$ -
								$ -					$ -	$ -
							$ -	$ -					$ -	$ -
							$ -	$ -					$ -	$ -
	etc.						$ -	$ -					$ -	$ -
		Total		**$ 3,741,105**	**$ 106,410**	**$ 645,539**	**$ (552)**	**$ 4,492,501**	**$ (1,765,745)**	**$ (205,123)**	**$ (69,311)**	**$ 552**	**$ (2,039,627)**	**$ 2,452,875**

10		Transportation	
8		Stores Equipment	$ 0

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ 552

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Appendix 2-B
Fixed Asset Continuity Schedule

Year 2013

				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)		$ 181,024	$ 28,000	$ -	$ 209,024	$ (129,951)	$ (22,727)		$ (152,678)	$ 56,346
CEC	1612	Land Rights (Formally known as Account 1906)		$ 8,588	$ -	$ -	$ 8,588	$ (2,608)	$ -		$ (2,608)	$ 5,980
N/A	1805	Land		$ 10,000	$ -	$ -	$ 10,000	$ -			$ -	$ 10,000
47	1808	Buildings		$ -		$ -	$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements		$ -		$ -	$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 482,802	$ 1,547,900	$ -	$ 2,030,702	$ (98,226)	$ (27,030)		$ (125,256)	$ 1,905,446
47	1820	Distribution Station Equipment <50 kV		$ 256,183	$ 800,000	$ -	$ 1,056,183	$ (124,366)	$ (17,639)		$ (142,005)	$ 914,178
47	1825	Storage Battery Equipment		$ -		$ -	$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 459,627	$ 99,000	$ -	$ 558,627	$ (228,694)	$ (13,447)		$ (242,141)	$ 316,487
47	1835	Overhead Conductors & Devices		$ 475,830	$ 25,000	$ -	$ 500,830	$ (265,760)	$ (10,212)		$ (275,972)	$ 224,858
47	1840	Underground Conduit		$ 113,855	$ 500	$ -	$ 114,355	$ (71,835)	$ (2,756)		$ (74,591)	$ 39,764
47	1845	Underground Conductors & Devices		$ 265,913	$ 17,000	$ -	$ 282,913	$ (120,808)	$ (10,321)		$ (131,129)	$ 151,784
47	1850	Line Transformers		$ 408,793	$ 28,000	$ (1,548)	$ 435,245	$ (218,651)	$ (10,012)	$ 1,548	$ (227,115)	$ 208,129
47	1855	Services (Overhead & Underground)		$ 32,420	$ 3,000	$ -	$ 35,420	$ (8,514)	$ (1,130)		$ (9,644)	$ 25,775
47	1860	Meters		$ 254,843		$ -	$ 254,843	$ (184,288)	$ (9,055)		$ (193,343)	**$ 61,500**
47	1860	Meters (Smart Meters)		$ 618,899	$ 3,500	$ -	$ 622,399	$ (105,333)	$ (41,377)		$ (146,710)	$ 475,689
N/A	1905	Land		$ 28,300	$ -	$ -	$ 28,300	$ -			$ -	$ 28,300
47	1908	Buildings & Fixtures - **BUILDING ROOF**		$ 165,167	$ 18,040	$ -	$ 183,207	$ (44,363)	$ (6,968)		$ (51,331)	$ 131,876
47	1908	Buildings & Fixtures - **INTERIOR FIXTURES**		$ 246,041	$ 19,460	$ -	$ 265,501	$ (65,298)	$ (17,053)		$ (82,351)	$ 183,150
47	1908	Buildings & Fixtures - **STRUCTURE**		$ 412,916	$ -	$ -	$ 412,916	$ (110,908)	$ (8,258)		$ (119,166)	$ 293,750
13	1910	Leasehold Improvements		$ -		$ -	$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 33,784	$ 5,700	$ -	$ 39,484	$ (20,320)	$ (3,041)		$ (23,361)	$ 16,123
8	1915	Office Furniture & Equipment (5 years)		$ -		$ -	$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 54,878	$ 3,000	$ -	$ 57,878	$ (47,804)	$ (2,974)		$ (50,778)	$ 7,100
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -		$ -	$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -		$ -	$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 204,794	$ -	$ -	$ 204,794	$ (195,846)	$ (2,556)		$ (198,402)	$ 6,392
8	1935	Stores Equipment		$ -		$ -	$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 27,996	$ 3,000	$ -	$ 30,996	$ (13,647)	$ (2,443)		$ (16,090)	$ 14,907
8	1945	Measurement & Testing Equipment		$ -		$ -	$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment		$ 4,363	$ 2,000	$ -	$ 6,363	$ (4,089)	$ (400)		$ (4,489)	$ 1,875
8	1955	Communications Equipment		$ -		$ -	$ -	$ -			$ -	$ -
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		$ -		$ -	$ -	$ -			$ -	$ -
47	1995	Contributions & Grants - ACCT 1830		$ (77,570)	$ -	$ -	$ (77,570)	$ 2,509	$ 1,724		$ 4,233	$ (73,337)
47	1995	Contributions & Grants - ACCT 1835		$ (49,661)	$ -	$ -	$ (49,661)	$ 2,190	$ 828		$ 3,018	$ (46,643)
47	1995	Contributions & Grants - ACCT 1840		$ (220)	$ -	$ -	$ (220)	$ 40	$ 4		$ 44	$ (176)
47	1995	Contributions & Grants - ACCT 1845		$ (80,350)	$ -	$ -	$ (80,350)	$ 10,442	$ 2,678		$ 13,120	$ (67,231)
47	1995	Contributions & Grants - ACCT 1850		$ (46,713)	$ -	$ -	$ (46,713)	$ 6,502	$ 1,168		$ 7,670	$ (39,043)
	etc.					$ -	$ -				$ -	$ -
		Total		**$ 4,492,501**	**$ 2,603,100**	**$ (1,548)**	**$ 7,094,053**	**$ (2,039,626)**	**$ (202,997)**	**$ 1,548**	**$ (2,241,075)**	**$ 4,852,979**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ 1,548

Notes:

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Appendix 2-B
Fixed Asset Continuity Schedule

Year 2014

				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)		$ 209,024	$ 17,000		$ 226,024	$ (152,678)	$ (20,822)		$ (173,500)	$ 52,524
CEC	1612	Land Rights (Formally known as Account 1906)		$ 8,588			$ 8,588	$ (2,608)			$ (2,608)	$ 5,980
N/A	1805	Land		$ 10,000			$ 10,000	$ -			$ -	$ 10,000
47	1808	Buildings		$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 2,030,702	$ 25,000		$ 2,055,702	$ (125,256)	$ (44,507)		$ (169,763)	$ 1,885,939
47	1820	Distribution Station Equipment <50 kV		$ 1,056,183	$ 60,000		$ 1,116,183	$ (142,005)	$ (27,195)		$ (169,200)	$ 946,983
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 558,627	$ 89,000		$ 647,627	$ (242,141)	$ (14,131)		$ (256,272)	$ 391,356
47	1835	Overhead Conductors & Devices		$ 500,830	$ 20,000		$ 520,830	$ (275,972)	$ (10,588)		$ (286,560)	$ 234,270
47	1840	Underground Conduit		$ 114,355	$ 500		$ 114,855	$ (74,591)	$ (2,763)		$ (77,354)	$ 37,501
47	1845	Underground Conductors & Devices		$ 282,913	$ 17,500		$ 300,413	$ (131,129)	$ (10,837)		$ (141,966)	$ 158,447
47	1850	Line Transformers		$ 435,245	$ 12,500		$ 447,745	$ (227,115)	$ (10,250)		$ (237,365)	$ 210,379
47	1855	Services (Overhead & Underground)		$ 35,420	$ 3,100		$ 38,520	$ (9,644)	$ (1,232)		$ (10,876)	$ 27,643
47	1860	Meters		$ 254,843	$ -	$ (254,843)	$ -	$ (193,343)	$ -	$ 193,343	$ -	$ -
47	1860	Meters (Smart Meters)		$ 622,399	$ 3,500		$ 625,899	$ (146,710)	$ (41,610)		$ (188,320)	$ 437,579
N/A	1905	Land		$ 28,300			$ 28,300	$ -			$ -	$ 28,300
47	1908	Buildings & Fixtures - **BUILDING ROOF**		$ 183,207	$ -		$ 183,207	$ (51,331)	$ (7,329)		$ (58,660)	$ 124,547
47	1908	Buildings & Fixtures - **INTERIOR FIXTURES**		$ 265,501	$ 12,500		$ 278,001	$ (82,351)	$ (18,118)		$ (100,469)	$ 177,532
47	1908	Buildings & Fixtures - **STRUCTURE**		$ 412,916	$ -		$ 412,916	$ (119,167)	$ (8,258)		$ (127,425)	$ 285,491
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 39,484	$ 3,500		$ 42,984	$ (23,361)	$ (3,128)		$ (26,489)	$ 16,495
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 57,878	$ 3,100		$ 60,978	$ (50,778)	$ (2,981)		$ (53,759)	$ 7,219
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 204,794			$ 204,794	$ (198,402)	$ (2,556)		$ (200,958)	$ 3,836
8	1935	Stores Equipment		$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 30,996	$ 3,100		$ 34,096	$ (16,090)	$ (2,576)		$ (18,666)	$ 15,431
8	1945	Measurement & Testing Equipment		$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment		$ 6,363	$ 2,000		$ 8,363	$ (4,489)	$ (375)		$ (4,864)	$ 3,500
8	1955	Communications Equipment		$ -			$ -	$ -			$ -	$ -
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		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants - ACCT 1830		$ (77,570)	$ -		$ (77,570)	$ 4,233	$ 1,724		$ 5,957	$ (71,613)
47	1995	Contributions & Grants - ACCT 1835		$ (49,661)	$ -		$ (49,661)	$ 3,018	$ 828		$ 3,846	$ (45,815)
47	1995	Contributions & Grants - ACCT 1840		$ (220)	$ -		$ (220)	$ 44	$ 4		$ 48	$ (172)
47	1995	Contributions & Grants - ACCT 1845		$ (80,350)	$ -		$ (80,350)	$ 13,120	$ 2,678		$ 15,798	$ (64,553)
47	1995	Contributions & Grants - ACCT 1850		$ (46,713)	$ -		$ (46,713)	$ 7,670	$ 1,168		$ 8,838	$ (37,875)
				$ -				$ -				
		Total		**$ 7,094,053**	**$ 272,300**	**$ (254,843)**	**$ 7,111,510**	**$ (2,241,076)**	**$ (222,854)**	**$ 193,343**	**$ (2,270,587)**	**$ 4,840,923**
							$ 7,102,782		$ (212,926)		$ (2,255,831)	

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ 193,343

E2.T1.S6 ACCUMULATED DEPRECIATION - APPENDIX 2-D

HHI has adopted depreciation rates based on the Kinectrics report. The rates used are presented below and Continuity Schedules of the Accumulated Depreciation are presented at the next pages.

Table 8 – Comparison of Depreciation Rates

Account	Description	CGAAP	Modified CGAAP Post 2012
1611	Computer Software (Formally known as Account 1925)	5.00	5.00
1820	Distribution Station Equipment <50 kV	30.00	55.00
1830	Poles, Towers & Fixtures	25.00	40.00
1835	Overhead Conductors & Devices	25.00	60.00
1845	Underground Conductors & Devices	25.00	35.00
1850	Line Transformers	25.00	40.00
1855	Services (Overhead & Underground)	25.00	40.00
1860	Meters	25.00	25.00
1860	Meters (Smart Meters)	25.00	15.00
1915	Office Furniture & Equipment (10 years)	10.00	10.00
1920	Computer Equipment - Hardware	5.00	5.00
1935	Stores Equipment	10.00	10.00
1940	Tools, Shop & Garage Equipment	10.00	10.00
1945	Measurement & Testing Equipment	10.00	10.00
1995	Contributions & Grants	25.00	40.00

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Appendix 2-B
Fixed Asset Continuity Schedule

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)		$ 113,796	$ 14,358		$ 128,153	$ (50,289)	$ (23,124)		$ (73,412)	$ 54,741
CEC	1612	Land Rights (Formally known as Account 1906)		$ 8,588	$ -		$ 8,588	$ (2,608)	$ -		$ (2,608)	$ 5,980
N/A	1805	Land		$ 10,000			$ 10,000	$ -	$ -		$ -	$ 10,000
47	1808	Buildings					$ -				$ -	$ -
13	1810	Leasehold Improvements					$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 349,917	$ 52,495		$ 402,412	$ (68,848)	$ (8,885)		$ (77,733)	$ 324,679
47	1820	Distribution Station Equipment <50 kV		$ 175,801	$ 9,059		$ 184,860	$ (88,861)	$ (10,597)		$ (99,458)	$ 85,402
47	1825	Storage Battery Equipment					$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 322,656	$ 28,411		$ 351,067	$ (171,009)	$ (18,316)		$ (189,325)	$ 161,742
47	1835	Overhead Conductors & Devices		$ 367,500	$ 34,806		$ 402,306	$ (198,824)	$ (22,294)		$ (221,118)	$ 181,188
47	1840	Underground Conduit		$ 113,708	$ 147		$ 113,855	$ (54,221)	$ (5,937)		$ (60,158)	$ 53,697
47	1845	Underground Conductors & Devices		$ 212,732	$ 47,660		$ 260,392	$ (84,447)	$ (11,544)		$ (95,991)	$ 164,401
47	1850	Line Transformers		$ 372,827	$ 24,321		$ 397,148	$ (170,766)	$ (16,654)		$ (187,420)	$ 209,728
47	1855	Services (Overhead & Underground)		$ 23,261	$ 3,574		$ 26,835	$ (5,121)	$ (1,001)		$ (6,122)	$ 20,713
47	1860	Meters		$ 246,912			$ 246,912	$ (140,473)	$ (15,656)		$ (156,129)	$ 90,783
47	1860	Meters (Smart Meters)					$ -				$ -	$ -
N/A	1905	Land		$ 28,300			$ 28,300	$ -	$ -		$ -	$ 28,300
47	1908	Buildings & Fixtures		$ 824,124			$ 824,124	$ (169,573)	$ (16,999)		$ (186,572)	$ 637,552
13	1910	Leasehold Improvements					$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 30,528	$ 2,126		$ 32,654	$ (12,211)	$ (2,616)		$ (14,827)	$ 17,827
8	1915	Office Furniture & Equipment (5 years)					$ -				$ -	$ -
10	1920	Computer Equipment - Hardware		$ 46,427	$ 3,691		$ 50,118	$ (35,048)	$ (4,725)		$ (39,773)	$ 10,345
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)					$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)					$ -				$ -	$ -
10	1930	Transportation Equipment		$ 205,346			$ 205,346	$ (188,730)	$ (2,556)		$ (191,286)	$ 14,060
8	1935	Stores Equipment					$ -				$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 13,960	$ 6,007		$ 19,966	$ (7,830)	$ (1,353)		$ (9,182)	$ 10,784
8	1945	Measurement & Testing Equipment					$ -				$ -	$ -
8	1950	Power Operated Equipment		$ 4,363			$ 4,363	$ (2,453)	$ (545)		$ (2,998)	$ 1,365
8	1955	Communications Equipment					$ -				$ -	$ -
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					$ -				$ -	$ -
47	1995	Contributions & Grants		$ (70,174)	$ (74,300)		$ (144,474)	$ 3,637	$ 4,291		$ 7,928	$ (136,546)
	etc.						$ -				$ -	$ -
		Total		**$ 3,400,571**	**$ 152,355**	**$ -**	**$ 3,552,926**	**$ (1,447,674)**	**$ (158,511)**	**$ -**	**$ (1,606,185)**	**$ 1,946,741**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	$ -

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Appendix 2-B
Fixed Asset Continuity Schedule

Year **2011**

				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)		$ 128,153	$ 8,639		$ 136,793	$ (73,412)	$ (23,439)		$ (96,851)	$ 39,941
CEC	1612	Land Rights (Formally known as Account 1906)		$ 8,588	$ -		$ 8,588	$ (2,608)	$ -		$ (2,608)	$ 5,980
N/A	1805	Land		$ 10,000			$ 10,000	$ -	$ -		$ -	$ 10,000
47	1808	Buildings		$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 402,412	$ 55,500		$ 457,912	$ (77,733)	$ (9,744)		$ (87,477)	$ 370,435
47	1820	Distribution Station Equipment <50 kV		$ 184,860	$ 66,691		$ 251,551	$ (99,458)	$ (11,860)		$ (111,318)	$ 140,233
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 351,067	$ 27,659		$ 378,725	$ (189,325)	$ (18,599)		$ (207,924)	$ 170,802
47	1835	Overhead Conductors & Devices		$ 402,306	$ 3,636		$ 405,943	$ (221,118)	$ (22,027)		$ (243,145)	$ 162,797
47	1840	Underground Conduit		$ 113,855	$ -		$ 113,855	$ (60,158)	$ (5,942)		$ (66,100)	$ 47,755
47	1845	Underground Conductors & Devices		$ 260,392	$ 585		$ 260,977	$ (95,991)	$ (12,507)		$ (108,498)	$ 152,479
47	1850	Line Transformers		$ 397,148	$ 6,025		$ 403,173	$ (187,420)	$ (15,567)		$ (202,987)	$ 200,186
47	1855	Services (Overhead & Underground)		$ 26,835	$ 3,350		$ 30,186	$ (6,122)	$ (1,140)		$ (7,262)	$ 22,923
47	1860	Meters		$ 246,912	$ 7,797		$ 254,709	$ (156,129)	$ (15,406)		$ (171,535)	$ 83,174
47	1860	Meters (Smart Meters)		$ -			$ -	$ -			$ -	$ -
N/A	1905	Land		$ 28,300	$ -		$ 28,300	$ -	$ -		$ -	$ 28,300
47	1908	Buildings & Fixtures		$ 824,124	$ -		$ 824,124	$ (186,572)	$ (16,999)		$ (203,571)	$ 620,553
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 32,654	$ 1,130		$ 33,784	$ (14,827)	$ (2,738)		$ (17,565)	$ 16,219
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 50,118	$ 2,103		$ 52,222	$ (39,773)	$ (4,392)		$ (44,165)	$ 8,056
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 205,346	$ -		$ 205,346	$ (191,286)	$ (2,556)		$ (193,842)	$ 11,504
8	1935	Stores Equipment		$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 19,966	$ 5,063		$ 25,029	$ (9,182)	$ (1,876)		$ (11,058)	$ 13,971
8	1945	Measurement & Testing Equipment		$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment		$ 4,363	$ -		$ 4,363	$ (2,998)	$ (545)		$ (3,543)	$ 820
8	1955	Communications Equipment		$ -			$ -	$ -			$ -	$ -
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		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		$ (144,474)	$ -		$ (144,474)	$ 7,928	$ 5,777		$ 13,705	$ (130,769)
	etc.			$ -			$ -	$ -			$ -	$ -
		Total		**$ 3,552,926**	**$ 188,179**	**$ -**	**$ 3,741,105**	**$ (1,606,185)**	**$ (159,560)**	**$ -**	**$ (1,765,745)**	**$ 1,975,359**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	$ -

Notes:

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Appendix 2-CA
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2015

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)	Smart Meter Additions (dd)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 136,793	$ (5,561)	$ 142,354	$ 2,683	$ 41,549	$ 143,695	5	20.00%	$ 28,739	$ 28,739	$ (0)
1612	Land Rights (Formally known as Account 1906)	$ 8,588	$ 8,588	$ -	$ -		$ -		0.00%	$ -		$ -
1805	Land	$ 10,000	$ 10,000	$ -	$ -		$ -		0.00%	$ -		$ -
1808	Buildings	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
1810	Leasehold Improvements	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ 457,912	$ 40,397	$ 417,515	$ 24,890		$ 429,960	40	2.50%	$ 10,749	$ 10,749	$ (0)
1820	Distribution Station Equipment <50 kV	$ 251,551	$ (137,573)	$ 389,124	$ 4,632		$ 391,440	30	3.33%	$ 13,048	$ 13,048	$ (0)
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
1830	Poles, Towers & Fixtures	$ 378,725	$ (100,074)	$ 478,799	$ 80,902		$ 519,250	25	4.00%	$ 20,770	$ 20,770	$ 0
1835	Overhead Conductors & Devices	$ 405,943	$ (124,489)	$ 530,432	$ 69,888		$ 565,375	25	4.00%	$ 22,615	$ 22,615	$ 0
1840	Underground Conduit	$ 113,855	$ (29,520)	$ 143,375	$ -		$ 143,375	25	4.00%	$ 5,735	$ 5,735	$ 0
1845	Underground Conductors & Devices	$ 260,977	$ (44,305)	$ 305,282	$ 4,936		$ 307,750	25	4.00%	$ 12,310	$ 12,310	$ (0)
1850	Line Transformers	$ 403,173	$ 14,383	$ 388,790	$ 5,620		$ 391,600	25	4.00%	$ 15,664	$ 15,664	$ (0)
1855	Services (Overhead & Underground)	$ 30,186		$ 30,186	$ 2,234		$ 31,303	25	4.00%	$ 1,252	$ 1,252	$ 0
1860	Meters	$ 254,709	$ (64,049)	$ 318,758	$ 135		$ 318,825	25	4.00%	$ 12,753	$ 12,753	$ 0
1860	Meters (Smart Meters)	$ -		$ 601,817	$ 17,082	$ 601,817	$ 610,358	15	6.67%	$ 40,691	$ 40,690	$ 1
1905	Land	$ 28,300	$ 28,300	$ (0)	$ -		$ (0)		0.00%	$ -		$ -
1908	Buildings & Fixtures	$ 824,124	$ (25,826)	$ 849,950	$ -		$ 849,950	50	2.00%	$ 16,999	$ 16,999	$ (0)
1910	Leasehold Improvements	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 33,784	$ 6,234	$ 27,550	$ -		$ 27,550	10	10.00%	$ 2,755	$ 2,755	$ (0)
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
1920	Computer Equipment - Hardware	$ 52,222	$ 35,355	$ 16,867	$ 2,656		$ 18,195	5	20.00%	$ 3,639	$ 3,639	$ (0)
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
1930	Transportation Equipment	$ 205,346	$ 184,898	$ 20,448	$ -		$ 20,448	8	12.50%	$ 2,556	$ 2,556	$ (0)
1935	Stores Equipment	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 25,029	$ 2,616	$ 22,413	$ 794	$ 2,173	$ 22,810	10	10.00%	$ 2,281	$ 2,281	$ 0
1945	Measurement & Testing Equipment	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
1950	Power Operated Equipment	$ 4,363		$ 4,363	$ -		$ 4,363	8	12.50%	$ 545	$ 545	$ 0
1955	Communications Equipment	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
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	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
1995	Contributions & Grants	$ (144,474)		$ (144,474)	$ (110,041)		$ (199,494)	25	4.00%	$ (7,980)	$ (7,978)	$ (2)
etc.		$ -		$ -	$ -		$ -		0.00%	$ -		$ -
		$ -		$ -	$ -		$ -		0.00%	$ -		$ -
	Total	**$ 3,741,105**	**$ (200,626)**	**$ 4,543,547**	**$ 106,410**	**$ 645,539**	**$ 4,596,752**			**$ 205,121**	**$ 205,123**	**$ (1)**

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence

General **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

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Appendix 2-CA
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2015

Year 2013 **CGAAP**

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2013 (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)	Depreciation Expense (h) = (e) / (f)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)	
1611	Computer Software (Formally known as Account 1925)	$ 181,024	$ 81,389	$ 99,635	$ 28,000	$ 113,635	5	20.00%	$ 22,727	$ 22,727	$ 0	$ 0.00
1612	Land Rights (Formally known as Account 1906)	$ 8,588	$ 8,588	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	
1805	Land	$ 10,000	$ 10,000	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	
1808	Buildings	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1815	Transformer Station Equipment >50 kV	$ 482,802	$ 40,402	$ 442,400	$ 1,547,900	$ 1,216,350	45	2.22%	$ 27,030	$ 27,030	$ (0)	
1820	Distribution Station Equipment <50 kV	$ 256,183	$ (137,564)	$ 393,747	$ 800,000	$ 793,747	45	2.22%	$ 17,639	$ 17,639	$ (0)	
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1830	Poles, Towers & Fixtures	$ 459,627	$ (95,988)	$ 555,615	$ 99,000	$ 605,115	45	2.22%	$ 13,447	$ 13,447	$ -	
1835	Overhead Conductors & Devices	$ 475,830	$ (124,390)	$ 600,220	$ 25,000	$ 612,720	60	1.67%	$ 10,212	$ 10,212	$ -	
1840	Underground Conduit	$ 113,855	$ (23,695)	$ 137,550	$ 500	$ 137,800	50	2.00%	$ 2,756	$ 2,756	$ -	
1845	Underground Conductors & Devices	$ 265,913	$ (35,217)	$ 301,130	$ 17,000	$ 309,630	30	3.33%	$ 10,321	$ 10,321	$ -	
1850	Line Transformers	$ 408,793	$ 22,313	$ 386,480	$ 28,000	$ 400,480	40	2.50%	$ 10,012	$ 10,012	$ 0	
1855	Services (Overhead & Underground)	$ 32,420	$ 20	$ 32,400	$ 3,000	$ 33,900	30	3.33%	$ 1,130	$ 1,130	$ -	
1860	Meters	$ 254,843	$ 28,468	$ 226,375	$ -	$ 226,375	25	4.00%	$ 9,055	$ 9,055	$ -	
1860	Meters (Smart Meters)	$ 618,899	$ -	$ 618,899	$ 3,500	$ 620,649	15	6.67%	$ 41,377	$ 41,377	$ (0)	
1905	Land	$ 28,300	$ -	$ 28,300	$ -	$ 28,300		0.00%	$ -		$ -	
1908	Buildings & Fixtures - **BUILDING ROOF**	$ 165,167	$ -	$ 165,167	$ 18,040	$ 174,187	25	4.00%	$ 6,967	$ 6,968	$ (1)	
1908	Buildings & Fixtures - **INTERIOR FIXTURES**	$ 246,041	$ -	$ 246,041	$ 19,460	$ 255,771	15	6.67%	$ 17,051	$ 17,053	$ (2)	
1908	Buildings & Fixtures - **STRUCTURE**	$ 412,916	$ -	$ 412,916	$ -	$ 412,916	50	2.00%	$ 8,258	$ 8,258	$ 0	
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1915	Office Furniture & Equipment (10 years)	$ 33,784	$ 6,224	$ 27,560	$ 5,700	$ 30,410	10	10.00%	$ 3,041	$ 3,041	$ -	
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1920	Computer Equipment - Hardware	$ 54,878	$ 41,508	$ 13,370	$ 3,000	$ 14,870	5	20.00%	$ 2,974	$ 2,974	$ (0)	
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1930	Transportation Equipment	$ 204,794	$ 184,346	$ 20,448	$ -	$ 20,448	8	12.50%	$ 2,556	$ 2,556	$ -	
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1940	Tools, Shop & Garage Equipment	$ 27,996	$ 5,066	$ 22,930	$ 3,000	$ 24,430	10	10.00%	$ 2,443	$ 2,443	$ -	
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1950	Power Operated Equipment	$ 4,363	$ 2,163	$ 2,200	$ 2,000	$ 3,200	8	12.50%	$ 400	$ 400	$ -	
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
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	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1995	Contributions & Grants - ACCT 1830	$ (77,570)	$ -	$ (77,570)	$ -	$ (77,570)	45	2.22%	$ (1,724)	$ (1,724)	$ 0	
1995	Contributions & Grants - ACCT 1835	$ (49,661)	$ -	$ (49,661)	$ -	$ (49,661)	60	1.67%	$ (828)	$ (828)	$ 0	
1995	Contributions & Grants - ACCT 1840	$ (220)	$ -	$ (220)	$ -	$ (220)	50	2.00%	$ (4)	$ (4)	$ (0)	
1995	Contributions & Grants - ACCT 1845	$ (80,350)	$ -	$ (80,350)	$ -	$ (80,350)	30	3.33%	$ (2,678)	$ (2,678)	$ (0)	
1995	Contributions & Grants - ACCT 1850	$ (46,713)	$ -	$ (46,713)	$ -	$ (46,713)	40	2.50%	$ (1,168)	$ (1,168)	$ 0	
				$ -		$ -		0.00%	$ -		$ -	
	Total	**$ 4,492,501**	**$ 13,634**	**$ 4,478,868**	**$ 2,603,100**	**$ 5,780,418**			**$ 202,995**	**$ 202,997**	**$ (2)**	

Notes:

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2 The applicant must provide an explanation of material variances in evidence

General **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

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Appendix 2-CA
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2015

Year 2014 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2014 (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)	Depreciation Expense (h) = (e) / (f)	2014 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)	
1611	Computer Software (Formally known as Account 1925)	$ 209,024	$ 113,414	$ 95,610	$ 17,000	$ 104,110	5	20.00%	$ 20,822	$ 20,822	$ 0	0.00
1612	Land Rights (Formally known as Account 1906)	$ 8,588	$ -	$ 8,588	$ -	$ 8,588		0.00%	$ -		$ -	
1805	Land	$ 10,000	$ -	$ 10,000	$ -	$ 10,000		0.00%	$ -		$ -	
1808	Buildings	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1815	Transformer Station Equipment >50 kV	$ 2,030,702	$ 40,387	$ 1,990,315	$ 25,000	$ 2,002,815	45	2.22%	$ 44,507	$ 44,507	$ -	
1820	Distribution Station Equipment <50 kV	$ 1,056,183	$ (137,592)	$ 1,193,775	$ 60,000	$ 1,223,775	45	2.22%	$ 27,195	$ 27,195	$ -	
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1830	Poles, Towers & Fixtures	$ 558,627	$ (32,768)	$ 591,395	$ 89,000	$ 635,895	45	2.22%	$ 14,131	$ 14,131	$ -	
1835	Overhead Conductors & Devices	$ 500,830	$ (124,450)	$ 625,280	$ 20,000	$ 635,280	60	1.67%	$ 10,588	$ 10,588	$ -	
1840	Underground Conduit	$ 114,355	$ (23,545)	$ 137,900	$ 500	$ 138,150	50	2.00%	$ 2,763	$ 2,763	$ -	
1845	Underground Conductors & Devices	$ 282,913	$ (33,447)	$ 316,360	$ 17,500	$ 325,110	30	3.33%	$ 10,837	$ 10,837	$ -	
1850	Line Transformers	$ 435,245	$ 31,495	$ 403,750	$ 12,500	$ 410,000	40	2.50%	$ 10,250	$ 10,250	$ 0	
1855	Services (Overhead & Underground)	$ 35,420	$ -	$ 35,420	$ 3,100	$ 36,970	30	3.33%	$ 1,232	$ 1,232	$ 0	
1860	Meters	$ 254,843	$ 254,843	$ -	$ -	$ -	25	4.00%	$ -	$ -	$ -	
1860	Meters (Smart Meters)	$ 622,399	$ -	$ 622,399	$ 3,500	$ 624,149	15	6.67%	$ 41,610	$ 41,610	$ (0)	
1905	Land	$ 28,300	$ -	$ 28,300	$ -	$ 28,300		0.00%	$ -		$ -	
1908	Buildings & Fixtures - **BUILDING ROOF**	$ 183,207	$ -	$ 183,207	$ -	$ 183,207	25	4.00%	$ 7,328	$ 7,329	$ (1)	
1908	Buildings & Fixtures - **INTERIOR FIXTURES**	$ 265,501	$ -	$ 265,501	$ 12,500	$ 271,751	15	6.67%	$ 18,117	$ 18,118	$ (1)	
1908	Buildings & Fixtures - **STRUCTURE**	$ 412,916	$ -	$ 412,916	$ -	$ 412,916	50	2.00%	$ 8,258	$ 8,258	$ 0	
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1915	Office Furniture & Equipment (10 years)	$ 39,484	$ 9,954	$ 29,530	$ 3,500	$ 31,280	10	10.00%	$ 3,128	$ 3,128	$ -	
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1920	Computer Equipment - Hardware	$ 57,878	$ 44,523	$ 13,355	$ 3,100	$ 14,905	5	20.00%	$ 2,981	$ 2,981	$ (0)	
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1930	Transportation Equipment	$ 204,794	$ 184,346	$ 20,448	$ -	$ 20,448	8	12.50%	$ 2,556	$ 2,556	$ -	
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1940	Tools, Shop & Garage Equipment	$ 30,996	$ 6,786	$ 24,210	$ 3,100	$ 25,760	10	10.00%	$ 2,576	$ 2,576	$ -	
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1950	Power Operated Equipment	$ 6,363	$ 4,363	$ 2,000	$ 2,000	$ 3,000	8	12.50%	$ 375	$ 375	$ -	
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
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	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1995	Contributions & Grants - ACCT 1830	$ (77,570)	$ -	$ (77,570)	$ -	$ (77,570)	45	2.22%	$ (1,724)	$ (1,724)	$ 0	
1995	Contributions & Grants - ACCT 1835	$ (49,661)	$ -	$ (49,661)	$ -	$ (49,661)	60	1.67%	$ (828)	$ (828)	$ 0	
1995	Contributions & Grants - ACCT 1840	$ (220)	$ -	$ (220)	$ -	$ (220)	50	2.00%	$ (4)	$ (4)	$ (0)	
1995	Contributions & Grants - ACCT 1845	$ (80,350)	$ -	$ (80,350)	$ -	$ (80,350)	30	3.33%	$ (2,678)	$ (2,678)	$ (0)	
1995	Contributions & Grants - ACCT 1850	$ (46,713)	$ -	$ (46,713)	$ -	$ (46,713)	40	2.50%	$ (1,168)	$ (1,168)	$ 0	
						$ -		0.00%	$ -		$ -	
	Total	**$ 7,094,053**	**$ 338,310**	**$ 6,755,744**	**$ 272,300**	**$ 6,891,894**			**$ 222,853**	**$ 222,854**	**$ (1)**	

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence

General **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

E2.T1.S7 ALLOWANCE FOR WORKING CAPITAL

HHI has used the 13% Allowance Approach for the purpose of calculating its Allowance for Working Capital. This was done in accordance with the letter issued by the Board on April 12, 2012 a rate of 13% of the sum of Cost of Power and controllable expenses (i.e., Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General).

Table 9 presented below show HHI's calculations in determining its Allowance for Working Capital.

Table 9 – Determination of Working Capital Allowance.

Particulars	**Test Year 2014**
Net Capital Assets in Service:	
Opening Balance	4,852,979
Ending Balance	4,840,923
Average Balance	4,846,951
Working Capital Allowance	2,216,985
Total Rate Base	7,063,936
Expenses for Working Capital	
Eligible Distribution Expenses:	
3500-Distribution Expenses - Operation	96,550
3550-Distribution Expenses - Maintenance	205,700
3650-Billing and Collecting	426,315
3700-Community Relations	200
3800-Administrative and General Expenses	397,900
Total Eligible Distribution Expenses	1,126,665
3350-Power Supply Expenses	15,927,063
Total Expenses for Working Capital	17,053,728
Working Capital factor	13%
Total Working Capital	2,216,985

E2.T1.S8 SMART METER

On July 16, 2012, HHI filed an application seeking Board approval for the disposition and recovery of costs related to smart meter deployment, offset by Smart Meter Funding Adder ("SMFA") revenues collected from May 1, 2006 to April 30, 2012. On August 23, 2012 the Board issued an Interim Rate Order making the current approved Tariff of Rates and Charges interim since HHI had proposed an effective date of September 1, 2012 in their Application.

In its decision, the Board found that HHI's documented costs, as revised in response to interrogatories and in HHI's reply submission, related to smart meter procurement, installation and operation, and including costs related to TOU rate implementation, were reasonable. As such, the Board approved the recovery of the costs applied for related to smart meter deployment and operation as of December 31, 2011, and the ongoing recovery of capital-related and operating expenses for 2012 and going forward until HHI's next cost of service application.

The Board's model and decision (Decision and Order, EB-2012-0198 dated November 1, 2012), which contains a summary of the specifics requested and approved, is presented at Appendix A and B of this Exhibit. Table 10 below shows details of the capital expenditures that have been added to the utility's rate base.

Table 10: Aggregate Smart Meter Costs by Category

Smart Meter		$601,817

Tools & Equipment		$2,173
Software		41,549
Total Capital Costs		**$645,539**

E2.T1.S9 TREATMENT OF STRANDED ASSETS RELATED TO SMART METER DEPLOYMENT.

In its Smart Meter application HHI stated: "No cost associated with stranded meters has been included in the application." The exclusion of stranded meters was consistent with the directions in G-2011-0001 Guideline: "Smart Meter Funding and Cost Recovery – Final Disposition", dated December 15, 2011.

HHI's decision to exclude its stranded meter costs in its Smart Meter application was accepted in the Decision and Order, EB-2012-0198, dated November 1, 2012, where it was stated:

"In its Application, HHI proposed not to dispose of stranded meters by way of stranded meter rate riders at this time, but to deal with disposition in its next cost of service application, scheduled for 2014 rates. In its Application, HHI stated that it has an estimated net book value of stranded conventional meters, including net salvage revenues, of $54,357 as of December 31, 2013. "

Subsequently in the Decision and Order, the Board instructed HHI to address both the recovery of all its stranded meter costs in its next rebasing application.

The total cost of the stranded meters that HHI is claiming in this current application is $61,500. The calculation of the proposed rate rider is presented at E8.T7.S1

The reason for the variance between the NBV amount of $54,357 stated in the smart meter application and the $61,500 amount that HHI is claiming in this application is that the $54,357 was an estimate done back in 2011. Please see table below for detailed explanations:

Table 11: Reconciliation of Stranded Meters NBV

ESTIMATED NET BOOK VALUE DONE IN 2011		ACTUAL NET BOOK VALUE FOR 2014 COS APPLICATION	
1860 - Meters		1860 - Meters	
Gross Book Value - Dec 31, 2011	246,912.13		
Accumulated Depreciation - Dec 31, 2011	(171,379.13)	Gross Book Value - Dec 31, 2012	254,843.38
Net Book Value - Dec 31, 2011	**75,533.00**	Accumulated Depreciation - Dec 31, 2012	(184,288.13)
Depreciation - 2012	(12,438.00)	Net Book Value - Dec 31, 2012	**70,555.25**
Depreciation - 2013	(8,738.00)	Depreciation - 2013	(9,055.00)
Estimated Net Book Value - Dec 31, 2013	**54,357.00**	Estimated Net Book Value - Dec 31, 2013	**61,500.25**

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		$ 221,805	$ 95,458		$ 126,347		$ 126,347
2007		$ 222,885	$ 110,272		$ 112,613		$ 112,613
2008		$ 224,822	$ 125,120		$ 99,702		$ 99,702
2009		$ 246,912	$ 140,473		$ 106,439		$ 106,439
2010		$ 246,912	$ 156,129		$ 90,783		$ 90,783
2011		$ 254,709	$ 171,535		$ 83,174		$ 83,174
2012	(1)	$ 254,843	$ 184,288		$ 70,555		$ 70,555
2013		$ 254,843	$ 193,343		$ 61,500		**$ 61,500**

Tab 2 – Capital Expenditures

E2.T2.S1 OVERVIEW

This section provides an analysis of HHI Capital Plan Projects. The analysis covers 2010 Actuals up to 2014 Test Year.

HHI has been, and continues to be, focused on maintaining the adequacy, reliability and quality of service to its distribution customers. HHI completes regular inspections throughout the year while carrying out necessary maintenance on the distribution system.

The reliability indices are recorded and monitored on an annual basis as demonstrated at E2.T3.S1. They are used to assess the asset condition which impacts the capital budgeting process. HHI has an obligation to serve new growth within the service area in a timely and cost effective way. In order to fulfill this obligation, the municipality along with input from HHI identifies all potential areas where new growth may occur, while recognizing that the actual timing of each possible new development is uncertain. Although growth has an impact on capital expenditures, reliability and safety are the main components taken into account.

The capital budget for 2014 reflects the level of growth that is anticipated based on input from the municipality and management judgment.

Each year HHI looks at its distribution system and determines the needs to ensure only those capital investments that are required to ensure a safe and reliable operation of HHI's distribution system are made.

Revised June 12, 2013. The only Asset Retirement Obligations are a line transformer in 2013 at a value of $1,548 and stranded meters in 2014 at a value of $254,843. The two asset retirements are reflected in the fixed assets continuity statements at E2.T1.S5

E2.T2.S2 PROJECT TABLE - APPENDIX 2-A

File Number:	EB-2012-0000
Exhibit:	2
Tab:	2
Schedule:	2
Page:	
Date:	

projects	2008	2009	2010	2011	2012	2013 Bridge Year	2014 Test Year
reporting basis							
(1815) 1 reclosers (new) ms#1	$ 20,664						
(1815) major transformer (gasing transformer 55t2) maintenance (degas)		$ 47,729					
(1815) add 1 recloser betterment to 55t1 and 55t2 tap changers externally add inhibitor			$ 52,495				
(1815) replacement of arcing contact on both tap changers				$ 55,500			
(1815) meetering and assure all ct's are not affected by operations. dismanttle meetering and assure all ct's are not affected by operations. internal tap changer repairs following recongnision that 55t1 is faulty. change all auxiliary contacts 55t1 and 55t2					$ 24,890		
(1815) revamp 110 kv station as per oeb approval eb-2011-0173 & regular expenditures on 55t1 and 55t2						$ 1,547,900	
regular expenditures on the new 55t1 and 55t2 and 55t3 (on pot)							$ 25,000
sub-total	**$ 20,664**	**$ 47,729**	**$ 52,495**	**$ 55,500**	**$ 24,890**	**$ 1,547,900**	**$ 25,000**
(1820) new recloser 44kv sub		$ 23,425					
(1820) add inhibitor to 10mva transformer			$ 9,059				
(1820) 2 new recloser 44kv sub (replacement complete), plus 44kv transformer maintenance and inspection, by-pass tap changer. high gas. change rotten x-arms on incoming and outgoind structures at 44 kv sub new fence				$ 66,691			
(1820) stone at sub for lineman safety					$ 4,632		
(1820) Expenditures of SUB 44KV recorded upon completion and annual maintenance on SUB 44KV structure.						$ 800,000	
(1820) Expenditures to obtain a report on the anomalies that caused the high combustible gases of transformer 43t1 of SUB 44KV. Obtain a re-vamp solution and quote and if feasible, repair the transformer in order to reach HHI's goal to have proper transformation capacity and mainly redundancy.							$ 60,000
sub-total	**$ -**	**$ 23,425**	**$ 9,059**	**$ 66,691**	**$ 4,632**	**$ 800,000**	**$ 60,000**
(1830) riser pole new subdivision	$ 1,065						
(1830) pole replacement & riser pole new subdivision		$ 24,399					

File Number:	EB-2012-0000
Exhibit:	2
Tab:	2
Schedule:	2
Page:	
Date:	

projects	2008	2009	2010	2011	2012	2013 Bridge Year	2014 Test Year
(1830) pole replacement, x-arms and hardware several location following annual inspections			$ 28,411				
(1830) pole replacement, x-arms and hardware several location following annual inspections				$ 27,659			
(1830) pole replacement, x-arms and hardware several location following annual inspections plus line extention on west st. for new customer on hwy 17, plus 44kv feeder between 44kv station and spence st.					$ 80,902		
(1830) replace poles, fixtures as per asset management plan						$ 99,000	
(1830) replace poles, fixtures as per asset management plan							$ 89,000
sub-total	**$ 1,065**	**$ 24,399**	**$ 28,411**	**$ 27,659**	**$ 80,902**	**$ 99,000**	**$ 89,000**
(1835) oh conductor (remove copper conductor)	$ 7,361						
(1835) oh conductor betterment increase size primary and neutral		$ 5,118					
(1835) oh conductor betterment increase size primary feeder 43f2 to 336 mcm			$ 34,806				
(1835) oh conductor (cooper) and new in-line switch				$ 3,636			
(1835) oh conductor line extention west st. and 44kv feeder betterment					$ 69,888		
(1835) replace 3/0 o.h. primary on circuit 43f2 with 336 mcm tulip continuity of work performed in 2011 and 2012						$ 25,000	
(1835) replace 3/0 o.h. primary on circuit 55f1. part of main st. pole # 304 to # 332 with 336 mcm tulip							$ 20,000

E2.T2.S3 PROJECT CLASSIFICATION AND CATEGORIZATION

HHI uses as a guideline to project classification, the classification and categorization shown in Chapter 4 of the Filing Requirements for Electricity Distribution and Distribution Application. Entitled "Minimum Filing requirements for electricity distribution projects under Section 92 of the Ontario Energy Board Act ("the Act")"

HHI has found the project Categorization, Classification to be helpful in determining the need and justification for projects.

Project Classification

Project Classification is the classification of a project into one of three project classes:

a) **Development projects** are those for providing:
   - an adequate supply capacity and/or maintaining an acceptable or prescribed level of customer or system reliability for load growth meeting increased stresses on the system; or
   - enhancing system efficiency such as minimizing congestion on the distribution system and reducing system losses.

b) **Connection projects** are those for providing connection of a load or generation customer or group of customers to the distribution system.

c) **Sustainment projects** are those for maintaining the performance of the distribution network at its current standard or replacing end-of-life facilities on a "like for like" basis.

It is acknowledged that projects can have elements of development, connection, or sustainment. In these cases, HHI should identify the proportional make-up of the project, and then classify the project based on the predominant driver.

Project Categorization

The purpose of project categorization is to distinguish whether the project need is beyond the control of the ("Non-discretionary") or at the discretion of HHI ("Discretionary"). The categorization stage identifies the project need as:

a) Non-discretionary – a "must do" project, the need for which is determined beyond the control of HHI ("Non-discretionary"). Non-discretionary projects may be triggered or determined by such things as:

- mandatory requirement to satisfy obligations specified by regulatory organizations;
- a need to connect new load (of a distributor or large user) or new generation (connection);
- a need to address equipment loading or voltage/short circuit stresses when their rated capacities are exceeded;
- projects identified in a Board or provincial government approved plan;
- projects that are required to achieve provincial government objectives that are prescribed in governmental directives or regulations; and
- a need to comply with direction from the Ontario Energy Board in the event it is determined that the distribution system's reliability is at risk.

or

b) Discretionary – the need is determined at the discretion of HHI ("Discretionary"). Discretionary projects are proposed by HHI to enhance the distribution system performance, benefiting its users. Projects in this category may include:

- projects to reduce distribution system losses;
- projects to reduce congestion;
- projects to build a new or enhance an existing interconnection to increase generation reserve margin within the IESO-controlled grid, beyond the minimum level required;
- projects to enhance reliability beyond a minimum standard; and
- projects which add flexibility to the operation and maintenance of the distribution system.

Table 11 below shows the total investment in project by classification and categorization.

Table 11 – Summary of Project Need

Project Need			
		Project Categorization	
		Non-Discretionary	Discretionary
Project Classification	Development	$19,500	$10,500
	Connection/Microfit		$300
	Sustainment	$227,000	$15,000

E2.T2.S4 HISTORICAL AND PROJECTED CAPITAL PLANS

The following section of The Application presents a breakdown of major capital projects for 2010 Actuals up to the 2014 Test Year.

E2.T2.S5 HISTORICAL AND PROJECTED CAPITAL PLANS

2010 Capital Expenditures

GL ACT #	2010 CAPITAL PROJECTS DESCRIPTION	AMOUNT
1815	110 KV TAP CHANGER 55T1 & 55T1	18,591.91
	110 KV INHIBITOR MINERAL OIL 55T1 & 55T2	10,400.00
	110 KV NEW 3 PHASES RECLOSERS	23,502.89
	SUB TOTAL	52,494.80
1820	INHIBITOR MINERAL OIL 43 T1 SUB 44KV	9,059.01
1830	2010 POLE REPLACEMENT PROGRAM POLES, FIXTURES AS PER ANNUAL INSPECTION	28,410.75
1835	SPENCE AND TUPPER ST REPLACE 3/0 O.H. PRIMARY WITH 336 MCM TULIP	34,806.04
1840 & 1845	NEW U.G SUBDIVISION PHASE 4 EAST PART TOWN	40,194.94
	NEW U.G SUBDIVISION NELSON ST.	7,612.58
	SUB TOTAL	47,807.52
1850	NEW U.G SUBDIVISION PHASE 4 EAST PART TOWN/ PADMOUNT TRANSFORMERS	15,864.92
	NEW U.G SUBDIVISION NELSON ST. PADMOUNT TRANSFORMERS	8,456.30
	SUB TOTAL	24,321.22
1855	NEW O.H. AND U.G SERVICES MATERIAL AND LABOUR	3,574.22
1915	CSR's TELEPHONE HEAD SETS	1,544.08
	PROJECTOR	582.12
	SUB TOTAL	2,126.20
1920	DELL DESKTOP & IT SERVICES	3,691.20
1925	CDW (W7 AND MS OFFICE)	6,135.13
	D&A BUSINESS (ACCPAC)	8,222.50
	SUB TOTAL	14,357.63
1940	MISC TOOLS FOR LINE CREW	3,850.87
	OWL-LITE TRAFFIC CONTROL SIGNS	1,469.35
	COMMECIAL EQUIP. PROTECTIVE HIGH VOLTAGE RUBBER PRODUCTS.	686.45
	SUB TOTAL	6,006.67
	TOTAL	$ 226,655.26

110 KV TAP CHANGERS

Scope:

Replace, inspect and correct external anomalies with the tap changers on 55T1 and 55T2

Objectives

Prevent further damages to these aging devices. Those are used to regulate the voltage at the source and distribute better power to our customers

Customer attachments

All customers on these 2 transformers (Approximately 4100 customers) would be affected if these devices are defective. Voltage fluctuation would cause customer's equipment to fail.

Load and capital costs

Total cost is $18,591.91. After remedy, load customers will not be affected by voltage fluctuations and customer equipment will not fail due to these fluctuations.

Detailed breakdown of starting dates and in-service dates for each project

In service date is October 13, 2010.

110 KV ADDITION OF INHIBITOR MINERAL OIL 55T1 and 5T 2.

Scope

In order to slow the aging process of the paper with the transformer, Inhibitor oil was added to the 2 aging transformers at our 110KV station.

Objectives

Increase the life of the isolating paper within the 2 transformers

Customer attachments

Approximately 4100 customers would be affected if these transformers are faulty.

Load and capital costs

Cost is $ 10,400 and this process will help to slow the aging of the isolating paper within the transformer and avoid failure.

Detailed breakdown of starting dates and in-service dates for each project

Addition made on October 13, 2010.

110 KV RECLOSER REPLACEMENT

Scope

Replace 1 of the 3 reclosers at the 110 KV Station

Objectives

Protect adequately our system and gradually remove the old reclosers with new ones.

Customer attachments

One recloser per circuit. Some 4100 customers are on the 110KV station. Each recloser has approximately 1/3 of the load.

Load and capital costs

Cost $ 23,502.89.

Detailed breakdown of starting dates and in-service dates for each project

In service date: September 2010.

44 KV ADDITION OF INHIBITOR MINERAL OIL 43T1.

Scope

In order to slow the aging process of the paper with the transformer, Inhibitor oil was added to the aging transformer.

Objectives

Increase the life of the isolating paper within the transformer.

Customer attachments

Approximately 1400 customers would be affected if this transformer is faulty.

Load and capital costs

Cost is $ 9,059.01 and this process will help to slow the aging of the isolating paper within the transformer and avoid failure.

Detailed breakdown of starting dates and in-service dates for each project

Addition made in October, 2010.

POLES & FIXTURES

Scope

Each year HHI performs inspection in order to identify which assets need to be removed from service in order to promote safety.

Objectives

Improve Safety and reliability with the removal of older assets.

Customer attachments

Poles and hardware were replaced at different locations.

Load and capital costs

Total capital cost for 2010 was $ 28,410.75

Detailed breakdown of starting dates and in-service dates for each project

Our replacement program started in April 2010 until the end of October 2010.

SPENCE AND TUPPER PRIMARY BETTERMENT.

Scope

Replace existing 3/0 primary conductor with 336 MCM, change cross arms and insulators.

Objectives

Bigger conductor will reduce line loss and has higher ampacity. Furthermore part if our circuit 43F1 already has 336MCM. Some sections of 43F1 are built with 3/0 and others 336MCM.

Customer attachments

Some 1400 customers receive electricity on this feeder. Furthermore HHI has the capability to switch load from different section in town since HHI has 2 stations. Bigger primary conductors will ease this process.

Load and capital costs

Capital cost $ 34,806.04.

Detailed breakdown of starting dates and in-service dates for each project

Work performed in fall 2010.

UNDERGROUND SUBDIVISION

Scope

Addition of Underground circuits for new residential properties.

Objectives

Provide new infrastructures for the new subdivision. Underground conductors, conduit and pad mounted transformer.

Customer attachments

New development on vacant lots.

Load and capital costs

Total cost in 2010 is $ 47,807.52.

Detailed breakdown of starting dates and in-service dates for each project

In service date for the Eastern part of town June 2010 and Nelson St in September 2010.

TRANFORMERS

Scope

Addition of Underground circuits for new residential properties.

Objectives
Provide new Transformers for the 2 new underground subdivisions.

Customer attachments
New development on vacant lots.

Load and capital costs
Total cost in 2010 is $ 24,321.22

Detailed breakdown of starting dates and in-service dates for each project
In service date for the Eastern part of town June 2010 and Nelson St in September 2010.

NEW SERVICES

Scope
Installation of Overhead or Underground facilities for new customers.

Objectives
Respond rapidly to customers request for end use services. Connection of new OH and UG service.

Customer attachments

Customer attachments
New Services

Load and capital costs
Total cost in 2010 is $ 3,574.22.

Detailed breakdown of starting dates and in-service dates for each project
New connections are performed all year round upon customer requests.

OFFICE FURNITURE & EQUIPMENT

Scope
Office equipment to facilitate working conditions.

Objectives

Increase performance and provide adequate working tools. (i.e. telephone headsets for the CSR and office projector)

Customer attachments

N/A

Load and capital costs

Capital cost in 2010: $2,126.20

Detailed breakdown of starting dates and in-service dates for each project

Expenditures done in January and March 2010

COMPUTER EQUIPMENT

Scope

Replacement of 2 desktop computers and IT services.

Objectives

Provide the required equipment to perform regular CSR task and recognize the different software application requirements. Modify accordingly the server, the network service and working stations.

Customer attachments

N/A

Load and capital costs

Cost in 2010 $ 3,691.20

Detailed breakdown of starting dates and in-service dates for each project

In service date November 2010

COMPUTER SOFTWARE

Scope

Software and application requirements for our daily business operations.
Software license (Windows 7 and Microsoft Office 2010), ACCPAC upgrades and licenses. IT services.

Objectives

Perform required work with the latest technology and software applications

Customer attachments

N/A

Load and capital costs

Cost in 2010: $ 14,357.63

Detailed breakdown of starting dates and in-service dates for each project

In service: November 2010

TOOL, SHOP AND GARAGE EQUIPMENT

Scope

Provide required working equipment and tools to line crew

Objectives

Facilitate working conditions, and provide required equipment to perform tasks while maintaining safe working conditions. Road signs, blankets, hoods etc. for HV /LV live line work, harness and pole chokers.

Customer attachments

N/A

Load and capital costs

Cost for 2010: $6,006.67

Detailed breakdown of starting dates and in-service dates for each project

In service: all year

2011 Capital Expenditures

GL ACT #	2011 CAPITAL PROJECTS DESCRIPTION	AMOUNT
1815	REPLACEMENT OF ARCING CONTACT ON BOTH TAP CHANGERS	$ 55,500.00
1820	NEW FENCE AROUND STATION FOR INCREASED SECURITY AND SAFETY	$ 4,348.00
	CHANGE CROSS-ARM COMING OUT OF STATION- ROTTEN, PLUS NEW POLE	$ 3,539.84
	44KV TRANSFORMER HAS HIGH GAZES INSPECT & BY-PASS TAP MANUAL TAP CHANGER. (CONTINU TO MONITOR CLOSELY (SEE IRM 2012)	$ 16,647.20
	REPLACE 2 RECLOSERS	$ 42,155.78
	SUB TOTAL	$ 66,690.82
1830	REPLACE POLES, FIXTURES AS PER ANNUAL INSPECTION	$ 27,658.52
1835	REPLACE 3 SPANS OF COPPER CONDUCTOR AND INSTALL IN-LINE SWITCHES TO FACILITATE SWITCHING OPTIONS	$ 3,636.30
1840 & 1845	NO SUBDIVISION- SECONDARY UG SERVICE ONLY	$ 585.31
	SUB TOTAL	$ 585.31
1850	NEW 167 KVA TRANSFORMER & EQUIPMENT	$ 6,024.65
1855	NEW O.H. AND U.G SERVICES MATERIAL AND LABOUR	$ 3,350.22
1860	METERS AT 110KV STATION (IESO)	$ 7,796.64
1915	NEW FRIDGE FOR EMPLOYEES LUNCH ROOM	$ 1,130.23
1920	NEW COMPUTER SCREENS FOR CSR	$ 768.00
	APC SMART UP & MANAGEMENT CARD	$ 777.55
	WATCHGARD	$ 557.83
	SUB TOTAL	$ 2,103.38
1925	TELEPHONE CALL SOFTWARE (OEB REQUIREMENTS CALL LOG)	$ 1,139.34

	ECARE MODULE & E-BILLING	$ 7,500.00
	SUB TOTAL	$ 8,639.34
1940	MISC TOOLS FOR LINE CREW	$ 1,892.27
	REQUIRED EQUIPMENT FOR UG TEMPORARY SERVICES(TROUBLE CALL) SAFETY ISSUES AND IN COMPLIANCE WITH HEALTH AND SAFETY ISSUES FOR OUR CREW AND CUSTOMERS	$ 3,171.00
	SUB TOTAL	$ 5,063.27
	TOTAL	$ 188,178.68

ARCING TAP CHANGERS

Scope

Previous year inspection showed deterioration on the tap changers contact.

Objectives

To make sure this devise operates correctly, HHI had all contacts on 55T1 and 55T2 tap changer replaced with new. This will avoid a major breakdown of the tap changers, voltage fluctuations at customer premise and avoid customer claims for damaged equipment.

Customer attachments

All customers on these 2 transformers (Approximately 4100 customers) would be affected if these devices are defective. Voltage fluctuation would cause customer's equipment to fail.

Load and capital costs

Cost 2011: $ 55,500.

Detailed breakdown of starting dates and in-service dates for each project

In service date: November 2011

44 KV STATION/FENCE

Scope

Increase security

Objectives
Add fencing around the station for security

Customer attachments
Approximately 1400 customers. This operation is for customer safety. Does not affect power quality nor delivery

Load and capital costs
Cost 2011: $4,348.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: November 2011.

44 KV STATION/ POLE AND CROSS-ARM

Scope
Inspection shows deterioration of cross-arm on the structures at the station

Objectives
Avoid loss of power and equipment damages. Secure incoming and outgoing feeders
Add 45' pole for incoming feeder

Customer attachments
Approximately 1400 customers would be affected if this structure fails.

Load and capital costs
Cost 2011: $ 3,539.84

Detailed breakdown of starting dates and in-service dates for each project
In service date: Cross-arms April 2011
Pole October 2011.

44 KV STATION/ GAZING TRANSFORMER

Scope
The 44KV (10MVA) transformer is performing high combustible gazes. Secure and analysis of the transformer is a major priority for HHI

Objectives

Analyze the transformer, secure the 10MVA transformer until HHI receives OEB approval in IRM 2012. By-pass some reachable components (in the field, not in a shop) to slow down as much as possible the gazing process.

Customer attachments

Approximately 1400 customers would be affected if this structure fails.

Load and capital costs

Cost in 2011: $ 16,647.20

Detailed breakdown of starting dates and in-service dates for each project

In service date June 2011.

44 KV STATION/ RECLOSERS

Scope

Project scope: Replace 2 reclosers at the 44 KV Station

Objectives

Protect adequately our system and replace the old reclosers with new ones.

Customer attachments

One recloser per circuit. Some 1400 customers are on the 44 KV station. Each recloser has approximately 1/2 of the load.

Load and capital costs

Cost in 2011: $ 42,155.78

Detailed breakdown of starting dates and in-service dates for each project

In service date: April 2011.

POLES & FIXTURES

Scope

Each year HHI performs inspection in order to identify which assets need to be removed from service in order to promote safety.

Objectives

Improve Safety and reliability with the removal of older assets.

Customer attachments

Poles and hardware were replaced at different locations.

Load and capital costs

Total capital cost for 2011 was $ 27,658.52

Detailed breakdown of starting dates and in-service dates for each project

Our replacement program started in April 2011 until the end of October 2011.

OVERHEAD BETTERMENT

Scope
Replace existing cooper conductors and add an in-line switch.

Objectives
Bigger conductor will reduce line loss, has higher ampacity. Only section in town with cooper conductor and HHI has been working during the years to replace cooper with aluminum.
Add an in-line switch to facilitate switching operations when need be.

Customer attachments
Some 80 customers are on the section with cooper conductors.

Load and capital costs
Capital cost $ 3,636.30

Detailed breakdown of starting dates and in-service dates for each project
Work performed in fall 2011.

UNDERGROUND SUBDIVISION

Scope
No new subdivision in 2011. So our activities were mainly to connect new services.

Objectives
Respond to customer request for new connections

Customer attachment
New customers on vacant lots.

Load and capital costs
Total cost in 2011 is $ 585.31

Detailed breakdown of starting dates and in-service dates for each project
During 2011

TRANFORMERS

Scope

Purchase the required transformation for future addition on our distribution system and/or replacement of transformers in case of failure.

Objectives

Have the required transformers ready for new connections or failures.

Customer attachments

N/A

Load and capital costs

Total cost in 2011 is $ 6,024.65

Detailed breakdown of starting dates and in-service dates for each project

August 2011

NEW SERVICES

Scope

Installation of Overhead or Underground facilities for new customers.

Objectives

Respond rapidly to customers request for end use services. Connection of new OH and UG service.

Customer attachments

New services.

Load and capital costs

Total cost in 2011 is $ 3,350.22

Detailed breakdown of starting dates and in-service dates for each project

New connections are performed all year round upon customer requests.

METERS

Scope

Meters at the 110KV station due for retest.

Objectives

Replace the existing meters that are due for retest. These meters are at our 110 KV station and HHI is a market participant (IESO) due to the voltage coming (110KV).

Customer attachments

N/A

Load and capital costs

Total cost in 2011 is $ 7,796.64

Detailed breakdown of starting dates and in-service dates for each project

In service date: November 2011.

OFFICE FURNITURE & EQUIPMENT/REFRIGERATOR

Scope

Office equipment to improve work site conditions.

Objectives

Replace the existing defective refrigerator in the lunch room.

Customer attachments

N/A

Load and capital costs

Capital cost in 2011: $1,130.23

Detailed breakdown of starting dates and in-service dates for each project

In service date: September 2011

COMPUTER EQUIPMENT/ SCREENS

Scope

Replacement 3 computer screens.

Objectives

Provide the required equipment to perform regular CSR task and increase working conditions.

Customer attachments

N/A

Load and capital costs

Cost in 2011 $ 768.00

Detailed breakdown of starting dates and in-service dates for each project

In service date September 2011.

COMPUTER EQUIPMENT/ ACP SMART- UP

Scope

Protect our desktop computers

Objectives

Provide the adequate protection to our desktop in case of power failure and power surge.

Customer attachments

N/A

Load and capital costs

Cost in 2011 $ 777.55

Detailed breakdown of starting dates and in-service dates for each project

In service date October 2011.

COMPUTER EQUIPMENT/ WATCHGARD

Scope

Protect our networks (computer system)

Objectives

Provide the adequate protection to our network by adding a solid firewall

Customer attachments

N/A

Load and capital costs

Cost in 2011 $ 557.83

Detailed breakdown of starting dates and in-service dates for each project

In service date November 2011.

COMPUTER SOFTWARE/OEB

Scope

Obtain software that will monitor calls in order to report adequate data to the OEB

Objectives

Adequate reporting tool for the OEB reporting requirements.

Customer attachments

N/A

Load and capital costs

Cost in 2011: $ 1,139.34

Detailed breakdown of starting dates and in-service dates for each project

In service: February 2011

COMPUTER SOFTWARE/ E-CARE AND E-BILLING

Scope

Obtain software that will provide more information to our customers.

Objectives

Facilitate customer information delivery with software that will provide access to our customer VIA internet. Customers will now be able to obtain account information, consumption and more VIA internet. Also HHI will from now on offer e-billing.

Customer attachments

Our entire customer base

Load and capital costs

Cost in 2011: $ 7,500.00

Detailed breakdown of starting dates and in-service dates for each project

In service: November 2011

TOOL, SHOP AND GARAGE EQUIPMENT

Scope
Provide required working equipment and tools to line crew

Objectives
Facilitate working conditions, and provide required equipment to perform tasks while maintaining safe working conditions.

Customer attachments
N/A

Load and capital costs

Cost for 2011: $1,892.27

Detailed breakdown of starting dates and in-service dates for each project
In service: all year

TOOL, SHOP AND GARAGE EQUIPMENT/ TEMPORARY UNDERGROUND

Scope
Provide required working equipment and tools to line crew.

Objectives
Provide the proper equipment in order to promote safety in cases of underground faults. Comply with the health and safety requirements to secure our customers in case of failures.

Customer attachments
Underground services only

Load and capital costs
Cost for 2011: $3,171.00

Detailed breakdown of starting dates and in-service dates for each project
In service: December 2011

2012 Capital Expenditures

GL ACT #	2012 CAPITAL PROJECTS DESCRIPTION	AMOUNT
1815	DISMANTTLE MEETERING AND ASSURE ALL CT'S ARE NOT AFFECTED BY OPERATIONS.	8,890.00
	INTERNAL TAP CHANGER REPAIRS FOLLOWING RECONGNISION THAT 55T1 IS FAULTY. CHANGE ALL AUXILIARY CONTACTS 55T1 AND 55T2	16,000.00
	SUB TOTAL	24,890.00
1820	ADD STONE WITHING ENCLOSURE FOR WORKER SECURITY	4,632.27
1830	NEW LINE EXTENTION 3 PHASE ON WEST ST FOR NEW SERVICE ON HWY 17 (POLE AND HARDWARE)	63,385.00
	REPLACE POLES, FIXTURES AS PER ANNUAL INSPECTION	17,517.08
	SUB TOTAL	80,902.08
1835	NEW LINE EXTENTION 3 PHASE ON WEST ST FOR NEW SERVICE ON HWY 17 (CONDUCTORS)	42,115.00
	REPLACE 3/0 O.H. PRIMARY FEEDER FROM SPENCE TO 44 KV SUBSTATION WITH 336 MCM TULIP	27,772.63
	SUB TOTAL	69,887.63
1840 & 1845	NO SUBDIVISION- UG. LOOP SYSTEM PAUL CRS.	4,935.66
1850	REVAMP BURN TRANSFORMER REPLACE CUT-OUTS & LIGHTNING ARRESTERS FOLLOWING ANNUAL INSPECTION	5,619.70

1855	NEW O.H. AND U.G SERVICES MATERIAL AND LABOUR	2,234.12
1860	SMART METERS RE-DISTRIBUTE SM EXPENSES AFTER MAY 1, 2012 AS PER OEB GUIDELINES (CAPITAL COST TRANSFER)	619,033.11
1920	1 LAPTOP & 2 TABLETS & FIREWALL	$ 2,656.32
1611	ACCPAC, HASSEN SOFTWARE (TELEPHONE CALL SOFTWARE), PLUS SMART METER (AMI ET SOFTWARE CAPITAL COST TRANSFER FOLLOWING OEB GUIDELINES EB-2012-0198	44,231.50
1940	MISC TOOLS FOR LINE CREW	2,967.00
	TOTAL	861,989.39

110 KV METERING/CURRENT TRANSFORMER AND POTENTIAL TRANSFORMER

Scope

Dismantle metering equipment and secure the Current and Potential Transformers within 55T1 and 55T2

Objectives

Safely remove from service the old metering (prior to market opening and new IESO rules) and make sure all existing metering items (built in transformer 55T1 and 55T2) remain activated and that all work perform will not affect the reliability of both transformers.

Customer attachment

All customers on these 2 transformers (Approximately 4100 customers) would be affected if these devices were not disconnected properly.

Load and capital costs

Cost 2012: $ 8,890.00

Detailed breakdown of starting dates and in-service dates for each project

In service date: November 2012

110 KV AUXILIARY CONTACT ON TAP CHANGERS

Scope

Replace auxiliary contacts on both tap changers 55T1 and 55T2 following failure in November 2012 during operations for dismantling metering unit

Objectives

Prevent further damages to these auxiliary contacts. Replace parts defective with new. Secure all apparatus and put back in service. Avoid long term voltage issues at customer premises.
Those are used to regulate the voltage at the source and distribute better power to our customers

Customer attachments

All customers on these 2 transformers (Approximately 4100 customers) would be affected if these devices are defective. Voltage fluctuation would cause customer's equipment to fail.

Load and capital costs

Total cost is $16,000.00

Detailed breakdown of starting dates and in-service dates for each project

In service date: November 2012

44 KV STATION/STONES

Scope

Increase security and grounding

Objectives

Add ¾ inches stone within the fenced area and around the station for proper grounding and the workers safety.

Customer attachments

N/A

Load and capital costs
Cost 2012: $ 4,632.27

Detailed breakdown of starting dates and in-service dates for each project
In service date: August 2012.

NEW LINE EXTENSION WEST ST. /POLES & HARDWARE

Scope
Build new Overhead Line, south of existing 3 phase circuit on West St. for new cement plan on Highway 17.

Objectives
Build the OH line according to HHI & ESA requirements for new customer.

Customer attachments
1 new commercial customer.

Load and capital costs
Cost 2012: $ 63,385.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: June 2012.

POLES & FIXTURES

Scope
Each year HHI performs inspection in order to identify which assets need to be removed from service in order to promote safety.

Objectives
Improve Safety and reliability with the removal of older assets.

Customer attachments
Poles and hardware were replaced at different locations.

Load and capital costs
Total capital cost for 2012 is $ 17,517.08

Detailed breakdown of starting dates and in-service dates for each project

Our replacement program started in April 2012 until the end of October 2012.

NEW LINE EXTENSION 44KV FEEDER OUT OF SUBSTATION / CONDUCTORS AND DEVICES

Scope

Replace existing 3/0 primary conductor with 336 MCM, change cross arms and insulators.

Objectives

Bigger conductor will reduce line loss and has higher ampacity. Furthermore part of our circuit 43F1/43F2/43F3 already has 336MCM. The main source of our distribution system, coming out of our distribution station 44KV is still on 3/0 primary. Our goal is to have all of our main feeder on 336 MCM

Customer attachments

Some 1400 customers receive electricity on this feeder. Furthermore HHI has the capability to switch load from different section in town since HHI has 2 stations. Bigger primary conductors will ease this process.

Load and capital costs

Capital cost $ 27,772.63

Detailed breakdown of starting dates and in-service dates for each project

In service date: December 2012.

NEW LINE EXTENSION WEST ST. / CONDUCTORS AND DEVICES

Scope

Build new Overhead Line, south of existing 3 phase circuit on West St. for new cement plan on Highway 17.

Objectives

Build the OH line according to HHI & ESA requirements for new customer.

Customer attachments

1 new commercial customer.

Load and capital costs

Cost 2012: $ 42,115.00

Detailed breakdown of starting dates and in-service dates for each project

In service date: June 2012.

UNDERGROUND CONDUIT CONDUCTORS AND DEVICES

Scope

No new subdivision in 2012. So our activities were mainly to connect new services and loop an existing underground subdivision

Objectives

Loop an existing UG subdivision in order to minimize future interruptions. Built several years ago, Paul Crescent wasn't terminated. No plans are in place for the continuity of this residential subdivision. If a failure occurs, (bad Primary conductor), these customers could be faced with an interruption that could last several hours or even days.   This action will minimize the outage.

Customer attachments

The subdivision contains some 40 residential customers

Load and capital costs

Total cost in 2012 is $ 4,935.66

Detailed breakdown of starting dates and in-service dates for each project

In service date: August 2012

TRANFORMERS

Scope

Have the required transformation for future addition on our distribution system and/or replacement of transformers in case of failure. Replace existing apparatus to prevent interruptions

Objectives

Revamp a burn transformer. Cost 42% of new transformer.   Change cut-out and lightning arresters following annual inspection

Customer attachments

N/A

Load and capital costs
Total cost in 2012 is $ 5,619.70

Detailed breakdown of starting dates and in-service dates for each project
Transformer May 2012
Other betterment March till End of October 2012

NEW SERVICES

Scope
Installation of Overhead or Underground facilities for new customers.

Objectives
Respond rapidly to customers request for end use services. Connection of new OH and UG service.

Customer attachments
New services.

Load and capital costs
Total cost in 2012 is $ 2,234.12

Detailed breakdown of starting dates and in-service dates for each project
New connections are performed all year round upon customer requests.

METERS

Scope
Smart meters and redistribute SM expenses according to OEB guidelines.

Objectives
Have the proper Smart meter available for new residential and commercial customer. (Gen<50 KW). Redistribute SM expenses according to OEB guidelines EB-2012-0198.

Customer attachments
N/A

Load and capital costs

Total cost in 2012 is $ 619,033.11 (new meters account for $ 17,216.38 of the total expense $619,033.11)

Detailed breakdown of starting dates and in-service dates for each project

In service date: meters purchase through 2012.

COMPUTER EQUIPMENT

Scope

Provide adequate working equipment.

Objectives

Provide tools to management to perform regular tasks. 2 tablets and 1 laptop.

Customer attachments

N/A

Load and capital costs

Cost in 2012 $ 2,656.32

Detailed breakdown of starting dates and in-service dates for each project

In service date: April 2012 and October 2012.

COMPUTER SOFTWARE

Scope

Annual Accpac Upgrade and Hansen software (telephone call monitoring upgrade). Redistribute Smart Meter expenses to software according to OEB guidelines

Objectives

Assure continuity of our existing tools (software) during 2012 with proper upgrades and or licensing. Redistribute Smart Meter Expenses as per EB-2012-0198

Customer attachments

N/A

Load and capital costs
Cost in 2012: $ 44,231.50

Detailed breakdown of starting dates and in-service dates for each project
In service: During 2012

TOOL, SHOP AND GARAGE EQUIPMENT

Scope
Provide required working equipment and tools to line crew

Objectives
Facilitate working conditions, and provide required equipment to perform tasks while maintaining safe working conditions.

Customer attachments
N/A

Load and capital costs
Cost for 2012: $ 2,967.00

Detailed breakdown of starting dates and in-service dates for each project
In service: all year

2013 Capital budget

GL ACT #	2013 CAPITAL PROJECTS DESCRIPTION	AMOUNT
1815	REVAMP 110 KV STATION AS PER OEB APPROVAL EB-2011-0173	1,517,813.00
	REGULAR EXPENDITURES ON 55T1 AND 55T2	30,087.00
	SUB TOTAL	1,547,900.00
1820	REGULAR EXPENDITURES ON 43T2/TESTING FOR WARRANTEE & TRANSFER ICM EXPENSES FROM EB-2011-0173	800,000.00
1830	REPLACE POLES, FIXTURES AS PER ASSET MANAGEMENT PLAN	99,000.00

1835	REPLACE 3/0 O.H. PRIMARY ON CIRCUIT 43F2 WITH 336 MCM TULIP CONTINUITY OF WORK PERFORMED IN 2011 AND 2012	25,000.00
1840 & 1845	SUBDIVISION PLAN SUBMITTED FOR APPROVAL IN JANUARY 2012 SECTION ON RUPPERT AND JACINTHE ST.	17,500.00
1850	TRANSFORMERS FOR THE PROPOSED SUBDIVISION	28,000.00
1855	NEW O.H. AND U.G SERVICES MATERIAL AND LABOUR	3,000.00
1860	SMART METERS	3,500.00
1908	BUILDING 21 YEARS OLD EATER INFILTRATION INTO CURTAIN WALL. CORRECTIONS REQUIRED	13,318.00
	REPLACE CARPETS IN COMMON AREA AND 2 OFFICES	11,258.00
	REPLACE 2 OUT 5 FURNASES IN OFFICE AREA BOTTOM FLOOR	7,924.00
	ROOF INSPECTION REPORT BY GARLAN CANADA. REMOVE EXISTING CAULKING, TERMINATION BARS AND DETORIATED BUTYL TAPE NA DREPLACE SAME. ALSO RE-SEALS THE SEAMS WITH NEW BUTYL TAPE AND URETHANE CAULKING	5,000.00
	SUB TOTAL	37,500.00
1915	REGULAR OFFICE EQUIPEMENT AND COMMERCIAL SHREDDER	5,700.00
1920	REGULAR COMPUTER EQUIPMENT AND HARDWARE	3,000.00
1925	YEARLY UPGRADES AND LICENSING REQUIREMENTS ACCPAC, HANSEN (CALL LOG SOFTWARE)	13,000.00

	WEB PRESENTMENT	5,000.00
	ASSET MANAGEMENT SOFTWARE TO SUPPORT OEB REQUIREMENT ON ASSET MANAGEMENT PLAN	10,000.00
	SUB TOTAL	28,000.00
1940	MISC TOOLS FOR LINE CREW	3,000.00
1950	POWERED EQUIPEMENT LINE CREW	2,000.00
	TOTAL	2,603,100

TRANSFORMER STATION REVAMP

Scope

Redesign our aging 110 KV station. Add new 15/20/25 MVA transformer and circuit switcher.
OEB Approval under EB-2011-0173

Objectives

Replace aging asset, improve reliability and provide growth capacity and redundancy. Also add oil containment to avoid environmental issues in case of oil spills. Add better transformer protection (circuit switcher).
Reports from G.E and BPR forming part of EB-2011-0173 provides all details on the importance of this investment for the town of Hawkesbury. HHI’s acted according to these reports and has shown due diligence in the process and solutions

Customer attachment

All customers on these 2 transformers (Approximately 4100 customers) are connected to these 2 aging transformers.

Load and capital costs

Cost 2013: $ 1,517,813.00

Detailed breakdown of starting dates and in-service dates for each project

In service date: Estimated date November 2013

110 KV REGULAR AND ONGOING INVESTMENTS

Scope

Maintain our existing asset in good shape and maintain our ongoing and yearly betterment.

Objectives

Every year HHI performs regular capital investments. HHI estimate that $30,000 will be required in 2013 for our ongoing betterment process. Regular testing and oil sample will be done in spring and will determine what interventions are required to maintain this asset in good condition. One transformer will be replaced following the revamp of this 110KV station and it will be kept on potential as a back-up while the other aging transformer will still be utilized by HHI. HHI has to make sure that these old transformer are still reliable and safe to operate.

Customer attachments

All customers on these 2 transformers (Approximately 4100 customers) would be affected if these devices are defective.

Load and capital costs

Total estimated cost in 2013 is $ 30,087.00

Detailed breakdown of starting dates and in-service dates for each project

In service date: during 2013

44 KV STATION

Scope

Maintain our existing asset in good shape and maintain our ongoing and yearly betterment.

Objectives

Every year HHI performs regular capital investments. HHI estimates that $20,000 will be required in 2013 for our ongoing betterment process and perform a comprehensive study to evaluate the new 10MVA transformer before the warrantee expires in April 2013. Regular testing and oil sample will be done in spring and will determine what interventions are required to maintain these assets in good condition.

Customer attachments

Some 1400 customers are on this distribution station.

Load and capital costs
Estimated cost in 2013: $ 800,000.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: During 2013.

POLES & FIXTURES

Scope
As per OEB requirements, establish a comprehensive Asset Management Plan and replace existing aging assets.

Objectives
Improve Safety and reliability with the removal of older assets.
Follow the Asset Management Plan and perform required replacement of aging assets.

Customer attachments
Our entire customer base.

Load and capital costs
Estimated Cost in 2013: $ 99,000.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: During 2013.

CONDUCTORS AND DEVICES

Scope
Replace existing 3/0 primary conductor with 336 MCM, change cross arms and insulators.

Objectives
Continue the replacement program started in 2010. A few sections in the east part of town still has 3/0 primary conductors and HHI will upgrade to 336MCM

Bigger conductor will reduce line loss and has higher ampacity. Furthermore part of our circuit 43F1/43F2/43F3 already has 336MCM.

Our goal is to have our entire main feeder on 336 MCM. Furthermore HHI has the capability to switch load from different section in town since HHI has 2 stations. Bigger primary conductors will ease this process.

Customer attachments
Some 1400 customers receive electricity on these feeders.

Load and capital costs
Estimated Capital cost in 2013 is $ 25,000.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: During 2013.

UNDERGROUND CONDUIT CONDUCTORS AND DEVICES

Scope
Early 2013, HHI met a proponent for 2 Underground subdivision.

Objectives
Respond to the entrepreneur's request if these 2 projects do occur in 2013.

Customer attachments
New residential subdivision. Vacant land.

Load and capital costs
Estimated cost in 2013 is $ 17,500.00 (capital contribution will be required from the entrepreneur)

Detailed breakdown of starting dates and in-service dates for each project
In service date: During 2013

TRANFORMERS

Scope
Early 2013, HHI met a proponent for 2 Underground subdivision. Have the required transformation for future addition on our distribution system and/or replacement of transformers in case of failure.

Objectives

If in fact these 2 underground subdivisions are built, transformers will be required.
Also HHI is in need of 2 three phases transformers for future use and/or replacement of failure. One transformer 12400/347/600 volts and one 12400/120/208 volts.

Customer attachments

New subdivision (vacant Land)

Load and capital costs

Estimated cost in 2013 is $ 28,000.00 (some capital contribution will be required from entrepreneur)

Detailed breakdown of starting dates and in-service dates for each project

In service date: 3 phases transformers Spring 2013

Subdivision transformers: during 2013

NEW SERVICES

Scope

Installation of Overhead or Underground facilities for new customers.

Objectives

Respond rapidly to customers request for end use services. Connection of new OH and UG service.

Customer attachments

New services.

Load and capital costs

Estimated cost in 2013 is $ 3,000.00

Detailed breakdown of starting dates and in-service dates for each project

New connections are performed all year round upon customer requests.

METERS

Scope

New Smart meters in order to respond to ongoing demand.

Objectives

Have the proper Smart meter available for new residential and commercial customer. (Gen<50 KW). Possibility of 2 new subdivisions in 2013.

Customer attachments

N/A

Load and capital costs

Estimated cost in 2013 is $ 3,500.00

Detailed breakdown of starting dates and in-service dates for each project

In service date: During 2013.

BUILDING AND FIXTURES /WINDOWS

Scope

Hydro Hawkesbury's building was built in 1962. Betterments are required to keep the building in good condition

Objectives

In the last year HHI had some issues with some windows in different are of the building. Some water infiltration has caused minor damages to window sills. The removal of the pressure plates, caps and old tremtape is required. Correct the anomalies in 2 offices, common area and kitchen on first floor as well as meeting room, 3 offices on second floors.

Re-install polyshim tape, verify drain holes and caulk all windows to prevent further damages

Customer attachments

N/A

Load and capital costs

Estimated cost in 2013 is $ 13,318.00

Detailed breakdown of starting dates and in-service dates for each project

In service date: Spring 2013.

BUILDING AND FIXTURES /CARPETS

Scope

Hydro Hawkesbury's building was built in 1962. Betterments are required to keep the building in good condition

Objectives

Remove all carpets in 2 offices and the common area on the first floor. Second floor of the building is in good condition.

Customer attachments

N/A

Load and capital costs

Estimated cost in 2013 is $ 11, 258.00

Detailed breakdown of starting dates and in-service dates for each project

In service date: During 2013

BUILDING AND FIXTURES /FURNASES

Scope

Hydro Hawkesbury's building was built in 1962. Betterments are required to keep the building in good condition

Objectives

Replace 2 out 5 furnaces in 2013. Steps to replace the aging furnaces were taken in 2012 for HHI's Asset Management Plan. In 2013 one of the first floor furnaces demonstrated some signs of fatigue. An estimate was provided to correct the faulty furnace.
The fan needs to be replaced and heat exchanger cleaned. Estimated cost $864.00 (plus coolant and maybe the Heat exchanger replacement). As part of our asset management plan HHI replaced the first floor furnaces with new units

Customer attachments

N/A

Load and capital costs

Estimated cost in 2013 is $ 7,924.00

Detailed breakdown of starting dates and in-service dates for each project

In service date: February 2013

BUILDING AND FIXTURES /ROOF

Scope

Hydro Hawkesbury's building was built in 1962. Betterments are required to keep the building in good condition. Early 2013 following warmer weather, water infiltration occurred in the lobby. Some minor damages resulted from this infiltration.
Garland Canada did an evaluation of the roof in November 2012 for HHI's Asset Management Plan.

Objectives

Follow Garland Canada Inc's recommendation for 2013.
Roof inspection report from garland Canada proposed the following solution in 2013.

- Remove the existing caulking and clean the roof area.
- Remove the termination bars
- Remove the deteriorated butyl tape.
- Re-caulk all areas with high quality urethane caulking
- Re-seal all seams with new butyl tape and urethane caulking.

Customer attachments
N/A

Load and capital costs
Estimated cost in 2013 is $ 5,000.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: Early Summer 2013

OFFICE FURNITURE & EQUIPMENT

Scope

Office equipment to improve work site conditions.

Objectives

Purchase a scanner in order to archives important documents and become more paperless. Purchase a commercial shredder. Important documents will be archived and documents will be disposed of in a proper manner.

Customer attachments
N/A

Load and capital costs
Estimated cost in 2013: $ 5,700.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: During 2013

COMPUTER EQUIPMENT

Scope
Provide adequate working equipment.

Objectives
Provide tools to management to perform regular tasks. Protect actual hardware as required by our service provider

Customer attachments
N/A

Load and capital costs
Estimated cost in 2013 $ 3,000.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: During 2013.

COMPUTER SOFTWARE

Scope
Annual Accpac Upgrade and Hansen software (telephone call monitoring upgrade).

Objectives
Assure continuity of our existing tools (software) during 2013 with proper upgrades and / or licensing.

Customer attachments
N/A

Load and capital costs
Estimated cost in 2013: $ 13,000

Detailed breakdown of starting dates and in-service dates for each project
In service: During 2013

COMPUTER SOFTWARE/WEB PRESENTMENT

Scope
Provide tools to our customers to promote conservation.

Objectives
In our Smart Meter Disposition application, EB-2012-0198 an investment amount of $5,000 was approved by the Board. In 2013 HHI will provide a Web presentment tool to its customers to help and promote energy conservation

Customer attachments
N/A

Load and capital costs
Estimated cost in 2013: $ 5,000

Detailed breakdown of starting dates and in-service dates for each project
In service: During 2013

COMPUTER SOFTWARE/ ASSET MANAGEMENT PLAN

Scope
Comply with OEB requirement on the Asset Management Plan.

Objectives
Obtain the proper software to comply with the Board's request on Asset Management Plan.

Customer attachments
N/A

Load and capital costs
Estimated cost in 2013: $ 10,000.00

Detailed breakdown of starting dates and in-service dates for each project

In service: During 2013

TOOL, SHOP AND GARAGE EQUIPMENT

Scope

Provide required working equipment and tools to line crew

Objectives

Facilitate working conditions, and provide required equipment to perform tasks while maintaining safe working conditions.

Customer attachments

N/A

Load and capital costs

Estimated cost in 2013: $ 3,000.00

Detailed breakdown of starting dates and in-service dates for each project

In service: During 2013

POWERED EQUIPEMENT

Scope

Provide required working equipment and tools to line crew

Objectives

Facilitate working conditions, and provide required equipment to perform tasks while maintaining safe working conditions.

Customer attachments

N/A

Load and capital costs

Estimated cost in 2013: $ 2,000.00

Detailed breakdown of starting dates and in-service dates for each project

In service: During 2013

2014 Capital budget

GL ACT #	2014 CAPITAL PROJECTS DESCRIPTION	AMOUNT
1815	REGULAR EXPENDITURES ON THE NEW 55T1 AND 55T2 AND 55T3 (ON POT)	25,000.00
1820	REGULAR EXPENDITURES ON 43T2	10,000.00
	REGULAR MAINTENANCE OF 44KV SUBSTATION ALONG WITH $50,000 FOR OFF-SITE INSPECTION OF THE FAULTY 10MVA TRANSFORMER. (SHIPMENT COST TO AND FROM STONEY CREEK)	60,000.00
	SUB TOTAL	60,000.00
1830	REPLACE POLES, FIXTURES AS PER ASSET MANAGEMENT PLAN	89,000.00
1835	REPLACE 3/0 O.H. PRIMARY ON CIRCUIT 55F1. PART OF MAIN ST. POLE # 304 TO # 332 WITH 336 MCM TULIP	20,000.00
1840 & 1845	SUBDIVISION AND U.G FACILITIES SECTION ON RUPPERT AND JACINTHE ST.	18,000.00
1850	TRANSFORMERS FOR THE PROPOSED SUBDIVISION AND LDC NEEDS	12,500.00
1855	NEW O.H. AND U.G SERVICES MATERIAL AND LABOUR	3,100.00
1860-01	SMART METERS	3,500.00
1908	REPLACE LAST 3 FURNACES (3 OUT OF 5)	12,500.00
1915	REGULAR OFFICE EQUIPEMENT	3,500.00
1920	REGULAR COMPUTER EQUIPMENT AND HARDWARE	3,100.00
1611	YEARLY UPGRADES AND LICENSING REQUIREMENTS ACCPAC, HANSEN (CALL LOG SOFTWARE)	17,000.00
1940	MISC TOOLS FOR LINE CREW	3,100.00
1950	POWERED EQUIPEMENT LINE CREW	2,000.00
	TOTAL	272,300.00

110 KV REGULAR AND ONGOING INVESTMENTS

Scope

Maintain our existing asset in good shape and maintain our ongoing and yearly betterment.
Transformer 55T1, 55T2 AND 55T3 (On pot), and structure

Objectives

Every year HHI performs regular capital investments. HHI estimates that $25,000 will be required in 2014 for our ongoing betterment. Regular testing and oil sample will be done in spring and will determine what interventions are required to maintain these assets in good condition. Reliability and safety is mandatory on all 3 transformers. (Even the one on Pot in case needed to replace the old 55T2 that will remain active)

Customer attachments

All customers on these 2 transformers (Approximately 4100 customers) would be affected if these devices are defective.

Load and capital costs

Total estimated cost in 2014 is $ 25,000.00

Detailed breakdown of starting dates and in-service dates for each project

In service date: during 2014

44 KV STATION

Scope

Maintain our existing asset in good shape and maintain our ongoing and yearly betterment.

Objectives

Every year HHI performs regular capital investments. HHI estimates that $10,000 will be required in 2014 for our ongoing betterment.
Furthermore HHI propose to repair the old 44KV transformer that produces high combustible gases. Our goal is to have this transformer shipped to a repair chop for investigation in order to obtain a comprehensive report on the internal fault responsible for the high combustible gases. Once determined, HHI will request a full report on solutions and repairs and a quote to perform the required work to solve these issues.

Customer attachments

Some 1400 customers are on this distribution station.

Load and capital costs

Estimated cost in 2014: $ 60,000

Detailed breakdown of starting dates and in-service dates for each project

Estimated In service date: End 2014

POLES & FIXTURES

Scope

As per OEB requirements, establish a comprehensive Asset Management Plan and replace existing aging assets.

Objectives

Improve Safety and reliability with the removal of older assets.
Follow the Asset Management Plan and perform required replacement of aging assets.

Customer attachments

Our entire customer base.

Load and capital costs

Estimated Cost in 2014: $ 89,000.00

Detailed breakdown of starting dates and in-service dates for each project

In service date: During 2014.

CONDUCTORS AND DEVICES

Scope

Replace existing 3/0 primary conductor with 336 MCM, change cross arms and insulators.

Objectives

As done between 2012 and 2013, HHI will not upgrade the primary trunks of its distribution system on Main St. This feeder 55F1 runs from The West end of town up to the East end. Sections will be done over 4 years to lower the coast impact on rates.

In 2014 HHI will start this upgrade from the west end at Pole # 304 to Pole #332. 3/0 primary conductor will be upgraded to 336 MCM

Our goal is to have our entire main feeder on 336 MCM. Furthermore HHI has the capability to switch load from different section in town since HHI has 2 stations. Bigger primary conductors will ease this process.

Customer attachments
Some 4100 customers receive electricity on these feeders.

Load and capital costs
Estimated Capital cost in 2014 is $ 20,000.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: During 2014.

UNDERGROUND CONDUIT CONDUCTORS AND DEVICES

Scope
No discussion in early 2013 on possible system expansion. (Subdivision).
It has been HHI's experience to see these projects evolve early in the New Year.

Objectives
Respond to the entrepreneur's request if in fact request for new subdivision arise.

Customer attachments
New residential subdivision. Vacant land.

Load and capital costs
Estimated cost in 2014 is $ 18,000 (capital contribution will be required from the entrepreneur)

Detailed breakdown of starting dates and in-service dates for each project
In service date: During 2014

TRANFORMERS

Scope

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

Objectives

Respond to the entrepreneur's request if in fact request for new subdivision arise and sufficient transformers in case of transformer failure.

Customer attachments

New residential subdivision. Vacant land.

Load and capital costs

Estimated cost in 2014 is $ 12,500 (capital contribution will be required from the entrepreneur)

Detailed breakdown of starting dates and in-service dates for each project

In service date: During 2014

NEW SERVICES

Scope

Installation of Overhead or Underground facilities for new customers.

Objectives

Respond rapidly to customers request for end use services. Connection of new OH and UG service.

Customer attachments

New services.

Load and capital costs

Estimated cost in 2014 is $ 3,100.00

Detailed breakdown of starting dates and in-service dates for each project

New connections are performed all year round upon customer requests.

METERS

Scope

New Smart meters in order to respond to ongoing demand.

Objectives

Have the proper Smart meter available for new residential and commercial customer. (Gen<50 KW).

Customer attachments

N/A

Load and capital costs

Estimated cost in 2014 is $ 3,500.00

Detailed breakdown of starting dates and in-service dates for each project

In service date: During 2014.

BUILDING AND FIXTURES /FURNASES

Scope

Hydro Hawkesbury's building was built in 1962. Betterments are required to keep the building in good condition

Objectives

In 2014 2 furnaces were replaced. HHI will replace the last 3 furnaces and complete this program in its entirety.

Customer attachments

N/A

Load and capital costs

Estimated cost in 2014 is $ 12,500

Detailed breakdown of starting dates and in-service dates for each project
In service date: During 2014

OFFICE FURNITURE & EQUIPMENT

Scope
Office equipment to improve work site conditions.

Objectives
Provision for regular office furniture

Customer attachments
N/A

Load and capital costs
Estimated cost in 2014: $ 3,500

Detailed breakdown of starting dates and in-service dates for each project
In service date: During 2014.

COMPUTER EQUIPMENT

Scope
Provide adequate working equipment.

Objectives
Provide tools to management to perform regular tasks. Protect actual hardware as required by our service provider

Customer attachments
N/A

Load and capital costs
Estimated cost in 2014 $ 3,500.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: During 2014.

COMPUTER SOFTWARE

Scope
Annual Accpac Upgrade and Hansen software (telephone call monitoring upgrade).

Objectives
Assure continuity of our existing tools (software) during 2014 with proper upgrades and / or licensing.

Customer attachments
N/A

Load and capital costs
Estimated cost in 2017: $ 17,000

Detailed breakdown of starting dates and in-service dates for each project
In service: During 2014

TOOL, SHOP AND GARAGE EQUIPMENT

Scope
Provide required working equipment and tools to line crew

Objectives
Facilitate working conditions, and provide required equipment to perform tasks while maintaining safe working conditions.

Customer attachments
N/A

Load and capital costs
Estimated cost in 2014: $ 3,100.00

Detailed breakdown of starting dates and in-service dates for each project
In service: During 2014

POWERED EQUIPEMENT

Scope

Provide required working equipment and tools to line crew

Objectives

Facilitate working conditions, and provide required equipment to perform tasks while maintaining safe working conditions.

Customer attachments

N/A

Load and capital costs

Estimated cost in 2014: $ 2,000.00

Detailed breakdown of starting dates and in-service dates for each project

In service: During 2014

E2.T2.S5 EXPLANATION OF EXPENSES OVER THE MATERIALITY THRESHOLD

The following projects are noted to be over the materiality threshold of $50,000 and therefore warrant further explanation

2010

1815-Transformer Station Equipment - Normally Primary above 50 kV

Back in September and October of 2010, HHI performed much needed maintenance on the 110kV. In September maintenance, the utility replaced one of the 3 failing reclosers. Most of the utility's customers depend on these reclosers therefore replacement was the only option. The material and labour for this expense was in the amount of $23,503. Further maintenance was done to replace tap changers at a cost of $18,592 and add inhibitor mineral oil at the two aging substation. The material and labour of the addition of oil amounted to $10,400. The total cost of this maintenance was in the amount of $52,495.

2011

1815-Transformer Station Equipment - Normally Primary above 50 kV $ $55,500

Again, HHI performed much needed maintenance on the 110kV. The previous year's inspection showed deterioration of the tap changer contacts. The utility replaced all contacts on 55T1 and 55T2 tap changer with new contacts. This was done in order to avoid a major breakdown of the tap changers, voltage fluctuations at customer premise and avoid customer claims for damaged equipment. Most of the utility's customers depend on the 110kW therefore replacement was the only option. The material and labour for this expense was in the amount of $55,500.

1820-Distribution Station Equipment - Normally Primary below 50 kV $ $66,691

Back in 2011 HHI put a fence around the substation in order to increase security and overall safety. This upgrade was priced at $4,348. Part of the expense for 2011 included having the aging transformer analyzed and monitored for high combustible gases. These issues were addressed in the utility's ICM application. The cost of monitoring the gases was $16,647. The utility also replace a pole and cross arm which added to the overall expense in account 1820.

2012

1830-Poles, Towers and Fixtures $ $80,902

Cost incurred in this account were attributed to the building of a new overhead line south of an existing three phase circuit on West St. for a new cement plant on Hwy 17. The total cost of this new overhead line was in the amount of 63,385.

HHI has also been monitoring its poles on a yearly basis and found that a substantial number of poles were in need of replacement which can significantly impact the safety and reliability of the distribution system. Poles are prioritized for replacement based upon age, condition and potential adverse impact on the reliability of the distribution system.

1835-Overhead Conductors and Devices $ $69,888

These cost are associated with the building of a new overhead line south of an existing three phase circuit on West St. for a new cement plant on Hwy 17 and were in the amount of $42,115. HHI also replaced existing 3/0 primary conductors with 336

MCM, change cross arms and insulators. The total cost for this work was in the amount of $17,773.

1860 – Smart Meters $ $618,899

HHI filed a stand-alone smart meter application in the fall of 2012. As indicated in Guideline G-2011-0001 "*A distributor can rely on the order obtained in a stand-alone proceeding in subsequent rate proceeding(s) as evidence that the Board has reviewed and approved the underlying costs. In its next cost of service application, the distributor should include the approved smart meter capital (and associated accumulated depreciation) and annual operating costs in its application and seek to include the above in its rate base and revenue requirement.*"

In accordance with the above guidelines, HHI has transferred its Smart Meter Capital related expenditures in the amount of 601,817 in its Rate Base, more specifically in 2012 when the bulk of the smart meters were installed. The decision and order is filed as an Appendix to this Exhibit.

2013

1815-Transformer Station Equipment - Normally Primary above 50 kV $1,547,900 and; 1820-Distribution Station Equipment - Normally Primary below 50 kV $800,000

As part of its 2012 IRM application, Hydro Hawkesbury applied for ICM treatment for two projects: (i) to replace two transformers at the 110 KV substation with a new 25 MVA transformer at a cost of $1,517,813; and (ii) to replace and undertake site preparation for a 44 KV distribution transformer at a cost of $712,909. The total applied-for ICM is $2,230,722.

In its decision, the Board agreed that the applied-for projects were consistent with the purpose of the ICM, and that it was appropriate to evaluate each of the two projects using the incremental capital investment eligibility criteria.

The Board found that the need, prudence and materiality for each for the two applied-for projects were established and that HHI has provided sufficient evidence documenting potential asset failure, the cost consequences of deferring action and risking asset failure, condition deterioration and safety issues to establish materiality, need and prudence of each project in the context of this application.

The Board ultimately approved an incremental capital module of $2,230,722. The Decision is appended to this Exhibit.

1830-Poles, Towers and Fixtures $99,000

HHI has also been monitoring its poles on a yearly basis and found that a substantial number of poles were in need of replacement which can significantly impact the safety and reliability of the distribution system. Poles are prioritized for replacement based upon age, condition and potential adverse impact on the reliability of the distribution system. Further details on pole replacement can be found at E2.T2.S8

2014

1820-Distribution Station Equipment - Normally Primary below 50 kV $60,000

Every year HHI performs regular capital investments. HHI estimates that $10,000 will be required in 2014 for our ongoing betterment.

Furthermore HHI proposes to repair the old 44KV transformer that produces high combustible gases. The goal is to have this transformer sent out for investigation in order to obtain a comprehensive report on the internal fault causing high combustible gases. Once the faults are determined, HHI will request a full report on solutions and repairs and a quote to perform the required work to solve these issues. The plan is to refurbish the 44KV station to by installing oil containment (prevent environment catastrophe in case of oil spills) and add this repaired transformer to the distribution system in order to have backup and redundancy in place for years to come. The estimated cost of this assessment is $71,000. of The total cost of refurbishing the transformer is estimated at $175,000 which is about 35% of the price of a new transformer.

1830-Poles, Towers and Fixtures $89,000

HHI has been monitoring its poles on a yearly basis and found that a substantial number of poles were in need of replacement which can significantly impact the safety and reliability of the distribution system. Poles are prioritized for replacement based upon age, condition and potential adverse impact on the reliability of the distribution system. Further details on pole replacement can be found at E2.T2.S8

E2.T2.S6 CAPITALIZATION AND OTHER ASSET RELATED POLICIES

HHI records capital assets at cost in accordance with Canadian Generally Accepted Accounting Principles as well as guidelines set out by the Ontario Energy Board, where applicable. All expenditures by the Corporation are classified as either capital or operating expenditures. The intention of these classifications is to allocate costs across accounting periods in a manner that appropriately matches those costs with the related current and future economic benefits. 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. HHI does not currently capitalize interest on funds for construction. HHI's adherence to the capitalization policy can be described as follows. Indirect overhead costs, such as general and administration costs that are not directly attributable to an asset, are no longer capitalized as of January 1, 2013 (see section E2.T2.S7 for further details.

- Assets that are intended to be used on an on-going basis and are expected to provide future economic benefit (generally considered to be greater than one year) will be capitalized.
- General Plant items with an estimated useful life greater than one year and valued at greater than $500 will be capitalized.
- Expenditures that create a physical betterment or improvement of the asset (i.e.) there is a significant increase in the physical output or service capacity; or the useful life of the capital asset is extended) will be capitalized.
- With respect to transportation equipment (e.g. vehicles), all costs associated with putting a vehicle into service are capitalized.

E2.T2.S7 CAPITALIZATION OF OVERHEAD

In compliance with the Board's letter issued July 17, 2012 which state that utilities must changes change their capitalization policies, HHI has adopted these mandatory changes effective on January 1, 2013.

HHI is proposing to change its accounting policy for the accounting of overhead costs associated with capital work as clarified by the Board in its letter dated February 24, 2010. On February 24, 2010 the OEB issued additional guidance on the accounting for overhead costs associated with capital work. In this letter the OEB specifically noted that the Board was requiring full compliance with IFRS requirements on capitalization of overheads which would result in a reduction in capitalized overhead for some electricity distributors that had previously capitalized administration and overhead costs. HHI concluded that it would cease the capitalization of general overhead costs, including indirect labour, general administration and material handling, for regulatory and external reporting as of January 13, 2013. This change results in a decrease in the amount of costs capitalized and an increase in operating expenses. Burdens rates are presented at table

REVISED JULY 22, 2013

Table 11a - Burdens

		Burden Rates
#1815(Trans STN 115KV)	1815	32%
#1820(Trans STN 44KV)	1820	32%
#1830(O/H Poles)	1830	32%
#1835(O/H Conductors)	1835	32%
#1840(U/G Conduit)	1840	32%
#1845(U/G Conductors)	1845	32%
#1850(Line Transformers)	1850	32%
#1855(Services)	1855	32%
#1860(Meters)	1860	32%

E2.T2.S8 ASSET MANAGEMENT PLAN

HHI's Asset Management Plan is presented at the next section

Asset Management Plan
2013

Table of Contents

1 Introduction

Hydro Hawkesbury Inc.'s Asset Management Plan is designed to present a fully integrated approach to capital expenditure planning. This includes a comprehensive documentation of its asset management process that supports its future capital expenditure plan while detailing its historical activities. It recognizes its responsibilities required in order to provide its customers with reliable service that is viewed as excellent value for money, by ensuring that its asset management activities maintain a focus on customers, both operational and cost effectiveness, public policy responsiveness and financial performance.

Asset management requires a thorough understanding of the characteristics and condition of infrastructure assets, as well as the service levels expected from them. It also involves setting strategic priorities to optimize decision-making about when and how to proceed with investments.

This Applicant's Asset Management Plan is not intended to be a detailed description of the utility's distribution system assets, but it is intended to be a description of the thinking, the policies, the strategies, the plans, and the resources that HHI's uses to manage the assets.

The information and statements made in this Asset Management Plan are prepared on the assumptions, projections, forecasts and represents HHI's' intentions and opinions at the date of preparation.

Circumstances will change, assumptions and forecasts may prove to be wrong, events may occur that were not predicted, and HHI's may, at a later date, decide to take different actions from those it currently intends to take as expressed in this Asset Management Plan.

HHI's cannot be held liable for any loss, injury, or damage arising directly or indirectly as a result of use or reliance on any information contained within this Asset Management Plan.

2 Period Covered

The planning horizon of the Asset Management Plan is from 2013 to 2023. It is intended that the Asset Management Plan will be a living document that will be reviewed on a periodic basis.

The planning horizon extends for a ten (10) year period. The main focus of the plan concentrates on both 2013 and 2014 as budgets for these years have been developed. The Inspection and Condition Assessment is based on a planning horizon of ten (10) years and predicts the sustainment of assets through to 2023.

It is very likely that new developments, that are not identified here, will arise at any given time even in the short term of five (5) years.

3 Purpose, Objectives, Challenges and Accountability

Purpose

The purpose of this Asset Management Plan is to define HHI''s approach to its core business which is to supply reliable electrical services to its customers at a reasonable cost. This requires:

- Maintain service levels that will meet customer, community, and regulatory expectations for its distribution system.
- Understand what levels of distribution system capacity, reliability, and security of supply will be required both now and in the future, and what issues will drive these requirements.
- A thorough understanding of the age, condition and performance of its assets.
- Documenting inspection practices in accordance with the Distribution System Code.
- Forecasting and planning for the future growth of load customers and renewable generation facilities.
- Recognizing and addressing constraints in the current distribution system and anticipating future capacity requirements.
- Demonstrating that the asset management process recognizes the above items and prioritizes projects to accommodate customers and system requirements.
- Developing a capital expenditure plan that anticipates the future growth, capacity and performance of the distribution system while remaining flexible to accommodate the unknown requirements of its customer base.

Objectives

Prudent capital investment plans, operations and maintenance budgets reflect current priorities and anticipated future spending.

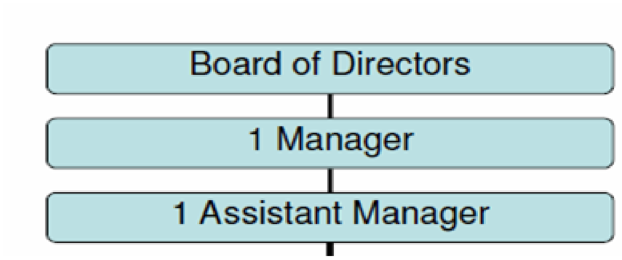
HHI's employs good utility practices to manage and operate its distribution system. Its Asset Management Strategy prioritizes work to achieve the following objectives:

- Maintain its reliability performance.
- Address significant health and safety issues.
- Meet regulatory and legal obligations.
- Address significant environmental risks.
- Replace end-of-life plant.

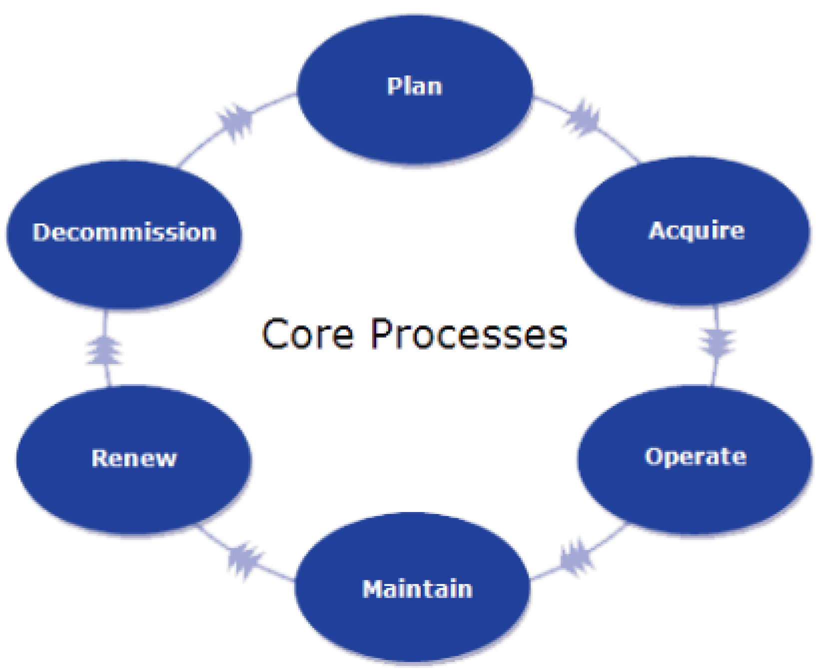
- Improve operational efficiency

Accountability

The following organizational chart includes the key positions that are accountable for the management of the distribution system assets, the asset management data and implementation of the Asset Management Plan including the allocation and control of the capital expenditures.



The following presents the typical process that HHI follows when managing its assets.



4 Utility Specifics and Assets

HHI has a licensed service area of 8.6 square kilometers and serves over 5500 residential and business customers within the Town of Hawkesbury. It is committed to service delivery excellence and is an incorporated entity, owned by its sole shareholder, the Town of Hawkesbury.

HHI relies on approximately 67.45 km of circuits to deliver power to approximately 5,500 customers. The circuits can be broken down into roughly 56.65 km of overhead lines and 10.8 km of underground conductor. The distribution system is comprised of 42.85 km of 3-phases circuits and 24.6 km of single phase circuits

HHI receives its electricity supply at two delivery points. A substation at 110KV with two distribution transformers at the West end of town from Hydro One's Hawthorne TS, and a 44KV station at the East end of Hawkesbury from Hydro One Longueuil TS. HHI own and operate the two distribution stations in questions..

HHI''s distribution system consists of the following major components.

- Poles – 1300
- Overhead Transformers – 686
- Single Phase Pad-mount Transformers – 85
- Three Phase Pad-mount Transformers – 60
- Kilometers of 3 Phase Circuits – 42.85
- Kilometers of 1 Phase Circuits – 24.6

Being a smaller utility with a fairly small service area allows HHI's to be well informed on the condition of its assets and uses management's operating judgment and experienced contractors to replace plant cost effectively when it can no longer be maintained effectively or safely. As demonstrated in its 2012 request for ICM, the utility exercises due diligence and prudence when investing in it distribution system.

In preparation for its 2014 Cost of Service application, HHI's performed a comprehensive survey of its distribution system. This provided updated information to accurately populate the data in its reporting system and served as a new baseline for the annual patrol inspections required by the Distribution System Code.

In addition HHI's reviewed the status and age of the major components, within its distribution system. These primary system components were:

- Substations
- Distribution Transformers
- Poles

The assessment of this study along with the utilities maintenance program is described at the next section.

Substation

Background

HHI receives its electricity supply at two delivery points. A substation at 110KV with two distribution transformers at the West end of town and a 44KV station at the East end of Hawkesbury. HHI own and operate the two distribution stations in questions.

Back in 2010-2011, HHI operated with two transformers that were approximately 45 year of age and had shown signs of deterioration. Their operating condition had been a growing concern for the utility and its customers.

At their current load capacity, they could only partially cover the load of each other. HHI could not feed the entire load delivered by both transformers with a single unit. Reliability and continuity of power supply was threatened by the loss of either substation. The two transformers at the 110kV station were reaching end of life.

HHI Board of Directors requested a station assessment study by GE Canada, (Reference: BPR Study report REF: 02070 Exh1, Tab2, Sch2, Att1, Num1) which was performed in 2010.

In its 2010 cost of service application HHI sought funding for an assessment of each transformer. This study, presented at Schedule 2, was part of HHI effort to asses an monitor its aging assets. The study conducted provided a detailed report outlining the overall condition of each transformer, its components and accessories.

Following the recommendations in the station assessment report, the Board of Directors initiated a comprehensive study by Professional Engineers to add a new transformer and correct the identified anomalies in order to maintain service reliability. Historically, the 110KV station has been a slowly growing source of concern.

HHI ongoing maintenance involved regular oil sample testing of all high voltage equipment on both substations. In 2006 and 2009 following oil test results, HHI did a major maintenance on the 110KV station (2 x 7.5MVA transformers).

The proposed solution to remedy the situation involved replacing one of the existing transformers by a new 25MVA. Add oil containment and circuit switchers for two transformers and place one of the existing transformers on a pad as spare.

This alternative addressed all the problems at the 110kV substation and provided for forward thinking. The alternative made the best use of the available space and retains proper access to the major equipment and for switching.

This alternative also addressed future operation flexibility. A new 25MVA transformer would provide for main supply and one of the existing 12.5MVA transformers would be kept for redundancy until funds are available for a second 25MVA transformer. One of the existing transformers would be placed on a new pad with oil containment, identical to the one for the new 25MVA transformer. This would allow maintenance during low loading period on the 25MVA transformer and provide some level of redundancy.

In 2012, the addition of a new 10 MVA transformer at the 44 KV sub-station facilities was completed and the sub-station put in service in March 2012.

As for the 25MVA transformer and circuit switcher, engineering are currently being done. The in-service date of operation is expected to be end of 2013. Both capital investments were approved by the OEB in an Incremental Capital Application. (IRM 2012).

Poles

The table below shows how many poles need to be replaced per year based on when the poles were originally installed. Annual inspections will also identify if other poles should be removed due to poor conditions, even if the expected replacement year is not reached.

Poles Replacement Schedule

Replacement Year	Count	Replacement Year	Count	Replacement Year	Count
2014	33	2023	60	2033	7
2015	32	2024	66	2034	15
2016	41	2025	45	2035	4
2017	78	2026	28	2036	1
2018	33	2027	4	2037	19
2019	29	2028	33	2038	49
2020	34	2029	13	2039	10
2021	43	2030	6		
2022	4	2031	36		
2022	6	2032	15		

Transformers and Switches

The table below shows how many transformers need to be replaced per year based on when they were originally installed. When replacement year is reached, HHI will perform testing and operational maneuvers to determine if the transformer should effectively be removed for further maintenance and reconditioning.

Transformer Replacement Schedule

Replacement Year	Count	Replacement Year	Count	Replacement Year	Count	Replacement Year	Count
2014	47	2024	14	2034	18	2044	6
2015	11	2025	6	2035	23	2045	4
2016	17	2026	21	2036	2	2046	8
2017	13	2027	38	2037	7	2047	5
2018	9	2028	16	2038	6	2048	4
2019	11	2029	7	2039	14	2049	3
2020	4	2030	6	2040	9	2050	9
2021	17	2031	14	2041	5	2051	3
2022	14	2032	4	2042	19	2052	4
2023	25	2033	16	2043	7	5012	1

Although age is in many ways the best overall proxy to determine the useful life of an asset, HHI believes that condition is the real issue. Some units of equipment might deteriorate so that condition is poor after only 40 years. Another unit, aged 70 years, might be in that same condition. HHI uses both the transformer and pole schedules above to determine whether or not the asset needs assessing. Once the condition is determined, the utility will decide whether or not it needs replacing.

5 Inspections and Condition Assessments

The OEB has documented its Minimum Inspection Requirements (Appendix C of the Distribution System Code, "DSC") that outlines minimum inspection standards and inspection intervals of the distribution system. The Minimum Inspection Requirements further define Patrol Inspection and provide a list of major assets within HHI's distribution system to be patrolled. The assets applicable to HHI's include:

- Poles and Supports
- Hardware and Attachments
- Conductors and Cables
- Switching & Protective Devices
- Distribution Transformers
- Substations
- Vegetation
- Civil Infrastructure

The following sections describe HHI''s regular inspection program that is consistent with the DSC. The purpose of such an inspection program is to determine asset condition, identify any risk to safety, reliability and/or the environment, and subsequently addresses findings through prudent capital, operations and maintenance expenditures, as necessary.

Inspection of the Overhead Distribution System

The overhead portion of the distribution system is comprised primarily of poles, conductors, distribution transformers and protective devices. These assets are inspected as briefly described in the sections to follow;

Poles/Supports/ Cross arms

- 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

Pole inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code as good utility practice. HHI conducts pole inspections annually to determine when poles need to be replaced.

Pole Replacements are undertaken for the following different reasons:

- Structural damage
- Taller or different class of pole required
- Health and safety hazard to the public and employees
- Pole damaged
- Line rebuilds and ESA compliance

HHI''s current pole inspection program is based on a comprehensive assessment performed in 2012. All poles within the geographic areas were inspected such that all poles were assessed by year-end. HHI's utilized its linemen to document the attributes of each pole (e.g. age, height, class, etc.), establishing a baseline of attribute information. Additionally, the linemen provided an assessment of each pole's condition and subsequently made recommendations for pole replacements based on these attributes (mainly pole condition and age), as per annual inspection process.

Today, there are approximately 1,300 wood poles within HHI's distribution system. Approximately 50%of all wood poles are inspected on an annual basis, thereby completing inspection of all such poles within the distribution service area on a two year cycle.

Cables

HHI's closely monitors its cable failure rates and initiates cable replacement projects as part of its annual capital budgeting process.

HHI's annual inspections also identifies the following hazard

- Low conductor clearance
- Broken/frayed conductors or tie wires
- Insulation fraying on secondary especially open-wire

HHI'S capital projects undertaken in 2011 includes replacement of all 3/0 primary conductors to 336MCM

Hardware and Attachments

HHI conducts hardware and attachments inspections annually to determine when they need to be replaced. Replacements are undertaken for the following different reasons:

- Loose or missing hardware
- Insulators unattached from pins
- Conductor unattached from insulators
- Insulators flashed over or obviously contaminated
- Tie wires unraveled
- Ground wire broken or removed
- Ground wire guards removed or broken

Distribution Transformers

Inspection of overhead distribution transformers is an integral component of HHI's predictive maintenance practice. It identifies conventional deficiencies such as rusted or leaking transformers. Infra-reds testing are also performed regularly to identify overheating transformers.

Switches/Protective Devices

Inspection of overhead switches and other protective devices is an integral component of HHI's predictive maintenance practice. It identifies conventional deficiencies such as loose, flashed or old switches, each of which may deteriorate the condition of the asset, pose a risk to safety, or reduce reliability of the overhead distribution system.

HHI meets the switch inspection requirements under the Minimum Inspection Requirements of the Distribution System Code. Switches are devices that allow or disallow the conductivity of high voltage conductors. They are available in single phase solid or fused configurations and three phase applications involving load break and air break. Fused cut-outs accept different sizes of fuses, which are used for the protection of lines, equipment or transformers from main feeder amperages. Fused switches (cutouts) are inspected during yearly patrol process.

Switch Replacements are undertaken for the following reasons:

- Mechanical or electrical failure
- Vehicle accidents, lightning strikes
- New customer requirements
- Line rebuilds or circuit reconfigurations

Inspection of the Underground Distribution System

The OEB's Minimum Inspection Requirements, in addition to listing major overhead distribution system assets, also identifies those major assets specific to the underground distribution system; including and applicable to HHI's are: distribution transformers, switches and protective devices, cables, civil infrastructure and vegetation. As with its overhead system, HHI's inspection cycles of these assets is based, in part, on its geographical areas but also on the category of distribution asset.

Substation Inspection and Maintenance

Recent significant expenditure in substation replacement was undertaken by HHI's in order to ensure the continued reliability of service. HHI's replaced one of its failing transformers with a new 10MVA at the 44 KV sub-station. The new transformer provides the main supply and the existing 10 MVA transformers will be eventually refurbished to provide some level of redundancy.

HHI's distribution system includes 2 Stations. Power is delivered to these stations by Hydro One's 110KV from Hawthorne TS and 44K from Hydro One's Longueil TS.

HHI's performs an inspection and condition assessment of all its stations on an annual basis or as required. The inspection is performed by a qualified HHI's employees at the beginning of each month and in accordance with the inspection forms. The inspection incorporates an assessment of the following:

• Feeder Readings
o Amperage on each phase
o Voltage on each phase
o Counter Reading
• Substation Monthly Readings
o Total KWH
o Maximum KW
o Maximum KVA
• Transformers
o Temperature
o Oil Level
o Leaks
• Vegetation
• Electrical Panel
• Receptacles and Light Switches
• Indoor & Outdoor Lighting Fixtures
• Battery Chargers and Batteries

• RTUs
• Cooling Fans
• Station Lights
• Grounding

Transformer Oil Analysis

Oil analysis is performed at each of HHI''s sub-stations transformers and equipments. Completed by a qualified contractor, the scope of gas analysis and oil testing as outlined in the contract includes the following:

Oil Tests:		Dissolved Gas Analysis:		Moisture In Oil:
Acid		Hydrogen		Percentage Moisture by Dry Weight
Relative Density		Oxygen		Aging Factor
Dielectric Breakdown		Nitrogen		Percentage Moisture Saturation
Interfacial Tension		Methane		
Specific Gravity		Carbon Monoxide		
Visual Condition		Carbon Dioxide		
Colour		Ethane		
Water Content		Ethylene		
Power Factor		Acetyline		
Neutralization No.				

Oil samples obtained by the contractor are subsequently sent to a laboratory for testing; the results of individual transformer oil analysis are provided to HHI's. Also provided is an informal report of the results, highlighting any anomalies/concerns that may exist and corresponding recommendations for remediation.

Relay Testing

Testing of both electrical and mechanical relays is performed on a three year cyclical basis by a qualified contractor at each of the Stations. HHI's provides the relay settings to the contractor and relies on the contractor's expertise in performing the testing. Critical deficiencies are reported immediately and HHI's endeavors to remediate immediately. Non-critical deficiencies are subsequently remediated through condition-based maintenance.

As Identified During Inspections

Condition-based maintenance of Stations is performed during or following the monthly inspection and condition assessment or as identified within the predictive maintenance program.

Following Transformer Oil Analysis

Recommendations for remediating anomalies or concerns identified during transformer oil analysis as presented to HHI's may include no action/observing, re-testing or replacing, for example. HHI's generally follows the recommendations and implements those condition-based maintenance recommendations or capital expenditures and within the recommended timeline.

Following Relay Testing

During relay testing, critical deficiencies are reported immediately and HHI's endeavors to remediate at such time.

Fleet

The utility operates and maintains 2 utility vehicles. This expected life replacement approach is in keeping with industry practice and is important to assist HHI's ability to forecast vehicle spending, assist HHI's in achieving a lower risk of catastrophic vehicle failure and enhancing HHI's ability to negotiate long term procurement contracts with vendors and realize savings.

Meters

HHI's installed Smart Meters throughout its service territory between 2009 and 2011 when the Provincial Government mandated the replacement of the electromechanical billing meters with the new Smart Meter and Advanced Meter Infrastructure ("AMI") two-way communication system.

HHI's has used a Typical Useful Life (TUL) of fifteen (15) years for Smart Meters.

Line Clearing and 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. Where overhead hydro lines are in the proximity to trees, regular trimming is required to prevent vegetation form contacting energized lines and inflicting.

- 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

Tree contacts are a major cause of distribution system outages and momentary interruptions for HHI's customers. HHI's has a regular line clearing and tree trimming maintenance program. This program cycles through the service territory on a three year basis. In 2011 the program was changed to an area by area program. Currently the schedule is to complete each area at least once in a three year period subject to change based on conditions found.

6 Capital Planning

Managing Aging Infrastructure

Distribution systems are growing older. In many service areas, significant portions of the equipment and facilities in place date from the economic boom during the heady growth periods of the 1960s. Equipment that is 50+ years of continuous operation is still in service in many areas.

For almost all electrical equipment, as it stays in service and ages, its potential failure rate increases, slowly year by year, and eventually reach their respective service life limits and begin to fail. When this happened, service reliability plummet, replacement costs skyrocket, and the utility's business performance suffers.

HHI is of the opinion that although age is in many ways the best overall proxy one has for the long-term effects of condition and deterioration, condition is the real issue. Some units of equipment might deteriorate so that condition is poor after only 40 years. Another unit, aged 70 years, might be in that same condition. The utility should be equally concerned about each.

Even among the oldest equipment, a majority might still be in serviceable condition and can provide years of good service. The utility's best course is to do what it can to find the bad actors and the questionable equipment and replace only those pieces of the system, continuing into the future each year with a system that is old but in a managed condition.

Thus, some combination of on-going testing, tracking, mitigation of continued deterioration and the effects of failures, and pro-active replacement and refurbishment of deteriorated equipment, will be needed in the long run.

Such preventative actions will not make the problem go way, they will just control it to an "optimum" level, a stable, sustainable point at which equipment in service continues to age and the utility continues to test, maintain, and service replace equipment sparingly but in a targeted manner, with overall cost is kept at a minimum.

Project Identification

Capital projects are identified through HHI's intimate knowledge of the system gained by experience, through regular inspection of the system and subsequent data analyses, as noted above. Projects are identified for a ten-year period such that they may be prioritized to achieve asset management objectives.

Project Prioritization

Development of Annual Capital Budget

The budget development process plays an important role to HHI's as it puts capital (and operational) plans into a financial plan, outlining its goals and asset management objectives.

With respect to all distribution assets, the General Manager reviews the capital planning to identify distribution projects that have been previously prioritized and are scheduled to be completed in the upcoming budget year. These projects are reviewed to determine whether priorities have changed. A project may become lower priority due to newly proposed or non-discretionary projects. Alternatively, a project may become higher priority in light of new information.

Following the review, those distribution projects identified as high priority are estimated and proposed within the annual capital budget.

7 Capital Expenditure Plan

Overhead Distribution

This category includes the following OEB Uniform System of Accounts (“USoA”) codes:

- 1830 (Poles, Towers and Fixtures),
- 1835 (Overhead Conductors and Devices), and
- 1850 (Line Transformers)

Program: Replacement or Upgrade due to Age or Condition

Replacement of overhead assets in poor condition, as noted in pole-line inspection records, is the primary purpose of this program. This includes the replacement and upgrade of primary and secondary conductor, where applicable, and transformers, where applicable. The replacement of aged assets will improve reliability, an asset management objective, as noted above. In some cases conductors, such as 3/0 primary conductors, will be removed during construction and replace with 336 mcm, thus improving operational efficiencies and reduction of line losses.

Within this program, projects are developed for all overhead distribution jobs at locations where a multiple pole replacements are taking place. The Capital Budget also allows for small unplanned/unexpected jobs, such as single pole or single transformer replacements.

Underground Distribution

Switching apparatus

Every 3 years, switching cubicles are visually inspected in accordance with the Minimum Inspection Requirements in the Distribution System Code.

Primary Cables

Underground primary cable inspection is conducted annually by visually examining the riser poles with respect to cable, cable guards, terminators and arrestors.

Secondary Services

Similarly, with respect to underground secondary services, riser poles are examined yearly with a visual check of cable, cable guards and connections

Transformers

Transformer inspection is performed as required under the Minimum Inspection Requirements of the Distribution System Code with visual inspections being conducted on an annual cycle basis to check for general appearance, loose wires, birds or animal nests.

Substation

Reclosures

As required under the Minimum Inspection Requirements of the Distribution System Code. HHI inspects and tests reclosure regularly and oil samples are taken on a yearly basis.

Transformers

Substation testing through oil samples is done annually.

8 Documentation & Data Analyses

Guidelines for Inspection and Maintenance Programs

There are several inspection and maintenance programs for which HHI's has developed documented guidelines; for example, vegetation management and padmount transformer inspection. Alternatively, HHI's relies on the expertise of the contractor implementing the program and therefore documented guidelines may not be required. For all other inspection and maintenance programs HHI's is currently developing or has plans to develop documented guidelines to provide direction and ensure consistency in executing the program and allowing for more consistent data reporting, analysis and prioritization of expenditures.

Information and Document Management

Inspection Records

Inspection results are clear and well-documented, allowing for reliable information to be obtained on the condition of assets inspected.

An annual summary report of Inspections is used to schedule and track the Inspection Process of the Distribution System Assets.

Maintenance Records

Maintenance is largely driven by work orders, developed in HHI's work order system.

Reporting

Currently, data from the individual reports prepared by HHI's and its contractors are reviewed to facilitate data analyses of the status, condition and operation of the distribution system and its assets. These reports include, but are not limited to, pole replacement report, transformer oil analysis report, PCB contaminated transformer replacement report, transformer/pad-mounted switchgear painting report and thermography reports.

A power interruption report is also prepared with each service outage. The report identifies the feeder, weather conditions, fault type, cause, effected components and details of the outage such as location, number of customers and duration.

E2.T2.S9 GREEN ENERGY ACT PLAN CAPITAL EXPENDITURES

HHI has filed a Basic Green Energy Plan in order to comply with the filing requirements however, it is important to mention that there is little interest in Green Energy project in HHI' service area. The utility currently has very little Microfit connections (4) and anticipates little change in the future.

Once a thriving mill town, Hawkesbury is still recovering from losing the thousand good-paying jobs the paper mill provided when it closed down in the early-80′s. The town has also seen the loss of hundreds of manufacturing jobs over the past decade, taking millions of dollars more out of the small city's already devastated economy. Hawkesbury currently sits in the middle of the most economically depressed region in Canada and as such, the town's primary focus at this time is on mending its injured economy as opposed to investing in Green Energy.

Green Energy Plan
2013

Table of Contents

1 Introduction

The *Green Energy and Green Economy Act, 2009* ("the Act" or "GEA") was introduced in the Ontario legislature on February 23, 2009. Its intent was to expand renewable energy production and encourage energy conservation. Under the GEA, a number of feed-in tariff rates for different types of energy sources were created. Most notably, the microFIT program for small non-commercial systems under 10 kilowatts, and FIT, the larger commercial version which covers a number of project types with sizes into the megawatts. The objectives of the Act include the following;

- To stimulate energy conservation, through the establishment of programs and policies within the Ministry or such agencies as may be prescribed, load management and the use of renewable energy sources throughout Ontario;
- To encourage prudence in the use of energy in Ontario;
- To stimulate the planning and increase the development of infrastructure in Ontario, and
- To support planning and growth and building strong communities in Ontario.

Two other key elements of the Act include:

- To facilitate the implementation of a smart grid in Ontario; and
- To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

GEA Plan Guiding Principle

The Act requires that each LDC file a Green Energy Act Plan ("GEA Plan") with the Ontario Energy Board ("the OEB" or "the Board"), in a manner consistent with the requirements in the GEA. The plan filing will serve three main purposes:

1) To provide information to the Board and interested stakeholders regarding the readiness of a distributor's system to accommodate the connection of renewable generation, as well as the

expansion or reinforcement necessary to accommodate renewable generation, and the development and implementation of "smart grid";

2) To provide evidence in rate applications for capital budget approvals related to infrastructure investments for renewable generation and smart grid, and the recovery of the resulting costs from ratepayers; and

3) To provide a basis, through the approval of a GEA Plan, by which the costs of certain investments will be the responsibility of the distributor under the DSC, and therefore possibly recovered through the provincial cost recovery mechanism set out in section 79.1 of the OEB Act.

The OEB has identified two types of Plans; the Basic GEA Plan and the Detailed GEA Plan. As a minimum, a Basic GEA Plan is required of all LDCs. A Detailed GEA Plan is required only for those distributors where:

a. The total capital costs of all a distributor's planned projects related to the connection of renewable generation and/or the development of a smart grid in any one year:
    i. *Are more than $100,000 and exceed 3% of the distributor's distribution rate base; and*
    ii. *Exceed $5,000,000.*

b. The total capital costs of all a distributor's planned projects related to the connection of renewable generation and/or the development of a smart grid over five years:
    i. *Are more than $100,000 and exceed 6% of the distributor's distribution rate base; and*
    ii. *Exceed $10,000,000.*

Hydro Hawkesbury Inc. ("HHI") does not meet the threshold for filing a Detailed GEA Plan and, as such, has prepared this Basic GEA Plan. The Basic GEA Plan includes requirements for:

1. A current assessment of the LDC's distribution system;

2. A planned approach (if required) to upgrading the distribution system to accommodate renewable generation; and
3. Proposed initiatives to enable the development of a “smart grid”.

In accordance with the OEB’s filing requirements under the *Green Energy and Green Economy Act, 2009,* HHI has prepared this Basic Green Energy Plan (“GEA Plan”). The GEA Plan provides summary information about current demands from generation, a description of the current efforts to enable renewable generation and future plans to accommodate anticipated new connections.

Enabling Renewable Generation Connections - Overview

To ensure that renewable generation projects can be readily connected to the LDCs distribution system without undue delay is a major focus of the Act. To this end, LDCs are subject to the following requirements:

a. The licensee is required to provide, in accordance with such rules as may be prescribed by regulation and in the manner mandated by the market rules or by the Board, priority connection access to its transmission system or distribution system for renewable energy generation facilities that meet the requirements prescribed by regulation made under subsection 26 (1.1) of the Electricity Act, 1998.

b. The licensee is required to prepare plans, in the manner and at the times mandated by the Board or as prescribed by regulation and to file them with the Board for approval for;
   i. the expansion or reinforcement of the licensee’s transmission system or distribution system to accommodate the connection of renewable energy generation facilities, and
   ii. the development and implementation of the smart grid in relation to the licensee’s transmission system or distribution system.

c. The licensee is required, in accordance with a plan referred to in Paragraph 2, that has been approved by the Board or in such other manner and at such other times as mandated by the Board or prescribed by regulation;

i. to expand or reinforce its transmission system or distribution system to accommodate the connection of renewable energy generation facilities, and
ii. to make investments for the development and implementation of the smart grid in relation to the licensee's transmission system or distribution system.

2 Current Assessment – HHI Distribution System

HHI relies on approximately 67.45 km of circuits deliver approximately 148,212,312 kWh of energy and 10,000 kW of power to approximately 5,500 customers. The circuits can be broken down into roughly 56.65 km of overhead lines and 10.8 km of underground conductor. The distribution system is comprised of 42.85 km of 3-phases circuits and 24.6 km of single phase circuits..

HHI's service territory is surrounded by Hydro One Networks Inc. HHI is directly connected to Hydro One's transmission system at 115 KV and 44KV and is not an embedded LDC that takes delivery of electricity from another LDC.

HHI distributes power to its customers through its municipal distribution substations which is comprised of primarily urban customers. HHI owns its municipal substations within its service territory.

HHI has completed the installation of approximately 4803 smart meters for residential and 578 smart meters for small commercial (GS<50kW) customers. HHI intends to explore the potential use of the communication capability of the Smart Meter system to further improve customer service through more advanced outage detection and outage response.

Since the introduction of the Feed-in-Tariff (FIT) program, HHI has connected a total of:

- 4 MicroFIT contracts issued

The distribution system has been unaffected by the projects connected thus far. The number of connections has continued on a slow pace and it is likely that the rate of connections will decrease slightly due to the decrease in the contract pricing offered by the Ontario Power Authority and the overall lack of interest in the service territory.

Overall, HHI's distribution system has been determined to be adequate to accept the renewable generation that is anticipated. There are no known barriers within HHI's distribution system for projects that are serviced by its own municipal substations.

Based on the fact that there are no known barriers to renewable generation related to matters under the control of HHI, the utility does not propose any material investments in renewable infrastructure. The utility does expect modest growth in renewable generation and minor system expansions/upgrades to accommodate renewable generation but does not seek to fund those expansions through this GEA Plan.

System Limitations

The number of connections has not had any impact on the distribution system and therefore HHI sees no apparent system limitations at this time. HHI will continue to monitor feeder loading data to determine minimum feeder loads.

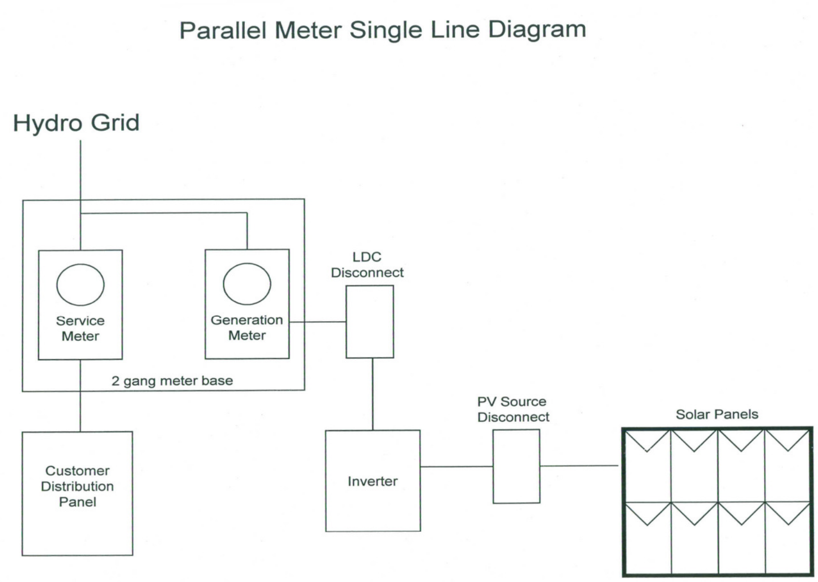
3 Anticipated Renewable Generation Connection Request

Given the level of interest expressed by HHI customers to-date, the forecasted the expected number of Micro-FIT applications is presented in Table 2 below. These numbers provided are speculative in nature, but they are based on experience dealing with customers over the past several years.

Table 2 – Forecast of connections

Application Type	2013	2014	2015	2016	2017
Forecast microFIT Connections	1-2	1-2	1-2	1-2	1-2

HHI expects these connections to be accommodated with standard metering and connection techniques. (example is provided in the schematic below)



With respect to large scale projects, HHI currently has 1 Fit connection. HHI does not anticipate significant uptake for large scale projects. In the event these projects do materialize, the utility generally has sufficient lead time to allow for an appropriate response by HHI and Hydro One.

In conclusion, based on the anticipated uptake of the program and an assessment of the systems capacities, HHI is forecasting sufficient capacity to accommodate the anticipated connections with the need to prioritize the projects.

Consultation with Affected Transmitter

Being an embedded utility, HHI must consult with Hydro One on each connection request. This gives Hydro One an opportunity to assess and address capacity issues within its service territory. HHI will continue to work co-operatively with Hydro One as new connections are added to the system.

Planned Development to accommodate Renewable Generation

As noted throughout this GEA Plan, HHI has not proposed any development or expansions of its distribution system in order to accommodate Renewable Generation.

Prioritization Method

Projects will be prioritized to align with the intent of the OPA FIT and microFIT programs. Prioritization of FIT projects is based on project application dates and the ongoing status of the new development. HHI intends to prioritize and expedite renewable generation projects that are ready to connect to the distribution system.

Direct Benefits for Customers

HHI is not proposing that any of its costs incurred to make eligible investments for the purpose of enabling the connection of renewable electricity generation be recovered from provincial ratepayers rather than solely from HHI's ratepayers. It is therefore not necessary to calculate the direct benefits accruing to HHI customers.

Proposed Budget

There is no proposed budget with respect to connection of renewable generation under the FIT program. HHI will undertake an annual review of the anticipated renewable generation connection project schedule as well as related costs.

4 Reporting

HHII will review this document on a regular basis and will publish updates to this document as needed or required by the OEB. Once the OEB provides further direction as to the time and manner of GEA Plan reporting, indicated as pending in EB-2009-0397 (page 25), HHI will comply with the OEB directives.

E2.T2.S10 HST

As a result of the implementation of HST in the province of Ontario on July 1, 2010, HHI 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 2013 Bridge Year forecast nor the 2014 Test Year budget for capital expenditures includes tax on purchases of products or services made after July 1, 2010.

Tab 3 – Service Quality and Reliability Performance

E2.T3.S1 ESQR's

HHI reports its service quality indicators ("SQIs") annually to the Ontario Energy Board. The SQIs are defined in Chapter 7 of the Distribution System Code. HHI has not only met but exceeded the minimum standards for all SQIs each year, as indicated in the following table:

Table 12 – 3 Year Historical SQI's

Unitized Statistics and Service Quality Requirements	2010	2011	2012
Service Quality Requirements			
Low Voltage Connections (OEB Min. Standard: 90%)	97.20	100.00	100.00
High Voltage Connections (OEB Min. Standard: 90%)	100.00	100.00	100.00
Telephone Accessibility (OEB Min. Standard: 65%)	99.90	99.80	99.90
Appointments Met (OEB Min. Standard: 90%)	94.10	100.00	97.80
Written Response to Enquiries (OEB Min. Standard: 80%)	99.70	100.00	100.00
Emergency Urban Response (OEB Min. Standard: 80%)	100.00	100.00	100.00
Emergency Rural Response (OEB Min. Standard: 80%)	N/A	N/A	N/A
Telephone Call Abandon Rate (OEB Standard: not exceed 10%)	0.00	0.00	0.10
Appointments Scheduling (OEB Min. Standard: 90%)	100.00	100.00	100.00
Rescheduling a Missed Appointment: (OEB Standard: 100%)	N/A	N/A	N/A
Reconnection Performance Standard (OEB Min. Standard: 85%)	100.00	100.00	100.00
Service Reliability Indices			
SAIDI-Annual	1.17	1.07	0.78
SAIFI-Annual	1.04	1.46	0.89
CAIDI-Annual	1.12	0.73	0.87
Loss of Supply Adjusted Service Reliability Indices			
SAIDI-Annual	1.17	0.19	0.76
SAIFI-Annual	0.90	0.19	0.69
CAIDI-Annual	1.30	0.98	1.09

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2012-0134

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an application by Hydro Hawkesbury Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2013.

BEFORE: Marika Hare
Presiding Member

DECISION AND ORDER
April 4, 2013

Introduction

Hydro Hawkesbury Inc. ("Hydro Hawkesbury"), a licensed distributor of electricity, filed an application with the Ontario Energy Board (the "Board") on October 5, 2012 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that Hydro Hawkesbury charges for electricity distribution, to be effective May 1, 2013.

Hydro Hawkesbury is one of 77 electricity distributors in Ontario regulated by the Board. The *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "IR Report"), issued on July 14, 2008, established a three year plan for 3rd generation incentive regulation mechanism ("IRM") (i.e., rebasing plus three years). In its October 27, 2010 letter regarding the development of a Renewed Regulatory Framework for Electricity ("RRFE"), the Board announced that it was extending the IRM plan until such time as the RRFE policy initiatives have been substantially completed. In a letter dated October 18, 2012, the Board stated its expectation that the three rate setting methods set out in the *Report of the Board – Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* would be available for the 2014 rate year.

As part of the plan, Hydro Hawkesbury is one of the electricity distributors that will have its rates adjusted for 2013 on the basis of the IRM process, which provides for a mechanistic and formulaic adjustment to distribution rates and charges between cost of service applications.

To streamline the process for the approval of distribution rates and charges for distributors, the Board issued its IR Report, *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on September 17, 2008 (the "Supplemental Report"), and *Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on January 28, 2009 (collectively the "Reports"). Among other things, the Reports provide the relevant guidelines for 2013 rate adjustments for distributors applying for distribution rate adjustments pursuant to the IRM process. On June 28, 2012, the Board issued an update to Chapter 3 of the Board's *Filing Requirements for Transmission and Distribution Applications* (the "Filing Requirements"), which outlines the application filing requirements for IRM applications based on the policies in the Reports.

Notice of Hydro Hawkesbury's rate application was given through newspaper publication in Hydro Hawkesbury's service area advising interested parties where the rate application could be viewed and advising how they could intervene in the proceeding or comment on the application. The Notice of Application indicated that the Board did not intend to award costs in this proceeding as the applicant has only made proposals of a mechanistic nature within the Board's guidelines. No parties requested intervenor status in this proceeding. No letters of comment were received. Board staff participated in the proceeding. The Board proceeded by way of a written hearing.

While the Board has considered the entire record in this proceeding, it has made reference only to such evidence as is necessary to provide context to its findings. The following issues are addressed in this Decision and Order:

- Price Cap Index Adjustment;
- Rural or Remote Electricity Rate Protection Charge;
- Wholesale Market Service Rate;

- Smart Metering Entity Charge;
- MicroFIT Service Charge;
- Shared Tax Savings Adjustments;
- Retail Transmission Service Rates; and
- Review and Disposition of Group 1 Deferral and Variance Account Balances.

Price Cap Index Adjustment

As outlined in the Reports, distribution rates under the IRM are to be adjusted by a price escalator, less a productivity factor of 0.72% and a stretch factor.

On March 21, 2013, the Board announced a price escalator of 1.6% for those distributors under IRM that have a rate year commencing May 1, 2013.

The stretch factors are assigned to distributors based on the results of two benchmarking evaluations to divide the Ontario industry into three efficiency cohorts. In its letter to Licensed Electricity Distributors dated November 28, 2012 the Board assigned Hydro Hawkesbury to efficiency cohort 1, being the most efficient group, and a resulting cohort specific stretch factor of 0.2%.

The Board therefore has determined, on that basis, that the resulting price cap index adjustment is 0.68% (i.e. 1.60% - (0.72% + 0.20%)). The price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across customer classes.

The price cap index adjustment does not apply to the following components of delivery rates:

- Rate Riders;
- Rate Adders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural or Remote Rate Protection Charge;
- Standard Supply Service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Loss Factors;

- Specific Service Charges;
- MicroFIT Service Charge; and
- Retail Service Charges.

Rural or Remote Electricity Rate Protection Charge

On March 21, 2013, the Board issued a Decision with Reasons and Rate Order (EB-2013-0067) establishing that the Rural or Remote Electricity Rate Protection ("RRRP") used by rate regulated distributors to bill their customers shall be $0.0012 per kilowatt hour effective May 1, 2013. The draft Tariff of Rates and Charges flowing from this Decision and Order reflects this RRRP charge.

Wholesale Market Service Rate

On March 21, 2013, the Board issued a Decision with Reasons and Rate Order (EB-2013-0067) establishing that the Wholesale Market Service rate ("WMS rate") used by rate regulated distributors to bill their customers shall be $0.0044 per kilowatt hour effective May 1, 2013. The draft Tariff of Rates and Charges flowing from this Decision and Order reflects this WMS rate.

Smart Metering Entity Charge

On March 28, 2013, the Board issued a Decision and Order (EB-2012-0100/EB-2012-0211) establishing a Smart Metering Entity charge of $0.79 per month for Residential and General Service Less Than 50 kW customers for those distributors identified in the Board's annual *Yearbook of Electricity Distributors*. This charge will be in effect from May 1, 2013 to October 31, 2018. The draft Tariff of Rates and Charges flowing from this Decision and Order reflects this Smart Metering Entity charge.

MicroFIT Service Charge

On September 20, 2012, the Board issued a letter advising that the default province-wide fixed monthly charge for all electricity distributors related to the microFIT Generator Service Classification was to be updated to $5.40 per month effective with the implementation of electricity distributors' 2013 rates applications. The draft Tariff of Rates and Charges flowing from this Decision and Order reflects the new default microFIT service charge.

Shared Tax Savings Adjustments

In its Supplemental Report, the Board determined that a 50/50 sharing of the impact of currently known legislated tax changes, as applied to the tax level reflected in the Board-approved base rates for a distributor, is appropriate.

The calculated annual tax reduction will be allocated to customer rate classes on the basis of the Board-approved base-year distribution revenue. These amounts will be refunded to customers over a 12-month period, through a volumetric rate rider using annualized consumption by customer class underlying the Board-approved base rates.

Hydro Hawkesbury's application originally included a tax sharing credit of $593. In response to Board staff interrogatory #2a, Hydro Hawkesbury corrected the regulatory taxable income used to calculate the savings, and updated this amount to a credit of $687.

Hydro Hawkesbury requested that the Board authorize that this amount be recorded in Account 1595 for disposition in a future application given that the associated rate riders are negligible. The Board agrees with Hydro Hawkesbury's request and directs Hydro Hawkesbury to record the tax sharing refund of $687 in variance Account 1595 by June 30, 2013 for disposition at a future date.

Retail Transmission Service Rates ("RTSRs")

Electricity distributors are charged for transmission costs at the wholesale level and subsequently pass these charges on to their distribution customers through the RTSRs. Variance accounts are used to capture timing differences and differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers (i.e. variance Accounts 1584 and 1586).

On June 22, 2012 the Board issued revision 3.0 of the *Guideline G-2008-0001 - Electricity Distribution Retail Transmission Service Rates* (the "RTSR Guideline"). The RTSR Guideline outlines the information that the Board requires electricity distributors to file to adjust their RTSRs for 2013. The RTSR Guideline requires electricity distributors to adjust their RTSRs based on a comparison of historical transmission costs adjusted for the new Ontario Uniform Transmission Rates ("UTRs") levels and the revenues generated under existing RTSRs. Similarly, embedded distributors whose host is Hydro One Networks Inc. ("Hydro One") should adjust their RTSRs to reflect any changes in Hydro One's Sub-Transmission class RTSRs. The objective of resetting the rates is to minimize the prospective balances in Accounts 1584 and 1586. In order to assist electricity distributors in the calculation of the distributors' specific RTSRs, Board staff provided a filing module.

Hydro Hawkesbury is a partially embedded distributor whose host is Hydro One.

On December 20, 2012 the Board issued its Rate Order for Hydro One Transmission (EB-2012-0031) which adjusted the UTRs effective January 1, 2013, as shown in the following table:

Table 1: 2013 Uniform Transmission Rates

Network Service Rate	$3.63 per kW
Connection Service Rates Line Connection Service Rate Transformation Connection Service Rate	 $0.75 per kW $1.85 per kW

The Board also approved new rates for Hydro One Sub-Transmission class RTSRs effective January 1, 2013 (EB-2012-0136), as shown in the following table.

Table 2: 2013 Sub-Transmission RTSRs

Network Service Rate	$3.18 per kW
Connection Service Rates Line Connection Service Rate Transformation Connection Service Rate	 $0.70 per kW $1.63 per kW

The Board finds that these 2013 UTRs and Sub-Transmission class RTSRs are to be incorporated into the filing module.

Review and Disposition of Group 1 Deferral and Variance Account Balances

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report Initiative* (the "EDDVAR Report") provides that, during the IRM plan term, the distributor's Group 1 account balances will be reviewed and disposed if the preset disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed.

Hydro Hawkesbury's 2011 actual year-end total balance for Group 1 Accounts including interest projected to April 30, 2013 is a debit of $704,040. This amount results in a total debit claim of $0.0046 per kWh, which exceeds the preset disposition threshold. Hydro Hawkesbury proposed to dispose of this debit amount over a one-year period.

In its submission, Board staff noted that the principal amounts to be disposed as of December 31, 2011 reconcile with the amounts reported as part of the *Reporting and Record-keeping Requirements* ("RRR"). Board staff submitted that the amounts should be disposed on a final basis. Board staff further submitted that Hydro Hawkesbury's proposal for a one-year disposition period is in accordance with the EDDVAR Report.

The Board approves, on a final basis, the disposition of a debit balance of $704,040 as of December 31, 2011, including interest as of April 30, 2013 for Group 1 accounts. These balances are to be disposed over a one year period from May 1, 2013 to April 30, 2014.

The table below identifies the principal and interest amounts approved for disposition for Group 1 Accounts.

Table 3: Group 1 Account Balances

Account Name	Account Number	Principal Balance A	Interest Balance B	Total Claim C = A + B
LV Variance Account	1550	$38,101	$1,090	$39,191
RSVA - Wholesale Market Service Charge	1580	-$171,833	-$5,771	-$177,604
RSVA - Retail Transmission Network Charge	1584	-$4,466	$42	-$4,424
RSVA - Retail Transmission Connection Charge	1586	-$33,890	-$1,251	-$35,141
RSVA - Power (excluding Global Adjustment)	1588	$334,728	$9,622	$344,350
RSVA - Power – Global Adjustment Sub-Account	1588	$520,284	$17,385	$537,669
Total Group 1 Excluding Global Adjustment Sub-Account				**$166,371**
Total Group 1				**$704,040**

For accounting and reporting purposes, the respective balance of each Group 1 account approved for disposition shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the *Accounting Procedures Handbook for Electricity Distributors*. The date of the journal entry to transfer the approved account balances to the sub-accounts of Account 1595 is the date on which disposition of the balances is effective in rates, which generally is the start of the rate year. This entry should be completed on a timely basis to ensure that these adjustments are included in the reporting period ending June 30, 2013 (Quarter 2).

Rate Model

With this Decision, the Board is providing Hydro Hawkesbury with a rate model (spreadsheet) and applicable supporting models and a draft Tariff of Rates and Charges (Appendix A) that reflects the elements of this Decision. The Board has reviewed the entries in the rate model to ensure that they are in accordance with the 2012 Board approved Tariff of Rates and Charges and the rate model was adjusted, where applicable, to correct any discrepancies.

THE BOARD ORDERS THAT:

1. Hydro Hawkesbury's new distribution rates shall be effective May 1, 2013.

2. Hydro Hawkesbury shall review the draft Tariff of Rates and Charges set out in Appendix A. Hydro Hawkesbury shall file with the Board a written confirmation assessing the completeness and accuracy of the draft Tariff of Rates and Charges, or provide a detailed explanation of any inaccuracies or missing information within **7 days** of the date of issuance of this Decision and Order.

3. If the Board does not receive a submission from Hydro Hawkesbury to the effect that inaccuracies were found or information was missing pursuant to item 2 of this Decision and Order, the draft Tariff of Rates and Charges set out in Appendix A of this Decision and Order will become final and effective May 1, 2013, and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2013. Hydro Hawkesbury shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

4. If the Board receives a submission from Hydro Hawkesbury to the effect that inaccuracies were found or information was missing pursuant to item 2 of this Decision and Order, the Board will consider the submission of Hydro Hawkesbury and will issue a final Tariff of Rates and Charges.

5. Hydro Hawkesbury shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote file number **EB-2012-0134,** be made through the Board's web portal at, https://www.pes.ontarioenergyboard.ca/eservice// and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available parties may email their document to BoardSec@ontarioenergyboard.ca. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 2 paper copies.

DATED at Toronto, April 4, 2013
ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

Appendix A
2013 IRM Decision

Appendix B

Decision and Order fixing just and reasonable distribution rates related to Smart Meter deployment, to be effective November 1, 2012

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2012-0198

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an application by Hydro Hawkesbury Inc. for an order or orders approving or fixing just and reasonable distribution rates related to Smart Meter deployment, to be effective November 1, 2012.

BEFORE: Ken Quesnelle
Presiding Member

Marika Hare
Member

DECISION AND ORDER
November 1, 2012

Introduction

Hydro Hawkesbury Inc. ("HHI"), a licensed distributor of electricity, filed an application (the "Application") with the Ontario Energy Board (the "Board") on July 16, 2012 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that HHI charges for electricity distribution, to be effective September 1, 2012.

HHI is seeking Board approval for the disposition and recovery of costs related to smart meter deployment, offset by Smart Meter Funding Adder ("SMFA") revenues collected from May 1, 2006 to April 30, 2012. HHI requested approval of proposed Smart Meter Disposition Riders ("SMDRs") and Smart Meter Incremental Revenue Requirement Rate Riders ("SMIRRs") effective September 1, 2012. The Application is based on the

Board's policy and practice with respect to recovery of smart meter costs.[1]

The Board issued its Letter of Direction and Notice of Application and Hearing (the "Notice") on August 2, 2012. The Vulnerable Energy Consumers' Coalition ("VECC") was granted intervenor status and cost award eligibility. No letters of comment were received. The Notice of Application and Hearing established that the Board would consider the Application by way of a written hearing and established timelines for discovery and submissions.

On August 23, 2012 the Board issued an Interim Rate Order making the current approved Tariff of Rates and Charges interim since HHI had proposed an effective date of September 1, 2012 in their Application.

While the Board has considered the entire record in this proceeding, it has made reference only to such evidence as is necessary to provide context to its findings. The following issues are addressed in this Decision and Order:

- Costs incurred with respect to Smart Meter Deployment and Operation;
- Cost Allocation;
- Stranded Meter Costs; and
- Implementation.

Costs Incurred with Respect to Smart Meter Deployment and Operation

In the Application, HHI sought the following approvals:

- Smart Meter Disposition Rider – An actual cost recovery credit rate of \$1.28 per Residential customer per month and a credit of \$1.25 per General Service less than 50kW customer per month. HHI proposed that these rate riders be effective for two years from September 1, 2012 to August 31, 2014. These rate riders will collect the difference between the deferred 2006 to December 31, 2011 and forecasted 2012 revenue requirement related to smart meters deployed as of December 31, 2011, plus interest on operations, maintenance and administration ("OM&A") and depreciation expenses, and the SMFA revenues collected from 2006 to

[1] On December 15, 2011, the Board issued *Guideline G -2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition* ("Guideline G-2011-0001").

April 30, 2012 and corresponding interest on the principal balance of SMFA revenues; and

- Smart Meter Incremental Revenue Requirement Rate Rider – A forecasted cost recovery rate rider of $1.38 per Residential customer per month and $2.56 per General Service less than 50kW customer per month until its next cost of service rate application, scheduled for 2014 rates. This rate rider will recover the 2013 incremental revenue requirement related to smart meter costs to be incurred from January 1, 2013 to December 31, 2013, for installed smart meters.

Prudence of Incurred Costs

HHI's costs in aggregate and on a per meter basis are summarized in the following table:

	2006	2007	2008	2009	2010	2011	2012	Total
Capital	$ -	$ -	$ -	$ 181,952	$ 307,843	$ 155,743	$ -	$ 645,539
OM&A	$ -	$ -	$ -	$ -	$ 5,243	$ 3,700	$ 5,958	$ 14,900
Number of Smart Meters	-	-	-	1,489	3,485	407	-	5,381

	Total	Average per Meter
Total (capex+opex)	$ 660,439	$ 122.74
Capex Only	$ 645,539	$ 119.97

Both Board staff and VECC noted that HHI's costs per meter are within the ranges observed for other utilities in the combined proceeding related to smart meters conducted by the Board in 2007 (EB-2007-0063). HHI's costs are also below the sector average total cost of $207.37 reported in the Board's *Sector Smart Meter Audit Review Report*, dated March 31, 2010 and the average total cost of $226.92 reported by distributors in the Monitoring Report of Smart Meter Investment as at September 30, 2010.

HHI did not include OM&A costs for 2012 in its Application. In response to Board staff interrogatories, HHI noted that its understanding was that starting May 1, 2012 all OM&A costs would be considered normal ongoing expenses. Board staff submitted that the SMIRR may be understated depending on what costs were included in HHI's 2010 revenue requirement and will not be recovered until HHI next rebases its rates through a cost of service application. HHI submitted that it is of the opinion that the difference in costs not recovered between May 1, 2012 and December 31, 2012 with persistence in

2013 and beyond is not material. VECC took no issue with HHI's treatment of OM&A costs.

The Board notes that authorization to procure and deploy smart meters has been done in accordance with Government regulations, including successful participation in the London Hydro RFP process, overseen by the Fairness Commissioner, to select (a) vendor(s) for the procurement and/or installation of smart meters and related systems. There is thus a significant degree of cost control discipline that distributors, including HHI, are subject to in smart meter procurement and deployment.

The Board finds that HHI's documented costs, as revised in response to interrogatories and in HHI's reply submission, related to smart meter procurement, installation and operation, and including costs related to TOU rate implementation, are reasonable. As such, the Board approves the recovery of the costs applied for related to smart meter deployment and operation as of December 31, 2011, and the ongoing recovery of capital-related and operating expenses for 2012 and going forward until HHI's next cost of service application.

Costs Beyond Minimum Functionality

HHI included capital costs of $6,043 in its Application, which are costs beyond minimum functionality. Board staff noted that HHI has included capital costs for deployment of smart meters to customers other than residential or GS < 50 kW customers in section 1.6.2 of the smart meter model. Board staff requested that HHI explain the capital expenditures documented under 1.6.2. Board staff submitted that the Board consider the option of disallowing the $6,043 documented under 1.6.2, in the absence of supporting material and because these costs are not for smart meter deployment to Residential and GS < 50 kW customers, and therefore should not be borne by them under the principle of cost causality.

In response to Board staff's submission HHI submitted that these costs were related to miscellaneous capital costs for the deployment of smart meters to Residential and GS < 50 kW customers only. HHI confirmed that it has not included any claims for costs related to its GS > 50 kW customers in its Application. HHI submitted that these costs were miscellaneous implementation costs including staff training etc. incurred that HHI has determined to be capital in nature.

The Board accepts HHI's explanation and approves the recovery of these costs as included in the Application.

Level of Unaudited Costs

HHI stated that as of April 2012 deployment of smart meters is complete. Board staff noted that HHI's Application complies with Guideline G-2011-0001 with regard to the expectation that at least 90% of the smart meter costs be audited. VECC submitted that HHI's percentage of audited costs conforms to the Board's Guidelines.

The Board accepts HHI's 2011 audited costs and approves the smart meter costs documented in the Application for recovery.

Cost Allocation

In its Application, HHI has only shown the SMFA revenues for the Residential and GS < 50 kW customer classes, using a direct allocation to determine SMFA revenues per class. The methodology accepted by the Board in PowerStream's smart meter application EB-2011-128, and in Guelph Hydro's 2012 cost of service application EB-2011-0123 and in subsequent smart meter applications also entails allocating SMFA revenues and interest collected from other metered customer classes (e.g. GS > 50 kW) equally to metered customer classes receiving smart meters. In this case, it would entail a 50:50 allocation to the Residential and GS < 50 kW classes for the purposes of determining the SMFA revenue offsets for class-specific SMDRs.

In Board staff interrogatory #8, Board staff provided HHI a cost allocation methodology based on Guelph Hydro's approach in its 2012 Cost of Service (EB-2011-0123) using the following approach:

- OM&A expenses allocated on the basis of the number of meters installed for each class;
- The return on capital and amortization allocated on the basis of the capital costs of the meters installed for each class;
- PILs allocated based on the revenue requirement before PILs derived for each class; and
- SMFA revenues and interest on the principal first calculated directly for the Residential and GS < 50 kW classes, with then the residual SMFA revenues and

interest collected from other metered customer classes (i.e., GS 50-4999 kW and Large Use) allocated 50:50 to the Residential and GS < 50 kW classes. This approach has been used and approved in some recent cost of service applications, including that for Guelph Hydro's 2012 rates application [EB-2011-0123].

In response to Board staff interrogatory # 8, HHI proposed the class-specific SMDRs and SMIRRs mirroring the Guelph Hydro spreadsheet from Guelph Hydro's 2012 cost of service rates application [EB-2011-0123] as provided by Board staff. Board staff submitted that the class-specific SMDRs and SMIRRs as provided in response to Board staff interrogatories have been calculated appropriately through class-specific models.

VECC did not agree with this approach and submitted that HHI did not provide a clear response to VECC Interrogatory # 5 a, b and c which had sought class-specific riders based on full cost causality and separate smart meter revenue requirement models for each customer class to recalculate the rate riders using the class specific revenue requirements.

VECC summarized that the total average installed smart meter costs as provided by HHI in response to VECC interrogatory #2 b is as follows:

Customer Class	Average Capital Cost Per Meter
Residential	$99.30
GS<50 kW	$180.09

Source: VECC Submission dated September 6, 2012, page 3

VECC submitted that, given the average installed meter cost for a GS < 50 kW customer is almost 2 times the average installed meter cost for a residential customer, VECC submits the better way to avoid undue cross subsidy is to calculate class-specific rate riders based on VECC's proposed cost allocation methodology of separate models to reflect the full costs for each customer class.

In its reply submission, HHI did not provide the information requested by VECC and noted that the methodology used in response to Board staff has been accepted by the Board previously as being reasonable for the purpose of cost allocation. HHI further noted that, it believes the data to complete smart meter recovery by rate class in the manner which VECC proposes in its submission would not be materially dissimilar to the proposed results obtained with the models already submitted.

In the past the Board has noted that the principle of cost causality would support class-specific cost recovery, as there would be differing costs in different customer classes, due in large part to the costs of the meters themselves, and to the extent that accurate data was available from the utility's records. To this end, the Board's Guideline[2] indicates that a utility is expected to address the allocation of costs in its application seeking the disposition of smart meter costs recorded in accounts 1555 and 1556. In recent decisions, the Board has reviewed and approved an evolution of approaches for calculating class-specific rate riders.[3]

The Board considers the cost causality approach of class-specific models proposed by VECC to be more exacting and principled, and will accept it where the utility has calculated it and is reasonably confident with the underlying data at the customer class level. However, HHI has stated that it believes that class-specific models would not result in materially different rate riders. The Board considers HHI's explanation reasonable.

As such, the Board approves HHI's methodology and the resulting class-specific SMDRs and SMIRRs as calculated in response to Board staff interrogatory # 8 to recover the historical and prospective revenue requirement on the approved smart meter costs.

Stranded Meter Costs

In its Application, HHI proposed not to dispose of stranded meters by way of stranded meter rate riders at this time, but to deal with disposition in its next cost of service application, scheduled for 2014 rates. In its Application, HHI stated that it has an estimated net book value of stranded conventional meters, including net salvage revenues, of $54,357 as of December 31, 2013.

Board staff submitted that HHI's proposal is also compliant with Guideline G-2011-0001. The Board agrees and on that basis approves HHI's proposal.

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[2] See footnote 1.
[3] The Board's decisions with respect to PowerStream Ltd.'s 2010 and 2011 smart meter applications (respectively, EB-2010-0209 and EB-2011-0128) confirmed approaches for allocating costs and calculating class-specific rate riders for recovery of smart meter costs. The approach approved in Decision EB-2011-0128, or an analogous or improved approach is expected where data of adequate quality at a class level is available.

Implementation

HHI requested an effective date of September 1, 2012 for its new rates. Given the filing date and the time required to process an application of this nature, the Board has determined that an implementation date of November 1, 2012 is appropriate. In developing its draft Rate Order, HHI is directed to establish the SMDRs based on an 18-month recovery period to April 30, 2014 and to accommodate within the SMDR the applicable revenue requirement amount related to the period from May 1, 2012 to October 31, 2012.

The SMIRRs shall be effective and implemented on November 1, 2012. The Board notes that these riders are based on an annual revenue requirement and will be in effect until the effective date of HHI's next cost of service rate order. As HHI is scheduled to rebase its rates for 2014, the Board notes that the SMIRR may be in effect from November 1, 2012 until April 30, 2014.

The Board expects HHI to file detailed supporting material, including all relevant calculations showing the impact of this Decision and Order on HHI's class specific smart meter revenue requirements and the determination of the updated SMDRs and SMIRRs.

Accounting Matters

In granting its approval for the historically incurred costs and the costs projected for 2012, the Board considers HHI to have completed its smart meter deployment. Going forward, no capital and operating costs for new smart meters and the operations of smart meters shall be tracked in Accounts 1555 and 1556. Instead, costs shall be recorded in regular capital and operating expense accounts (e.g. Account 1860 for meter capital costs) as is the case with other regular distribution assets and costs.

HHI is authorized to continue to use the established sub-account Stranded Meter Costs of Account 1555 to record and track remaining costs of the stranded conventional meters replaced by smart meters. The balance of this sub-account should be brought forward for disposition in HHI's next cost of service application.

THE BOARD ORDERS THAT:

1. Hydro Hawkesbury Inc. shall file with the Board, and shall also forward to the Vulnerable Energy Consumers Coalition, a draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision and Order, within **7 days** of the date of this Decision and Order. The draft Rate Order shall also include customer rate impacts and detailed supporting information showing the calculation of the final rates.

2. The Vulnerable Energy Consumers Coalition and Board staff shall file any comments on the draft Rate Order with the Board and forward to Hydro Hawkesbury Inc. within **7 days** of the date of filing of the draft Rate Order.

3. Hydro Hawkesbury Inc. shall file with the Board and forward to the Vulnerable Energy Consumers Coalition responses to any comments on its draft Rate Order within **7 days** of the date of receipt of the submission.

Cost Awards

The Board will issue a separate decision on cost awards once the following steps are completed:

4. The Vulnerable Energy Consumers Coalition shall submit its cost claims no later than **7 days** from the date of issuance of the final Rate Order.

5. Hydro Hawkesbury Inc. shall file with the Board and forward to the Vulnerable Energy Consumers Coalition any objections to the claimed costs within **14 days** from the date of issuance of the final Rate Order.

6. The Vulnerable Energy Consumers Coalition shall file with the Board and forward to Hydro Hawkesbury Inc. any responses to any objections for cost claims within **21 days** from the date of issuance of the final Rate Order.

7. Hydro Hawkesbury Inc. shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote file number **EB-2012-0198,** be made through the

Board's web portal at, www.pes.ontarioenergyboard.ca/eservice/ and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available parties may email their document to BoardSec@ontarioenergyboard.ca. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 2 paper copies.

DATED at Toronto, November 1, 2012

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix C

Decision and Order (EB-2011-0173) regarding application for incremental capital funding.

EB-2011-0173

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an application by Hydro Hawkesbury Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2012.

BEFORE: Karen Taylor
Presiding Member

Paula Conboy
Member

DECISION AND ORDER

Introduction

Hydro Hawkesbury Inc. ("HHI"), a licensed distributor of electricity, filed an application with the Ontario Energy Board (the "Board") on November 15, 2011 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that HHI charges for electricity distribution, to be effective May 1, 2012.

HHI is one of 77 electricity distributors in Ontario regulated by the Board. The *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "IR Report"), issued on July 14, 2008, establishes a three year plan term for 3rd generation incentive regulation mechanism ("IRM") (i.e., rebasing plus three years). In its October 27, 2010 letter regarding the development of a Renewed Regulatory Framework for Electricity ("RRFE"), the Board announced that it was extending the IRM plan until such time as the RRFE policy initiatives have been substantially completed. As part of the plan, HHI is one of the electricity distributors that will have its rates adjusted for 2012 on the basis of the IRM process, which provides for a mechanistic and formulaic adjustment to distribution rates and charges between cost of service applications.

To streamline the process for the approval of distribution rates and charges for distributors, the Board issued its IR Report, its *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on September 17, 2008 (the "Supplemental Report"), and its *Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on January 28, 2009 (collectively the "Reports"). Among other things, the Reports contain the relevant guidelines for 2012 rate adjustments for distributors applying for distribution rate adjustments pursuant to the IRM process. On June 22, 2011, the Board issued an update to Chapter 3 of the Board's *Filing Requirements for Transmission and Distribution Applications* (the "Filing Requirements"), which outlines the application filing requirements for IRM applications based on the policies in the Reports.

Notice of HHI's rate application was given through newspaper publication in HHI's service area advising interested parties where the rate application could be viewed and advising how they could intervene in the proceeding or comment on the application. No letters of comment were received. The Notice of Application indicated that intervenors would be eligible for cost awards with respect to HHI's proposal for the lost revenue adjustment mechanism ("LRAM") and recovery of the costs of replacing two transformer stations. The Vulnerable Energy Consumers Coalition ("VECC") and School Energy Coalition ("SEC") applied and were granted intervenor status in this proceeding. The Board granted VECC and SEC eligibility for cost awards in regards to HHI's request for LRAM recovery and recovery of the costs of replacing two transformer stations. Board staff also participated in the proceeding. The Board proceeded by way of a written hearing.

While the Board has considered the entire record in this proceeding, it has made reference only to such evidence as is necessary to provide context to its findings. The following issues are addressed in this Decision and Order:

- Price Cap Index Adjustment;
- Rural or Remote Electricity Rate Protection Charge;

- Use of Actual versus Forecasted Load Data
- Shared Tax Savings Adjustments;
- Retail Transmission Service Rates;
- Review and Disposition of Group 1 Deferral and Variance Account Balances;
- Review and Disposition of Account 1521: Special Purpose Charge;
- Review and Disposition of Lost Revenue Adjustment Mechanism;
- Review and Disposition of Account 1562: Deferred Payments In Lieu of Taxes; and
- Incremental Capital Module ("ICM").

Price Cap Index Adjustment

As outlined in the Reports, distribution rates under the 3rd Generation IRM are to be adjusted by a price escalator, less a productivity factor (X-factor) of 0.72% and a stretch factor.

On March 13, 2012, the Board announced a price escalator of 2.0% for those distributors under IRM that have a rate year commencing May 1, 2012.

The stretch factors are assigned to distributors based on the results of two benchmarking evaluations to divide the Ontario industry into three efficiency cohorts. In its letter to Licensed Electricity Distributors dated December 1, 2011 the Board assigned HHI to efficiency cohort 1 and a cohort specific stretch factor of 0.2%.

On that basis, the resulting price cap index adjustment is 1.08%. The price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across customer classes that are not eligible for Rural or Remote Electricity Rate Protection.

The price cap index adjustment will not apply to the following components of delivery rates:

- Rate Riders;
- Rate Adders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural or Remote Rate Protection Charge;

- Standard Supply Service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Loss Factors;
- Specific Service Charges;
- MicroFIT Service Charges; and
- Retail Service Charges.

Rural or Remote Electricity Rate Protection Charge

On December 21, 2011, the Board issued a Decision with Reasons and Rate Order (EB-2011-0405) establishing the Rural or Remote Electricity Rate Protection ("RRRP") benefit and charge for 2012. The Board amended the RRRP charge to be collected by the Independent Electricity System Operator from the current $0.0013 per kWh to $0.0011 per kWh effective May 1, 2012. The draft Tariff of Rates and Charges flowing from this Decision and Order will reflect the new RRRP charge.

Use of Actual versus Forecasted Load Data

In its 2012 IRM application HHI sought Board approval to use actual kWh as of December 31, 2010 instead of the load forecast approved as part of its 2010 cost of service application to derive the rate riders for: (i) the shared tax savings; (ii) LRAM recovery; and (iii) ICM and Z-factor. The rationale provided by HHI is that in its cost of service application, the kWhs came from a Cost Allocation Study following the loss of its only large user. HHI felt that the cost of service data is less representative than the 2010 actual data.

In its submission VECC noted that *Chapter 3 of the Filing Requirements for Transmission and Distribution Application* issued June 22, 2011 states:

> *"The IRM application process is intended to streamline the processing of a large volume of rate adjustment applications, and is therefore mechanistic in nature. For this reason, the Board has determined that the IRM process is not the appropriate venue by which a distributor should seek relief on issues which are substantially unique to an individual distributor or more complicated and potentially contentious."*[1]

[1] *Chapter 3 of the Filing Requirements for Transmission and Distribution Application,* Section 4.0, p. 24

On that basis, VECC submitted that it does not support HHI's proposal to use 2010 actuals. VECC considered changes to revenue forecasts to be an exclusion from IRM applications and any changes should be addressed in HHI's next cost of service application rather than in this 2012 IRM application.

Similarly, SEC submitted that adjusting the load forecast within the IRM term is inappropriate. SEC noted that during a cost of service hearing, the load forecast is approved by the Board after being rigorously tested by Board staff and intervenors. SEC argued that since rate payers do not benefit from an adjustment when the actual load is higher than what was approved by the Board, utilities in turn should not receive an adjustment when the actual load is less than approved. Variations in load from forecast to actual are one of the risks for which the utility is compensated through a Return on Equity ("ROE").

SEC noted that the Applicant is seeking to use its 2010 actual kWh and not the 2011 actual numbers, which would be more reflective of its expected 2012 load. SEC noted that a detailed load forecast for the 2010 test year was reviewed by the parties and established by the Board as a final basis for rates. Absent compelling factors to the contrary, that should be the basis on which rates are set until the next rebasing.

Board staff made no submission on the load forecast issue.

In it reply submission, HHI maintained that in times of economic uncertainty, especially in a smaller municipality, using 2010 actual data is a better reflection of the actual economical conditions since they reflect costs which have occurred and can be reliably measured. HHI stated that it was not its objective to increase its revenues, but to present an accurate picture of its current load.

HHI submitted that while it made its best effort to predict the impact of the loss of the large user on future years in its 2010 approved load forecast, the 2010 actuals were much lower than anticipated. In the same manner in which a utility must update its interest rates and its cost of capital to reflect the most up-to-date information, HHI felt that the 2010 actuals versus forecast would reflect the most up-to-date information available. Therefore, HHI requested approval to utilize actual kWh data as of December 31, 2010.

The Board agrees with the submissions of intervenors that Hydro Hawkesbury's proposal to use actual kWh data as of December 31, 2010 for the purpose of calculating the rate riders for the ICM, shared tax savings and LRAM is inconsistent with the IRM framework. In particular, the Board is of the view that given the limited opportunity for discovery in an IRM application, it is more appropriate to use the 2010 load forecast and the associated kWh data approved by the Board in Hydro Hawkesbury's 2010 cost of service rate application for the purpose of calculating the rate riders for the ICM, shared tax savings, and LRAM.

Shared Tax Savings Adjustments

In its Supplemental Report, the Board determined that a 50/50 sharing of the impact of currently known legislated tax changes, as applied to the tax level reflected in the Board-approved base rates for a distributor, is appropriate.

The calculated annual tax reduction over the IRM plan term will be allocated to customer rate classes on the basis of the Board-approved base-year distribution revenue. These amounts will be refunded to customers each year of the plan term, over a 12-month period, through a volumetric rate rider using annualized consumption by customer class underlying the Board-approved base rates.

HHI's application identified a total tax savings of $1,375 resulting in a shared amount of $687 to be refunded to rate payers.

The Board approves a shared tax savings of $687 to be refunded to customers over a one year period from May 1, 2012 to April 30, 2013.

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 the Retail Transmission Service Rates ("RTSRs"). Variance accounts are used to capture timing differences and differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers (i.e. variance Accounts 1584 and 1586).

On June 22, 2011 the Board issued revision 3.0 of the *Guideline G-2008-0001 - Electricity Distribution Retail Transmission Service Rates* (the "RTSR Guideline"). The RTSR Guideline outlines the information that the Board requires electricity distributors to file to adjust their RTSRs for 2012. The RTSR Guideline requires electricity distributors to adjust their RTSRs based on a comparison of historical transmission costs adjusted for the new UTR levels and the revenues generated under existing RTSRs. The objective of resetting the rates is to minimize the prospective balances in Accounts 1584 and 1586. In order to assist electricity distributors in the calculation of the distributors' specific RTSRs, Board staff provided a filing module.

On December 20, 2011 the Board issued its Rate Order for Hydro One Transmission (EB-2011-0268) which adjusted the UTRs effective January 1, 2012, as shown in the following table:

2012 Uniform Transmission Rates

Network Service Rate	$3.57 per kW
Connection Service Rates Line Connection Service Rate Transformation Connection Service Rate	 $0.80 per kW $1.86 per kW

The Board finds that these 2012 UTRs are to be incorporated into the filing module.

Review and Disposition of Group 1 Deferral and Variance Account Balances

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report Initiative* (the "EDDVAR Report") provides that, during the IRM plan term, the distributor's Group 1 account balances will be reviewed and disposed if the preset disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed.

HHI's 2010 actual year-end total balance for Group 1 Accounts including interest projected to April 30, 2012 is a debit of $164,300. This amount results in a total debit claim of $0.00108 per kWh, which exceeds the preset disposition threshold. HHI proposed to dispose of this debit amount over a one-year period.

In its submission, Board staff noted that the principal amounts to be disposed as of December 31, 2010 reconcile with the amounts reported as part of the *Reporting and Record-keeping Requirements* ("RRR") with the exception of Account 1588 Power excluding Global Adjustment and Account 1588 Power – Sub-Account – Global Adjustment, which show a difference of $505,329 between the reported amounts and the balance sought for disposition. In response to Board staff interrogatory #15 regarding the reasons for these differences, HHI stated that as part of the RRR it reported the balances as of December 31, 2010 recorded in its accounting books at that time. Furthermore, HHI stated that the corrections as per the Board's Decision EB-2010-0090 were made in its general ledgers in September 2011 in Account 1588 Power excluding Global Adjustment and Account 1588 Power - Sub-Account - Global Adjustment.

Board staff noted that it appears that HHI's RRR balances as of December 31, 2010 were reported using the figures that HHI had on its general ledgers at that time. The evidence provided by HHI indicates that HHI has made the required corrections in its general ledgers to correct the errors noted in the Board's Decision EB-2010-0090. Board staff submitted that the variances between the 2010 RRR balances and the amounts sought for disposition as of December 31, 2010 are due to a timing difference. Therefore, Board staff expressed no concerns with the December 31, 2010 Group 1 account balances sought for disposition in this proceeding.

Board staff further submitted that HHI's proposal for a one-year disposition period is in accordance with the EDDVAR Report.

The Board notes that the EDDVAR disposition threshold of $0.001/kWh has been exceeded. The Board approves, on a final basis, the disposition of a debit of $164,300, representing principal as at December 31, 2010 and interest to April 30, 2012, over a one year period, from May 1, 2012 to April 30, 2013.

The table below identifies the principal and interest amounts approved for disposition for Group 1 Accounts.

Account Name	**Account Number**	**Principal Balance A**	**Interest Balance B**	**Total Claim C = A + B**
LV Variance Account	1550	$31,225	$986	$32,211

RSVA - Wholesale Market Service Charge	1580	-$204,029	-$4,713	-$208,742
RSVA - Retail Transmission Network Charge	1584	$58,508	$1,277	$59,785
RSVA - Retail Transmission Connection Charge	1586	-$32,156	-$2,952	-$35,108
RSVA - Power (excluding Global Adjustment)	1588	$281183	$16,024	$297,207
RSVA - Power – Global Adjustment Sub-Account	1588	$53,797	$10,029	$43,768
Recovery of Regulatory Asset Balances	1590	-	$158	$76
Disposition and Recovery of Regulatory Balances (2008)	1595		-$24,897	-$24,897
Disposition and Recovery of Regulatory Balances (2009)	1595			
Group 1 Total		**$188,528**	**-$24,228**	**$164,300**

For accounting and reporting purposes, the respective balance of each Group 1 account approved for disposition shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the *Accounting Procedures Handbook for Electricity Distributors*. The date of the journal entry to transfer the approved account balances to the sub-accounts of Account 1595 is the date on which disposition of the balances is effective in rates, which generally is the start of the rate year (e.g. May 1). This entry should be completed on a timely basis to ensure that these adjustments are included in the June 30, 2012 (3rd Quarter) RRR data reported.

Review and Disposition of Account 1521: Special Purpose Charge

The Board authorized Account 1521, Special Purpose Charge Assessment ("SPC") Variance Account in accordance with Section 8 of *Ontario Regulation 66/10* (*Assessments for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program Costs*) (the "SPC Regulation"). Accordingly, any difference between (a) the amount remitted to the Minister of Finance for the distributor's SPC assessment and (b) the amounts recovered from customers on account of the assessment were to be recorded in "Sub-account 2010 SPC Assessment Variance" of Account 1521.

In accordance with Section 8 of the SPC Regulation, distributors are required to apply no later than April 15, 2012 for an order authorizing the disposition of any residual balance in sub-account 2010 SPC Assessment Variance. The Filing Requirements sets out the Board's expectation that requests for disposition of this account balance would be heard as part of the proceedings to set rates for the 2012 year.

HHI originally requested the disposition of a residual debit balance of $13,776 as at December 31, 2010, plus collections in 2011 and carrying costs until April 30, 2012 over a one year period. In response to Board staff interrogatory #16, HHI updated the residual debit balance to $13,387.

Board staff submitted that despite the usual practice, the Board should authorize the disposition of Account 1521 as of December 31, 2010, plus the amounts recovered from customers in 2011, including interest, because the account balance does not require a prudence review, and electricity distributors are required by regulation to apply for disposition of this account. Board staff submitted that the $13,387 debit balance in Account 1521 should be approved for disposition on a final basis. In its reply submission, HHI reiterated its request for the disposition of a debit balance of $13,387 over a one-year period. .

The Board approves the disposition on a final basis of a debit balance in Account 1521 of $13,387, representing principal and interest to April 30, 2012, over a one year period from May 1, 2012 to April 30, 2013. The Board directs Hydro Hawkesbury to close Account 1521 effective May 1, 2012.

Review and Disposition of Lost Revenue Adjustment Mechanism ("LRAM")

The Board's *Guidelines for Electricity Distributor Conservation and Demand Management* (the "CDM Guidelines") issued on March 28, 2008 outline the information that is required when filing an application for LRAM or SSM.

HHI requested the recovery of an LRAM claim of $48,919 over a one-year period. In response to interrogatories from Board staff and intervenors, HHI updated its LRAM claim to $48,981 to reflect the Ontario Power Authority's ("OPA") 2010 final results. HHI's LRAM claim consists of the effect of 2010 programs in 2010, and persisting effects of 2006, 2007, 2008, 2009 and 2010 programs from January 1, 2010 to April 30, 2012.

Board staff’s submission noted that HHI’s rates were last rebased in 2010. Board staff noted that in its Decision and Order in the EB-2011-0174 proceeding, the Board disallowed LRAM claims for the rebasing year as well as persistence of prior year programs in and beyond the test year on the basis that these savings should have been incorporated into the applicant’s load forecast at the time of rebasing.

Board staff noted that in cases in which it was clear in the application or settlement agreement that an adjustment for CDM was not being incorporated into the load forecast specifically because of an expectation that an LRAM application would address the issue, and if this approach was accepted by the Board, then Board staff would agree that an LRAM application is appropriate. Board staff requested that HHI highlight in its reply submission whether the issue of an LRAM application was addressed in their cost of service application.

Board staff submitted that in the absence of the above information, HHI should not be permitted to recover the requested persisting lost revenues from 2010 CDM programs in 2010, and lost revenues from 2006 - 2009 programs persisting from 2010 through 2012 since these should have been built into HHI’s last approved load forecast in 2010.

Board staff supported the recovery of 2006, 2007, 2008, and 2009 lost revenues, including the persisting lost revenues from 2006 programs in 2007, 2008 and 2009, the persisting lost revenues from 2007 programs in 2008 and 2009, and the persisting lost revenues from 2008 programs in 2009 as these lost revenues took place during IRM years and HHI did not previously recover these amounts. Board staff requested that HHI provide an updated LRAM amount to only include these amounts and the associated rate riders.

VECC submitted that the LRAM claim approved by the Board should be adjusted to include lost revenue for the years 2006, 2007, 2008 and 2009 resulting from the impact of 2006 – 2009 CDM programs.

HHI agreed with Board staff’s and VECC’s submission with respect to lost revenues prior to 2010. With respect to 2010 programs and persisting amounts in 2011 and 2012, HHI indicated that while some LDCs in their applications specifically lowered their load forecast to include expected future load reduction due to CDM, HHI did not have the sophistication to adopt this approach. HHI confirmed that it did not include CDM programs in its 2010 load forecast.

In response to Board staff's request, HHI indicated that the LRAM associated with the recovery of 2006, 2007, 2008, and 2009 lost revenues, including the persisting lost revenues from 2006 programs in 2007, 2008, and 2009, the persisting lost revenues from 2007 programs in 2008 and 2009, and the persisting lost revenues from 2008 programs in 2009, would be $33,950.55.

HHI submitted that its LRAM claim is appropriate and is fully consistent with previous Board decisions. HHI requested that the Board approve its LRAM claim for $48,981.

The Board approves an LRAM claim of $33,950.55 representing lost revenue for the years 2006 to 2009 resulting from the impact of CDM programs implemented from 2006 to 2009, as Hydro Hawkesbury was in IRM during these years and has not otherwise claimed LRAM for this period. The Board will not approve an LRAM for lost revenues in 2010 from 2010 CDM programs or the persisting lost revenues from 2006, 2007, 2008, 2009, and 2010 CDM programs in 2010 to 2012, as these amounts should have been reflected in Hydro Hawkesbury's last approved load forecast. The 2008 CDM Guidelines state that lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time. The Board notes that absent specific wording in the Decision and Order of the Board relating to Hydro Hawkesbury's last cost of service application, there is no reasonable basis upon which to diverge from the 2008 CDM Guidelines. The Board approves a one year disposition period from May 1, 2012 to April 30, 2013.

Review and Disposition of Account 1562: Deferred Payments in Lieu of Taxes

In 2001, the Board approved a regulatory payments in lieu of tax proxy approach for rate applications coupled with a true-up mechanism filed under the RRR to account for changes in tax legislation and rules and to true-up between certain proxy amounts used to set rates and the actual amount of taxes paid. The variances resulting from the true-up were tracked in Account 1562 for the period 2001 through April 30, 2006.

On November 28, 2008, pursuant to sections 78, 19 (4) and 21 (5) of the *Ontario Energy Board Act, 1998*, the Board commenced a Combined Proceeding (EB-2008-0381) on its own motion to determine the accuracy of the final account balances with respect to Account 1562 Deferred Payments in Lieu of Taxes ("Deferred PILs") (for the period October 1, 2001 to April 30, 2006) for certain electricity distributors that filed 2008 and 2009 distribution rate applications.

The Notice in the Combined Proceeding included a statement of the Board's expectation that the decision resulting from the Combined Proceeding would be used to determine the final account balances with respect to Account 1562 Deferred PILs for the remaining distributors. In its decision and order, the Board stated that, "[e]ach remaining distributor will be expected to apply for final disposition of Account 1562 with its next general rates application (either IRM or cost of service)."[2]

HHI originally applied to dispose of a debit balance in Account 1562 of $4,138 including carrying charges projected to April 30, 2012 over a one-year period. In response to Board staff interrogatories, HHI amended its evidence to support a credit balance of approximately $6,299.

Board staff submitted that the revised credit amount of $6,299 has been calculated in accordance with the regulatory guidance and the Board's decision in the Combined PILs Proceeding[3].

The Board approves the disposition on a final basis of a credit balance in Account 1562 of $6,299 representing principal and interest to April 30, 2012, over a one year period, from May 1, 2012 to April 30, 2013. The Board finds that the revised credit amount has been calculated in accordance with the regulatory guidance and prior decisions issued by the Board.

For accounting and reporting purposes, the balance of Account 1562 shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the *Accounting Procedures Handbook for Electricity Distributors*. The date of the journal entry to transfer the approved account balances to the sub-accounts of Account 1595 is the date on which disposition of the balances is effective in rates, which generally is the start of the rate year (e.g. May 1). This entry should be completed on a timely basis to ensure that these adjustments are included in the June 30, 2012 (3rd Quarter) RRR data reported.

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[2] EB-2008-0381 Account 1562 Deferred PILs Combined Proceeding, Decision and Order, p. 28
[3] Decisions in Combined Proceeding, EB-2008-0381 – August 12, 2011; June 24, 2011; December 23, 2010; December 18, 2009. Hydro One Brampton, EB-2011-0174, December 22, 2011. Whitby Hydro, EB-2011-0206, December 22, 2011. Staff Discussion Paper, August 20, 2008.

Z-factor Claim

HHI applied to recover the revenue requirement associated with an amount of $712,909 intended for the replacement of a 44KV substation and site preparation through a Z-factor claim. HHI proposed to recover these costs through fixed and variable rate riders that would be in place until HHI's next rebasing application.

HHI stated that the 44KV substation has a scheduled in-service date of February 2012. HHI noted that this purchase was deemed necessary to provide safe and reliable electricity supply to customers.

On July 14, 2008, the Board issued the Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (the "Report"). In section 2.6 of the Report, the Board set out its approach for dealing with the costs of unforeseen events that are outside of management's control. The Board determined that in order for amounts to be considered for recovery by way of a Z-factor, the amounts must satisfy all three eligibility criteria of causation, materiality and prudence. The Board determined a materiality threshold of $50,000 for small size distributors such as HHI. In the Report, the Board noted that it expects that any application for a Z-factor will be accompanied by a clear demonstration that the distributor's management could not have been able to plan and budget for the event and that the harm caused by extraordinary events is genuinely incremental to the distributor's experience or reasonable expectation.

In its submission, Board staff noted that risk management of this distribution asset was clearly within management's control and that the replacement of a transformer station is not an extraordinary event. Therefore, Board staff submitted that this event does not qualify for Z-factor treatment. Board staff however submitted that cost recovery should be considered under the umbrella of an incremental Capital Module ("ICM").

VECC submitted that given the age of the assets, the recent studies documenting the condition of the transformer and the timeline of the events and the preventative measures undertaken by HHI, the need to replace the asset should not be treated as an unforeseen event. VECC submitted that HHI should seek recovery of the amounts under an ICM, not a Z-factor.

Similarly, SEC agreed with the Applicant that HHI should be allowed to recover expenditures for its replacement of its failing 44KV transformer, but submitted that the appropriate regulatory mechanism is the ICM, not a Z-factor.

In its reply submission, HHI requested approval of an ICM claim in the amount of $712,909 to replace its defective 44 KV substation.

The Board finds that the proposed replacement of the 44 kV substation does not quality for Z-factor treatment, as the requirement to replace the asset is not an unforeseen event that is outside of the control of management. As such, the proposed Z-factor treatment for this expenditure is inconsistent with the policy of the Board as set out in section 2.6 of the *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*. The Board agrees with the submissions of Board staff and intervenors that it is appropriate to consider the cost recovery associated with this proposal in the context of the ICM.

Incremental Capital Module

The Request

HHI proposed to recover, through an ICM, the incremental capital costs of $1,517,813 associated with the replacement of existing transformers with a new 25MVA in addition to the incremental capital cost of $712,909 associated with the above mentioned 44kV substation.

HHI currently receives electricity at a substation at 110kV with two distribution transformers in the West end and a 44kV station in the East end of Hawkesbury. HHI noted that the two transformers at the 110 KV station are approximately 45 years of age and have shown signs of deterioration.

HHI indicated that if the approval is not granted, it has no other alternative but to take a reactive stance and wait until the 110KV fails. HHI also noted that if one transformer fails, the other cannot support its load.

HHI proposed to allocate the revenue requirement associated with the incremental capital expenditures eligible for cost recovery on the basis of distribution revenue. HHI proposed to recover this amount by means of fixed and variable rate riders that would remain in effect until its next cost of service application (scheduled for the 2014 rate year).

The Eligibility Criteria

The Reports referenced in the introduction of this Decision and Order require that incremental capital expenditures satisfy the eligibility criteria of materiality, need and prudence in order to be considered for recovery prior to rebasing. Applicants must demonstrate that the amounts exceed the Board's materiality threshold and clearly have a significant influence on the operation of the distributor, must be clearly non-discretionary and the amounts must be outside the base upon which rates were derived. In addition, the decision to incur the amounts must represent the most cost-effective option for ratepayers.

(i) Need and Prudence

Two Transformers at the 110KV station

HHI indicated that the incremental capital expenditures are related to the replacement of one of the existing transformers with a new 25 MVA that will have the capability to support the entire service area.

HHI provided evidence supporting the need for this project in its application and interrogatory responses. HHI indicated that the transformer at the 110KV station is non-discretionary and that the assets are reaching end of life and showing signs of deterioration.

In support of its Application, HHI submitted an assessment of the two transformers, dated November 2, 2010 by GE Canada International and an evaluation of alternatives in the form of a report by BPR, dated September 5, 2011.

Board staff submitted that HHI's request for incremental capital funding associated with the design, construction, and operation of the 25MVA transformer for the 110kV station should be granted. Board staff also submitted that HHI has demonstrated immediate short term and long term need as evidenced by the GE and BPR reports.

VECC submitted that the incremental capital meets the Board's materiality, need and prudence criteria based on the evidence provided. However, VECC noted that the failing condition of the aging assets at the West substation have been identified by HHI on an ongoing basis and were most recently identified in its last cost of service application in 2010. VECC submitted that the proposed capital investment is not new, and because its condition has not changed significantly since 2010, VECC submitted that HHI should continue with its original plan to budget for the replacement of this transformer in its next cost of service application in 2014.

SEC submitted that the Board previously stated that the need for a specific project under an ICM must be unusual and outside the ordinary course of business. SEC stated that in this specific Application, the evidence does not demonstrate that the replacement cannot wait until the Applicant's next cost of service application. SEC submitted that the Applicant has not shown that the change in condition is material enough to be considered outside the base from which rates were derived. SEC also submitted that the evidence provided by the Applicant does not demonstrate that the condition of the transformer is that of near catastrophic failure or is an unacceptable risk to the health and safety of the community or any worker. SEC submitted that the cost should not be recovered from ratepayers until its next cost of service proceeding in 2014.

In its reply submission, HHI interpreted VECC and SEC's position as "taking no action", which was one of the options considered in GE's report. HHI dismissed this option, since it would put the distributor's customers at considerable risk and would also pose an unacceptable risk to the distributor. HHI stated that there is a high probability that the 110kV could fail unexpectedly in the next year given the age of the transformers and HHI's experience with the 44kV station. HHI submitted that the potential financial cost associated with a reactive stance, estimated from $5,215,000 to $6,455,000, could be devastating to the distributor and its customers.

HHI further noted the GE report regarded a "take no action" alternative as an unacceptable risk of losing service for a long period of time and re-submitted its request for an ICM claim of $1,517,813 for the 110kV station and $712,909 to replace its defective 44kV substation.

44kV substation

As noted earlier in this Decision and Order, the Board finds it appropriate to consider the cost recovery associated with the replacement of the 44kV substation in the context of the ICM claim.

Board staff noted in its submission that HHI provided an extensive evaluation of the alternatives considered and the reasons supporting the preferred solutions and that HHI's request satisfies the prudence requirement for an ICM claim. It was Board staff's view that while the costs of the options adopted by HHI are marginally higher than some of the alternatives considered, HHI's preferred options are cost effective.

VECC submitted that HHI has satisfied the Board's materiality, need and prudence criteria regarding this incremental capital project. VECC further submitted that the replacement of the 44kV transformer should be eligible for recovery through the ICM.

Similarly, SEC submitted that the project met the requirements of an ICM and that materiality, prudence and need have been met.

(ii) Materiality

Board staff indicated that HHI completed the 2012 IRM3 ICM Workform and calculated a materiality threshold of $121,150. Board staff also noted that HHI's 2012 forecasted capital expenditures amount to $2,458,840, which includes the forecasted costs of $712,909 to replace the failing transformer at the 44KV station and the forecasted cost of $1,517,813 to replace an existing transformer at HHI's 110KV station with a 25 MVA for a total amount of $2,230,722. On that basis, Board staff noted that the maximum amount eligible for recovery would be $2,337,690 ($2,458,840 - $121,150).

VECC submitted that the calculation of the threshold should be updated to reflect the 1.7% price escalator announced by the Board on November 10, 2011. VECC also submitted that the model will need to be updated to reflect the price escalator when updated data becomes available.

VECC noted that in response to interrogatories, HHI indicated that it could potentially defer $20,000 in capital projects under account 1830 (Poles, Towers, Fixtures) to a later date. VECC submitted that the 2012 proposed capital expenditures, less the $20,000 under account 1830, can be reasonably viewed as non-discretionary.

The Board notes that Hydro Hawkesbury has applied for ICM treatment for two projects: (i) to replace two transformers at the 110 KV substation with a new 25 MVA transformer at a cost of $1,517,813; and (ii) to replace and undertake site preparation for a 44 KV distribution transformer at a cost of $712,909. The total applied-for ICM is $2,230,722.

As set out in the IR Report, the incremental capital module was designed to address the treatment of incremental capital needs that may arise during the IRM term and do so on a modular basis. The Supplemental Report, states that the capital module is intended to be reserved for unusual circumstances that are not captured as a Z-factor and where the distributor has no other options for meeting its capital requirements within the context of its financial capacities underpinned by existing rates.

Both reports set out incremental capital investment eligibility criteria, which are repeated below:

Materiality: The amounts must exceed the Board-defined materiality threshold and clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with a rebasing.

Need: Amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which rates were derived.

Prudence: The amounts to be incurred must be prudent. This means that the distributor’s decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

The materiality threshold is based on the premise that revenue generated under the price cap plan automatically generates more revenue for capital investment. The materiality threshold set by the Board in its Supplemental Report established a level of capital expenditure that can be financed by increases in revenue due to the price cap formula and load growth. The Board also set a 20 percent adder, or dead band, to prevent marginal applications.

The Board is of the view that the applied-for projects are consistent with the purpose of the ICM, and that it is appropriate to evaluate each of the two projects using the incremental capital investment eligibility criteria.

The Board finds that the need, prudence and materiality for each for the two applied-for projects have been established. HHI has provided sufficient evidence documenting potential asset failure, the cost consequences of deferring action and risking asset failure, condition deterioration and safety issues to establish materiality, need and prudence of each project in the context of this application. In the case of the 110 KV project, a number of alternatives were also assessed.

The Board also highlights that each project individually exceeds the materiality threshold. The Board points out that the materiality threshold calculates the amount of ongoing capital expenditures that can be supported by rates during IRM. As such, there is no question that the costs of the applied-for projects are not presently reflected in current rates. The Board is of the view that Hydro Hawkesbury has also adequately demonstrated that its 2012 capital budget of $2,458,840 is non-discretionary.

In light of the evidence presented, the Board finds that the revised materiality threshold should be further adjusted to reflect the 2.0% price escalator announced by the Board on March 13, 2012, a stretch factor of 0.2%, and growth using the 2010 Board-approved load forecast. Using these parameters, the Board has calculated a materiality threshold of $126,961. The maximum amount eligible for recovery will be the difference between the total non-discretionary capital expenditures of $2,458,840 and the materiality threshold value of $126,961 or $2,331,879. Hydro Hawkesbury has applied for an ICM of $2,230,722, which is less than the maximum amount eligible for recovery. The Board therefore approves an incremental capital module of $2,230,722.

Incremental Revenue Requirement Calculation

(i) The Half Year Rule, Capital Structure and Treatment of Capital Contribution

In its Application, HHI used a full year depreciation amount to calculate its incremental revenue requirement amounts. HHI used a 60% debt and 40% equity deemed capital structure and the cost of capital parameters approved in its 2010 cost of service application when calculating the revenue requirement associated with the ICM.

Board staff agreed that the half-year rule should not apply in this case, since HHI is at the half-point of its IRM plan term. Board staff also submitted that the capital structure used to calculate the revenue requirement associated with the incremental capital expenditures is appropriate.

The Board finds that the half-year rule will not apply as HHI is not scheduled to file a rebasing application until 2013 for 2014 rates. The Board also approves a 60/40 (debt/equity) capital structure and the use of the cost of capital parameters as approved in HHI’s 2010 cost of service application.

(ii) Allocation of the Incremental Revenue Requirement

HHI proposed to allocate the revenue requirement associated with the incremental capital expenditures eligible for cost recovery on the basis of distribution revenue.

Board staff submitted that the transformers are distribution assets. Board staff was of the view that an allocation based on distribution revenue is appropriate and took no issue with HHI’s proposed cost allocation methodology.

The Board approves the allocation of the revenue requirement associated with the incremental capital on the basis of distribution revenue, consistent with the methodology contained within the Incremental Capital Workform.

(iii) Recovery of the Incremental Revenue Requirement

HHI proposed to recover the revenue requirement associated with the ICM amounts by means of fixed and variable rate riders that would remain in effect until its next cost of service application. Board staff noted that the Board previously approved in the case of Guelph Hydro (EB-2010-0130) and Oakville Hydro (EB-2010-0104) the recovery of the incremental annual revenue requirement by means of a variable rate rider. Board staff was of the view that recovery by means of fixed and variable rate riders creates additional complexities that may not be warranted and invited HHI to provide in its reply submission a schedule showing rate riders expressed on a variable basis.

The Board finds that the incremental revenue requirement should be recovered by means of a variable rate rider, as this approach is consistent with the Board’s approach in the Guelph (EB-2010-0130) and Oakville (EB-2010-0104) decisions.

IMPLEMENTATION

The Board has made findings in this Decision which change the 2012 distribution rates from those proposed by HHI

The Board expects HHI to file a draft Rate Order, including all relevant calculations showing the impact of this Decision on HHI's determination of the final rates. Supporting documentation shall include, but not be limited to, filing completed versions of the 2012 IRM Rate Generator model, shared tax savings model, updated SIMPIL models and continuity tables to support the claim for disposition of account 1562 Deferred PILs, LRAM calculations showing the derivation of the final rate riders to recover the approved LRAM amount and the updated Incremental Capital Workform and Incremental Capital Project Summaries for each of the ICM projects.

A Rate Order will be issued after the steps set out below are completed.

THE BOARD ORDERS THAT:

1. HHI shall file with the Board, and shall also forward to VECC and SEC, a draft Rate Order that includes revised models in Microsoft Excel format and a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision and Order within **7 days** from the issuance of this Decision and Order.

2. Board staff, VECC and SEC shall file any comments on the draft Rate Order including the revised models and proposed rates with the Board and forward to HHI within 7 days of the date of filing of the draft Rate Order.

3. HHI shall file with the Board and forward to VECC and SEC responses to any comments on its draft Rate Order including the revised models and proposed rates within **4 days** of the date of receipt of comments from Board staff and the intervenors.

Cost Awards

The Board will issue a separate decision on cost awards once the following steps are completed:

1. VECC and SEC shall submit their cost claims no later than **7 days** from the date of issuance of the final Rate Order.

2. HHI shall file with the Board and forward to VECC and SEC any objections to the claimed costs within **21 days** from the date of issuance of the final Rate Order.

3. VECC and SEC shall file with the Board and forward to HHI any responses to any objections for cost claims within **28 days** from the date of issuance of the final Rate Order.

4. HHI shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote file number **EB-2011-0173,** be made through the Board's web portal at, www.errr.ontarioenergyboard.ca and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available parties may email their document to BoardSec@ontarioenergyboard.ca. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 2 paper copies.

DATED at Toronto, April 19, 2012
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Exhibit 3 – Operating Revenues

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EXHIBIT 3 – OPERATING REVENUE

The evidence presented in this exhibit provides information supporting the revenues derived from activities regulated by the OEB. Actual operating revenues from the regulated operations come mainly from fixed and variable tariff charges as well as pass through charges and specific service charges. The evidence herein is organized according to the following topics;

1) Load and Revenue Forecast
2) Variance Analysis
3) Other Revenues

Tab 1 – Load and Revenue Forecasts

E3.T1.S1 OVERVIEW

The schedules included in this Exhibit outline and describe HHI's load, customer, and distribution revenue forecasts. The load forecast methodology and assumptions are described in detail at E3.T1.S3. HHI's purchase forecast is based on a regression model. The load forecasting model relates monthly historical purchases to monthly weather conditions (measured in cooling-degree-days ("CDD") and heating-degree days (HDD)), and other variables such as which are discussed in detail at E3.T1.S3. Further adjustments for projected Conservation and Demand Management ("CDM") reductions and estimated distribution losses are made to derive distribution sales. HHI has applied current approved rates to the test year customer and sales forecast in order to derive the test year distribution revenue. Projected Revenues at current and proposed rates are presented at Tab 2 of this Exhibit. Other Revenues are discussed at Tab 3 of this Exhibit and the derivation of the Power Supply Expense is presented at E3.T3.S8.

E3.T1.S2 HISTORICAL AND FORECAST VOLUME TABLE

Table 1 below shows the actual and forecast trends for customer/connection counts, kWh consumption and billed kW demand. The derivation of forecast for the Test Year can be found at E3.T1.S4.

Table 1: Proposed 2014 Load Forecast

kWh	Year	2010 Act	2011 Act	2012 Act	2013WN	2014WN CDM Adj
Residential	Cust	4,817	4,835	4,869	4,905	4,950
	kWh	50,277,839	51,273,093	51,132,834	54,711,762	52,443,428
GS<50	Cust	593	592	616	630	634
	kWh	19,562,613	18,457,375	18,531,354	20,128,592	18,859,305
GS>50	Cust	86	94	94	96	98
	kWh	80,745,583	82,739,387	77,875,019	82,718,651	79,126,290
	kW	209,711	211,681	206,655	206,144	197,191
Streetlight	Cust	1,180	1,201	1,204	1,210	1,215
	kWh	1,156,978	1,343,667	1,355,855	1,150,473	1,105,837
	kW	3,194	3,724	3,748	3,250	3,124
Sentinel Lights	Cust	21	21	21	21	21
	kWh	105,383	102,889	102,354	106,349	101,802
	kW	297	280	284	297	284
USL	Cust	5	5	5	5	5
	kWh	242,514	215,299	214,901	224,238	214,651
Total Cust		6,702	6,748	6,809	6,867	6,923
Total Demand		213,202	215,685	210,687	209,691	200,599
Total Energy		152,090,910	154,131,710	149,212,317	159,040,065	151,851,313

The Residential class has shown slow yet stable growth in customers. Typically slow growth reflects the lack of new development. Hawkesbury's slow growth is largely due to the town's elderly population. The town of 11,000 has four old-age homes with more than 400 seniors living on small pensions.

Table 2 below shows the yearly change in consumption for the Residential class. The utility expects 36 new connections from 2012 to 2013 and an additional 45 new connections from 2013 to 2014.

Table 2: Residential Variance

	Cust	%chg	kWh Adj	%chg
2004	4,580		53,822,287	
2005	4,611	1%	54,938,708	2%
2006	4,642	1%	50,433,983	-8%
2007	4,775	3%	51,782,360	3%
2008	4,778	0%	52,394,201	2%
2009	4,781	0%	51,630,250	-9%
2010	4,817	1%	51,091,608	7%
2011	4,835	0%	51,074,042	0%
2012	4,869	1%	53,355,787	5%
2013	4,905	1%	54,711,762	1%
2014	4,950	1%	54,785,724	0%

The number of customers for GS<50 kW have been growing slowly but steadily since 2004. HHI anticipates a small increase of 14 connections from 2012 to 2013 and an additional 4 connection in in 2014.

Table 3: GS<50 Variance

	Cust	%chg	kWh Adj	%chg
2004	568		22,718,827	
2005	564	-1%	22,682,901	0%
2006	566	0%	20,433,877	-10%
2007	573	1%	20,469,754	0%
2008	579	1%	20,233,621	-1%
2009	586	1%	19,270,125	-12%
2010	593	1%	19,879,243	12%
2011	592	0%	18,385,720	-8%
2012	616	4%	19,336,988	5%
2013	630	2%	20,128,592	3%
2014	634	1%	19,701,623	-2%

The customer count for the GS>50 kW class has also seen a marginal yet steady increase over the past years. HHI anticipates 2 connections per year from 2012 to 2014.

Table 4: GS>50 Variance

	Cust	%chg	kWh Adj	%chg	kW	%chg
2004	78		132,195,856		281,031	
2005	72	-8%	122,148,161	-8%	275,148	-2%
2006	78	8%	113,815,460	-6%	274,200	0%
2007	80	3%	114,573,101	1%	290,290	6%
2008	80	0%	110,571,690	-3%	304,147	5%
2009	82	3%	94,311,095	-21%	253,516	-17%
2010	86	5%	82,052,486	-6%	209,711	-17%
2011	94	9%	82,418,178	0%	211,681	1%
2012	94	0%	81,260,564	-1%	206,655	-2%
2013	96	2%	82,718,651	0%	206,144	0%
2014	98	2%	82,660,329	0%	205,999	0%

Street Lighting, USL and Sentinel connections have also been historically stable. Only a slight increase of 6 connections from 2012-is expected in Streetlights. The USL and Sentinel Lights are not expected to change in 2013 and 2014.

Table 5: Streetlights Variance

	Cust	%chg	kWh Adj	%chg	kW Adj	%chg
2004	1,158		904,010		2777	
2005	1,158	0%	912,952	1%	2843	2%
2006	1,158	0%	1,025,217	12%	2872	1%
2007	1,158	0%	972,414	-5%	2874	0%
2008	1,158	0%	1,208,366	24%	3098	8%
2009	1,158	0%	1,151,305	-5%	3198	3%
2010	1,180	2%	1,156,978	0%	3194	0%
2011	1,201	2%	1,343,667	16%	3724	17%
2012	1,204	0%	1,355,855	1%	3748	1%
2013	1,210	0%	1,150,473	-15%	3250	-13%
2014	1,215	0%	1,155,227	0%	3263	0%

Table 6: Sentinel Variance

	Cust	%chg	kWh Adj	%chg	kW	%chg
2004	23		104,334		304	
2005	24	4%	109,474	5%	300	-1%
2006	22	-8%	106,680	-3%	302	1%
2007	21	-5%	108,699	2%	300	-1%
2008	21	0%	108,472	0%	300	0%
2009	21	0%	108,855	0%	300	0%
2010	21	0%	105,383	-3%	297	-1%
2011	21	0%	102,889	-2%	280	-6%
2012	21	0%	102,354	-1%	284	1%
2013	21	0%	106,349	4%	297	5%
2014	21	0%	106,349	0%	297	0%

Table 7: USL Variance

	Conn.	%chg	Energy
2004	0		
2005	0	0%	53,987
2006	0	0%	64,965
2007	0	0%	76,398
2008	4	100%+	86,849
2009	4	0%	181,221
2010	5	25%	242,514
2011	5	0%	215,299
2012	5	0%	214,901
2013	5	0%	224,238
2014	5	0%	224,238

As part of its 2010 Load Forecast Study, HHI removed its large user from its load forecast. This large user has comprised anywhere from 15 to over 20 per cent of total retail kWh sales in the LDC from 2004-2009. This large user had steadily declining use every year since 2004 and has had a dramatic decline in use in the fourth quarter of 2008 and the first four months of 2009. The company shut down completely in the month of January (2009) and has resumed production in February with only one out of three production lines.

Back in 2009, the company informed HHI that this is likely for the foreseeable future until automotive demand recovers, and would also likely involve several weeks of complete, lights out shutdown from time-to-time. Subsequently, the company permanently ceased it operation at the end of 2009.

In its 2014 proposed load forecast, specifically for 2004 to 2008 HHI used the same adjusted wholesale purchases that were used in its 2010 Load Forecast. In the interest of consistency, 2009 was also adjusted to remove the large user's consumption. Table 8 below shows the adjusted wholesale purchases (large user removed) for the period of 2004 to 2008.

Table 8: Adjusted Wholesale Purchases 2004-2008

	2004	2005	2006	2007	2008
January	18,637,678	17,870,916	16,388,891	16,852,233	16,819,638
February	15,824,597	15,185,261	15,340,991	16,146,860	16,106,414
March	15,151,388	15,401,451	15,831,060	16,075,177	15,917,303
April	13,105,910	12,546,018	12,717,270	13,292,923	13,249,917
May	12,030,458	8,016,770	12,509,932	12,531,854	12,145,403
June	12,072,109	12,955,942	12,713,980	12,467,928	12,078,793
July	12,162,321	12,262,516	13,030,943	12,374,953	12,676,710
August	12,534,002	12,339,980	13,193,056	13,234,020	12,733,825
September	11,886,209	11,447,564	12,006,692	12,246,087	12,344,575
October	12,630,027	11,922,695	13,698,125	12,901,675	13,017,951
November	14,372,743	14,103,083	13,777,519	14,405,846	14,022,435
December	16,443,722	16,017,182	14,773,857	15,984,980	16,262,824
Annual	**166,851,163**	**160,069,380**	**165,982,315**	**168,514,536**	**167,375,788**
% change		***-4.10%***	***3.70%***	***1.50%***	***-0.70%***

With the exception of the adjustment described above, the utility load has been relatively stable in the historical years, with adjusted wholesale deliveries decreasing by two per cent from 2003 to 2012. The bulk of the increase occurred prior to 2008 and have since then plateaued mainly due to the fact that additional energy usage typical of more air conditioners, computers, TVs and, pool heaters will be offset by the additional transitioning to energy efficient lighting, appliances and other energy efficient changes.

Table 9: Wholesale Purchases VS Weather Adjusted

Year	Wholesale Purchases	%chg	Adjusted Purchases	%chg	Purch vs. Adj
2004	166,851,164		165,821,248		-1%
2005	160,069,378	-4%	166,241,558	0%	4%
2006	165,982,316	4%	162,449,680	-2%	-2%
2007	168,514,536	2%	164,532,648	1%	-2%
2008	167,375,788	-1%	164,003,916	0%	-2%
2009	167,014,596	0%	164,063,489	0%	-2%
2010	159,288,613	-5%	161,866,770	-1%	2%
2011	161,859,215	2%	161,230,849	0%	0%
2012	155,160,223	-4%	161,905,672	0%	4%

E3.T1.S3 APPROACH TO WEATHER NORMALIZED LOAD FORECAST

The load forecast was developed based on monthly wholesale purchased kWh from January 2003 to December 2012 as measured at the wholesale point of delivery (exclusive of losses; i.e., not loss adjusted). HHI purchases wholesale energy from Hydro One Networks and the IESO. While it may be desirable to isolate demand determinants related to individual rate classes, such as residential, commercial, and industrial, it is not always possible nor is it necessary to do so especially for smaller utilities such as HHI. Therefore the decision was made to continue working with the same approach as the last cost of service, thus using total monthly energy. Many other LDC distribution rate applications considered by the Board have also used this approach and that this approach has been approved by the Board in the past.

The methodology predicts wholesale consumption using a multiple regression analysis that relates historical monthly wholesale kWh usage to monthly historical heating degree days and cooling degree days. Heating degree-day figures come with a "base temperature", and provide a measure of how much (in degrees), and for how long (in days), the outside temperature was below that base temperature. The most readily available heating degree days come with a base temperature of 18°C. Cooling degree-day figures also come with a base temperature, and provide a measure of how much, and for how long, the outside temperature was above that base temperature. Historical monthly full-time employment levels are also used to account for regional economic patterns that may influence consumption of electricity within the LDC. For degree days, daily observations as reported at Ottawa (Macdonald-Cartier) International Airport are used. For employment levels, monthly full-time employment for the Ottawa Economic Region, as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM) has been used.

The number of days in the month did not yield meaningful results in predicting HHI's load. Therefore, these were not included as explanatory variables.

The resulting regression equation yields an adjusted R-squared of 0.84. When actual annual wholesale values are compared to annual values predicted by the regression equation, the mean absolute percentage error (MAPE) is 2.12 per cent. More detailed model statistics can be found in the next section.

Weather normalized values are determined by using the regression equation with a 9-year average monthly degree days (2004-2012). The utility did not have confidence in their 2003 wholesale data therefore opted to use 2004 to 2012 instead.

A 10-year average (in this case 9) is consistent with recent years' weather and has been used in other electricity distribution rate applications and has been accepted by the Board.

Allocation to specific weather sensitive rate classes (Residential, GS<50, GS>50) is based on the share of each classes' actual retail kWh (exclusive of distribution losses) share of actual wholesale kWh. Weather normalized wholesale kWh, for historical years, are allocated to these classes based on these historical shares. Forecast values for 2013 and 2014 are allocated based on the most recent year's (2012) actual share.

For those rate classes that use kW consumption as a billing determinant, sales for these customer classes are then converted to kW based on the historical volumetric relationship between kWh and kW

E3.T1.S4 LOAD FORECAST

The load forecast presented in this application uses a similar approach as HHI's last Cost of Service application (2010).

HHI's energy purchase forecast is based on a multiple regression model. Distribution sales/consumption is derived from purchases Distribution consumption is then allocated to the rate classes based on historical billing trends (% share). For those rate classes that use kW consumption as a billing determinant, sales for these customer classes are then converted to kW based on the historical volumetric relationship between kWh and kW.

The following table (Table 10) outlines monthly wholesale deliveries to HHI from January 2004 to December 2012.

Table 10: Monthly Actual Energy (kWh), HHI

	2004	2005	2006	2007	2008	2009	2010	2011	2012
Jan	18637678.00	17870916.00	16388891.00	16852233.00	16819638.00	18711435.97	17203978.00	16854566.00	16729278.00
Feb	15824597.00	15185261.00	15340991.00	16146860.00	16106414.00	16518823.46	15040751.00	15362389.00	14846741.00
Mar	15151388.00	15401451.00	15831060.00	16075177.00	15917303.00	16686068.22	14229105.00	15540989.00	13823698.00
Apr	13105910.00	12546018.00	12717270.00	13292923.00	13249917.00	12517025.33	12112446.00	12632683.00	11932417.00
May	12030458.00	8016770.00	12509932.00	12531854.00	12145403.00	11130814.47	12101753.00	11748273.00	11638145.00
Jun	12072109.00	12955942.00	12713980.00	12467928.00	12078793.00	11544724.90	11911567.00	12149693.00	11877651.00
Jul	12162321.00	12262516.00	13030943.00	12374953.00	12676710.00	11659044.23	12637313.00	12845015.00	12063416.00
Aug	12534002.00	12339980.00	13193056.00	13234020.00	12733825.00	13560102.69	12028503.00	12809412.00	11905509.00
Sep	11886209.00	11447564.00	12006692.00	12246087.00	12344575.00	12318093.31	11465896.00	11903431.00	10733049.00
Oct	12630027.00	11922695.00	13698125.00	12901675.00	13017951.00	13885376.36	11927425.00	12153966.00	11493823.00
Nov	14372743.00	14103083.00	13777519.00	14405846.00	14022435.00	13123695.87	13217791.00	13063188.00	13327753.00
Dec	16443722.00	16017182.00	14773857.00	15984980.00	16262824.00	15359390.72	15412085.00	14795610.00	14788743.00

The purpose of a multiple regression equation is to predict a single dependent variable from multiple independent variables. Several variables and the interactions among each variables, affects overall electricity purchases. Various combination of economic drivers were tested using different model specifications and while adding and removing independent variable at a time. Results from these various scenarios can be found in the excel model filed in conjunction with this application. The decision to add/delete a variable is made on the basis of whether that variable improves the accuracy of the model. The variables listed below were used as initial inputs for the purpose of regression analysis.

- Heating Degree Days (included)
- Cooling Degree Days (included)
- Spring Fall Flag (included)
- Days/month (excluded)
- Full Time Employment for Ottawa Region (urban) (included)
- Full Time Employment for Kingston Pembroke (rural) (excluded)

Variation in monthly electricity consumption is influenced by three main factors – weather (e.g. heating and cooling), which is by far the most dominant effect for most systems; employment factors (increases or decreases in economic activity leads to changes in employment); and a seasonality, in this case, a spring/fall factors.

Heating and Cooling:

In order to determine the relationship between observed weather and energy consumption, monthly weather observations describing the extent of heating or cooling required within the month are necessary. Environment Canada publishes monthly observations on heating degree days (HDD) and cooling degree days (CDD) for selected weather stations across Canada. Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18°C. Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18°C. For HHI, the monthly HDD and CDD as reported at Ottawa International Airport were used.

HHI has adopted the 9 year average from 2004 to 2012 as the definition of weather normal. Our view is that a ten-year average based on the most recent ten calendar years available is a reasonable compromise that likely reflects the "average" weather experienced in recent years. Many other LDCs have also adopted this definition for the purposes of cost-of-service rebasing. The following table (Table 11) outlines the monthly weather data used in the regression analysis.

Table 11: HDD and CDD as reported at Ottawa International Airport

	2004		2005		2006		2007		2008		2009		2010		2011		2012	
	HDD	CDD	HDD	CDD	HDD	CDD	HDD	CDD	HDD	CDD	HDD	CDD	HDD	CDD	HDD	CDD	HDD	CDD
Jan	1045	0	921	0	734	0	797	0	754	0	980	0	789	0	893	0	831	0
Feb	750	0	701	0	721	0	820	0	774	0	712	0	656	0	729	0	671	0
Mar	559	0	669	0	600	0	643	0	721	0	598	0	461	0	636	0	460	0
Apr	378	2	325	0	322	0	361	0	300	0	334	0	258	0	347	0	363	3
May	166	4	205	2	128	17	157	0	185	0	182	3	112	2	143	17	96	21
Jun	54	27	16	112	28	48	34	17	22	0	50	3	38	38	19	59	0	70
Jul	2	87	3	129	0	131	12	67	0	61	13	45	5	33	0	138	0	142
Aug	30	48	8	115	18	68	20	65	14	79	26	43	15	151	2	82	8	98
Sep	67	11	59	33	121	5	76	79	95	50	107	82	112	93	55	33	127	21
Oct	287	0	270	6	336	0	228	26	322	25	356	5	311	26	259	1	243	0
Nov	484	0	484	0	417	0	517	2	503	0	417	0	492	0	393	0	542	0
Dec	815	0	762	0	610	0	788	0	797	0	759	0	731	0	415	0	681	0

Employment Factor:

In order to measure the change in economic activity, a data series must be chosen which represents, as much as possible, regional economic activity. Although full-time employment levels for the Pembroke-Kingston region are available, a decision was made to use the monthly full-time employment levels for the Ottawa economic region, as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM).

The following table (Table 12) outlines the full-time employment levels for the Ottawa economic region.

Table 12: full-time employment levels for the Ottawa economic region

	2004	2005	2006	2007	2008	2009	2010	2011	2012
Jan	490.70	497.90	505.30	495.50	545.40	537.90	548.80	540.80	552.80
Feb	486.10	494.80	506.30	497.40	537.90	528.30	544.40	539.90	549.50
Mar	481.80	485.30	505.90	501.90	533.30	520.10	540.20	542.70	554.50
Apr	478.30	488.30	513.50	508.20	536.00	520.70	540.60	546.20	562.70
May	487.10	494.80	524.40	524.30	542.90	529.20	547.20	555.90	573.70
Jun	500.50	506.80	532.80	538.00	552.90	544.10	564.30	564.00	580.30
Jul	513.30	517.10	542.10	556.90	568.40	563.80	577.50	571.90	586.50
Aug	517.00	521.10	544.50	563.70	578.50	577.30	581.00	576.40	588.90
Sep	513.30	514.50	535.20	562.70	571.40	577.10	571.30	568.50	584.00
Oct	511.20	509.00	518.80	558.60	559.40	570.00	562.10	560.00	575.00
Nov	505.60	502.80	501.30	553.60	546.50	561.70	550.90	552.70	570.40
Dec	505.80	508.80	497.50	553.80	546.00	556.30	546.50	551.80	567.50

Spring/Fall Flag:

The forecast equation for HHI's monthly wholesale kWh also contains a seasonal factor, specifically a spring/fall flag to account for the seasonal increase in consumption in the summer and winter months.

Using these variables, an excel based multiple regression analysis was used to develop an equation describing the relationship between monthly actual wholesale kWh and the explanatory variables. HHI also used a correlation function to examine the relationship between the variables included in the analysis.

The following table (Table 13) presents the regression results used to determine the load forecast

Table 13: Correlation/Regression Results

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.923925728
R Square	0.85363875
Adjusted R Square	0.847954818
Standard Error	751094.0192
Observations	108

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	4	3.39E+14	8.47E+13	150.1845	4.7E-42
Residual	103	5.81E+13	5.64E+11		
Total	107	3.97E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	12655144.17	1535357	8.242479	5.74E-13	9610127	15700162	9610127	15700162
HDD	6100.745368	358.0589	17.03839	9.8E-32	5390.62	6810.871	5390.62	6810.871
CDD	8347.999145	2929.428	2.849703	0.005286	2538.17	14157.83	2538.17	14157.83
Spring Fall	-713674.8467	172183.6	-4.14485	6.99E-05	-1055160	-372189	-1055160	-372189
FTE for Ottawa Region	-1925.480886	2784.022	-0.69162	0.490733	-7446.93	3595.969	-7446.93	3595.969

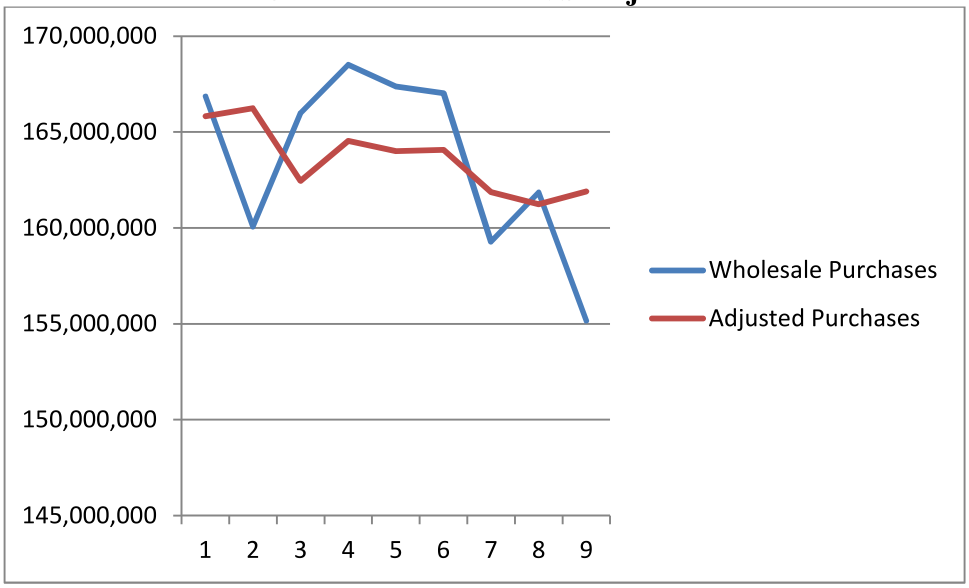
Table 14 below provides a comparison of the forecasted, actual and weather-normalized purchases kWhs over the past ten years. In accordance with the Filing Requirements, HHI has also provided a 2013 forecast assuming twenty-year normal weather conditions. Following table 14 is a Chart 1 which plots Actual Purchases vs Adjusted.

Table 14: Purchased VS Adjusted

Year	Wholesale Purchases	%chg	Adjusted Purchases	%chg	Purch vs. Adj
2004	166,851,164		165,821,248		-1%
2005	160,069,378	-4%	166,241,558	0%	4%
2006	165,982,316	4%	162,449,680	-2%	-2%
2007	168,514,536	2%	164,532,648	1%	-2%
2008	167,375,788	-1%	164,003,916	0%	-2%
2009	167,014,596	0%	164,063,489	0%	-2%
2010	159,288,613	-5%	161,866,770	-1%	2%
2011	161,859,215	2%	161,230,849	0%	0%
2012	155,160,223	-4%	161,905,672	0%	4%

As shown in the table above, 2012 adjusted wholesale purchases are up 2.37% from 2011 and 2.58% higher than the Actual Wholesale Purchases.

Chart 1: Purchased VS Adjusted



Annual estimates using actual weather are compared to actual values in the table 15 below. Mean absolute percentage error (MAPE is a measure of how high or low are the differences between the predictions and actual data) of annual estimates for the period is 1.69%. On a monthly basis, the MAPE was calculated as 5.6%. Although the MAPE calculated on a monthly basis is higher than the MAPE calculated on a yearly basis, this forecast is intended for determination of annual load; therefore, an annual MAPE is an appropriate measure for predictive accuracy. The median is calculated at 2.01%.

Table 15 – Actual vs. Predicted Wholesale kWh

Year	kWh Purchased	Adjusted	Purch. VS Adj.	MAPE
2004	166,851,164.00	165,821,247.57	-0.62%	0.62%
2005	160,069,378.00	166,241,557.76	3.86%	3.86%
2006	165,982,316.00	162,449,680.06	-2.13%	2.13%
2007	168,514,536.00	164,532,647.58	-2.36%	2.36%
2008	167,375,788.00	164,003,915.65	-2.01%	2.01%
2009	167,014,595.54	164,063,488.91	-1.77%	1.77%
2010	159,288,613.00	161,866,770.15	1.62%	1.62%
2011	161,859,215.00	161,230,848.61	-0.39%	0.39%
2012	155,160,223.00	161,905,672.25	4.35%	4.35%
MAPE				**2.12%**
Median				**2.01%**

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Customer Forecast

HHI has used a simple geometric mean function to determine the forecasted number of customers of 2013 and 2014. Geometric mean is more appropriate to use when dealing with percentages and rates of change. Although the formula is somewhat simplistic, it is reasonably representative of HHI's natural customer growth. The geometric mean results were analyzed by HHI and then further adjusted for known connections. Being a small allows the utility to be well informed on new connections in all classes. Historic customer counts and projected customer counts for 2013 and 2014 are presented in Table 16 at the next page.

Table 16 – Customer Forecast

	Residential		GS<50		GS>50		Street Lights		Sentinel Lights		USL	
Date	Conn.	Growth Rate	Conn.	Growth Rate	Conn.	Growth Rate	Conn.	Growth Rate	Conn.	Growth Rate	Conn	Growth Rate
2003	4553		583		77		1158		23		0	
2004	4580	1.0059	568	0.9743	78	1.0130	1158	1.0000	23	1.0000	0	1.0000
2005	4611	1.0068	564	0.9930	72	0.9231	1158	1.0000	24	1.0435	0	1.0000
2006	4642	1.0067	566	1.0035	78	1.0833	1158	1.0000	22	0.9167	0	1.0000
2007	4775	1.0287	573	1.0124	80	1.0256	1158	1.0000	21	0.9545	0	1.0000
2008	4778	1.0006	579	1.0105	80	1.0000	1158	1.0000	21	1.0000	4	4000.0000
2009	4781	1.0006	586	1.0121	82	1.0250	1158	1.0000	21	1.0000	4	1.0000
2010	4817	1.0075	593	1.0119	86	1.0488	1180	1.0190	21	1.0000	5	1.2500
2011	4835	1.0037	592	0.9983	94	1.0930	1201	1.0178	21	1.0000	5	1.0000
2012	4869	1.0070	616	1.0405	94	1.0000	1204	1.0025	21	1.0000	5	1.0000
Geomean		*1.0075*		*1.0061*		*1.0224*		*1.0043*		*0.9899*		*2.5763*
2013	4905		620		96		1209		21		13	
2014	4942		624		98		1214		21		33	

adjusted												
2013	4905	1.0074	630	1.0227	96	1.0213	1210	1.0050	21	1.0000	5	1.0000
2014	4950	1.0092	634	1.0063	98	1.0208	1215	1.0041	21	1.0000	5	1.0000

Residential customers grew steadily up until 2006. However, growth in the residential class has tapered off since 2006, the reason being that, as mentioned earlier in the application, Hawkesbury has a high elderly population and also has the lowest household income in the country. Typically, high income jobs are found in proximity to Canada's largest cities. Equally, the smaller and more rural the city, the fewer the opportunities there are for higher income careers. Residential counts are expected to grow by 81 from 2012 to 2014.

An increase in inhabitants usually results in an increase in commercial or municipal services. HHI anticipates an increase of 18 customers in General Services <50 from 2012 to 2014 and four customer s in the GS>50 class. Eleven additional Streetlights connections are also anticipated from 2012 to 2014.

Class specific weather normalization and consumption

The following section presents class specific weather normal historic and forecast values for those classes that have weather sensitive load. Historic class specific kWh consumption is allocated based on each class' share in wholesale kWh, exclusive of distribution losses. Forecast class values are allocated based on the class share for 2012.

HHI estimates that the load growth of existing customers will be no more than 1% per year. Additional energy usage typical of more air conditioners, computers, TVs and, pool will be offset by the additional transitioning to energy efficient lighting, appliances and other energy efficient changes.

Tables 17-18-19 show historical and forecasted details for each of the weather sensitive classes.

Table 17 – Annual Residential Forecast

Residential						
Year	Actual residential kWh	Wholesale Purchases	Adjusted Purchases	*Share%*	Weather Normal	Per customer
2004	54,156,577	166,851,164	165,821,248	32.46%	53,822,287	11,752
2005	52,898,956	160,069,378	166,241,558	33.05%	54,938,708	11,915
2006	51,530,722	165,982,316	162,449,680	31.05%	50,433,983	10,865
2007	53,035,556	168,514,536	164,532,648	31.47%	51,782,360	10,844
2008	53,471,410	167,375,788	164,003,916	31.95%	52,394,201	10,966
2009	52,558,954	167,014,596	164,063,489	31.47%	51,630,250	10,799
2010	50,277,839	159,288,613	161,866,770	31.56%	51,091,608	10,607
2011	51,273,093	161,859,215	161,230,849	31.68%	51,074,042	10,563
2012	51,132,834	155,160,223	161,905,672	32.95%	53,355,787	10,958
2013			164,810,801	32.95%	54,313,169	11,072
2014			164,694,601	32.95%	54,274,875	11,352

* consumption is further adjusted below

Load corrected based on HHI input

Residential						
Year	Actual residential kWh	Wholesale Purchases	Adjusted Purchases	*Share%*	Weather Normal	Per customer
2012	51,132,834	155,160,223	161,905,672	32.95%	53,355,787	10,958
2013	0	0	164,810,801	32.95%	54,313,169	11,072
2014	0	0	164,694,601	32.95%	54,274,875	11,352

Residential				
Year	New Customer	Per Customer Weather Normalized (based on 2012 cust count)	Added Load	Total
2013	36	11,072	398,593	**54,711,762**
2014	45	11,352	510,849	**54,785,724**

Table 18 – Annual General Service <50 Consumption

GS<50						
Year	Actual GS<50 kWh	Wholesale Purchases	Adjusted Purchases	*Share%*	Weather Normal	Per customer
2004	22,859,934	166,851,164	165,821,248	13.70%	22,718,827	39,998
2005	21,840,735	160,069,378	166,241,558	13.64%	22,682,901	40,218
2006	20,878,233	165,982,316	162,449,680	12.58%	20,433,877	36,102
2007	20,965,147	168,514,536	164,532,648	12.44%	20,469,754	35,724
2008	20,649,618	167,375,788	164,003,916	12.34%	20,233,621	34,946
2009	19,616,748	167,014,596	164,063,489	11.75%	19,270,125	32,884
2010	19,562,613	159,288,613	161,866,770	12.28%	19,879,243	33,523
2011	18,457,375	161,859,215	161,230,849	11.40%	18,385,720	31,057
2012	18,531,354	155,160,223	161,905,672	11.94%	19,336,988	31,391
2013			164,810,801	11.94%	19,683,958	31,760
2014			164,694,601	11.94%	19,670,080	31,544

* consumption is further adjusted below

Load corrected based on HHI input

GS<50						
Year	Actual GS<50 kWh			*Share%*	Weather Normal	Per customer
2012	18,531,354	155,160,223	161,905,672	11.94%	19,336,988	31,391
2013	0	0	164,810,801	11.94%	19,683,958	31,760
2014	0	0	164,694,601	11.94%	19,670,080	31,544

GS<50				
Year	New Customer	Per Customer Weather Normalized	Added Load	Total
2013	14	31,760	444,634	**20,128,592**
2014	1	31,544	31,544	**19,701,623**

Table 19 – Annual General Service >50 Consumption

GS>50						
Year	Actual GS>50 kWh	Wholesale Purchases	Adjusted Purchases	*Share%*	Weather Normal	Per customer
2004	133,016,925	166,851,164	165,821,248	79.72%	132,195,856	1,694,819
2005	117,613,071	160,069,378	166,241,558	73.48%	122,148,161	1,696,502
2006	116,290,495	165,982,316	162,449,680	70.06%	113,815,460	1,459,173
2007	117,345,908	168,514,536	164,532,648	69.64%	114,573,101	1,432,164
2008	112,845,011	167,375,788	164,003,916	67.42%	110,571,690	1,382,146
2009	96,007,524	167,014,596	164,063,489	57.48%	94,311,095	1,150,135
2010	80,745,583	159,288,613	161,866,770	50.69%	82,052,486	954,099
2011	82,739,387	161,859,215	161,230,849	51.12%	82,418,178	876,789
2012	77,875,019	155,160,223	161,905,672	50.19%	81,260,564	864,474
2013			164,810,801	50.19%	82,718,651	860,695
2014			164,694,601	50.19%	82,660,329	841,234

Actual, normalized and forecast kW for the weather sensitive GS>50 class are summarized in Table 20 below. Historical normalized values are calculated based on the annual ratio of class kW to class kWh. Forecast kW is based on the class kW to class kWh ratio in 2008.

Table 20 – Annual General Service >50 Demand (kW)

	GS>50			
Year	Energy	Weather Adj	Demand	KW/kWh Ratio
2004	133,016,925		281,031	0.00211
2005	117,613,071		275,148	0.00234
2006	116,290,495		274,200	0.00236
2007	117,345,908		290,290	0.00247
2008	112,845,011		304,147	0.00270
2009	96,007,524		253,516	0.00264
2010	80,745,583		209,711	0.00260
2011	82,739,387		211,681	0.00256
2012	77,875,019		206,655	0.00265
2013		82,718,651	206,144	
2014		82,660,329	205,999	
Avg				*0.00249*

Table 21 a) and b) presents actual and forecast kWh and kW for the non-weather sensitive Street Lighting and Sentinel Lights, and kWh for non-weather sensitive USL. The forecast throughput for USL and Sentinel Lights classes is only changing marginally as no changes to the number of customer connections are anticipated in 2013 or 2014. Street Lighting will see a marginal increase equivalent to the increase in connections. The USL class did not have any connections prior to 2008 and as such, only 4 years of data is available to use as an average. HHI feels that the demand predictions for 2013 and 2014 are accurate.

Table 21a)- non-weather sensitive Street Lighting, Sentinel Lights

Streetlight					
Energy	Demand	Connection	kWh per connection	KW per connection	KW/kWh Ratio
904,010	2,777	1,158	781	2.3981	0.00307
912,952	2,843	1,158	788	2.4551	0.00311
1,025,217	2,872	1,158	885	2.4801	0.00280
972,414	2,874	1,158	840	2.4819	0.00296
1,208,366	3,098	1,158	1,043	2.6753	0.00256
1,151,305	3,198	1,158	994	2.7617	0.00278
1,156,978	3,194	1,180	980	2.7068	0.00276
1,343,667	3,724	1,201	1,119	3.1007	0.00277
1,355,855	3,748	1,204	1,126	3.1130	0.00276
1,150,473	3,250	1,210			
1,155,227	3,263	1,215			
			951	*2.6858*	*0.00284*

Sentinel Lights					
Energy	Demand	Connection	kWh per connection	KW per connection	KW/kWh Ratio
104,334	304	23	4,536	13.2174	0.00291
109,474	300	24	4,561	12.5000	0.00274
106,680	302	22	4,849	13.7273	0.00283
108,699	300	21	5,176	14.2857	0.00276
108,472	300	21	5,165	14.2857	0.00277
108,855	300	21	5,184	14.2857	0.00276
105,383	297	21	5,018	14.1429	0.00282
102,889	280	21	4,899	13.3333	0.00272
102,354	284	21	4,874	13.5238	0.00277
106,349	297	21			
106,349	297	21			
106,349	*296*		*4,918*	*13.7002*	*0.00279*

Table 21b)- non-weather sensitive Street Lighting, Sentinel Lights

USL		
kWh Adj	Connection	kWh per connection
42,962	0	
53,987	0	
64,965	0	
76,398	0	
86,849	4	21,712
181,221	4	45,305
242,514	5	48,503
215,299	5	43,060
214,901	5	42,980
224,238	5	
224,238	5	
		44,848

Table 22 below presents the results for class specific historic actual and historic normalized kWh and kW (where applicable), and normalized forecast values for bridge year (2009) and test year (2010).

Table 22 – Load Forecast (Historical, Bridge and Test Years).

	Residential		GS<50		GS>50			Streetlights			Sentinel Lights			USL	
Year	Cust	Adj kWh	Cust	Adj kWh	Cust	Adj kWh	Adj kW	Cust	Adj kWh	Adj kW	Cust	Adj kWh	Adj kW	Con	Adj kWh
2004	4,580	53,822,287	568	22,718,827	78	132,195,856	281,031	1,158	904,010	2,777	23	104,334	304	0	42,962
2005	4,611	54,938,708	564	22,682,901	72	122,148,161	275,148	1,158	912,952	2,843	24	109,474	300	0	53,987
2006	4,642	50,433,983	566	20,433,877	78	113,815,460	274,200	1,158	1,025,217	2,872	22	106,680	302	0	64,965
2007	4,775	51,782,360	573	20,469,754	80	114,573,101	290,290	1,158	972,414	2,874	21	108,699	300	0	76,398
2008	4,778	52,394,201	579	20,233,621	80	110,571,690	304,147	1,158	1,208,366	3,098	21	108,472	300	4	86,849
2009	4,781	51,630,250	586	19,270,125	82	94,311,095	253,516	1,158	1,151,305	3,198	21	108,855	300	4	181,221
2010	4,817	51,091,608	593	19,879,243	86	82,052,486	209,711	1,180	1,156,978	3,194	21	105,383	297	5	242,514
2011	4,835	51,074,042	592	18,385,720	94	82,418,178	211,681	1,201	1,343,667	3,724	21	102,889	280	5	215,299
2012	4,869	53,355,787	616	19,336,988	94	81,260,564	206,655	1,204	1,355,855	3,748	21	102,354	284	5	214,901
2013	4,905	54,711,762	630	20,128,592	96	82,718,651	206,144	1,210	1,150,473	3,250	21	106,349	297	5	224,238
2014	4,950	54,785,724	634	19,701,623	98	82,660,329	205,999	1,215	1,155,227	3,263	21	106,349	297	5	224,238

<u>Average use</u>

Table 23 below presents the actual average use per customer, by customer class, and historical and adjusted forecast average use per customer generated using our load forecast. As can be seen from the results below, the predicted use per customer is in line with historical usage per customer.

Table 23 – Average use per customer (Historical, Bridge and Test Years).

	Residenttial	GS<50	GS>50		Streetlights		Sentinel Lights		USL
Year	Per cust	Per cust	per cust kWh	per cust kW	per cust kWh	per cust kW	per cust kWh	per cust kW	per cust kWh
2004	11,825	40,246	1,705,345	3,603	781	2	4,536	13	
2005	11,472	38,725	1,633,515	3,822	788	2	4,561	13	
2006	11,101	36,887	1,490,904	3,515	885	2	4,849	14	
2007	11,107	36,588	1,466,824	3,629	840	2	5,176	14	
2008	11,191	35,664	1,410,563	3,802	1,043	3	5,165	14	21,712
2009	10,993	33,476	1,170,823	3,092	994	3	5,184	14	45,305
2010	10,438	32,989	938,902	2,439	980	3	5,018	14	48,503
2011	10,605	31,178	880,206	2,252	1,119	3	4,899	13	43,060
2012	10,502	30,083	828,458	2,198	1,126	3	4,874	14	42,980
2013	11,154	31,950	861,653	2,147	951	3	5,064	14	44,848
2014	11,068	31,075	843,473	2,102	951	3	5,064	14	44,848

E3.T1.S5 PERSISTENCE FROM HISTORICAL CDM PROGRAMS

While the forecast as presented in the previous section assumes some level of embedded “natural conservation, it does not take into account the impacts on energy purchases arising from CDM programs undertaken by HHI’s customers. The load forecast is a projection of the expected level of electricity purchases that would occur over the specified period in the absence of any CDM initiatives. Therefore, in accordance with the filing requirements, the forecasted energy purchases are further adjusted to reflect CDM reductions.

The schedule to achieve CDM targets are presented at Table 24 below.

Table 24 – Utility specific 2011-2014 CDM target

4 Year (2011-2014) kWh Target:	**9,280,000**

	2011	2012	2013	2014	Total
	%				
2011 CDM Programs	7.76%	7.76%	7.76%	7.11%	30.39%
2012 CDM Programs		18.57%	4.63%	4.63%	13.90%
2013 CDM Programs			18.57%	18.57%	37.14%
2014 CDM Programs				18.57%	18.57%
Total in Year	**6.33%**	**18.78%**	**31.23%**	**43.66%**	**100.00%**

	kWh				
2011 CDM Programs	720,000	720,000	720,000	660,000	2,820,000
2012 CDM Programs		430,000	430,000	430,000	1,290,000
2013 CDM Programs			1,723,333	1,723,333	3,446,667
2014 CDM Programs				1,723,333	1,723,333
Total in Year	**720,000**	**1,150,000**	**2,873,333**	**4,536,667**	**9,280,000**
				Check	9,280,000

The following table shows the net-to gross ratio (conversion factor). The values for 2011 entered in this sheet originate from the OPA issued report; 2006-2010 Final OPA CDM Results. The report provides a portfolio-level summary of the annual resource savings (demand and energy, net and gross for each) for the 2006–2010 program portfolios for HHI. HHI used the Q4 report from the OPA. The most recent annual results of OPA CDM programs and the Q4 results are presented as an appendix to this Exhibit.

Table 25 – Q4 OPA report

Table 2: Net Energy Savings at the End-User Level (GWh)

#	Implementation Period	Annual (GWh)				Cumulative (GWh)
		2011	2012	2013	2014	2011-2014
1	2011 - Final*	0.72	0.72	0.72	0.66	2.82
2	2012 - Reported - Quarter 1		0.19	0.19	0.19	0.57
3	2012 - Reported - Quarter 2		0.19	0.19	0.19	0.56
4	2012 - Reported - Quarter 3		0.03	0.03	0.03	0.08
5	2012 - Reported - Quarter 4		0.06	0.06	0.06	0.18
6	2013					
7	2014					
	Energy Efficiency	0.72	1.18	1.18	1.12	4.20
	Demand Response	0.00	0.00	0.00	0.00	0.00
	Net Energy Savings	0.72	1.18	1.18	1.13	4.20
	Unverified Net Cumulative Energy Savings 2011-2014:					**4.20**
	2011-2014 Cumulative Energy Savings Target as per OEB:					**9.28**
	Unverified 2011-2014 Cumulative Energy Target Achieved (%):					**45.3%**
	Incremental Reported (Unverified)	0.27	0.46			
	Incremental Final (Verified)	0.72	n/a			

Table 26 – Calculation of adjustment to the Load Forecast

Net-to-Gross Conversion kWh					
		"Gross"	**"Net"**	**Difference**	**"Net-to-Gross" Conversion Factor ("g")**
2006		574,000	514,000	-60,000	-10.45%
2007		2,432,000	926,000	-1,506,000	-61.92%
2008		1,623,000	971,000	-652,000	-40.17%
2009		1,907,000	1,211,000	-696,000	-36.50%
2010		1,621,000	929,000	-692,000	-42.69%
2011		1,425,000	730,000	-695,000	-48.77%
2012		1,329,000	689,000	-640,000	-48.16%
2013		1,327,000	688,000	-639,000	-48.15%
2014		1,247,000	649,000	-598,000	-47.96%
2006 to 2011 OPA CDM programs: Persistence to 2014		**13,485,000**	**7,307,000**	**6,178,000**	**84.55%**

	2011	**2012**	**2013**	**2014**	**Total for 2014**
Amount used for CDM threshold for LRAMVA	660,000	430,000	1,723,333	1,723,333	4,536,667
Manual Adjustment for 2013 Load Forecast	1,218,024	793,561	3,180,396	1,590,198	6,782,178
Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g)					

E3.T1.S6 CLASS SPECIFIC CDM COMPONENT

The overall CDM adjustment for 2014, as calculated above, is allocated on pro-rata basis (using kWh forecast) per class.

Table 27 – CDM adjustments to Load Forecast

kWh	2013	2014	Share	Target	Target
Residential	54,711,762	54,785,724	34.54%	2,342,295.64	52,443,428.21
GS<50	20,128,592	19,701,623	12.42%	842,318.46	18,859,304.83
GS>50	82,718,651	82,660,329	52.11%	3,534,039.81	79,126,289.66
Streetlight	1,150,473	1,155,227	0.73%	49,390.31	1,105,837.04
Sentinel Lights	106,349	106,349	0.07%	4,546.81	101,802.07
USL	224,238	224,238	0.14%	9,587.02	214,650.98
Total	159,040,065	158,633,491	100.00%	6,782,178.05	151,851,312.79

CDM Adjusted demand forecast

	2013	2014			
GS>50	206,144	205,999			197,191
Streetlight	3,250	3,263			3,124
Sentinel Lights	297	297			284
Total		209,559			200,599

Tab 2 – Variance Analysis of Proposed Revenues

E3.T2.S1 OVERVIEW

HHI's 2013 forecasted revenues recovered through its currently approved distribution rates will be $1,363,660 (exclusive of all rate riders). This amount is determined by applying the currently approved distribution rates to the forecasted consumption and customer counts. When the same formula is applied to the 2014 consumption, resulting revenues are $1,329,732. The forecasted 2014 distribution revenues are $33,110 higher than the 2013 actual amounts.

E3.T2.S2 PROJECTED REVENUES AT CURRENT AND PROPOSED RATES

These following tables show HHI's projected revenues for both the Bridge and Test Year at current and proposed rates.

Table 28 – Revenues at Current

Bridge Year

	Bridge Year Projected Revenue from Existing Variable Charges							
Customer Class Name	**Variable Distribution Rate**	**per**	**Bridge Year Volume**	**Gross Variable Revenue**	**Transform. Allowance Rate**	**Transform. Allowance kW's**	**Transform. Allowance $'s**	**Net Variable Revenue**
Residential	$0.0081	kWh	54,711,762	443,165			0	443,165
General Service < 50 kW	$0.0055	kWh	20,128,592	110,707			0	110,707
General Service > 50 to 4999 kW	$1.5558	kW	206,144	320,719	($0.60)	189,205	-113,523	207,196
Unmetered Scattered Load	$0.0021	kWh	224,238	471			0	471
Sentinel Lighting	$3.2285	kW	297	959	($0.60)		0	959
Street Lighting	$6.7744	kW	3,250	22,017	($0.60)		0	22,017
Total Variable Revenue			**75,274,283**	**898,038**		**189,205**	**-113,523**	**784,515**

Bridge Year

	Bridge Year Projected Revenue from Existing Fixed Charges							
Customer Class Name	**Fixed Rate**	**Customers (Connections)**	**Fixed Charge Revenue**	**Variable Revenue**	**TOTAL**	**% Fixed Revenue**	**% Variable Revenue**	**% Total Revenue**
Residential	$5.9900	4,905	352,571	443,165	795,737	44.31%	55.69%	58.35%
General Service < 50 kW	$13.8400	630	104,630	110,707	215,338	48.59%	51.41%	15.79%
General Service > 50 to 4999 kW	$97.3500	96	112,147	207,196	319,343	35.12%	64.88%	23.42%
Unmetered Scattered Load	$6.3900	5	383	471	854	44.88%	55.12%	0.06%
Sentinel Lighting	$1.6300	21	411	959	1,370	29.99%	70.01%	0.10%
Street Lighting	$0.6200	1,210	9,002	22,017	31,019	29.02%	70.98%	2.27%
Total Fixed Revenue		**6,867**	**579,146**	**784,515**	**1,363,660**			

Table 29 – Revenues at Proposed Rates

Test Year

	Test Year Projected Revenue from Existing Variable Charges							
Customer Class Name	**Variable Distribution Rate**	**per**	**Test Year Volume**	**Gross Variable Revenue**	**Transform. Allowance Rate**	**Transform. Allowance kW's**	**Transform. Allowance $'s**	**Net Variable Revenue**
Residential	$0.0081	kWh	52,443,428	424,792			0	424,792
General Service < 50 kW	$0.0055	kWh	18,859,305	103,726			0	103,726
General Service > 50 to 4999 kW	$1.5558	kW	197,191	306,790	($0.60)	189,205	-113,523	193,267
Unmetered Scattered Load	$0.0021	kWh	214,651	451			0	451
Sentinel Lighting	$3.2285	kW	284	918	($0.60)			918
Street Lighting	$6.7744	kW	3,124	21,161	($0.60)		0	21,161
Total Variable Revenue			**71,717,983**	**857,837**		**189,205**	**-113,523**	**744,314**

Test Year

	Test Year Projected Revenue from Existing Fixed Charges							
Customer Class Name	**Fixed Rate**	**Customers (Connections)**	**Fixed Charge Revenue**	**Variable Revenue**	**TOTAL**	**% Fixed Revenue**	**% Variable Revenue**	**% Total Revenue**
Residential	$5.9900	4,950	355,806	424,792	780,598	45.58%	54.42%	58.70%
General Service < 50 kW	$13.8400	634	105,295	103,726	209,021	50.38%	49.62%	15.72%
General Service > 50 to 4999 kW	$97.3500	98	114,484	193,267	307,750	37.20%	62.80%	23.14%
Unmetered Scattered Load	$6.3900	5	383	451	834	45.96%	54.04%	0.06%
Sentinel Lighting	$1.6300	21	411	918	1,329	30.92%	69.08%	0.10%
Street Lighting	$0.6200	1,215	9,040	21,161	30,200	29.93%	70.07%	2.27%
Total Fixed Revenue		**6,923**	**585,418**	**744,314**	**1,329,732**			

E3.T2.S2 VARIANCE ANALYSIS BY CLASS

The bulk of the increase is in the Residential Class which is expected since nearly 73% of the utility's load stems from the Residential Class. The main reasons for this variance, as explained in the load forecast, is due primarily to the lack of new development in the service area over the last several years. Secondly, additional energy consumption that does not depend on the weather (often referred to as "baseload" energy consumption) is often offset by the additional transitioning to energy efficient lighting, appliances and other energy efficient changes. Revenue Deficiency is discussed further in Exhibit 6.

Table 30 – Variance Analysis by Class

Variance Analysis

	Bridge Year to Test Year Variance			
Customer Class Name	**2013**	**2014**	**Variance**	**% change**
Residential	$795,736.67	$780,597.77	-15,139	-1.90%
General Service < 50 kW	$215,337.66	$209,020.90	-6,317	-2.93%
General Service > 50 to 4999 kW	$319,343.04	$307,750.36	-11,593	-3.63%
Unmetered Scattered Load	$854.30	$834.17	-20	-2.36%
Street Lighting	$1,369.62	$1,328.59	-41	-3.00%
MicroFit	$31,019.20	$30,200.49		
Total Fixed Revenue	**1,363,660**	**1,329,732**	**-33,110**	-2.49%

Tab 3 – Other Revenues

E3.T3.S1 OVERVIEW

Other Distribution Revenues are revenues that are distribution related but that are sourced from means other than distribution rates. It includes items such as

- Specific Service Charges
- Late Payment Charges
- Other Distribution Revenues
- Other Income and Expenses

Details of these revenues are provided at the next section E3.T3.S2. Variances on the revenue items will be explained at E3.T3.S3.

E3.T3.S2 BREAKDOWN BY ACCOUNT – APPENDIX 2-F

Appendix 2-F is presented at the next page.

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Appendix 2-F
Other Operating Revenue

USoA #	USoA Description	2010 Actual	2011 Actual	2012 Actual²	2012 Actual²	Bridge Year³	Bridge Year³	Test Year
						2013	2013	2014
	Reporting Basis					CGAAP	MIFRS	CGAAP
4235	Specific Service Charges	-$72,825.59	-$75,517.97	-$64,162.36		-$70,000.00		-$70,000.00
4225	Late Payment Charges	-$28,329.26	-$27,264.73	-$31,973.44		-$30,000.00		-$30,000.00
4080	Distribution Services Revenue	-$14,391.11	-$14,502.22	-$15,392.81		-$15,400.00		-$15,400.00
4082	Retail Services Revenues							
4084	STR Revenues							
4210	Rent from Electric Property	-$16,394.48	-$16,389.44	-$16,739.44		-$16,739.44		-$16,739.44
4325	Revenues from Jobbing	-$34,415.03	-$8,159.10	-$22,937.11		-$20,000.00		-$20,000.00
4330	Costs and Expenses from Jobbing	$19,817.12	$8,159.10	$14,618.53		$15,000.00		$15,000.00
4390	Misc Non-Operating Income	-$3,655.22	-$902.68	$0.00		$0.00		$0.00
4405	Interest and Dividend Income	-$12,059.97	-$36,255.44	-$39,530.41		-$20,000.00		-$20,000.00
Specific Service Charges		-$72,825.59	-$75,517.97	-$64,162.36	$0.00	-$70,000.00	$0.00	-$70,000.00
Late Payment Charges		-$28,329.26	-$27,264.73	-$31,973.44	$0.00	-$30,000.00	$0.00	-$30,000.00
Other Operating Revenues		-$30,785.59	-$30,891.66	-$32,132.25	$0.00	-$32,139.44	$0.00	-$32,139.44
Other Income or Deductions		-$30,313.10	-$37,158.12	-$47,848.99	$0.00	-$25,000.00	$0.00	-$25,000.00
Total		-$162,253.54	-$170,832.48	-$176,117.04	$0.00	-$157,139.44	$0.00	-$157,139.44

Description	Account(s)
Specific Service Charges:	4235
Late Payment Charges:	4225
Other Distribution Revenues:	4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Note: Add all applicable accounts listed above to the table and include all relevant information.

The above table assumes adoption of MIFRS as of January 1, 2013. If the adoption year differs, please adjust the table accordingly.

Account Breakdown Details

For each "Other Operating Revenue" and "Other Income or Deductions" Account, a detailed breakdown of the account components is required. See the example below for Account 4405, Interest and Dividend Income.

4210 - Rent from Electric Property

	2010 Actual	2011 Actual	2012 Actual²	2012 Actual²	Bridge Year	Bridge Year	Test Year
Reporting Basis					CGAAP	MIFRS	CGAAP
Office Rent	$ (1,200)	$ (1,200)	$ (1,200)	$ -	$ (1,200)	$ -	$ (1,200)
COGECO Pole Rental	$ (13,310)	$ (13,332)	$ (13,332)	$ -	$ (13,325)	$ -	$ (13,325)

BELL Pole Rental - Expense	$ 12,435	$ 12,462	$ 12,462	$ -	$ 12,453	$ -	$ 12,453
BELL Pole Rental - Revenue	$ (14,170)	$ (14,170)	$ (14,170)		$ (14,170)		$ (14,170)
Conference Room Rental	$ (150)	$ (150)	$ (500)	$ -	$ (498)	$ -	$ (498)
	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ (16,394)	$ (16,389)	$ (16,739)	$ -	$ (16,739)	$ -	$ (16,739)

4325 - Revenues from Jobbing

	2010 Actual	2011 Actual	2012 Actual[2]	2012 Actual[2]	Bridge Year	Bridge Year	Test Year
Reporting Basis					CGAAP	MIFRS	CGAAP
Miscelleneous jobbing revenues	$ (34,415)	$ (8,159)	$ (22,937)		$ (20,000)	$ -	$ (20,000)
	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ (34,415)	$ (8,159)	$ (22,937)	$ -	$ (20,000)	$ -	$ (20,000)

4330 - Costs and Expenses from Jobbing

	2010 Actual	2011 Actual	2012 Actual[2]	2012 Actual[2]	Bridge Year	Bridge Year	Test Year
Reporting Basis					CGAAP	MIFRS	CGAAP
Miscelleneous jobbing expenses	$ 19,817	$ 8,159	$ 14,619		$ 15,000	$ -	$ 15,000
	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 19,817	$ 8,159	$ 14,619	$ -	$ 15,000	$ -	$ 15,000

4390 - Miscellaneous Non-Operating Income

	2010 Actual	2011 Actual	2012 Actual[2]	2012 Actual[2]	Bridge Year	Bridge Year	Test Year
Reporting Basis					CGAAP	MIFRS	CGAAP
UTILISMART Dividend	$ (1,566)	$ (483)	$ -	$ -	$ -	$ -	$ -
Sale of Scrap	$ (2,089)	$ (420)	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ (3,655)	$ (903)	$ -	$ -	$ -	$ -	$ -

4405 - Interest and Divided Income

	2010 Actual	2011 Actual	2012 Actual[2]	2012 Actual[2]	Bridge Year	Bridge Year	Test Year
Reporting Basis					CGAAP	MIFRS	CGAAP
Short-term Investment Interest	$ (10,835)	$ (1,404)	$ -		$ -		$ -
Bank Deposit Interest	$ (987)	$ (4,616)	$ (2,385)		$ (2,000)		$ (2,000)
Miscellaneous Interest Revenue	$ (238)	$ (2,635)	$ (21)		$ (1,000)		$ (1,000)
Carrying Charges on RSVA Accts	$ -	$ (27,601)	$ (26,442)		$ (17,000)		$ (17,000)
Write-Off of Accts 1570 & 1571 as per OEB Regulatory Auditors			$ (10,682)				
Total	$ (12,060)	$ (36,255)	$ (39,530)	$ -	$ (20,000)	$ -	$ (20,000)

Notes:

1. List and specify any other interest revenue
2. If the applicant is adopting IFRS or an alternate accounting standard as of January 1, 2012 for financial reporting purposes, 2011 must be presented on both a CGAAP and MIFRS
3. If the applicant is adopting IFRS or an alternate accounting standard as of January 1, 2013 for financial reporting purposes, 2012 must be presented on both a CGAAP and MIFRS

E3.T3.S3 VARIANCE ANALYSIS

Table 31 below presents the summary and year over year variances of other operating revenues. Account 4235 and 4225 saw a spike from 2011-2012 due to the increase in the amount of collection that occurred in that particular year. The increase in these two accounts coincides with the utility abolishing its security deposit policy. The number of collections and late payment charges show no signs of slowing down in the test year and beyond.

Table 31 – Variance Analysis of Other Operating Revenues

USoA #	USoA Description	2010	2011	2012	2013	2014
	Specific Service Charges	$72,825.59	$75,517.97	$64,162.36	$70,000.00	$70,000.00
	Late Payment Charges	$28,329.26	$27,264.73	$31,973.44	$30,000.00	$30,000.00
	Other Operating Revenues	$30,785.59	$30,891.66	$32,132.25	$32,139.44	$32,139.44
	Other Income or Deductions	$30,313.10	$37,158.12	$47,848.99	$25,000.00	$25,000.00

USoA #	USoA Description		2011-2010	2012-2011	2013-2012	2014-2013
4235	Specific Service Charges		4%	-15%	9%	0%
4225	Late Payment Charges		-4%	17%	-6%	0%
4082	Retail Services Revenues		0%	4%	0%	0%
4080	Admin Charge		23%	29%	-48%	0%

The percentage increase in other accounts is misleading due to the relatively small dollar amounts being compared.

E3.T3.S4 SPECIFIC SERVICE CHARGES

A Specific Service Charge is an approved fixed rate charged to a customer for a specific activity or service, or as a penalty. Activities include services that are only available from, or under the control of, the distributor. There are also special or extra services that a distributor chooses to provide. Such services may be those that are of benefit to the distributor or to other customers, and that are provided at a customer's request or as the result of a customer's action or inaction. Specific Service Charges are established for activities that are over and above the distributor's standard level of service. The costs of providing the standard level of service are recovered in the regular distribution rates. The proposed list of specific service charges is presented at the next page.

Table 32 – Current and Proposed Specific Service Charge

		Curent Rates	Proposed Rates
Service	***USoA***	**Rate**	**Rate**
Standard Supply Service -- Administrative Charge	4080	$0.25	$0.25
Retailer Service Agreement -- standard charge	4082	$100.00	$100.00
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	$20.00	$20.00
Retailer Service Agreement -- monthly variable charge (per customer)	4082	$0.50	$0.50
Distributor-Consolidated Billing -- monthly charge (per customer)	4082	$0.30	$0.30
Retailer-Consolidated Billing -- monthly credit (per customer)	4082	-$0.30	-$0.30
Service Transaction Request - request fee,per request, applied to the requesting party	4084	$0.25	$0.25
Service Transaction Request - processing fee,per request, applied to the requesting party	4084	$0.50	$0.50
Arrears Certificate	4084	$15.00	$15.00
Statement of Account	4084	$15.00	$15.00
Duplicate invoices for previous billing	4084	$15.00	$15.00
Notification Charge	4084	$30.00	$30.00
Customer Information request -- non-EBT (more than twice a year, per request)	4084	$2.00	$2.00
Specific Charge for Access to the Power Poles – per pole/year	4210	$22.35	$22.35
Late Payment - per month	4225	$0.02	$0.02
Collection of account charge – no disconnection	4225	$15.00	$15.00
Credit reference/credit check (plus credit agency costs)	4235	$15.00	$15.00
Returned Cheque charge (plus bank charges)	4235	$20.00	$20.00
Account set up charge / change of occupancy charge	4235	**$30.00**	**$40.00**
Meter dispute charge plus Measurement Canada fees (if meter found correct)	4235	$30.00	$30.00
Disconnect/Reconnect at meter – during regular hours	4235	$30.00	$30.00
Disconnect/Reconnect at meter – after regular hours	4235	**$130.00**	**$170.00**
Disconnect/Reconnect at pole – during regular hours	4235	$100.00	$100.00
Disconnect/Reconnect at pole – after regular hours	4235	$300.00	$300.00
Install / remove load control device – during regular hours	4235	$30.00	$30.00
Install / remove load control device – after regular hours	4235	**$130.00**	**$170.00**
Service call – after regular hours	4235	**$130.00**	**$170.00**
Temporary service install and remove – overhead – no transformer	4235	$500.00	$500.00
Temporary service install and remove – overhead – with transformer	4235	$1,000.00	$1,000.00

E3.T3.S5 PROPOSED CHANGES TO SPECIFIC SERVICE REVENUES

HHI proposes to update the rates of four of its specific service revenues. (1) Change of occupancy charge from its current rate of $30.00 to $40.00. (2) Disconnect/Reconnect at meter – after regular hours from its current rate of $130.00 to $170.00; (3) Install / remove load control device – after regular hours from its current rate of $130.00 to $170.00. (4) Service call – after regular hours from its current rate of $130.00 to $170.00. HHI management has evaluated the costs currently charged for these services and determined that the current rates were not sufficient to fully recover the actual costs. Details are presented in the tables below.

Table 33 - Change of occupancy charge

CURRENT FEE:	$30.00
ADJUSTED FEE REQUESTED:	**$40.00**
ACTUAL COSTS	
Lineman out in field for meter disconnection:	$11.00
(Average time - 15 minutes)	
Fuel costs:	$3.00
CSR at counter to complete "Demand of Service" contract:	$8.00
(Average time - 15 minutes)	
Billing clerk to complete the opening of account in CIS:	$15.00
(Average time - 20 minutes)	
TOTAL COSTS:	**$37.00**

Table 34 - Disconnect/Reconnect at meter – after regular hours

CURRENT FEE:	$130.00
ADJUSTED FEE REQUESTED:	**$170.00**
ACTUAL COSTS	
Lineman out in field for meter disconnection:	$159.56
(Paid 4 hours as per Union contract)	
Fuel costs:	$3.00
TOTAL COSTS:	**$162.56**

Table 35 - Install / remove load control device – after regular hours

CURRENT FEE:	$130.00
ADJUSTED FEE REQUESTED:	**$170.00**
ACTUAL COSTS	
Lineman out in field for installation of load control device:	$159.56
(Paid 4 hours as per Union contract)	
Fuel costs:	$3.00
TOTAL COSTS:	**$162.56**

Table 36 - Service call – after regular hours

CURRENT FEE:	$130.00
ADJUSTED FEE REQUESTED:	**$170.00**
ACTUAL COSTS	
Lineman out in field for service call:	$159.56
(Paid 4 hours as per Union contract)	
Fuel costs:	$3.00
TOTAL COSTS:	**$162.56**

E3.T3.S6 REVENUES FOR AFFILIATE TRANSACTIONS

HHI does not have affiliates and as such does not engage in affiliate transactions.

E3.T3.S7 PASS THROUGH REVENUES

HHI is an embedded distributor of Hydro One Networks Inc. ("HONI") and is charged monthly by HONI for its power supply expenses.

Pass-through charges for power supply include commodity, retail transmission services, wholesale market service, rural rate protection and low voltage service. Debt retirement charges are not included. A total loss factor applies to forecast retail volumes for all pass-through charges other than low voltage service, when the billing determinant is kWh.

Commodity Price

The assumed commodity prices are based on the Regulated Price Plan ("RPP") Report issued by the OEB on April 5, 2013. The estimated price for RPP customers corresponds to the average supply cost for RPP customers specified in the report's Table ES-1 as indicated in the excerpt below.

Table ES-1: Average RPP Supply Cost Summary (for the 12 months from May 1, 2013)

RPP Supply Cost Summary
for the period from May 1, 2013 through April 30, 2014

		Current
Forecast Wholesale Electricity Price		$19.33
Load-Weighted Price for RPP Consumers ($ / MWh)		$21.05
Impact of the Global Adjustment ($ / MWh)	+	$66.12
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	+	$1.00
Adjustment to Clear Existing Variance ($ / MWh)	+	($4.21)
Average Supply Cost for RPP Consumers ($ / MWh)	=	**$83.95**

HHI used RPP and non-RPP split to calculate the weighted average commodity price. The table below shows HHI's determinate of its commodity.

Table 33 – Determination of Commodity

Determination of Commodity

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

Forecast Price

HOEP ($/MWh)				$19.33	
Global Adjustment ($/MWh)				$66.12	
Adjustments					
TOTAL ($/MWh)				**$85.45**	**$83.95**
$/kWh				***$0.08545***	***$0.08395***
%				54.90%	45.10%
WEIGHTED AVERAGE PRICE		**$0.0848**		**$0.0469**	**$0.0379**

Electricity Projections
(loss adjusted)

	Bridge Year 2013			Test Year 2014		
Customer						
Class Name	Volume	rate ($/kWh):	Amount	Volume	rate ($/kWh):	Amount
Residential	57,672,462	0.08069	$4,653,591	55,281,378	$0.08477	$4,686,398
General Service < 50 kW	21,217,841	0.08069	$1,712,068	19,879,867	$0.08477	$1,685,287
General Service > 50 to 4999 kW	87,194,930	0.08069	$7,035,759	83,408,170	$0.08477	$7,070,805
Unmetered Scattered Load	236,373	0.08069	$19,073	226,267	$0.08477	$19,181
Sentinel Lighting	112,104	0.08069	$9,046	107,311	$0.08477	$9,097
Street Lighting	1,212,731	0.08069	$97,855	1,165,679	$0.08477	$98,819
TOTAL	**167,646,440**		**$13,527,391**	**160,068,672**		**$13,569,587**

HHI reserves the right to update its commodity price based on updated prices are they become available.

Retail Transmission Service ("RTSR") Rates

Proposed RTSRs for Network Service and Line and Transformation Connection Service are described in E8.T2.S1.

Wholesale Market Service ("WMS") Rate

WPI proposes to maintain its cuurent WMS rate of $0.0044 per kWh, as prescribed by the OEB.

Rural Rate Protection

The existing Rural Rate Protection charge of $0.0011 per kWh has been maintained.

Low Voltage ("LV") Service

HHI estimates total charges of $57,414 in 2014 for LV service. Proposed retail rates for LV are described in E8.T5.S1

E3.T3.S8 POWER SUPPLY EXPENSES

The next page presents the utility's power supply expense for both the Bridge Year and Test Year.

Precedent: LoadForecast

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TESI-6
Power Supply Expense

Determination of Commodity

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

Forecast Price

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

Electricity Projections

(loss adjusted)

				Bridge Year 2013			Test Year 2014		
Customer		**Revenue**	**Expense**						
Class Name		USA #	USA #	Volume	rate ($/kWh):	Amount	Volume	rate ($/kWh):	Amount
Residential	kWh	4006	4705	57,672,462	0.08069	$4,653,591	55,281,378	$0.08477	$4,686,398
General Service < 50 kW	kWh	4010	4705	21,217,841	0.08069	$1,712,068	19,879,867	$0.08477	$1,685,287
General Service > 50 to 4999 kW	kWh	4035	4705	87,194,930	0.08069	$7,035,759	83,408,170	$0.08477	$7,070,805
Unmetered Scattered Load	kWh	4010	4705	236,373	0.08069	$19,073	226,267	$0.08477	$19,181
Sentinel Lighting	kWh	4025	4705	112,104	0.08069	$9,046	107,311	$0.08477	$9,097
Street Lighting	kWh	4025	4705	1,212,731	0.08069	$97,855	1,165,679	$0.08477	$98,819
TOTAL				**167,646,440**		**$13,527,391**	**160,068,672**		**$13,569,587**

Transmission - Network

(loss adjusted)

				Bridge Year 2013			Test Year 2014		
Customer		**Revenue**	**Expense**						
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	4066	4714	57,672,462	0.0069	$397,940	55,281,378	0.0063	$350,475
General Service < 50 kW	kWh	4066	4714	21,217,841	0.0063	$133,672	19,879,867	0.0057	$113,315
General Service > 50 to 4999 kW	kW	4066	4714	206,144	2.5533	$526,347	197,191	2.3286	$459,179
Unmetered Scattered Load	kWh	4066	4714	236,373	0.0063	$1,489	226,267	0.0057	$1,290
Sentinel Lighting	kW	4066	4714	297	1.9264	$572	284	1.7569	$499
Street Lighting	kW	4066	4714	3,250	1.9258	$6,259	3,124	1.7564	$5,486
TOTAL				**79,336,366**		**$1,066,280**	**75,588,111**		**$930,245**

Transmission - Connection

(loss adjusted)

				Bridge Year 2013			Test Year 2014		
Customer		**Revenue**	**Expense**						
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	4068	4716	57,672,462	0.0031	$178,785	55,281,378	0.0030	$165,844
General Service < 50 kW	kWh	4068	4716	21,217,841	0.0027	$57,288	19,879,867	0.0026	$51,688
General Service > 50 to 4999 kW	kW	4068	4716	206,144	1.1197	$230,819	197,191	1.0753	$212,039
Unmetered Scattered Load	kWh	4068	4716	236,373	0.0027	$638	226,267	0.0026	$588
Sentinel Lighting	kW	4068	4716	297	1.7674	$525	284	1.6973	$483
Street Lighting	kW	4068	4716	3,250	0.8656	$2,813	3,124	0.8313	$2,597
TOTAL		**0**	**0**	**79,336,366**		**$470,869**	**75,588,111**		**$433,239**

Wholesale Market Service

(loss adjusted)

				Bridge Year 2013			Test Year 2014		
Customer		**Revenue**	**Expense**		**rate ($/kWh):**	**0.0052**		**rate ($/kWh):**	**0.0052**
Class Name		USA #	USA #	Volume		Amount	Volume		Amount
Residential	kWh	4062	4708	57,672,462	0.00440	$253,759	55,281,378	0.00440	$243,238
General Service < 50 kW	kWh	4062	4708	21,217,841	0.00440	$93,359	19,879,867	0.00440	$87,471
General Service > 50 to 4999 kW	kWh	4062	4708	87,194,930	0.00440	$383,658	83,408,170	0.00440	$366,996
Unmetered Scattered Load	kWh	4062	4708	236,373	0.00440	$1,040	226,267	0.00440	$996
Sentinel Lighting	kWh	4062	4708	112,104	0.00440	$493	107,311	0.00440	$472
Street Lighting	kWh	4062	4708	1,212,731	0.00440	$5,336	1,165,679	0.00440	$5,129
TOTAL		**0**	**0**	**167,646,440**		**$737,644**	**160,068,672**		**$704,302**

Rural Rate Protection

Precedent: LoadForecast

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TESI-6
Power Supply Expense

(loss adjusted)

Customer		**Revenue**	**Expense**	**Bridge Year 2013**			**Test Year 2014**		
Class Name		USA #	USA #	Volume	**rate ($/kWh):**	Amount	Volume	**rate ($/kWh):**	Amount
Residential	kWh	4062	4730	57,672,462	0.00120	$69,207	55,281,378	0.00120	$66,338
General Service < 50 kW	kWh	4062	4730	21,217,841	0.00120	$25,461	19,879,867	0.00120	$23,856
General Service > 50 to 4999 kW	kWh	4062	4730	87,194,930	0.00120	$104,634	83,408,170	0.00120	$100,090
Unmetered Scattered Load	kWh	4062	4730	236,373	0.00120	$284	226,267	0.00120	$272
Sentinel Lighting	kWh	4062	4730	112,104	0.00120	$135	107,311	0.00120	$129
Street Lighting	kWh	4062	4730	1,212,731	0.00120	$1,455	1,165,679	0.00120	$1,399
TOTAL		**0**	**0**	**167,646,440**		**$201,176**	**160,068,672**		**$192,082**

Low Voltage Charges

	Current Low Voltage Rates		**2013 PROJECTED TRANSMISSION-CONNECTION REVENUE**				
Customer Class Name	**Rate**	**per**	**Rate**	**per**	**Uplifted Volumes**	**Revenue**	**%**
Residential	$0.0004	kWh	**$0.0030**	kWh	55,281,378	$165,844	38.28%
General Service < 50 kW	$0.0004	kWh	**$0.0026**	kWh	19,879,867	$51,688	11.93%
General Service > 50 to 4999 kW	$0.1369	kW	**$1.0753**	kW	197,191	$212,039	48.94%
Unmetered Scattered Load	$0.0004	kWh	**$0.0026**	kWh	226,267	$588	0.14%
Sentinel Lighting	$0.2162	kW	**$1.6973**	kW	284	$483	0.11%
Street Lighting	$0.1059	kW	**$0.8313**	kW	3,124	$2,597	0.60%
TOTAL	**0**	**0**		**$0**	**75,588,111**	**$433,239**	**100%**

Low Voltage Charges
(not loss adjusted)

	2013 PROPOSED LOW VOLTAGE CHARGES & RATES				
Customer Class Name	**% Allocation**	**Charges**	**Not Uplifted Volumes**	**Rate**	**per**
Residential	38.28%	38,125	52,443,428	$0.0007	kWh
General Service < 50 kW	11.93%	11,882	18,859,305	$0.0006	kWh
General Service > 50 to 4999 kW	48.94%	48,744	197,191	$0.2472	kW
Unmetered Scattered Load	0.14%	135	214,651	$0.0006	kWh
Sentinel Lighting	0.11%	111	284	$0.3902	kW
Street Lighting	0.60%	597	3,124	$0.1911	kW
TOTAL	**100.00%**	**99,595**	**71,717,983**		

Customer		**Revenue**	**Expense**	**Bridge Year 2013**			**Test Year 2014**		
					2013			**2014**	
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	4075	4750	54,711,762	$0.0004	$21,885	52,443,428	$0.0007	$36,710.40
General Service < 50 kW	kWh	4075	4750	20,128,592	$0.0004	$8,051	18,859,305	$0.0006	$11,315.58
General Service > 50 to 4999 kW	kW	4075	4750	206,144	$0.1369	$28,221	197,191	$0.2472	$48,745.62
Unmetered Scattered Load	kWh	4075	4750	224,238	$0.0004	$90	214,651	$0.0006	$128.79
Sentinel Lighting	kW	4075	4750	297	$0.2162	$64	284	$0.3902	$110.93
Street Lighting	kW	4075	4750	3,250	$0.1059	$344	3,124	$0.1911	$596.93
TOTAL		**0**	**0**	**75,274,283**		**$58,655**	**71,717,983**		**$97,608.25**

Projected Power Supply Expense					**$16,062,015**			**$15,927,063**

Appendix A – HHI 2006-2010 OPA results

OPA Conservation & Demand Management Programs
Annual Results at the End-User Level

For: Hydro Hawkesbury Inc.

Net Summer Peak Demand Savings (MW)

#	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013
1	2006 Programs	Final	0.5378	0.0249	0.0249	0.0249	0.0249	0.0249	0.0231	0.0231
2	2007 Programs	Final	0.0000	0.7366	0.0592	0.0432	0.0432	0.0432	0.0417	0.0417
3	2008 Programs	Final	0.0000	0.0000	0.9749	0.0299	0.0299	0.0299	0.0291	0.0291
4	2009 Programs	Final	0.0000	0.0000	0.0000	0.8197	0.0406	0.0406	0.0405	0.0404
5	2010 Programs	Final	0.0000	0.0000	0.0000	0.0000	0.5693	0.0230	0.0230	0.0230
Total			**0.5378**	**0.7615**	**1.0589**	**0.9177**	**0.7079**	**0.1616**	**0.1574**	**0.1573**

Net Energy Savings (MWh)

#	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013
1	2006 Programs	Final	514	514	514	514	89	89	82	82
2	2007 Programs	Final	0	412	257	238	238	238	230	230
3	2008 Programs	Final	0	0	200	199	199	199	175	175
4	2009 Programs	Final	0	0	0	260	127	127	127	126
5	2010 Programs	Final	0	0	0	0	276	76	76	76
Total			**514**	**926**	**971**	**1,211**	**929**	**730**	**689**	**688**

Gross Summer Peak Demand Savings (MW)

#	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013
1	2006 Programs	Final	0.5424	0.0295	0.0295	0.0295	0.0295	0.0295	0.0275	0.0275
2	2007 Programs	Final	0.0000	1.5169	0.3092	0.1766	0.1766	0.1766	0.1667	0.1667
3	2008 Programs	Final	0.0000	0.0000	1.0029	0.0572	0.0572	0.0572	0.0552	0.0552
4	2009 Programs	Final	0.0000	0.0000	0.0000	0.8698	0.0900	0.0900	0.0899	0.0897
5	2010 Programs	Final	0.0000	0.0000	0.0000	0.0000	0.5835	0.0373	0.0373	0.0373
Total			**0.5424**	**1.5463**	**1.3416**	**1.1330**	**0.9367**	**0.3906**	**0.3766**	**0.3764**

Gross Energy Savings (MWh)

#	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013
1	2006 Programs	Final	574	574	574	574	102	102	94	94
2	2007 Programs	Final	0	1,858	580	420	420	420	397	397
3	2008 Programs	Final	0	0	469	467	467	467	403	403
4	2009 Programs	Final	0.0000	0.0000	0.0000	446.5618	298.0391	298.0391	297.8852	295.7572
5	2010 Programs	Final	0	0	0	0	335	138	138	138
Total			**574**	**2,432**	**1,623**	**1,907**	**1,621**	**1,425**	**1,329**	**1,327**

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
0.0181	0.0181	0.0181	0.0181	0.0181	0.0181	0.0111	0.0076	0.0076	0.0076	0.0002
0.0417	0.0368	0.0365	0.0331	0.0331	0.0331	0.0331	0.0185	0.0035	0.0034	0.0034
0.0273	0.0267	0.0252	0.0241	0.0237	0.0237	0.0223	0.0223	0.0217	0.0178	0.0165
0.0398	0.0393	0.0393	0.0378	0.0378	0.0368	0.0368	0.0346	0.0346	0.0345	0.0321
0.0227	0.0218	0.0217	0.0217	0.0217	0.0213	0.0203	0.0203	0.0203	0.0203	0.0203
0.1496	**0.1427**	**0.1409**	**0.1348**	**0.1344**	**0.1330**	**0.1236**	**0.1033**	**0.0876**	**0.0837**	**0.0725**

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
77	77	72	72	72	72	66	57	57	57	31
230	68	66	39	39	39	39	31	5	4	4
149	130	95	91	80	80	78	78	77	69	26
119	106	105	87	87	77	77	70	70	69	60
74	58	56	56	55	51	49	49	49	49	49
649	**439**	**395**	**344**	**333**	**319**	**308**	**285**	**257**	**247**	**169**

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
0.0219	0.0219	0.0219	0.0219	0.0219	0.0219	0.0141	0.0086	0.0086	0.0086	0.0002
0.1667	0.1594	0.1588	0.1542	0.1542	0.1542	0.1542	0.0322	0.0061	0.0060	0.0060
0.0513	0.0497	0.0468	0.0443	0.0434	0.0434	0.0402	0.0402	0.0393	0.0327	0.0286
0.0887	0.0876	0.0876	0.0841	0.0841	0.0820	0.0820	0.0778	0.0778	0.0774	0.0694
0.0368	0.0351	0.0350	0.0350	0.0350	0.0340	0.0316	0.0316	0.0315	0.0315	0.0315
0.3653	**0.3537**	**0.3501**	**0.3396**	**0.3387**	**0.3356**	**0.3221**	**0.1904**	**0.1634**	**0.1562**	**0.1358**

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
88	88	83	83	83	83	76	64	64	64	34
397	158	153	116	116	116	116	54	8	6	6
346	295	228	220	195	195	189	189	189	174	45
281.7343	257.1409	256.5008	214.7355	214.7355	187.7208	187.6859	173.9903	173.9903	169.9987	139.4872
134	94	89	89	89	83	78	78	76	76	76
1,247	**892**	**810**	**723**	**699**	**666**	**647**	**559**	**510**	**490**	**301**

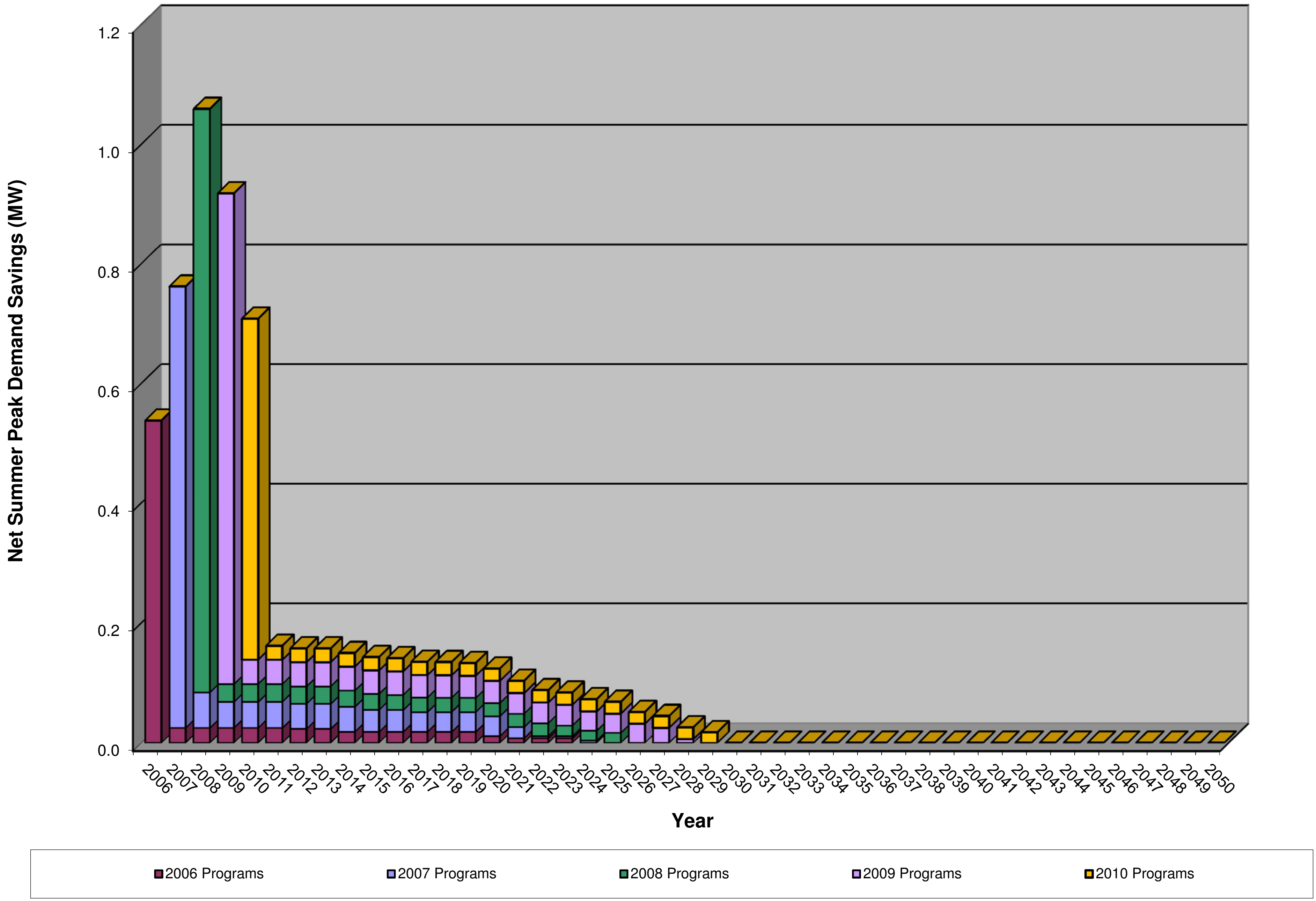
2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.0165	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.0319	0.0319	0.0251	0.0062	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.0196	0.0195	0.0195	0.0194	0.0176	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.0682	**0.0514**	**0.0446**	**0.0257**	**0.0176**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

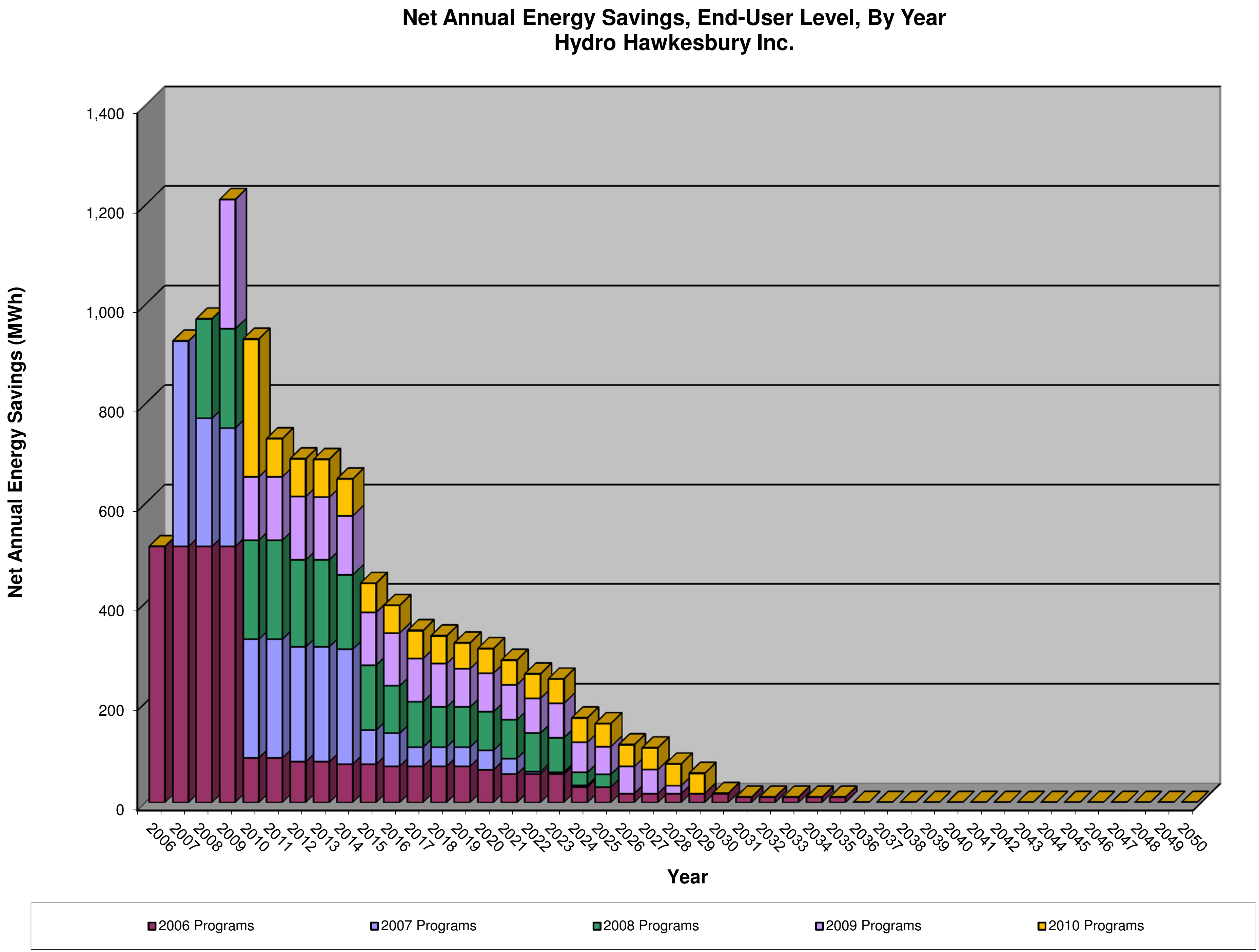
2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
31	18	18	18	18	18	11	11	11	11	11
0	0	0	0	0	0	0	0	0	0	0
26	0	0	0	0	0	0	0	0	0	0
55	54	48	16	0	0	0	0	0	0	0
46	43	43	43	40	0	0	0	0	0	0
158	**116**	**109**	**77**	**58**	**18**	**11**	**11**	**11**	**11**	**11**

2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.0286	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.0690	0.0690	0.0570	0.0095	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.0299	0.0297	0.0297	0.0296	0.0252	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.1278	**0.0987**	**0.0866**	**0.0391**	**0.0252**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
34	20	20	20	20	20	12	12	12	12	12
0	0	0	0	0	0	0	0	0	0	0
45	0	0	0	0	0	0	0	0	0	0
128.9147	121.6463	110.6538	29.6077	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
72	65	65	65	58	0	0	0	0	0	0
280	**207**	**196**	**115**	**77**	**20**	**12**	**12**	**12**	**12**	**12**

Net Summer Peak Demand Savings, End-User Level, By Year
Hydro Hawkesbury Inc.




Net Annual Energy Savings, End-User Level, By Year
Hydro Hawkesbury Inc.
Net Annual Energy Savings (MWh)
0
200
400
600
800
1,000
1,200
1,400
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
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2045
2046
2047
2048
2049
2050
Year
2006 Programs
2007 Programs
2008 Programs
2009 Programs
2010 Programs

Appendix B – Q4 2012 OPA Report

Ontario Power Authority
Conservation & Demand Management Status Report

Q4 2012 Preliminary Results Update

Hydro Hawkesbury Inc.

Unverified OPA-Contracted Province-Wide CDM Program Progress at a Glance

Unverified Progress to Targets	Incremental Q4 2012	Program-to-Date Progress Towards OEB Target				Rank (of 76)
		Scenario 1		Scenario 2		
		Savings	%	Savings	%	Scenario 2
Net Peak Demand Savings (MW)	**0.0**	**0.2**	13.7%	**0.3**	14.4%	**69**
Net Energy Savings (GWh)	**0.1**	**4.2**	45.3%	**4.2**	45.3%	**61**

Program-to-Date towards Target: *Combination of 2011 verified and 2012 preliminary results. To align with savings accounted towards OEB targets, peak Demand is represented by annual savings in 2014 and energy is represented by the cumulative savings from 2011-2014.*

Scenario 1: *Assumes that demand response resources have a persistence of 1 year. Official reporting policy for demand response resources.*

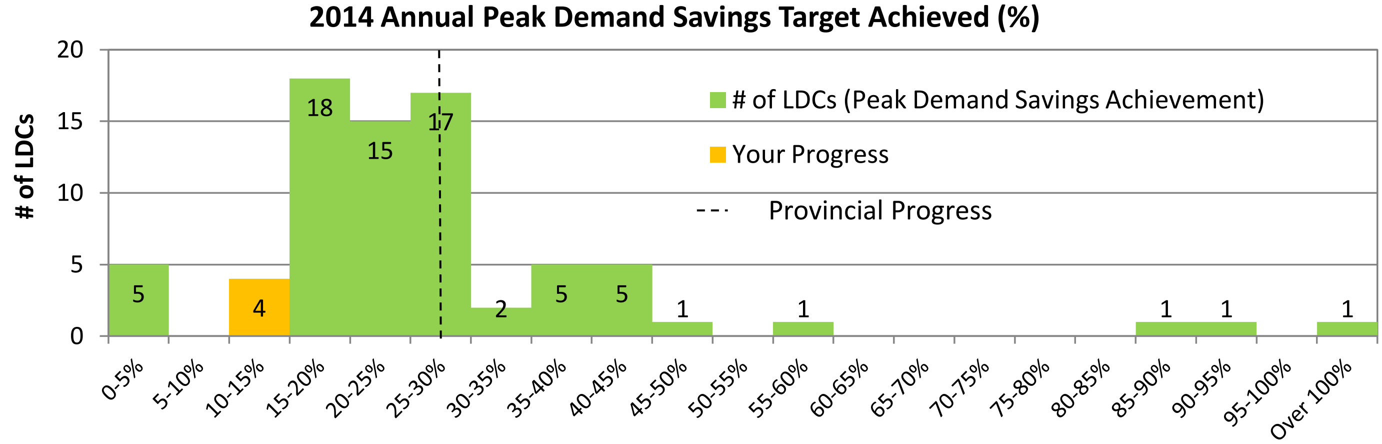
Scenario 2: *Assumes that demand response resources remain in your territory until 2014. Used to better assess progress to demand targets.*

Rank: *Sorts each LDC by % of peak demand or energy target achieved as of the current reporting period using scenario 2.*

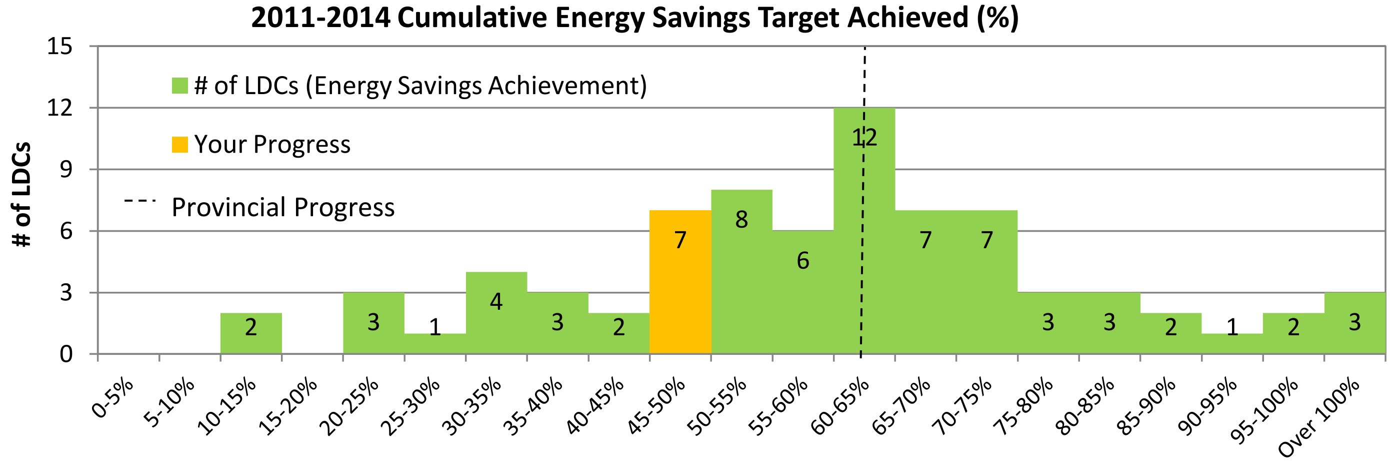
Comparison: Your Achievement vs. LDC Community Achievement

The following graphs assume that demand response resources remain in your territory until 2014 (aligns with Scenario 2)

2014 Annual Peak Demand Savings Target Achieved (%)



2011-2014 Cumulative Energy Savings Target Achieved (%)



Questions? Please check the "About this Report" Section on page 2, Table 5 on page 9 and "Reporting Methodology" on page 10.
More Questions? Please contact LDC.Support@powerauthority.on.ca

Message from the Vice President

I am pleased to present our Q4 2012 LDC report. We continue to achieve great success across all sectors and provincially our progress to date continues to rise for both energy and demand. In Q4, 62% of the cumulative 6,000 GWh energy target was achieved and progress towards the 1,330 MW demand target increased from last quarter at 28%.

In Q4 we received the Minister's directive to extend the programs to December 31st, 2015. This is great news for our customers and we continue to work towards identifying additional tools, training, and information that will help LDCs achieve their targets.

Programs are being enhanced through LDC feedback to further drive participation in conservation and channel partners are being engaged to build stronger relationships across all sectors. A few highlights of our efforts so far include:

- 7 regionally-located Energy Efficiency Service Providers are now available to help engage Municipalities and capture more projects for the municipal sector
- Retrofit projects are moving beyond commercial lighting and capturing more peak demand savings relative to energy savings
- Partnerships between LDCs and retailers resulted in 130 in-store events in 2012
- The Home Assistance Program is ramping up in 2012 with over 3,000 basic and extended audits completed for income eligible homes resulting in the installation of almost 40,000 energy efficient products

We encourage you to continue to share your success stories to learn from best practices and share our experiences across the province.

Please contact the OPA Conservation Business Development team at ldc.support@powerauthority.on.ca with any questions regarding this report.

Congratulations on another successful quarter!

Sincerely,

Andrew Pride

About this Report

This report contains:

- Peak demand and energy savings for OPA-Contracted Province-Wide programs (does not include Ontario Energy Board (OEB) approved CDM programs or other LDC conservation efforts)
- Progress as of the end of Q4 2012 using unverified quarterly results for 2012 and final results for 2011
- Program activity data (i.e. projects completed, appliances picked up) completed on or before December 31, 2012 and received and entered into the OPA processing systems as per the dates specified in Table 5
- Updates to the previous quarter's participation as a result of further data received
- Information to assist the LDC in reconciling internal data sources with the data contained in this report. Table 5 (page 9) contains:
  1. The date in which savings are considered to 'start';
  2. At what point the data becomes available to the OPA;
  3. The expected probability and magnitude of updates to the data as more information becomes available.
- iCON CRM Post Stage Retrofit Report data queried on **January 31, 2013**
  - Retrofit projects completed after December 31, 2011 will be tracked as part of the Business program only
- Preliminary results for ***peaksaver* PLUS®** representing customers that have signed a Participant Agreement and information has been successfully uploaded into the RDR settlement system

New this quarter based on LDC feedback:

- ***peaksaver* PLUS r**eporting is now split into two line items: switch/thermostat and IHD

2011-2014 Summary: Net Peak Demand Savings Achieved (MW)

This section provides a portfolio level view of net peak demand savings procured to date through Tier 1 programs.
Table 1 presents:

- Net peak demand savings results from 2011 to Q4 2012 listed by implementation period, status (i.e. final or reported) and summarized by resource type (i.e. energy efficiency or demand response)
- Net annual peak demand savings that are expected to persist through to 2014 from program activity completed as of Q4 2012 using both Scenarios 1 and 2
- A comparison between reported, unverified results (as of Q4 2011) and final, verified 2011 results
- Energy efficiency resources reported with persistence according to the effective useful life of the technology

Figure 1 presents:

- Net peak demand savings results from 2011 to date using scenario 1 for demand response resources (persistence of 1 year)

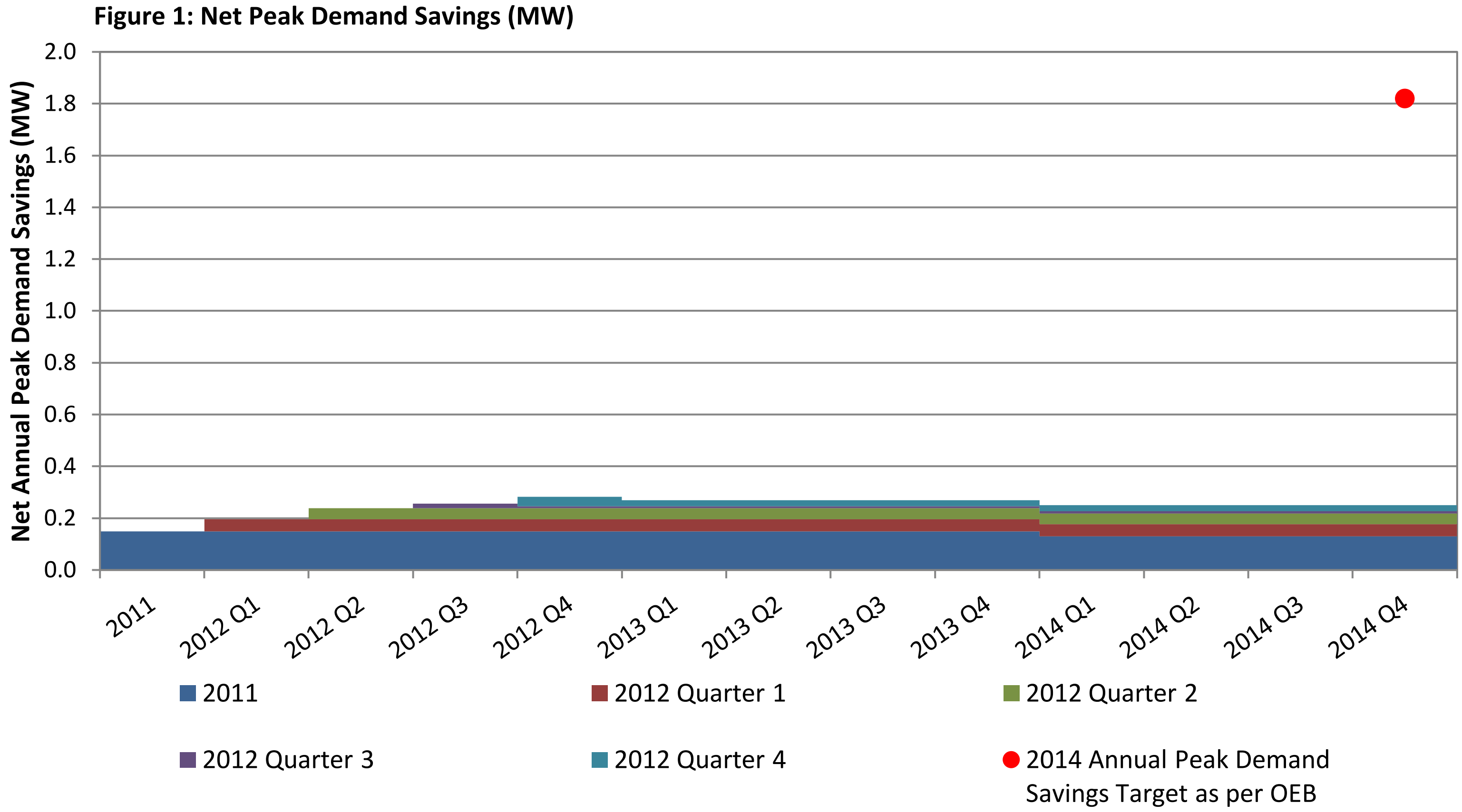
Please note: demand response resources are only presented in the final quarter of each year and the current reporting quarter (i.e. quarter 4 2011 and quarter 4 2012) to correctly aggregate the annual savings in the table below. However, the figure below and tables 3B and 4B present Demand Response in each quarter to display any changes that may have occurred quarter over quarter.

Table 1: Net Peak Demand Savings at the End-User Level (MW)

#	Implementation Period	Annual (MW)				
		Scenario 1				Scenario 2
		2011	2012	2013	2014	2014
1	2011 - Final*	0.15	0.15	0.15	0.13	0.13
2	2012 - Reported - Quarter 1		0.05	0.05	0.05	0.05
3	2012 - Reported - Quarter 2		0.04	0.04	0.04	0.04
4	2012 - Reported - Quarter 3		0.01	0.01	0.01	0.01
5	2012 - Reported - Quarter 4		0.04	0.02	0.02	0.04
6	2013					
7	2014					
	Energy Efficiency	0.15	0.27	0.27	0.25	0.25
	Demand Response	0.00	0.01	0.00	0.00	0.01
	Net Annual Peak Demand Savings	0.15	0.28	0.27	0.25	0.26
	Unverified Net Annual Peak Demand Savings in 2014:				**0.25**	**0.26**
	2014 Annual Peak Demand Savings Target as per OEB:				**1.82**	**1.82**
	Unverified 2014 Peak Demand Savings Target Achieved (%):				**13.7%**	**14.4%**
	Incremental Reported (Unverified)	0.04	0.13			
	Incremental Final (Verified)	0.15	n/a			

* Drop from 2011 to 2012 due to demand response persistence assumption (scenario 1)

Figure 1: Net Peak Demand Savings (MW)



2011-2014 Summary: Net Energy Savings Achieved (GWh)

This section provides a portfolio level view of net energy savings procured to date through Tier 1 programs.

Table 2 presents net annual energy savings results from 2011 to date listed by implementation period, status (i.e. final or reported) and summarized by resource type. This table aligns with scenario 1 and presents 2011-2014 net cumulative energy savings expected in 2014 from program activity completed to date. At the bottom of the table a comparison is made between reported (as of Q4 2011) and final 2011 results.

Table 2: Net Energy Savings at the End-User Level (GWh)

#	Implementation Period	Annual (GWh)				Cumulative (GWh)
		2011	2012	2013	2014	2011-2014
1	2011 - Final*	0.72	0.72	0.72	0.66	2.82
2	2012 - Reported - Quarter 1		0.19	0.19	0.19	0.57
3	2012 - Reported - Quarter 2		0.19	0.19	0.19	0.56
4	2012 - Reported - Quarter 3		0.03	0.03	0.03	0.08
5	2012 - Reported - Quarter 4		0.06	0.06	0.06	0.18
6	2013					
7	2014					
	Energy Efficiency	0.72	1.18	1.18	1.12	4.20
	Demand Response	0.00	0.00	0.00	0.00	0.00
	Net Energy Savings	0.72	1.18	1.18	1.13	4.20
	Unverified Net Cumulative Energy Savings 2011-2014:					**4.20**
	2011-2014 Cumulative Energy Savings Target as per OEB:					**9.28**
	Unverified 2011-2014 Cumulative Energy Target Achieved (%):					**45.3%**
	Incremental Reported (Unverified)	0.27	0.46			
	Incremental Final (Verified)	0.72	n/a			

Figure 2: Net Cumulative Energy Savings (GWh)

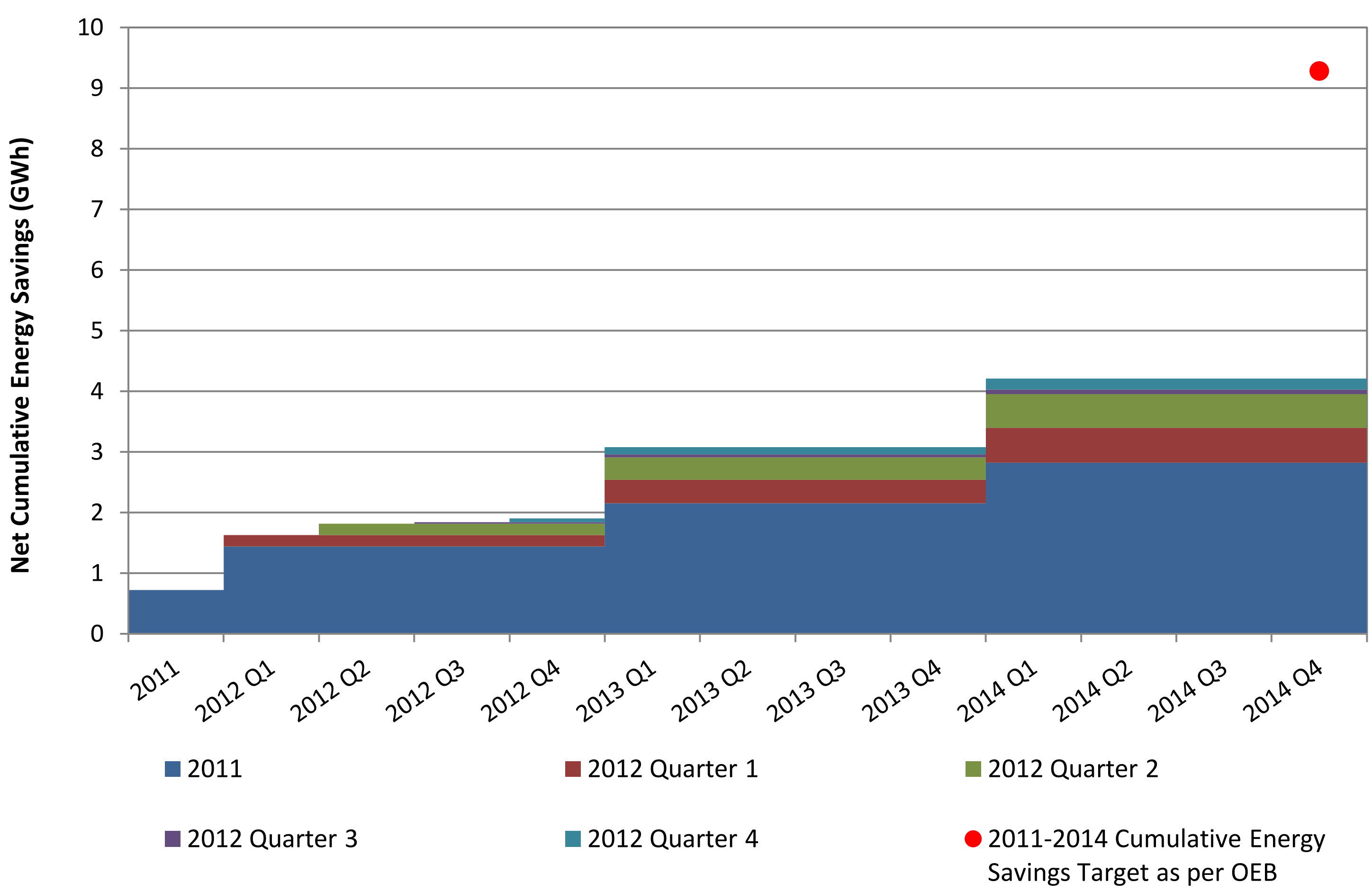


Table 3A: **Hydro Hawkesbury Inc.** Initiative and Program Level Savings by Year (Scenario 1)

#	Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Unverified Progress to Target (excludes DR)	
															2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
			2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program																
1	Appliance Retirement	Appliances	29	13			2	1			12,263	5,998			3	67,045
2	Appliance Exchange	Appliances	14	0			1	0			1,855	31			1	6,797
3	HVAC Incentives	Equipment	19	25			6	9			12,690	18,268			15	105,564
4	Conservation Instant Coupon Booklet	Coupons	744	4			2	0			27,819	153			2	111,735
5	Bi-Annual Retailer Event	Coupons	1,213	439			2	1			40,962	17,111			3	215,180
6	Retailer Co-op	Items	0	0			0	0			0	0			0	0
7	Residential Demand Response (switch/pstat)*	Devices	0	22			0	12			0	47			0	47
8	Residential Demand Response (IHD)	Devices	0	19			0	1			0	7,296			1	21,888
9	Residential New Construction	Homes	0	0			0	0			0	0			0	0
Consumer Program Total							**14**	**24**			**95,589**	**48,904**			**25**	**528,256**
Business Program																
10	Retrofit	Projects	5	5			68	48			470,057	255,433			116	2,646,527
11	Direct Install Lighting	Projects	25	37			59	61			149,570	158,010			100	1,019,880
12	Building Commissioning	Buildings	0	0			0	0			0	0			0	0
13	New Construction	Buildings	0	0			0	0			0	0			0	0
14	Energy Audit	Audits	0	0			0	0			0	0			0	0
15	Small Commercial Demand Response (switch/pstat)*	Devices	0	0			0	0			0	0			0	0
16	Small Commercial Demand Response (IHD)	Devices	0	0			0	0			0	0			0	0
17	Demand Response 3*	Facilities	0	0			0	0			0	0			0	0
Business Program Total							**127**	**108**			**619,627**	**413,443**			**216**	**3,666,407**
Industrial Program																
18	Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
19	Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
20	Energy Manager	Projects	0	0			0	0			0	0			0	0
21	Retrofit	Projects	1				9				104				9	416
22	Demand Response 3*	Facilities	0	0			0	0			0	0			0	0
Industrial Program Total							**9**	**0**			**104**	**0**			**9**	**416**
Home Assistance Program																
23	Home Assistance Program	Homes	0	0			0	0			0	0			0	0
Home Assistance Program Total							**0**	**0**			**0**	**0**			**0**	**0**
Pre-2011 Programs completed in 2011																
24	Electricity Retrofit Incentive Program	Projects	1	0			0	0			1,838	0			0	7,352
25	High Performance New Construction	Projects	0	0			0	0			560	0			0	2,242
26	Toronto Comprehensive	Projects	0	0			0	0			0	0			0	0
27	Multifamily Energy Efficiency Rebates	Projects	0	0			0	0			0	0			0	0
28	LDC Custom Programs	Projects	0	0			0	0			0	0			0	0
Pre-2011 Programs completed in 2011 Total							**0**	**0**			**2,398**	**0**			**0**	**9,594**
Energy Efficiency Total							**149**	**120**			**717,718**	**462,300**			**250**	**4,204,626**
Demand Response Total (Scenario 1)							**0**	**12**			**0**	**47**			**0**	**47**
OPA-Contracted LDC Portfolio Total							**149**	**133**			**717,718**	**462,347**			**250**	**4,204,673**
														Full OEB Target:	**1,820**	**9,280,000**
														Preliminary % of Full OEB Target Achieved to Date (Scenario 1):	**13.7%**	**45.3%**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Table 3B: **Hydro Hawkesbury Inc.** Initiative and Program Level Savings by Quarter for current reporting year**

#	Initiative	Unit	**Incremental Activity** (new program activity occurring within the specified reporting period)				**Net Incremental Peak Demand Savings (kW)** (new peak demand savings from activity within the specified reporting period)				**Net Incremental Energy Savings (kWh)** (new energy savings from activity within the specified reporting period)			
			Q1 2012	**Q2 2012**	**Q3 2012**	**Q4 2012**	**Q1 2012**	**Q2 2012**	**Q3 2012**	**Q4 2012**	**Q1 2012**	**Q2 2012**	**Q3 2012**	**Q4 2012**
Consumer Program														
1	Appliance Retirement	Appliances	2	4	5	2	0	0	0	0	951	1,835	2,275	938
2	Appliance Exchange	Appliances	0	0	0	0	0	0	0	0	0	31	0	0
3	HVAC Incentives	Equipment	5	8	4	7	2	3	2	3	3,988	5,548	3,196	5,535
4	Conservation Instant Coupon Booklet	Coupons	0	0	0	4	0	0	0	0	0	0	0	153
5	Bi-Annual Retailer Event	Coupons	0	128	0	311	0	0	0	0	0	4,820	0	12,291
6	Retailer Co-op	Items	0	0	0	0	0	0	0	0	0	0	0	0
7	Residential Demand Response (switch/pstat)*	Devices	0	0	18	22	0	0	10	12	0	0	39	47
8	Residential Demand Response (IHD)	Devices	0	0	16	3	0	0	1	1	0	0	3,840	3,456
9	Residential New Construction	Homes	0	0	0	0	0	0	0	0	0	0	0	0
Consumer Program Total							**2**	**3**	**12**	**16**	**4,939**	**12,234**	**9,350**	**22,420**
Business Program														
10	Retrofit	Projects	1	2	1	1	16	20	1	11	111,600	126,221	2,255	15,357
11	Direct Install Lighting	Projects	18	11	4	4	29	18	5	9	75,122	47,258	13,566	22,064
12	Building Commissioning	Buildings	0	0	0	0	0	0	0	0	0	0	0	0
13	New Construction	Buildings	0	0	0	0	0	0	0	0	0	0	0	0
14	Energy Audit	Audits	0	0	0	0	0	0	0	0	0	0	0	0
15	Small Commercial Demand Response (switch/pstat)*	Devices	0	0	0	0	0	0	0	0	0	0	0	0
16	Small Commercial Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0	0	0	0	0
17	Demand Response 3*	Facilities	0	0	0	0	0	0	0	0	0	0	0	0
Business Program Total							**45**	**38**	**6**	**20**	**186,722**	**173,479**	**15,821**	**37,421**
Industrial Program														
18	Process & System Upgrades	Projects	0	0	0	0	0	0	0	0	0	0	0	0
19	Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0	0	0	0	0
20	Energy Manager	Projects	0	0	0	0	0	0	0	0	0	0	0	0
21	Retrofit	Projects												
22	Demand Response 3*	Facilities	0	0	0	0	0	0	0	0	0	0	0	0
Industrial Program Total							**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Home Assistance Program														
23	Home Assistance Program	Homes	0	0	0	0	0	0	0	0	0	0	0	0
Home Assistance Program Total							**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Pre-2011 Programs completed in 2011														
24	Electricity Retrofit Incentive Program	Projects	0	0	0	0	0	0	0	0	0	0	0	0
25	High Performance New Construction	Projects	0	0	0	0	0	0	0	0	0	0	0	0
26	Toronto Comprehensive	Projects	0	0	0	0	0	0	0	0	0	0	0	0
27	Multifamily Energy Efficiency Rebates	Projects	0	0	0	0	0	0	0	0	0	0	0	0
28	LDC Custom Programs	Projects	0	0	0	0	0	0	0	0	0	0	0	0
Pre-2011 Programs completed in 2011 Total							**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Energy Efficiency Total							**47**	**42**	**9**	**24**	**191,661**	**185,712**	**25,132**	**59,794**
Demand Response Total (Scenario 1)							**0**	**0**	**10**	**12**	**0**	**0**	**39**	**47**
OPA-Contracted LDC Portfolio Total							**47**	**42**	**19**	**36**	**191,661**	**185,712**	**25,171**	**59,841**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

**** Updates to the previous quarter's participation may occur as a result of further data received**

Table 4A: Province-Wide Initiative and Program Level Savings by Year (Scenario 1)

#	Initiative	Unit	Incremental Activity (new program activity occuring within the specified reporting period) 2011	2012	2013	2014	Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period) 2011	2012	2013	2014	Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period) 2011	2012	2013	2014	Program-to-Date Unverified Progress to Target (excluding DR): 2014 Net Annual Peak Demand Savings (kW) 2014	Program-to-Date Unverified Progress to Target (excluding DR): 2011-2014 Net Cumulative Energy Savings (kWh) 2014
Consumer Program																
1	Appliance Retirement	Appliances	56,110	34,155			3,299	2,144			23,005,812	14,479,436			5,304	135,341,610
2	Appliance Exchange	Appliances	3,688	2,243			371	311			450,187	526,845			444	3,169,198
3	HVAC Incentives	Equipment	111,587	84,668			32,037	23,927			59,437,670	44,084,702			55,964	370,004,787
4	Conservation Instant Coupon Booklet	Coupons	559,462	2,604			1,344	8			21,211,537	109,679			1,352	85,175,185
5	Bi-Annual Retailer Event	Coupons	870,332	315,023			1,681	667			29,387,468	12,276,249			2,349	154,378,622
6	Retailer Co-op	Items	152	0			0	0			2,652	0			0	10,607
7	Residential Demand Response (switch/pstat)*	Devices	19,550	59,408			10,947	33,268			24,870	127,144			0	152,014
8	Residential Demand Response (IHD)	Devices	0	35,388			0	1,399			0	9,320,016			1,399	9,320,016
9	Residential New Construction	Homes	7	26			0	0			743	2,703			0	11,081
Consumer Program Total							**49,681**	**61,725**			**133,520,941**	**80,926,773**			**66,813**	**757,563,120**
Business Program																
10	Retrofit	Projects	2,516	5,033			24,467	53,009			136,002,258	270,478,412			77,453	1,355,349,569
11	Direct Install Lighting	Projects	20,297	16,257			23,724	28,455			61,076,701	72,747,089			44,942	439,762,244
12	Building Commissioning	Buildings	0	0			0	0			0	0			0	0
13	New Construction	Buildings	10	21			123	853			411,717	1,355,405			976	5,713,083
14	Energy Audit	Audits	103	221			0	0			0	0			0	0
15	Small Commercial Demand Response (switch/pstat)*	Devices	132	363			84	203			157	698			0	854
16	Small Commercial Demand Response (IHD)	Devices	124	43			0	1			0	9,288			1	9,288
17	Demand Response 3*	Facilities	0	150			16,224	19,283			633,421	755,205			0	1,388,625
Business Program Total							**64,623**	**101,805**			**198,124,253**	**345,346,095**			**123,373**	**1,802,223,663**
Industrial Program																
18	Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
19	Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
20	Energy Manager	Projects	0	37			0	828			0	7,587,760			828	22,763,281
21	Retrofit	Projects	433	0			4,615				28,866,840				4,613	115,462,282
22	Demand Response 3*	Facilities	124	186			52,484	71,353			3,080,737	4,188,340			0	7,269,078
Industrial Program Total							**57,098**	**72,181**			**31,947,577**	**11,776,101**			**5,442**	**145,494,640**
Home Assistance Program																
23	Home Assistance Program	Homes	46	3,036			2	204			39,283	2,051,762			207	6,312,419
Home Assistance Program Total							**2**	**204**			**39,283**	**2,051,762**			**207**	**6,312,419**
Pre-2011 Programs completed in 2011																
24	Electricity Retrofit Incentive Program	Projects	2,016	0			21,662	0			121,138,219	0			21,662	484,552,876
25	High Performance New Construction	Projects	145	20			5,098	1,869			26,185,591	9,936,694			6,968	134,552,447
26	Toronto Comprehensive	Projects	577	0			15,805	0			86,964,886	0			15,805	347,859,545
27	Multifamily Energy Efficiency Rebates	Projects	110	0			1,981	0			7,595,683	0			1,981	30,382,733
28	LDC Custom Programs	Projects	8	0			399	0			614,310	0			399	2,457,238
Pre-2011 Programs completed in 2011 Total							**44,945**	**1,869**			**242,498,689**	**9,936,694**			**46,814**	**999,804,839**
Energy Efficiency Total							**136,610**	**113,677**			**602,391,559**	**444,966,038**			**242,648**	**3,702,588,109**
Demand Response Total (Scenario 1)							**79,739**	**124,107**			**3,739,185**	**5,071,387**			**0**	**8,810,572**
OPA-Contracted LDC Portfolio Total							**216,349**	**237,785**			**606,130,744**	**450,037,425**			**242,648**	**3,711,398,681**
														Full OEB Target:	**1,330,000**	**6,000,000,000**
														Preliminary % of Full OEB Target Achieved to Date (Scenario 1):	**18.2%**	**61.9%**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Table 4B: Province-Wide Initiative and Program Level Savings by Quarter for current reporting year**

#	Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
			Q1 2012	Q2 2012	Q3 2012	Q4 2012	Q1 2012	Q2 2012	Q3 2012	Q4 2012	Q1 2012	Q2 2012	Q3 2012	Q4 2012
Consumer Program														
1	Appliance Retirement	Appliances	7,344	8,668	9,193	8,950	458	548	579	560	3,083,758	3,681,924	3,909,570	3,804,184
2	Appliance Exchange	Appliances	0	2,243	0	0	0	311	0	0	0	526,845	0	0
3	HVAC Incentives	Equipment	20,185	21,956	22,624	19,903	6,206	5,407	5,977	6,337	11,795,155	9,344,736	10,695,218	12,249,593
4	Conservation Instant Coupon Booklet	Coupons	0	0	0	2,604	0	0	0	8	0	0	0	109,679
5	Bi-Annual Retailer Event	Coupons	0	91,968	0	223,055	0	312	0	355	0	3,457,870	0	8,818,379
6	Retailer Co-op	Items	0	0	0	0	0	0	0	0	0	0	0	0
7	Residential Demand Response (switch/pstat)*	Devices	24,159	24,257	46,008	59,408	13,529	13,584	25,764	33,268	51,359	51,570	98,334	127,144
8	Residential Demand Response (IHD)	Devices	0	251	20,319	14,818	0	10	695	695	0	60,240	4,870,872	4,388,904
9	Residential New Construction	Homes	4	19	1	2	0	0	0	0	373	1,622	123	585
Consumer Program Total							**20,193**	**20,171**	**33,015**	**41,224**	**14,930,644**	**17,124,807**	**19,574,118**	**29,498,467**
Business Program														
10	Retrofit	Projects	1,080	1,264	1,530	1,159	12,614	13,581	14,250	12,564	68,920,271	70,484,025	71,179,848	59,894,268
11	Direct Install Lighting	Projects	4,743	4,563	4,063	2,888	7,965	7,958	7,146	5,385	20,335,190	20,331,442	18,339,284	13,741,172
12	Building Commissioning	Buildings	0	0	0	0	0	0	0	0	0	0	0	0
13	New Construction	Buildings	2	9	7	3	22	559	201	70	64,503	355,782	732,990	202,131
14	Energy Audit	Audits	48	98	51	24	0	0	0	0	0	0	0	0
15	Small Commercial Demand Response (switch/pstat)*	Devices	188	188	337	363	105	105	189	203	361	361	648	698
16	Small Commercial Demand Response (IHD)	Devices	0	0	26	17	0	0	1	1	0	0	5,616	3,672
17	Demand Response 3*	Facilities	149	153	153	150	16,390	20,623	19,573	19,283	641,918	807,681	766,575	755,205
Business Program Total							**37,097**	**42,826**	**41,361**	**37,506**	**89,962,243**	**91,979,291**	**91,024,961**	**74,597,145**
Industrial Program														
18	Process & System Upgrades	Projects	0	0	0	0	0	0	0	0	0	0	0	0
19	Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0	0	0	0	0
20	Energy Manager	Projects	8	8	14	7	16	332	201	280	726,093	3,441,901	1,296,676	2,123,089
21	Retrofit	Projects												
22	Demand Response 3*	Facilities	132	145	177	186	56,120	62,864	63,239	71,353	3,294,157	3,690,043	3,712,034	4,188,340
Industrial Program Total							**56,135**	**63,196**	**63,440**	**71,633**	**4,020,250**	**7,131,944**	**5,008,710**	**6,311,430**
Home Assistance Program														
23	Home Assistance Program	Homes	135	1,018	954	929	20	76	89	20	171,593	751,230	735,013	393,925
Home Assistance Program Total							**20**	**76**	**89**	**20**	**171,593**	**751,230**	**735,013**	**393,925**
Pre-2011 Programs completed in 2011														
24	Electricity Retrofit Incentive Program	Projects	0	0	0	0	0	0	0	0	0	0	0	0
25	High Performance New Construction	Projects	13	6	1	0	1,654	201	14	0	8,794,790	1,069,101	72,803	0
26	Toronto Comprehensive	Projects	0	0	0	0	0	0	0	0	0	0	0	0
27	Multifamily Energy Efficiency Rebates	Projects	0	0	0	0	0	0	0	0	0	0	0	0
28	LDC Custom Programs	Projects	0	0	0	0	0	0	0	0	0	0	0	0
Pre-2011 Programs completed in 2011 Total							**1,654**	**201**	**14**	**0**	**8,794,790**	**1,069,101**	**72,803**	**0**
Energy Efficiency Total							**28,955**	**29,294**	**29,154**	**26,275**	**113,891,726**	**113,506,718**	**111,838,014**	**105,729,580**
Demand Response Total (Scenario 1)							**86,144**	**97,176**	**108,765**	**124,107**	**3,987,795**	**4,549,655**	**4,577,591**	**5,071,387**
OPA-Contracted LDC Portfolio Total							**115,099**	**126,469**	**137,919**	**150,383**	**117,879,521**	**118,056,373**	**116,415,605**	**110,800,967**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

**** Updates to the previous quarter's participation may occur as a result of further data received**

Table 5: Data Qualifiers for Initiatives Currently In-Market & Likelihood of Additional Data

Data included in the Q4 2012 report includes all program activity completed (as per the savings 'start' date) on or before December 31, 2012.

Initiative	Savings 'start' Date	Data Available	Additional Data Likely
Consumer Program			
Appliance Retirement	Pick-up date	When database is queried (Q3 Report Date: January 17, 2013). Typically up-to-date.	Moderate
Appliance Exchange	Exchange event date	Once data is submitted to the OPA by retailers and undergoes QA/QC by OPA staff. Typically 3 - 6 months to receive and process all data.	High
HVAC Incentives	Installation date[1]	Rebate Status = Approved, Cheque Issued/Cashed, Pending, Under Review (Q3 Report Date: January 17, 2013). Typically 1 - 4 months delay.	High
Conservation Instant Coupon Booklet	Coupon redemption year	Once data is submitted to the OPA by retailers and undergoes QA/QC by OPA staff. Typically 3 - 6 months to receive and process all data.	High
Bi-Annual Retailer Event	Year and quarter of the event		High
Retailer co-op activities	Will vary by specific project	Will vary by specific project	Low
Residential Demand Response	Device installation date	Data successfully uploaded into RDR settlement system as of January 24, 2013.	High
Residential New Construction	Project completion	Preliminary Billing Report submitted to OPA as of January 17, 2013.	Low
Business (Commercial & Institutional) Program			
Retrofit	Actual project completion date	In the "Post Project Submission" Stage (excluding "Payment Denied by LDC") within iCON CRM as of January 31, 2013.	Low
Direct Installed Lighting	Retrofit date	Work-order: invoiced, approved and paid to LDC as of January 17, 2013. Typically 1.5 - 2 months delay. Any projects that are flagged as duplicates will not appear in reports until duplicates have been resolved.	High
Building Commissioning	Hand off date	Preliminary Billing Report submitted to OPA and reviewed as of January 17, 2013.	Moderate
New Construction	Actual project completion date	Preliminary Billing Report submitted to OPA and reviewed as of January 17, 2013.	Moderate
Energy Audit	Audit completion date	Preliminary Billing Report submitted to OPA and reviewed as of January 17, 2013.	Moderate
Small Commercial Demand Response	Device installation date	Data successfully uploaded into RDR settlement system as of January 24, 2013.	Moderate
Demand Response 3	Facility is available under contract	Facility available under contract with aggregator	Low
Industrial Program			
Process & System Upgrades	In-service date	Preliminary Billing Report submitted to OPA and reviewed as of January 17, 2013.	Low
Monitoring & Targeting	Project completion date	Preliminary Billing Report submitted to OPA and reviewed as of January 17, 2013.	Low
Energy Manager (EEM or REM)	Project completion date	Completed, non-incented projects submitted quarterly by Energy Manager.	High
Retrofit	All Retrofit projects are now reported under the Business Program		
Demand Response 3	Facility is available under contract	Facility available under contract with aggregator.	Low
Home Assistance Program			
Home Assistance Program	Project completion date	Preliminary Billing Report submitted to OPA and reviewed as of January 17, 2013.	High
Pre-2011 Projects Completed in 2011			
High Performance New Construction	Project completion date	Reviewed and processed from delivery agent, quarterly	Moderate

1: Monthly reports split savings into months using the approval date

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). Annual savings for Demand Response resources represent the savings from all active facilities contracted since January 1, 2011.

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.

Current Reporting Period: the calendar quarter specified on page 1 of this report.

Effective Useful Life: detemines the persistence of savings for a given technology or initiative. Factors that may effect the useful life of a technology are typical use and operating hours, upcoming code changes, etc. Demand response resources are assumed to have a persistence of 1 year.

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). All savings presented in this report are at the end-user level.

Final or Verified Savings: savings achieved that have undergone annual Evaluation, Measurement & Verification (EM&V) and thus have had activity audited and savings assumptions measured and verified.

Implementation Period: the particular calendar quarter or calendar year that conservation activity is achieved based on when the savings are considered to 'start' (please see table 5).

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). Incremental savings for Demand Response resources represent the savings from all active facilities contracted since January 1, 2011 (i.e. Incremental = Annual for demand response only).

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc. Please refer to the webinars in the "Reporting Methodology" section for more information.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc. Please refer to the webinars in the "Reporting Methodology" section for more information.

Program-to-Date: the reporting period from January 1, 2011 until the end of the Current Reporting Period.

Program: a group of initiatives that target a particular market sector (i.e. Consumer, Industrial).

Reported or Unverified Savings: savings achieved that are based on reported activity and forecasted or best available savings assumptions. These savings are not verified, i.e. have not undergone the Evaluation, Measurement & Verification processes.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

Reporting Methodology (Quarterly, Unverified results):

There are several resources on reporting that are available to LDCs:

- Reporting Policy & FAQ Document found on the iCON Portal in the "Other Program Materials" under "Reporting Tools"
- LDC Consumer Program Tracking Tool found on the iCON Portal in "Other Program Materials" under "Reporting Tools"
- Webinars (available at the following link: http://www.snwebcastcenter.com/custom_events/opa-20111781/site/index.php)
    - Understanding your Q4 2011 Report (April 11, 2012)
    - Tools from the Reporting WG (April 25, 2012)
    - A Deeper Look at: ***peaksaver* PLUS®** (May 23, 2012)
    - A Deeper Look at: Demand Response 3 (June 6, 2012)
    - Revisiting Reporting (June 20, 2012)
    - Quarterly CDM Status Report update (October 24, 2012) http://powerauthority.webex.com; password: DCx2012

Exhibit 4 – Operation Cost

EXHIBIT 4 – OPERATING COST

The purpose of this Appendix is to provide an analysis of The Applicant's Operating, Maintenance and Administrative (OM&A) costs on an actual and forecast basis. The evidence herein is organized according to the following topics;

1) Manager 'Summary
2) Employee Compensation
3) Shared Services and Corporate Allocation
4) Purchases of Non-Affiliate Services
5) Depreciation/Amortization/Depletion
6) PILs and Property Taxes
7) GEA Plan
8) CDM Costs
9) Patronage Dividends

Tab 1 – Manager 'Summary

E4.T1.S1 OVERVIEW OF OPERATING COSTS

Table 1 below shows a summary of HHI's Operations, Maintenance and Administrative ("OM&A") costs as required by the OEB's filing guidelines.

Table 1 - Summary of Operating Costs

	Last Rebasing Year (2010 BA)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Operations	$75,463.00	$75,104.18	$71,031.24	$74,387.00	$85,250.00	$96,550.00
Maintenance	$171,887.00	$131,509.28	$147,633.64	$178,745.00	$189,700.00	$205,700.00
SubTotal	**$247,350.00**	**$206,613.46**	**$218,664.88**	**$253,132.00**	**$274,950.00**	**$302,250.00**
%Change (year over year)			5.8%	15.8%	8.6%	9.9%
%Change (Test Year vs Last Rebasing Year - Actual)						46.3%
Billing and Collecting	$327,572.00	$325,519.12	$339,942.43	$347,731.00	$390,190.00	$426,315.00
Community Relations	$108.00	$100.00	$225.00	$0.00	$200.00	$200.00
Administrative and General	$370,562.00	$335,456.02	$352,658.83	$405,557.00	$467,400.00	$397,900.00
SubTotal	**$698,242.00**	**$661,075.14**	**$692,826.26**	**$753,288.00**	**$857,790.00**	**$824,415.00**
%Change (year over year)			4.8%	8.7%	13.9%	-3.9%
%Change (Test Year vs Last Rebasing Year - Actual)						24.7%
Total	**$945,592.00**	**$867,688.60**	**$911,491.14**	**$1,006,420.00**	**$1,132,740.00**	**$1,126,665.00**
%Change (year over year)			5.0%	10.4%	12.6%	-0.5%

As indicated at Exhibit 1 section E1.T1.S5 HHI has followed the Canadian Generally Accepted Accounting Principles (CGAAP) in preparation of its forecasted years. In a January 1, 2013, the Board instructed utilities to change their capitalization policy which meant expensing certain costs rather than applying them as burdens to capital projects. HHI's burdens now charged to OM&A are estimated at $5,984 for 2013 and $6,224 for the test year. Details are presented at the next page.

HHI's increase in OM&A spending from its 2010 Cost of Service to the 2014 Test Year amounts to approximately $181,073. The increase can be attributed to several factors related to the operating and maintenance of the distribution system and administrative costs. The costs related to maintenance (approx. 55K) of the distribution system are for the most part aimed at HHI's distribution substations and its protective equipment, along with general maintenance on overhead and underground assets. The maintenance is done following HHI's annual inspection and is carried out to meet ESA's requirements. As for the variance of 126K, it can be attributed to billing, collecting and general administration expenditures. These projects are discussed in detail at Exhibit 2. Another significant contributor to the increase in OM&A is the on-going costs associated with supporting smart metering. These costs, at $92,921, account for almost 50% of the overall increase. If HHI were to remove these costs, the overall increase from 2010 to 2014 would be approximately $88,000 or 12.2% as seen in Table 2 below.

Table 2a) Summary of Operating Costs net of Smart Meter Cost

	Last Rebasing Year (2010 BA)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Operations	$75,463.00	$75,104.18	$71,031.24	$74,387.00	$85,250.00	$87,550.00
Maintenance	$171,887.00	$131,509.28	$147,633.64	$178,745.00	$189,700.00	$204,500.00
SubTotal	**$247,350.00**	**$206,613.46**	**$218,664.88**	**$253,132.00**	**$274,950.00**	**$292,050.00**
%Change (year over year)			5.8%	15.8%	8.6%	6.2%
%Change (Test Year vs Last Rebasing Year - Actual)						41.4%
Billing and Collecting	$327,572.00	$325,519.12	$339,942.43	$347,731.00	$390,190.00	$343,593.00
Community Relations	$108.00	$100.00	$225.00	$0.00	$200.00	$200.00
Administrative and General	$370,562.00	$335,456.02	$352,658.83	$405,557.00	$467,400.00	$397,900.00
SubTotal	**$698,242.00**	**$661,075.14**	**$692,826.26**	**$753,288.00**	**$857,790.00**	**$741,693.00**
%Change (year over year)			4.8%	8.7%	13.9%	-13.5%
%Change (Test Year vs Last Rebasing Year - Actual)						12.2%
Total	**$945,592.00**	**$867,688.60**	**$911,491.14**	**$1,006,420.00**	**$1,132,740.00**	**$1,033,743.00**
%Change (year over year)			5.0%	10.4%	12.6%	-8.7%

Table 2b) Smart Meter Related On-Going Costs

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

Financial pressures in specific areas, such as bad debts, have also influenced the spending in the OM&A. Staff and management salaries are adjusted yearly to reflect inflation and cost of living. The cost of living is based on an inflation rate of 2% as published by the Bank of Canada. The Bank of Canada is a well-known, reliable and widely used source in establishing inflation rates, not to mention the prescribed interest rates approved by the OEB . The Central Bank's system provides a clear measure of the effectiveness of monetary policy, and increases the predictability of inflation. In addition, at page 16 of the Report of the Board entitled "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" issued October 18, 2012, the Board quotes the Bank of Canada as an objective source. "the inflation factor must be constructed and updated using data that is readily available from public and objective sources such as, for example, Statistics Canada, the Bank of Canada, and Human Resources and Social Development Canada"

HHI's approach to budgeting and managing its OM&A costs is that whenever possible, HHI attempts to keep its operating cost within the boundaries of the last board approved OM&A costs, while performing regular asset maintenance, meet customer needs and promote safety to the public and employees. If unexpected costs arise, the utility makes every effort to reduce costs elsewhere in order to stay within the board approved budget. Reasonableness of OM&A costs are scrutinized with particular care and consideration of the needs and requirement of the organization, its members, employees, and clients, the public at large, and the regulators.

E4.T1.S2 SUMMARY OF RECOVERABLE OM&A EXPENSES – APPENDIX 2-I

The following Table (3) summarizes HHI's recoverable OM&A expenses.

Table 3 – Summary of recoverable OM&A expenses

	Last Rebasing Year (2010 BA)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Operations	$75,463	$75,104	$71,031	$74,387	$85,250	$96,550
Maintenance	$171,887	$131,509	$147,634	$178,745	$189,700	$205,700
Billing and Collecting	$327,572	$325,519	$339,942	$347,731	$390,190	$426,315
Community Relations	$108	$100	$225	$-	$200	$200
Administrative and General	$370,562	$335,456	$352,659	$405,557	$467,400	$397,900
Total	**$945,592**	**$867,689**	**$911,491**	**$1,006,420**	**$1,132,740**	**$1,126,665**
%Change (year over year)			5.0%	10.4%	12.6%	-0.5%

E4.T1.S3 DETAILED OM&A EXPENSES BY ACCOUNT – APPENDIX 2-H

A more detailed breakdown of HHI's year over year OM&A is presented at the next page (Appendix 2-H)

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Appendix 2-G
Detailed, Account by Account, OM&A Expense Table
(excluding Depreciation and Amortization)

Account Description	Last Rebasing Year (2010 Actuals)	2011 Actual	2012 Actual[2]	Bridge Year 2013[3]	Bridge Year 2013[3]	Test Year 2014	Test Year 2014
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	CGAAP	MIFRS
Operations							
5005 Operation Supervision and Engineering	$ -	$ -	$ -	$ -		$ -	
5010 Load Dispatching	$ -	$ -	$ -	$ -		$ -	
5012 Station Buildings and Fixtures Expense	$ -	$ -	$ -	$ -		$ -	
5014 Transformer Station Equipment - Operation Labour	$ 3,290	$ 11,351	$ 6,356	$ 9,500		$ 10,000	
5015 Transformer Station Equipment - Operation Supplies and Expenses	$ 8,023	$ 3,780	$ 5,261	$ 8,500		$ 9,000	
5016 Distribution Station Equipment - Operation Labour	$ 4,359	$ 10,381	$ 8,507	$ 10,000		$ 12,000	
5017 Distribution Station Equipment - Operation Supplies and Expenses	$ 4,905	$ 2,053	$ 6,400	$ 5,000		$ 6,500	
5020 Overhead Distribution Lines and Feeders - Operation Labour	$ 9,936	$ 9,931	$ 11,028	$ 11,500		$ 13,500	
5025 Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 1,171	$ 1,751	$ 1,404	$ 1,500		$ 1,600	
5030 Overhead Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -		$ -	
5035 Overhead Distribution Transformers - Operation	$ 7,628	$ 4,195	$ 5,585	$ 8,000		$ 10,000	
5040 Underground Distribution Lines and Feeders - Operation Labour	$ 911	$ 3,096	$ 1,920	$ 2,100		$ 2,500	
5045 Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 32	$ 32	$ 50	$ 50		$ 50	
5050 Underground Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -		$ -	
5055 Underground Distribution Transformers - Operation	$ 317	$ 1,837	$ 1,274	$ 3,000		$ 3,500	
5060 Street Lighting and Signal System Expense	$ -	$ -	$ -	$ -		$ -	
5065 Meter Expense	$ 33,645	$ 21,738	$ 25,715	$ 24,600		$ 26,300	
5070 Customer Premises - Operation Labour	$ -	$ -	$ -	$ -		$ -	
5075 Customer Premises - Operation Materials and Expenses	$ -	$ -	$ -	$ -		$ -	
5085 Miscellaneous Distribution Expenses	$ -	$ -	$ -	$ -		$ -	
5090 Underground Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -		$ -	
5095 Overhead Distribution Lines and Feeders - Rental Paid	$ 887	$ 887	$ 887	$ 1,500		$ 1,600	
5096 Other Rent	$ -	$ -	$ -	$ -		$ -	
Total - Operations	$ 75,104	$ 71,031	$ 74,387	$ 85,250	$ -	$ 96,550	$ -
Account Description	**Last Rebasing Year (2010 Actuals)**	**2011 Actual**	**2012 Actual[2]**	**Bridge Year 2013[3]**	**Bridge Year 2013[3]**	**Test Year 2014**	**Test Year 2014**
Maintenance							
5105 Maintenance Supervision and Engineering	$ 720	$ -	$ -	$ 1,000		$ 1,100	
5110 Maintenance of Buildings and Fixtures - Distribution Stations	$ -	$ -	$ -	$ -		$ -	
5112 Maintenance of Transformer Station Equipment	$ -	$ -	$ -	$ -		$ -	
5114 Maintenance of Distribution Station Equipment	$ -	$ -	$ -	$ -		$ -	
5120 Maintenance of Poles, Towers and Fixtures	$ 5,217	$ 3,987	$ 11,552	$ 10,000		$ 11,000	
5125 Maintenance of Overhead Conductors and Devices	$ 36,894	$ 28,090	$ 35,188	$ 34,000		$ 35,000	
5130 Maintenance of Overhead Services	$ 28,278	$ 34,875	$ 42,724	$ 46,000		$ 50,000	
5135 Overhead Distribution Lines and Feeders - Right of Way	$ 40,523	$ 44,239	$ 62,172	$ 65,000		$ 70,000	
5145 Maintenance of Underground Conduit	$ 333	$ 545	$ 1,606	$ 1,500		$ 1,500	
5150 Maintenance of Underground Conductors and Devices	$ 5,408	$ 15,280	$ 4,084	$ 8,900		$ 10,300	
5155 Maintenance of Underground Services	$ 7,402	$ 7,582	$ 7,468	$ 8,500		$ 9,900	
5160 Maintenance of Line Transformers	$ 7,717	$ 11,806	$ 11,988	$ 13,000		$ 15,000	
5165 Maintenance of Street Lighting and Signal Systems	$ -	$ -	$ -	$ -		$ -	
5170 Sentinel Lights - Labour	$ -	$ -	$ -	$ -		$ -	
5172 Sentinel Lights - Materials and Expenses	$ -	$ -	$ -	$ -		$ -	
5175 Maintenance of Meters	-$ 982	$ 1,229	$ 1,963	$ 1,800		$ 1,900	
5178 Customer Installations Expenses - Leased Property	$ -	$ -	$ -	$ -		$ -	
5195 Maintenance of Other Installations on Customer Premises	$ -	$ -	$ -	$ -		$ -	
Total - Maintenance	$ 131,509	$ 147,634	$ 178,745	$ 189,700	$ -	$ 205,700	$ -
Account Description	**Last Rebasing Year (2010 Actuals)**	**2011 Actual**	**2012 Actual[2]**	**Bridge Year 2013[3]**	**Bridge Year 2013[3]**		**Test Year 2014**
Billing and Collecting							
5305 Supervision	$ -	$ -	$ -	$ -		$ -	
5310 Meter Reading Expense	$ 29,864	$ 42,062	$ 35,200	$ 38,000		$ 45,000	
5315 Customer Billing	$ 175,731	$ 185,552	$ 211,800	$ 230,000		$ 245,000	
5320 Collecting	$ 100,396	$ 94,827	$ 97,931	$ 102,130		$ 106,250	
5325 Collecting - Cash Over and Short	$ -	$ 5	$ -	$ 60		$ 65	
5330 Collection Charges	$ -	$ -	$ -	$ -		$ -	
5335 Bad Debt Expense	$ 19,528	$ 17,497	$ 2,800	$ 20,000		$ 30,000	
5340 Miscellaneous Customer Accounts Expenses	$ -	$ -	$ -	$ -		$ -	
Total - Billing and Collecting	$ 325,519	$ 339,942	$ 347,731	$ 390,190	$ -	$ 426,315	$ -
Account Description	**Last Rebasing Year (2010 Actuals)**	**2011 Actual**	**2012 Actual[2]**	**Bridge Year 2013[3]**	**Bridge Year 2013[3]**		**Test Year 2014**
Community Relations							
5405 Supervision	$ -	$ -	$ -	$ -		$ -	
5410 Community Relations - Sundry	$ 100	$ 225	$ -	$ 200		$ 200	
5415 Energy Conservation	$ -	$ -	$ -	$ -		$ -	
5420 Community Safety Program	$ -	$ -	$ -	$ -		$ -	
5425 Miscellaneous Customer Service and Informational Expenses	$ -	$ -	$ -	$ -		$ -	
5505 Supervision	$ -	$ -	$ -	$ -		$ -	
5510 Demonstrating and Selling Expense	$ -	$ -	$ -	$ -		$ -	

5515	Advertising Expenses	$ -	$ -	$ -	$ -		$ -	
5520	Miscellaneous Sales Expense	$ -	$ -	$ -	$ -		$ -	
Total - Community Relations		$ 100	$ 225	$ -	$ 200	$ -	$ 200	$ -
Account	**Description**	**Last Rebasing Year (2010 Actuals)**	**2011 Actual**	**2012 Actual[2]**	**Bridge Year 2013[3]**	**Bridge Year 2013[3]**		**Test Year 2014**
Administrative and General Expenses								
5605	Executive Salaries and Expenses	$ 105,990	$ 105,072	$ 105,734	$ 109,000		$ 112,000	
5610	Management Salaries and Expenses	$ 69,181	$ 72,507	$ 74,249	$ 76,000		$ 78,000	
5615	General Administrative Salaries and Expenses	$ -	$ -	$ -	$ -		$ -	
5620	Office Supplies and Expenses	$ 21,409	$ 24,655	$ 22,744	$ 27,000		$ 30,000	
5625	Administrative Expense Transferred - Credit	$ -	$ -	$ -	$ -		$ -	
5630	Outside Services Employed	$ 11,213	$ 19,495	$ 17,784	$ 19,850		$ 20,600	
5635	Property Insurance	$ 4,566	$ 4,658	$ 4,798	$ 7,700		$ 12,000	
5640	Injuries and Damages	$ 6,178	$ 9,018	$ 3,509	$ 7,700		$ 8,000	
5645	OMERS Pensions and Benefits	$ 3,250	$ 3,688	$ 3,627	$ 3,750		$ 3,900	
5646	Employee Pensions and OPEB	$ -	$ -	$ -	$ -		$ -	
5647	Employee Sick Leave	$ -	$ -	$ -	$ -		$ -	
5650	Franchise Requirements	$ -	$ -	$ -	$ -		$ -	
5655	Regulatory Expenses	$ 47,004	$ 66,083	$ 128,605	$ 138,000		$ 65,400	
5660	General Advertising Expenses	$ -	$ -	$ -	$ -		$ -	
5665	Miscellaneous General Expenses	$ 13,817	$ 13,850	$ 14,600	$ 15,100		$ 15,700	
5670	Rent	$ -	$ -	$ -	$ -		$ -	
5672	Lease Payment Charge	$ -	$ -	$ -	$ -		$ -	
5675	Maintenance of General Plant	$ 25,833	$ 26,746	$ 23,003	$ 56,200		$ 45,000	
5680	Electrical Safety Authority Fees	$ 4,914	$ 4,887	$ 4,904	$ 5,100		$ 5,300	
5681	Special Purpose Charge Expense	$ 22,101	$ -		$ -		$ -	
5685	Independent Electricity System Operator Fees and Penalties	$ -	$ -		$ -		$ -	
5695	OM&A Contra Account							
6205	Donations							
6205	Donations, Sub-account LEAP Funding	$ -	$ 2,000	$ 2,000	$ 2,000		$ 2,000	
Total - Administrative and General Expenses		$ 335,456	$ 352,659	$ 405,557	$ 467,400	$ -	$ 397,900	$ -
Total OM&A		$ 867,689	$ 911,491	$ 1,006,420	$ 1,132,740	$ -	$ 1,126,665	$ -
Adjustments for non-recoverable items								
5681	Special Purpose Charge Expense	$ 22,101						
6205	Donations[1]							
Total Recoverable OM&A		$ 845,587	$ 911,491	$ 1,006,420	$ 1,132,740	$ -	$ 1,126,665	$ -

[1] Account 6205 - Donations is generally non-recoverable. However, the sub-account LEAP funding of account 6205 is generally recoverable.

Note:

1. If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.
2. If the applicant is adopting IFRS or an alternate accounting standard as of January 1, 2013 for financial reporting purposes, 2012 must be presented on both a CGAAP and MIFRS (or alternate accounting standard) basis.
3. If the applicant is adopting IFRS or an alternate accounting standard as of January 1, 2014 for financial reporting purposes, 2013 must be presented on both a CGAAP and MIFRS (or alternate accounting standard) basis.

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Appendix 2-H
OM&A Detailed Variance Analysis
(excluding Depreciation and Amortization)

Account	Description	Last Board-approved Rebasing Year (2010 Year)	Most Current Actuals Year 2012	Test Year 2014	Test Year Versus Last Rebasing		Test Year Versus Most Current Actuals	
					Variance ($)	Percentage	Variance ($)	Percentage
Reporting Basis		CGAAP	CGAAP	CGAAP				
Operations								
5005	Operation Supervision and Engineering	$ -	$ -	$ -	$ -		$ -	
5010	Load Dispatching	$ -	$ -	$ -	$ -		$ -	
5012	Station Buildings and Fixtures Expense	$ -	$ -	$ -	$ -		$ -	
5014	Transformer Station Equipment - Operation Labour	$ 11,695	$ 6,356	$ 10,000	$ (1,695)	-14.49%	$ 3,644	57.33%
5015	Transformer Station Equipment - Operation Supplies and Expenses	$ 12,944	$ 5,261	$ 9,000	$ (3,944)	-30.47%	$ 3,739	71.07%
5016	Distribution Station Equipment - Operation Labour	$ 9,672	$ 8,507	$ 12,000	$ 2,328	24.07%	$ 3,493	41.06%
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ 66	$ 6,400	$ 6,500	$ 6,434	9748.48%	$ 100	1.56%
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 10,154	$ 11,028	$ 13,500	$ 3,346	32.95%	$ 2,472	22.42%
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 1,120	$ 1,404	$ 1,600	$ 480	42.86%	$ 196	13.96%
5030	Overhead Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -		$ -	
5035	Overhead Distribution Transformers - Operation	$ 12,046	$ 5,585	$ 10,000	$ (2,046)	-16.98%	$ 4,415	79.05%
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 2,130	$ 1,920	$ 2,500	$ 370	17.37%	$ 580	30.21%
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 25	$ 50	$ 50	$ 25	100.00%	$ -	0.00%
5050	Underground Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -		$ -	
5055	Underground Distribution Transformers - Operation	$ 2,465	$ 1,274	$ 3,500	$ 1,035	41.99%	$ 2,226	174.73%
5060	Street Lighting and Signal System Expense	$ -	$ -	$ -	$ -		$ -	
5065	Meter Expense	$ 12,032	$ 25,715	$ 26,300	$ 14,268	118.58%	$ 585	2.27%
5070	Customer Premises - Operation Labour	$ -	$ -	$ -	$ -		$ -	
5075	Customer Premises - Operation Materials and Expenses	$ -	$ -	$ -	$ -		$ -	
5085	Miscellaneous Distribution Expenses	$ -	$ -	$ -	$ -		$ -	
5090	Underground Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -		$ -	
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ 1,114	$ 887	$ 1,600	$ 486	43.63%	$ 713	80.38%
5096	Other Rent	$ -	$ -	$ -	$ -		$ -	
Total - Operations		$ 75,463	$ 74,387	$ 96,550	$ 21,087	27.94%	$ 22,163	29.79%
Account	**Description**							
Maintenance								
5105	Maintenance Supervision and Engineering	$ 4,815	$ -	$ 1,100	$ (3,715)	-77.15%	$ 1,100	
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$ -	$ -	$ -	$ -		$ -	
5112	Maintenance of Transformer Station Equipment	$ -	$ -	$ -	$ -		$ -	
5114	Maintenance of Distribution Station Equipment	$ -	$ -	$ -	$ -		$ -	
5120	Maintenance of Poles, Towers and Fixtures	$ 18,022	$ 11,552	$ 11,000	$ (7,022)	-38.96%	$ (552)	-4.78%
5125	Maintenance of Overhead Conductors and Devices	$ 32,799	$ 35,188	$ 35,000	$ 2,201	6.71%	$ (188)	-0.53%
5130	Maintenance of Overhead Services	$ 33,392	$ 42,724	$ 50,000	$ 16,608	49.74%	$ 7,276	17.03%
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 44,827	$ 62,172	$ 70,000	$ 25,173	56.16%	$ 7,828	12.59%
5145	Maintenance of Underground Conduit	$ 1,198	$ 1,606	$ 1,500	$ 302	25.21%	$ (106)	-6.60%
5150	Maintenance of Underground Conductors and Devices	$ 18,596	$ 4,084	$ 10,300	$ (8,296)	-44.61%	$ 6,216	152.20%
5155	Maintenance of Underground Services	$ 7,176	$ 7,468	$ 9,900	$ 2,724	37.96%	$ 2,432	32.57%
5160	Maintenance of Line Transformers	$ 2,362	$ 11,988	$ 15,000	$ 12,638	535.06%	$ 3,012	25.13%
5165	Maintenance of Street Lighting and Signal Systems	$ -	$ -	$ -	$ -		$ -	
5170	Sentinel Lights - Labour	$ -	$ -	$ -	$ -		$ -	
5172	Sentinel Lights - Materials and Expenses	$ -	$ -	$ -	$ -		$ -	
5175	Maintenance of Meters	$ 8,700	$ 1,963	$ 1,900	$ (6,800)	-78.16%	$ (63)	-3.21%
5178	Customer Installations Expenses - Leased Property	$ -	$ -	$ -	$ -		$ -	
5195	Maintenance of Other Installations on Customer Premises	$ -	$ -	$ -	$ -		$ -	
Total - Maintenance		$ 171,887	$ 178,745	$ 205,700	$ 33,813	19.67%	$ 26,955	15.08%
Account	**Description**							
Billing and Collecting								
5305	Supervision	$ -	$ -	$ -	$ -		$ -	
5310	Meter Reading Expense	$ 33,376	$ 35,200	$ 45,000	$ 11,624	34.83%	$ 9,800	27.84%
5315	Customer Billing	$ 185,880	$ 211,800	$ 245,000	$ 59,120	31.81%	$ 33,200	15.68%
5320	Collecting	$ 100,389	$ 97,931	$ 106,250	$ 5,861	5.84%	$ 8,319	8.49%
5325	Collecting - Cash Over and Short	$ -	$ -	$ 65	$ 65		$ 65	
5330	Collection Charges	$ -	$ -	$ -	$ -		$ -	
5335	Bad Debt Expense	$ 7,927	$ 2,800	$ 30,000	$ 22,073	278.45%	$ 27,200	971.43%
5340	Miscellaneous Customer Accounts Expenses	$ -	$ -	$ -	$ -		$ -	
Total - Billing and Collecting		$ 327,572	$ 347,731	$ 426,315	$ 98,743	30.14%	$ 78,584	22.60%
Account	**Description**							
Community Relations								
5405	Supervision	$ -	$ -	$ -	$ -		$ -	
5410	Community Relations - Sundry	$ 108	$ -	$ 200	$ 92	85.19%	$ 200	
5415	Energy Conservation	$ -	$ -	$ -	$ -		$ -	
5420	Community Safety Program	$ -	$ -	$ -	$ -		$ -	
5425	Miscellaneous Customer Service and Informational Expenses	$ -	$ -	$ -	$ -		$ -	
5505	Supervision	$ -	$ -	$ -	$ -		$ -	
5510	Demonstrating and Selling Expense	$ -	$ -	$ -	$ -		$ -	
5515	Advertising Expenses	$ -	$ -	$ -	$ -		$ -	
5520	Miscellaneous Sales Expense	$ -	$ -	$ -	$ -		$ -	
Total - Community Relations		$ 108	$ -	$ 200	$ 92	85.19%	$ 200	
Account	**Description**							
Administrative and General Expenses								
5605	Executive Salaries and Expenses	$ 107,289	$ 105,734	$ 112,000	$ 4,711	4.39%	$ 6,266	5.93%
5610	Management Salaries and Expenses	$ 74,757	$ 74,249	$ 78,000	$ 3,243	4.34%	$ 3,751	5.05%
5615	General Administrative Salaries and Expenses	$ -	$ -	$ -	$ -		$ -	
5620	Office Supplies and Expenses	$ 21,702	$ 22,744	$ 30,000	$ 8,298	38.24%	$ 7,256	31.90%
5625	Administrative Expense Transferred - Credit	$ -	$ -	$ -	$ -		$ -	
5630	Outside Services Employed	$ 28,817	$ 17,784	$ 20,600	$ (8,217)	-28.51%	$ 2,816	15.83%
5635	Property Insurance	$ 4,698	$ 4,798	$ 12,000	$ 7,302	155.43%	$ 7,202	150.10%
5640	Injuries and Damages	$ 12,427	$ 3,509	$ 8,000	$ (4,427)	-35.62%	$ 4,491	127.99%
5645	OMERS Pensions and Benefits	$ 3,699	$ 3,627	$ 3,900	$ 201	5.43%	$ 273	7.53%
5646	Employee Pensions and OPEB	$ -	$ -	$ -	$ -		$ -	
5647	Employee Sick Leave	$ -	$ -	$ -	$ -		$ -	
5650	Franchise Requirements	$ -	$ -	$ -	$ -		$ -	
5655	Regulatory Expenses	$ 67,531	$ 128,605	$ 65,400	$ (2,131)	-3.16%	$ (63,205)	-49.15%
5660	General Advertising Expenses	$ -	$ -	$ -	$ -		$ -	
5665	Miscellaneous General Expenses	$ 13,520	$ 14,600	$ 15,700	$ 2,180	16.12%	$ 1,100	7.53%
5670	Rent	$ -	$ -	$ -	$ -		$ -	
5672	Lease Payment Charge	$ -	$ -	$ -	$ -		$ -	
5675	Maintenance of General Plant	$ 30,596	$ 23,003	$ 45,000	$ 14,404	47.08%	$ 21,997	95.63%
5680	Electrical Safety Authority Fees	$ 5,526	$ 4,904	$ 5,300	$ (226)	-4.09%	$ 396	8.08%
5681	Special Purpose Charge Expense	$ -	$ -	$ -	$ -		$ -	
5685	Independent Electricity System Operator Fees and Penalties	$ -	$ -	$ -	$ -		$ -	
5695	OM&A Contra Account	$ -	$ -	$ -	$ -		$ -	
6205	Donations	$ -	$ -	$ -	$ -		$ -	
6205	Donations, Sub-account LEAP Funding	$ -	$ 2,000	$ 2,000	$ 2,000		$ -	0.00%
Total - Administrative and General Expenses		$ 370,562	$ 405,557	$ 397,900	$ 27,338	7.38%	$ (7,657)	-1.89%
Total OM&A		$ 945,592	$ 1,006,420	$ 1,126,665	$ 181,073	19.15%	$ 120,245	11.95%
Adjustments for non-recoverable items								
5681	Special Purpose Charge Expense	$ -	$ -	$ -	$ -		$ -	
6205	Donations[1]				$ -		$ -	
					$ -		$ -	
					$ -		$ -	
					$ -		$ -	
Total Recoverable OM&A		$ 945,592	$ 1,006,420	$ 1,126,665	$ 181,073	19.15%	$ 120,245	11.95%

E4.T1.S4 OM&A COST DRIVERS – APPENDIX 2-J

In accordance with the OEB's minimum filing requirements, Table 4, below, outlines the key drivers of OM&A costs over the 2010 to 2014 period. The key cost driver's discussions follow Table 4.

**Please note that each week all salary expenses are distributed in different GL accounts according to the work performed. Depending on the month or year, variances occur due to different situations, such as time spent doing a regular, emergency or special task. Consequently, the variance that occur from year to year is not caused by a large wage increase but is simply caused by salary (time spent on a particular task) distribution due to different jobs.

As per negotiated union contract the wage increase from 2010 to 2013 is 2% per year.

For easy reference, each time that the variance is caused by salary distribution, HHI will indicate it by putting two asterisks (**).

Table 4 - OM&A Cost Drivers – Appendix 2-J

OM&A	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Reporting Basis					
Opening Balance	$945,592.00	$845,587.34	$911,491.14	$1,006,420.00	$1,132,740.00
5014-Transformer Station Equipment - Operation Labour		$8,061.01		$3,144.00	
5015-Transformer Station Equipment - Operation Supplies and Expenses				$3,239.00	
5016-Distribution Station Equipment - Operation Labour		$6,022.23			
5017-Distribution Station Equipment - Operation Supplies and Expenses	$4,839.24		$4,346.89		
5040-Underground Distribution Lines and Feeders - Operation Labour		$2,184.84			
5065-Meter Expense	$21,613.26		$3,976.84		
5120-Maintenance of Poles, Towers and Fixtures			$7,565.43		
5125-Maintenance of Overhead Conductors and Devices	$4,095.46		$7,097.98		
5130-Maintenance of Overhead Services		$6,597.15	$7,848.90	$3,276.00	$4,000.00
5135-Overhead Distribution Lines and Feeders - Right of Way		$3,716.17	$17,932.92		$5,000.00
5150-Maintenance of Underground Conductors and Devices		$9,872.61		$4,816.00	
5160-Maintenance of Line Transformers	$5,354.53	$4,089.38			
5175-Maintenance of Meters		$2,211.30			
5310-Meter Reading Expense		$12,197.85			$7,000.00
5315-Customer Billing		$9,821.05	$26,247.82	$18,200.00	$15,000.00
5320-Collecting			$3,104.16	$4,199.00	$4,120.00
5335-Bad Debt Expense	$11,601.13			$17,200.00	$10,000.00
5605-Executive Salaries and Expenses				$3,266.00	$3,000.00
5610-Management Salaries and Expenses		$3,326.13			
5620-Office Supplies and Expenses		$3,245.49		$4,256.00	$3,000.00
5630-Outside Services Employed		$8,282.45			
5635-Property Insurance					$4,300.00
5640-Injuries and Damages		$2,840.40		$4,191.00	

5655-Regulatory Expenses		$19,079.23	$62,521.52	$9,395.00	
5675-Maintenance of General Plant				$33,197.00	
Other	$588.34	$6,097.71	$9,274.23	$23,465.00	$22,305.00
Cost Reduction	-$148,096.62	-$41,741.20	-$54,987.83	-$5,524.00	-$83,800.00
Total Adjustment	**-$100,004.66**	**$65,903.80**	**$94,928.86**	**$126,320.00**	**-$6,075.00**
Closing Balance	$845,587.34	$911,491.14	$1,006,420.00	$1,132,740.00	$1,126,665.00

Table 5 - 2010 Cost Drivers

OEB	Description	Variance	
3500-Distribution Expenses - Operation	5065-Meter Expense	$21,613.26	1
3650-Billing and Collecting	5335-Bad Debt Expense	$11,601.13	2
3550-Distribution Expenses - Maintenance	5160-Maintenance of Line Transformers	$5,354.53	3
3500-Distribution Expenses - Operation	5017-Distribution Station Equipment - Operation Supplies and Expenses	$4,839.24	4
3550-Distribution Expenses - Maintenance	5125-Maintenance of Overhead Conductors and Devices	$4,095.46	5
	Others	$588.34	
	Cost Reductions	-$148,096.62	
	OM&ATotal	-$100,004.66	

5065-Meter Expense: increase of $21,613 (Over 2010BA-2010Actual period)

The increase is attributed to labour costs associated with the installation of smart meters. In the interest of cost savings, HHI used its own linesman to install all smart meters as opposed to outsource the work to an external firm. HHI's linesmen are responsible for the installation, testing and commissioning of all new and upgrades meters. Performing the work internally allows HHI also eliminate potential diversion and theft of power which in turn contributes to revenue stability and protection.

5335-Bad Debt Expense: increase of $11,601.13 (Over 2010BA-2010Actual period)

The increase is due to and uncollected accounts and several unexpected bankruptcies. HHI's process involves reviewing the outstanding accounts for the current year and determining which accounts may not be collectable in the following year. A yearly adjustment is made to the bad debt expense and allowance for doubtful accounts.

5160-Maintenance of Line Transformers: increase of $5,354.53 (Over 2010BA-2010Actual period)

**This cost attributed to an increase in linemen's wages for the inspection and infrared testing on 50% of HHI's transformers in order to assure their reliability and safety. Non capital spending to support preventive and reactive maintenance is the main driver of cost increase. Activities included; distribute load on overhead transformers to prevent overloading (Change buss-break location), visual check of transformer bushing, as well as connections on primary and secondary.

5017-Distribution Station Equipment - Operation Supplies and Expenses: increase of $4,839.24 (Over 2010BA-2010Actual period)

These costs were necessary in order to replace ground grid following theft of copper at the utility's 44KV substation. HHI did not claim replacement costs to its insurance company since the deductible was determined to be higher than the actual replacement costs. The cost can be broken down as such; Total cost $3,592.50 for cooper replacement and a lighting system, in the amount of $685.91 was added to the station to prevent further theft attempt.

5125-Maintenance of Overhead Conductors and Devices increase of $4,095.46 (Over 2010BA-2010Actual period)

**The variance is explained by an increase in maintenance on all open points on the distribution system, as well as for the purchase of linemen fire resistant (FR) clothing supplied to the linemen as per the utility's 2010 union contract agreement. FR clothing is priced at $2,251.47.

Furthermore, as per the annual inspection, HHI replaced some porcelain insulators with polymer, and as part of ongoing maintenance some old connections were replaced with h-taps connections.

Table 6 - 2011 Cost Drivers

OEB	Description	Variance	
3800-Administrative and General Expenses	5655-Regulatory Expenses	$19,079.23	1
3650-Billing and Collecting	5310-Meter Reading Expense	$12,197.85	2
3550-Distribution Expenses - Maintenance	5150-Maintenance of Underground Conductors and Devices	$9,872.61	3
3650-Billing and Collecting	5315-Customer Billing	$9,821.05	4
3800-Administrative and General Expenses	5630-Outside Services Employed	$8,282.45	5
3500-Distribution Expenses - Operation	5014-Transformer Station Equipment - Operation Labour	$8,061.01	6
3550-Distribution Expenses - Maintenance	5130-Maintenance of Overhead Services	$6,597.15	7
3500-Distribution Expenses - Operation	5016-Distribution Station Equipment - Operation Labour	$6,022.23	8
3550-Distribution Expenses - Maintenance	5160-Maintenance of Line Transformers	$4,089.38	9
3550-Distribution Expenses - Maintenance	5135-Overhead Distribution Lines and Feeders - Right of Way	$3,716.17	10
3800-Administrative and General Expenses	5610-Management Salaries and Expenses	$3,326.13	11
3800-Administrative and General Expenses	5620-Office Supplies and Expenses	$3,245.49	12
3800-Administrative and General Expenses	5640-Injuries and Damages	$2,840.40	13
3550-Distribution Expenses - Maintenance	5175-Maintenance of Meters	$2,211.30	14
3500-Distribution Expenses - Operation	5040-Underground Distribution Lines and Feeders - Operation Labour	$2,184.84	15
	Others	$6,097.71	
	Cost Reduction	-$41,741.20	
	OM&ATotal	$65,904	

5655-Regulatory Expenses: increase of $19,079.23 (Over 2011-2010)

The increase is attributed to the 2010 cost of service application for which actual expenses were higher in 2011 than 2010 by $18,100. This is explained by the variance between the prorating of the OEB approved 2010 COS expense to be recorded over a four year period vs actual costs incurred by the utility.

5310-Meter Reading Expense: increase of $12,197.85 (Over 2011-2010)

In March of 2011, in anticipation of the conversion to smart meters, HHI's service provided "Utilismart", started reading meters on a monthly basis as opposed to bi-monthly. Cost associated with this conversion to monthly billing was in the amount of $10,500. The utility kept its contractor over the testing period to ensure a seamless conversion. The cost related to utilising the utility's contractor was approximately $1700. This overlap was deemed necessary in order to ensure that Utilismart results were accurate.

5150-Maintenance of Underground Conductors and Devices; increase of $9,872.61 (Over 2011-2010)

**The increase was due to necessary maintenance as a result of the inspection findings in 2010 and 2011 of transformers in order to meet ESA safety requirements. Following the results, maintenance was performed on elbows and inserts within the pad mount transformers and connections on overhead transformers. These were performed to maintain service reliability at the source. (Transformer terminations) Furthermore, during 2011, HHI experienced 2 bad secondary underground faults for a total amount of $2763

5315-Customer billing; increase of $9,821.05 (Over 2011-2010)

This increase in cost can be attributed to adjustment to salaries for cost of living. Other costs include; postage and training. The breakdown of this overall increase is as such; $3,490 for an increase in ERTH services; training on billing activities

(OHUG) in the amount of $410; salary adjustment of $1,400 for additional billing activities, bills reminders and collection forms in the amount of $4,535.

5630-Outside Services Employed; increase of $8,282.45 (Over 2011-2010)

The increase is due to cost associated with auditor and consultant costs to assist with the ICM requirements. $8,000 direct cost were attributed to annual audits increased by $ 2,900, ICM requirements $2,500 and year end provision $2,600

5014-Transformer Station Equipment - Operation Labour; increase of $8,061.01 (Over 2011-2010)

**The increase is attributed to compliance with IESO metering requirements on the seal expiry of old meters. HHI's MSP provider, Peterborough Utilities, performed a meter change as well as reported HHI'S compliance to the IESO. Extra labour from HHI's internal staff represents $ 1200.00 and MSP cost were $6.873

5130-Maintenance of Overhead Services increase $6,597.15 (Over 2011-2010)

**Salaries represent an increase of $5,985. The balance is due to maintenance on HHI's distribution line following the annual inspections. Connections at customer premise were replaced to avoid part power interruption. Old Kearney connections were replaced by H-Tap. Testing of the high voltage equipment for the safety of the lineman was performed by Kinectrics for $612.50.

5016-Distribution Station Equipment - Operation Labour; increase of $6,022.23 (Over 2011-2010)

**The increase is attributed to maintenance done on three reclosers at the 44KV substation along with PCP oil testing. Evaluation of all internal and external parts of each recloser, testing and commissioning of all controls and oils tests for a cost of $ 2,600. Extra labour and burden from HHI's personnel to perform tasks required during shutdowns to perform testing with GE Electric is in the amount of $3,400.

5160-Maintenance of Line Transformers; increase of $4,089.38 (Over 2011-2010)

**The increase is attributed to inspection and infrared testing on the remaining balance of HHI's transformers in order to assure reliability and safety. (Year 2 of inspection program) Non capital related spending to support preventive and reactive maintenance is the main driver of cost increase. Activities included; distribute load on overhead transformers to prevent overloading (Change buss-break location), visual check of transformer bushing, as well as connections on primary and secondary. Cost drivers are: Assistance from Sproule Power lines to remove a transformer on Omer St. (back Yard) $800; CISA locks for padmount transformers $ 800; Material $740 and extra labour and burden to perform the inspection and correction activities $ 1,749.

5135-Overhead Distribution Lines and Feeders - Right of Way; increase of $3,716.17

(Over 2011-2010)

**The increase is caused by on-going tree trimming costs to clear out lines in order to prevent power outages caused by limbs on power lines.

5610-Management Salaries and Expenses; increase of $3,326.13 (Over 2011-2010)

This increase in cost can be attributed to adjustment to management salaries for cost of living and overtime.

5620-Office Supplies and Expenses: increase of $3,245.49(Over 2011-2010)

The increase is caused by the purchase of office supplies. The main drivers are: Sage ACCPAC (accounting system) related costs in the amount of $2,963.17 and a Bell service call $ 172

5640-Injuries and Damages; increase of $2,840.40 (Over 2011-2010)

The variance is caused by an increase in cost of liability insurance.

5175-Maintenance of Meters; increase of $2,211.30 (Over 2011-2010)

The increase is attributed to the removal and inspection of our demand meters for general customers greater than 50kW.

5040-Underground Distribution Lines and Feeders - Operation Labour: increase of $2,184.84 (Over 2011-2010)

**The increase is caused by labour costs for maintenance of underground line and feeders following the utility's annual inspection.

Table 7 - 2012 Cost Drivers

OEB	Description	Variance	
3800-Administrative and General Expenses	5655-Regulatory Expenses	$62,521.52	1
3650-Billing and Collecting	5315-Customer Billing	$26,247.82	2
3550-Distribution Expenses - Maintenance	5135-Overhead Distribution Lines and Feeders - Right of Way	$17,932.92	3
3550-Distribution Expenses - Maintenance	5130-Maintenance of Overhead Services	$7,848.90	4
3550-Distribution Expenses - Maintenance	5120-Maintenance of Poles, Towers and Fixtures	$7,565.43	5
3550-Distribution Expenses - Maintenance	5125-Maintenance of Overhead Conductors and Devices	$7,097.98	6
3500-Distribution Expenses - Operation	5017-Distribution Station Equipment - Operation Supplies and Expenses	$4,346.89	7
3500-Distribution Expenses - Operation	5065-Meter Expense	$3,976.84	8
3650-Billing and Collecting	5320-Collecting	$3,104.16	9
	Others	$9,274.23	
	Cost Reduction	-$54,987.83	
	OM&ATotal	$94,928.86	

5655-Regulatory Expenses: Increase of $62,521.52

The increase is attributed the prorated 2010 rebasing costs which were higher in 2012 over 2011 by $13,157. This is explained by OEB approved 2010 COS expensed over a four year period but was up to that time prorated from May 1, 2010 to April 30, 2014. Expenses for the IRM of years 2010, 2011 and 2012 were previously recorded in a variance account for disposition at a later date. When informed that they couldn't recuperate these regulatory costs, all costs related to IRM applications were transferred from a variance account to account 5655-Regulatory Expense. Consequently the amount of $50,183 was recorded in 2012 for all IRM incurred expenses.

5315-Customer Billing: Increase of $26,247.82

This increase in cost can be attributed to adjustment in salaries to account for cost of living. HHI also incurred additional costs to outsource certain billing functions performed by a CSR on maternity leave. HHI used a service provider ERTH to perform these services. Using ERTH ensured that billing functionalities would be done without issues. It also avoided training a replacement CSR. By outsourcing certain functions, HHI was able to avoid the addition of an extra full time employee. Outsourcing costs were in the amount of $16,000. Billing on a monthly basis increased the postage cost by $ 9,200.

5135-Overhead Distribution Lines and Feeders - Right of Way: Increase of $17,932.92

**The increase is caused by on-going tree trimming costs to clear our main feeders, along with wood chipper and disposal costs to maintain safety and reliability. Prior to 2012, HHI had the permission to dispose of trees, shrubs and branches on a vacant lot and eventually obtain a permit to burn the debris. At the end of 2011, this option was no longer permitted. Consequently HHI is now contracting out debris disposal and wood chipper services at a cost of $8,100. Also, in 2012 most of our activities were done on feeders located in backyards which caused an increase of approximately $ 9,790.

5130-Maintenance of Overhead Services: Increase of $7,848.90

**The increase is caused by maintenance done on HHI’s distribution lines following the utility’s annual inspections. A breakdown of the overall increase is as such; $6,892 for salaries, high voltage rubber gloves $ 455 and electrical equipment for $200.00.

5120-Maintenance of Poles, Towers and Fixtures: Increase of $7,565.43

**Replacement of wood cross-arms was done following the utility's annual maintenance inspection. The major contributor to this cost driver was to perform the Asset Assessment required as part of the Asset Management Plan. The utility's Asset Management Plan is presented at Exhibit 2. A total of $7,685 was allocated in salary to perform the task.

5125-Maintenance of Overhead Conductors and Devices: Increase of $7,097.98

**The increase can be attributed to additional maintenance done during the year on HHI's feeders at the 44KV substation following the addition of the new 10MVA transformer. The variance is mainly due to year-end adjustments.

5017-Distribution Station Equipment - Operation Supplies and Expenses: Increase of $4,346.89

The variance is the cost for the final inspection survey and the monitoring of the new 10MVA transformer at the 44KV substation. GE was involved in installing, testing and commissioning new stabilizer bars on the 10MVA heat sink. The cost for this work was in the amount of $2,600. Several oil samples were taken for analysis on the new and old 10MVA transformer, and reclosers. The cost of oil analysis was in the amount of $1,659.

5065-Meter Expense: Increase of $3,976.84

The increase is mainly due to the smart meter transactions recorded in 2012 as per OEB Decision.

5320-Collecting: Increase of $3,104.16

**Salary increase due to additional time spent collecting outstanding accounts. Each week all salary expenses are distributed in different GL accounts accordingly. Depending on the month or year, variances occur due to different situations, such as time spent doing a regular or special task. The variance is caused by additional salaries recorded due to additional time spent collecting outstanding accounts.

Table 8 - 2013 Cost Drivers

OEB	Description	Variance	
3800-Administrative and General Expenses	5675-Maintenance of General Plant	$33,197.00	1
3650-Billing and Collecting	5315-Customer Billing	$18,200.00	2
3650-Billing and Collecting	5335-Bad Debt Expense	$17,200.00	3
3800-Administrative and General Expenses	5655-Regulatory Expenses	$9,395.00	4
3550-Distribution Expenses - Maintenance	5150-Maintenance of Underground Conductors and Devices	$4,816.00	5
3800-Administrative and General Expenses	5620-Office Supplies and Expenses	$4,256.00	6
3650-Billing and Collecting	5320-Collecting	$4,199.00	7
3800-Administrative and General Expenses	5640-Injuries and Damages	$4,191.00	8
3550-Distribution Expenses - Maintenance	5130-Maintenance of Overhead Services	$3,276.00	9
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	$3,266.00	10
3500-Distribution Expenses - Operation	5015-Transformer Station Equipment - Operation Supplies and Expenses	$3,239.00	11
3500-Distribution Expenses - Operation	5014-Transformer Station Equipment - Operation Labour	$3,144.00	12
	Other	$23,465.00	
	Cost Reduction	-$5,524.00	
	OM&ATotal	$126,320.00	

5675-Maintenance of General Plant: Increase of $33,197.00

The increase is caused by office renovations done in 2013 since the building built in 1991 never had major renovations done. Repairs were done on interior walls where water damage had occurred over the past years. **An amount of $8,500 for labour and material is attributed for work performed by HHI's staff where feasible. A third party was hired to do some plastering (drywall) and painting of all the lower section of the administration building. Cost for this work was in the amount of $14,000. Blinds and other accessories were purchased for $5,500. The other section of our main building is the attached garage. Some repairs and maintenance are to be done to the garage for a budgeted amount of $5,000. These maintenance included; Garage automatic door system (open and close), labour and material for 3 of 5 doors to be done for an amount of $2,300; maintenance and upgrade to washrooms in the amount of $800 (sink and toilet exhaust fans system). Also, the addition of a storage cabinet for hardware and substation material in the amount of $1,900 is to be purchased.

5315-Customer Billing: Increase of $18,200.00

This increase in cost can be attributed to adjustment in salaries to account for cost of living. HHI also incurred additional costs to outsource certain billing functions performed by a CSR on maternity leave. HHI used a service provider ERTH to perform these services. Using ERTH ensured that billing functionalities would be done without issues. It also avoided training a replacement CSR. By outsourcing certain functions, HHI was able to avoid the addition of an extra full time employee. Additional costs were in the amount of $18,000.

5335-Bad Debt Expense: Increase of $17,200.00

The increase is explained by a projection for uncollected accounts. We estimate approximately $20,000 in losses due to HHI being compliant with the new OEB rules. Our estimation is based on a review of all of our outstanding accounts at the present time.

5655-Regulatory Expenses: Increase of $9,395.00

The increase is caused by expected additional intervenor costs since we are completing our 2014 COS. Adjustments were made to the 2013 year-end balance to show recovery up to December 2013 instead of April 2014.

5150-Maintenance of Underground Conductors and Devices: Increase of $4,816.00

The increase is caused by planned work to loop underground subdivisions to assure power reliability to our customers

5620-Office Supplies and Expense: Increase of $4,256.00

The increase is caused by the purchase of office supplies, filling cabinets and a scanner since HHI is working on going paperless in 2013. Also, we are expecting an increase in website maintenance, interact and bank fees as discussed with our service providers.

5320-Collecting; Increase of $4,199.00

**Salary increase due to additional time spent collecting outstanding accounts. Each week all salary expenses are distributed in different GL accounts accordingly. Depending on the month or year, variances occur due to different situations, such as time spent doing a regular or special task. The variance is caused by additional salaries recorded due to additional time spent collecting outstanding accounts and HHI is expecting higher bad debts which will also increase collection agency costs.

5640-Injuries and Damages: Increase of $4,191.00

Increase in cost of liability insurance. In 2012 there was a premium adjustment reducing the invoice considerably therefore causing a large variance between 2012 and 2013.

5130-Maintenance of Overhead Services: Increase of $3,276.00

**The increase is caused by maintenance done on our distribution line following our annual inspections to maintain safety and reliability. Salaries account for approximately $840.00 and the material for the required work is estimated at $ 2,400.

Throughout each year HHI makes every effort to minimize power interruptions. Connections at customer premise were replaced in the previous years and HHI will continue to be proactive and try to reduce customer interruptions. Old connections both on the distribution system and the customer service mast will be inspected and replaced when necessary.

5605-Executive Salaries and Expenses: Increase of $3,266.00

The increase is caused by training and meeting expenses in the amount of $ 1,300 as well as expected salary increase of 2% for a total amount of $1,920

5015-Transformer Station Equipment - Operation Supplies and Expenses: Increase of $3,239.00

The increase can be attributed to the utility's MSP, (Peterborough Utilities) refurbishing the 110KV substation in order to comply with the IESO. HHI's MSP provider will supply all required metering units and cabinet.

5014-Transformer Station Equipment - Operation Labour: Increase of $3,144.00

The increase can be attributed to the utility's MSP, (Peterborough Utilities) refurbishing the 110KV substation in order to comply with the IESO. HHI's MSP provider will be involved in the installation of all required cabinet and relocation of the metering units.

Table 10 -2014 Cost Drivers

OEB	Description	Variance	
3650-Billing and Collecting	5315-Customer Billing	$15,000.00	1
3650-Billing and Collecting	5335-Bad Debt Expense	$10,000.00	2
3650-Billing and Collecting	5310-Meter Reading Expense	$7,000.00	3
3550-Distribution Expenses - Maintenance	5135-Overhead Distribution Lines and Feeders - Right of Way	$5,000.00	4
3800-Administrative and General Expenses	5635-Property Insurance	$4,300.00	5
3650-Billing and Collecting	5320-Collecting	$4,120.00	6
3550-Distribution Expenses - Maintenance	5130-Maintenance of Overhead Services	$4,000.00	7
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	$3,000.00	8
3800-Administrative and General Expenses	5620-Office Supplies and Expenses	$3,000.00	9
	Other	$22,305.00	
	Cost Reduction	-$83,800.00	
	OM&ATotal	-$6,075.00	

5315-Customer Billing; Increase of $15,000.00

The increase is attributed to the implementation and maintenance of a new web presentment module to be purchased in 2013. An increase in costs from the utility's service provider is anticipated in order to meet all requirements and changes to the Ontario Market.

5335-Bad Debt Expense; Increase of $10,000.00

The increase is explained by a projection for uncollected accounts. We estimate approximately $10,000 in losses due to HHI being compliant with the new OEB rules. Our estimation is based on a review of all of our outstanding accounts at the present time.

5310-Meter Reading Expense; Increase of $7,000.00

The variance is explained by the expected increase in smart meter reading costs from smart meter service provider and AMI solutions.

5135-Overhead Distribution Lines and Feeders - Right of Way; Increase of $5,000.00

**The increase is a result of on-going tree trimming costs to clear the main feeders and overhead lines mainly in back yards. The costs also include disposal costs in order to maintain safety and reliability.

5635-Property Insurance; Increase of $4,300.00

The variance is explained by our property and liability premium increase due to the addition of our new transformers at both our substations.

5320-Collecting; Increase of $4,120.00

**Salary increase due to additional time spent collecting outstanding accounts. Each week all salary expenses are distributed in different GL accounts accordingly. Depending on the month or year, variances occur due to different situations, such as time spent doing a regular or special task. The variance is caused by additional salaries recorded due to additional time spent collecting outstanding accounts.

5130-Maintenance of Overhead Services; Increase of $4,000.00

**The increase is explained by maintenance to be done on HHI's distribution line to maintain safety and reliability following HHI's annual inspections. HHI's ongoing maintenance will continue in order to reduce outages. Unplanned emergencies are also part of these cost increases even if HHI does everything possible to be proactive. Furthermore our live line protective equipment will need to be revamped. We expect approximately $1,500 towards the purchase of cable covers rated at 28KV.

5605-Executive Salaries and Expenses; Increase of $3,000.00

The increase is triggered by training and meeting expenses estimated at $1,000 as well as expected salary increase for an amount of $1,980.

5620-Office Supplies and Expenses; Increase of $3,000.00

The increase is caused by the purchase of office supplies and an upgrade to our office telephone system.

E4.T1.S5 OM&A COST PER CUSTOMER AND PER FTE - APPENDIX 2-L

Table 11, below, outlines the cost per customer per full time employee. This information is provided for the 2010 to 2014 period, in accordance with the OEB's minimum filing requirements, discussions of cost per customer follow Table 11 below.

Table 11a) –Recoverable OM&A Cost per Customer and per FTEE

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Number of Customers	$5,523.00	$5,523.00	$5,547.00	$5,606.00	$5,647.00	$5,690.00
Total Recoverable OM&A from Appendix 2-I	$945,592.00	$867,688.60	$911,491.14	$1,006,420.00	$1,132,740.00	$1,126,665.00
OM&A cost per customer	$171.21	$157.10	$164.32	$179.53	$200.59	$198.01
Number of FTEEs	8	8	8	8	8	8
Customers/FTEEs	690	690	693	701	706	711
OM&A Cost per FTEE	$118,199.00	$108,461.08	$113,936.39	$125,802.50	$141,592.50	$140,833.13

As shown in the Table above, the OM&A costs per customer have increased reasonably between the last rebasing and this current application. The costs are required in order to comply with increased regulation, to maintain and upgrade aging infrastructure in a safe and reliable manner, to invest in new generation projects, to provide rate stability and predictability and avoid the need for much higher rate increases in the future.

When Smart Meter related costs are removed from the equation, the reduction further drops to $181 per customer as indicated in the table below.

Table 11b) –Recoverable OM&A Cost per Customer and per FTEE Net of Smart Meter Costs

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Number of Customers	$5,523.00	$5,523.00	$5,547.00	$5,606.00	$5,647.00	$5,690.00
Total Recoverable OM&A from Appendix 2-I	$945,592.00	$867,688.60	$911,491.14	$1,006,420.00	$1,132,740.00	$1,033,743.00
OM&A cost per customer	$171.21	$157.10	$164.32	$179.53	$200.59	$181.68
Number of FTEEs	8	8	8	8	8	8
Customers/FTEEs	690	690	693	701	706	711
OM&A Cost per FTEE	$118,199.00	$108,461.08	$113,936.39	$125,802.50	$141,592.50	$129,217.88

E4.T1.S6 VARIANCE ANALYSIS

HHI does not have any variances in excess of the materiality threshold of $50,000. Variances above $2,000 are explained in detail in the Cost Driver section of the application.

E4.T1.S7 ONE-TIME COSTS

In 2010, the only "one-time costs" of $28,152 was identified. This one-time cost was in relation to smart meter installations. The same expense was identified in 2011 for a total of $20,050.35. In 2012 IT services for the data migration to the United Counties of Prescott-Russell was incurred (service provider) in the amount of $5, 000.

In 2013 HHI will incur a one-time expense of $10,000 for an Asset Management tracking software. In 2014 an amount of $71,000 will be spent towards the testing and evaluation of our 10 MVA transformer. These are non-recurring costs and as such, were removed in subsequent years. All costs associated with 2014 Cost of Service application are amortized over a period of 5 years. Regulatory costs are discussed at the next section.

E4.T1.S8 REGULATORY COSTS – APPENDIX 2-M

Table 12 below shows HHI's regulatory costs for the 3 historical years, bridge and test year. Note that the consultants' costs for regulatory matters shown at line 6 of the table reflect actual costs as opposed to the 2010 approved regulatory costs of $250,000 (amortized over 4 years) in regulatory costs.

A detailed breakdown of regulatory costs for the 2014 test years is presented at table 13. These costs are attributed to the 2010 Cost of Service, intervener costs and the regulatory applications such as IRM applications, an ICM application and a Smart Meter application.

All costs listed below are tracked in account 5655 – Regulatory Expenses. Costs directly associated with the Cost of Service application are amortized over a period of 5 years. Such costs include Accounting services by Deloitte and Intervener cost.

Table 12 –Regulatory Cost

		Ongoing or One-time Cost? [2]	2010 Actual	2012 Actual	2013 Bridge Year	Annual % Change	Test Year	Annual % Change
1	OEB Annual Assessment	On-Going	$7,976.00	$8,268.00	$8,600.00	4.02%	$8,900.00	3.49%
2	OEB Section 30 Costs (Applicant-originated)							
3	OEB Section 30 Costs (OEB-initiated) - **COST AWARDS & AN. REGIST. FEE**	On-Going	$1,111.00	$1,448.00	$1,500.00	3.59%	$1,500.00	0.00%
4	Expert Witness costs for regulatory matters							
5	Legal costs for regulatory matters							
6	Consultants' costs for regulatory matters - **UP TO DEC. 31, 2010**	On-Going	$22,640.33	$110,013.00	$106,500.25	-3.19%	$45,000.00	-57.75%
7	Operating expenses associated with staff resources allocated to regulatory matters							
8	Operating expenses associated with other resources allocated to regulatory matters [1]							
9	Other regulatory agency fees or assessments		$0.00					
10	Any other costs for regulatory matters (please define) - **FEE FOR PUBLICATION OF APPLICATION IN LOCAL NEWSPAPERS**	On-Going	$1,740.00	$1,280.00	$1,400.00	9.38%		-100.00%
11	Intervenor costs		$13,536.67	$7,597.00	$20,000.00	163.26%	$10,000.00	-50.00%

HHI has reduced its overall regulatory cost by entering into a fixed yearly contract agreement with Tandem Energy Services Inc. ("TESI") to assist the utility with its regulatory needs. The fixed fee include regulatory services such as; Preparing various documentation and submissions required to meet the regulatory requirements of the utility; Provide advice so that the utility operates in continuous compliance with OEB regulations; Preparation and defense of rate applications; Assist in creating a work environment that facilitates the utility's understanding the regulatory requirements.

The projected amount of $65,400 in Regulatory Services is broken down into the following expenses.

Table 13 –Detailed Regulatory Cost for 2014

OEB Assessment fee	$8,900/year
Intervener (2014COS)	$25,000 ($5,000 over 5 years)
Intervener (on-going)	$5,000/year (IRM etc.)
TESI (on-going)	$30,000/year
Deloitte (2014COS)	$25,000 ($5000 over 5 years)
Deloitte (on-going)	$10,000/year (IRM and other filings)

E4.T1.S9 LEAP

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

HHI has partnered with United Way- Centraide / Prescott Russell to assist in program intended to provide emergency relief to eligible low-income customers who may be experiencing difficulty paying current arrears be our lead agency.

The United Way of Prescott-Russell will pre-screen customers to see if they meet the household low-income guidelines, and other eligibility criteria, including if the customer is in threat of disconnection for non-payment.

Filings 2.1.16 of HHI's RRR filings are presented at the next page.

2012 LEAP FUNDING

LEAP funds disbursed for:

Agency administration and program delivery	Grants to distributor customers	Grants to unit sub-metered customers**	Total grants disbursed	Total funds disbursed
260.87	1,778.26		1,778.26	2,039.13

Total unused funds: 0.00

Funds depleted

* Month in which LEAP funds were depleted: April

Number of LEAP applicants who were:

Distributor customers	Unit sub-metered customers**	Total
9		9

Number of applicants assisted who were:

Distributor customers	Unit sub-metered customers**	Total assisted
6		6

Number of applicants denied who were:

Distributor customers	Unit sub-metered customers**	Total denied
3		3

Average grant per accepted applicant for:

Distributor customer	Unit Sub metered average**	Overall average
296.38		296.38

**Applicants that were customers of licensed unit sub-metering providers operating in the distributor's service area, including the distributor if licensed as such.

2011 LEAP FUNDING

LEAP funds disbursed for:

Agency administration and program delivery	Grants to distributor customers	Grants to unit sub-metered customers**	Total grants disbursed	Total funds disbursed
260.87	1,700.00	0.00	1,700.00	1,960.87

Total unused funds:

Funds depleted

* Month in which LEAP funds were depleted: April

Number of LEAP applicants who were:

Distributor customers	Unit sub-metered customers**	Total
6	0	6

Number of applicants assisted who were:

Distributor customers	Unit sub-metered customers**	Total assisted
5	0	5

Number of applicants denied who were:

Distributor customers	Unit sub-metered customers**	Total denied
1	0	1

Average grant per accepted applicant for:

Distributor customer	Unit Sub metered average**	Overall average

**Applicants that were customers of licensed unit sub-metering providers operating in the distributor's service area, including the distributor if licensed as such.

E4.T1.S10 CHARITABLE DONATIONS

HHI has a policy in place that it does not donate to charities and as such, the utility confirms that no charitable donations have been included in OM&A expenses for 2014 other than the $2000 for LEAP funding.

Tab 2 – Employee Compensation

E4.T2.S1 OVERVIEW OF EMPLOYEE COMPENSATION

HHI has 8 full time employees, a General Manager, an Assistant Manager, three customer service representatives and 3 linemen.

All non-union employees' compensation levels are reviewed by the general manager and the Board of Directors. The increase in total compensation paid to employees in non-union and management position are attributable to cost of living increase and a provision for benefit coverage. A percentage of the staff's annual salary is invested in a pension plan.

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

Year over year variances are shown below. The average increase in the over the past 4 years is 3%.

Table 13b –Variance Analysis of Salary and Wages

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Salary and Wages		$149,986	$155,200	$158,784	$172,127	$186,043
Variance						
			3%	2%	8%	8%
					Average	6%

8% Salary Increase in 2013 & 2014 over 2012 for Management Salaries:

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

8% Salary Increase in 2013 over 2012 for Union Employee Salaries:

HHI is planning on going paperless in 2013 therefore budgeted an additionnal salary to hire a student to help with the implementation and the scanning of all our documents.

-2% Salary decrease in 2014 over 2013 for Union Employee Salaries:

HHI did not include in its budget an expense for a student since the transition to paperless should be complete. Also, one of its lineman is planning retirement in fall of 2014.

E4.T2.S2 EMPLOYEE COMPENSATION – APPENDIX 2-K

Appendix 2-K presented at the next page details HHI's employee compensation. As a rule, the utility applies the inflation rate to salaries and wages.

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Appendix 2-K
Employee Costs

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Reporting Basis						
Number of Employees (FTEs including Part-Time)[1]						
Executive						
Management	2	2	2	2	2	2
Non-Union						
Union	6	6	6	6	6	6
Total	8	8	8	8	8	8
Number of Part-Time Employees						
Executive						
Management						
Non-Union						
Union						
Total	-	-	-	-	-	-
Total Salary and Wages						
Executive						
Management		$ 149,986	$ 155,200	$ 158,784	$ 172,127	$ 186,043
Non-Union						
Union		$ 314,865	$ 322,593	$ 324,114	$ 349,258	$ 343,241
Total	$ -	$ 464,851	$ 477,793	$ 482,898	$ 521,385	$ 529,284
Current Benefits						
Executive						
Management		$ 8,502	$ 9,067	$ 9,569	$ 10,411	$ 10,901
Non-Union						
Union		$ 32,025	$ 34,028	$ 35,809	$ 38,684	$ 40,423
Total	$ -	$ 40,527	$ 43,095	$ 45,378	$ 49,095	$ 51,324
Accrued Pension and Post-Retirement Benefits						
Executive						
Management		$ 10,549	$ 12,398	$ 14,511	$ 16,563	$ 18,200
Non-Union		$ 3,250	$ 3,688	$ 3,627	$ 3,529	$ 3,523
Union		$ 19,394	$ 22,680	$ 25,374	$ 27,044	$ 31,512
Total	$-	$ 33,193	$ 38,766	$ 43,512	$ 47,135	$ 53,235
Total Benefits (Current + Accrued)						
Executive	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ -	$ 19,051	$ 21,465	$ 24,080	$ 26,974	$ 29,101
Non-Union	$ -	$ 3,250	$ 3,688	$ 3,627	$ 3,529	$ 3,523
Union	$ -	$ 51,419	$ 56,708	$ 61,183	$ 65,728	$ 71,935
Total		$ 73,720	$ 81,861	$ 88,890	$ 96,230	$ 104,559
Total Compensation (Salary, Wages, & Benefits)						
Executive	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ -	$ 169,037	$ 176,665	$ 182,864	$ 199,101	$ 215,144
Non-Union	$ -	$ 3,250	$ 3,688	$ 3,627	$ 3,529	$ 3,523
Union	$ -	$ 366,284	$ 379,301	$ 385,297	$ 414,986	$ 415,176
Total		$ 538,571	$ 559,654	$ 571,788	$ 617,615	$ 633,843
Compensation - Average Yearly Base Wages						
Executive						
Management		$ 74,993	$ 77,600	$ 79,392	$ 86,064	$ 93,022
Non-Union						
Union		$ 52,477	$ 53,765	$ 54,019	$ 58,210	$ 57,207
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		$ 4,251	$ 4,533	$ 4,785	$ 5,205	$ 5,451
Non-Union						
Union		$ 5,337	$ 5,671	$ 5,968	$ 6,447	$ 6,737
Total						
Total Compensation	$ -	$ 538,571	$ 559,654	$ 571,788	$ 617,616	$ 633,843
Total Compensation Capitalized (CGAAP)						
Total Compensation Charged to OM&A (CGAAP)	$ -	$ 538,571.00	$ 559,654.00	$ 571,788.00	$ 617,616.00	
Total Compensation Capitalized (MIFRS)						
Total Compensation Charged to OM&A (MIFRS)				$ 571,788.00	$ 617,616.00	$ 633,843.00

[1] If an applicant wishes to use headcount, it must also file the same schedule on an FTE basis.

Note:

Tab 3 –Shared Services and Corporate Cost Allocation

E4.T3.S1 OVERVIEW OF SHARED SERVICES AND CORPORATE COST ALLOCATION

HHI does not have any affiliates and therefore is not subject to shared services or corporate cost allocation.

Tab 4 –Purchases of Non-Affiliate Services

E4.T4.S1 OVERVIEW OF PURCHASES OF SUPPLIER PURCHASES.

HHI's purchases equipment, materials, and services in a cost effective manner with full consideration given to price as well as product quality, the ability to deliver on time, reliability, compliance with engineering specifications and quality of service. Vendors are screened to ensure knowledge, reputation, and the capability to meet HHI's needs. The procurement of goods and/or services for HHI is carried out with highest of ethical standards and consideration to the public nature of the expenditures.

Purchase Authorization: The General Manager, with the input of board members, approves all purchases of goods and/or services.

Tendering: When goods or services are tendered, a Tender/Request for Proposal/Request for Quote will be issued to a minimum of three vendors, if availability permits. Once again, the General Manager, along with the input of the board members, shall authorize the acceptance of the proposals.

Revised June 12, 2013. Although tendering processes provide essential information to potential suppliers and ensure a fair chance for businesses, the tendering process is not always possible in small towns where there is a limited supply of skilled services that can provide support to utilities. The utility does not have a written procurement policy per se however as described above, the General

Manager, with the input of board members, approves all purchases of goods and/or services.

General Electric Canada Inc. is the only supplier which shows yearly transactions in excess of the materiality threshold of $50,000. GE Canada offers services and a set of expertise that is not commonly found in the service area or general surrounding area or offer efficiencies due to their intimate knowledge of HHI's distribution system.

On a regular basis, HHI's manager will review how well the current outsource contracts support the overall sourcing strategy. Some contracts may not be as relevant as they once were and may have to be modified to fine-tune the services delivered. Other contracts may need to be expanded to meet additional requirements or changes in internal staffing. Key considerations include: Flexibility for service delivery, Staffing complement and expertise, Management skills, Operational efficiency and financial benefits and finally cost consciousness.

HHI's 2012 Vendor list is presented at the next page.

Name Of Supplier	2010	2011	2012	Type Of Expense	Cost Or Contract Approach
Tandem Energy Services Inc			$10,000.00	Regulatory Services	Contract
Hydro Ottawa	$1,714.00	$2,424.14	$533.00	Metering Points Settlement Services Till End Of June 2008 & Meter Verification	Contract
Partner Technologies Incorporated	$23,502.89	$42,155.78	$-	Reclosers for 115 & 44 KV Substations	Cost
Lakeport Power	$4,740.20	$2,180.20	$10,290.90	Inventory Purchases: Pole Top Extensions, Rubber Gloves, Padmount Transformers, Conductor Covers And Gripall	Cost
Sylvain Goulet	$21,025.21	$7,254.02	$-	Meter Reading Services	Contract
Harris Computer Systems	$1,748.80	$1,717.00	$-	Annual Maintenance Support Till May 31st 2008, Dereg Support & Users Conference	Contract
Canada Post Corporation	$18,933.91	$19,022.19	$30,262.10	Stamps And Postage For Billing And Other Correspondence	Cost
Deloitte Touche	$20,850.00	$19,463.00	$20,979.00	Annual Audit Fees, IRM and Rate Rebasing Costs.	Cost
Bell Canada	$17,397.42	$17,018.30	$18,643.51	Monthly Service Charge & Equipement Rental	Contract
Elenchus Research Associates Inc.	$38,595.95	$14,923.75	$14,343.75	Rate Rebasing & IRM Costs	Contract
Electricity Distributors Association	$13,850.00	$14,600.00	$15,300.00	Eda Annual Membership Fees	Cost
Summitt Energy Management Inc.	$36,691.23	$40,192.67	$37,483.06	Retail Settlement Charges	Contract
Master Card (BNC)	$12,340.34	$8,265.83	$12,008.24	Miscelleneous	Cost
Mearie-Liability Insurance	$9,018.00	$3,508.92	$7,698.24	Liability Insurance	Contract
Carkner Office Supply Ltd.	$5,664.66	$3,082.42	$2,915.97	Office Supplies & Equipment	Cost
Ontario Energy Board	$11,486.13	$9,130.87	$9,716.43	Regulatory Expenses	Cost
Econo Gas Bar	$7,226.79	$9,024.30	$8,548.73	Fuel & Gas	Cost
Stantec Consulting Ltd. (Scl)	$1,840.00	$-	$-	Smart grid study GEA	Contract
Minister Of Finance	$8,641.10	$8,880.41	$8,975.06	Employer Health Tax	Cost
Theoret & Martel Insurance	$6,293.16	$6,384.96	$9,135.72	Board, Comprehensive Crime & Property Insurance	Contract
General Electric Canada Inc.	$45,626.72	$73,995.00	$61,957.50	Maintenance Sub 115KV, Tap changer Sub 115KV	Contract
Sage Accpac Canada Inc.	$3,068.00	$6,054.06	$4,007.10	Accpac Support & Updates	Cost
Cupe -Local 1026H	$4,871.99	$4,975.62	$4,923.24	Union Fees	Pass Through
Workplace Safety & Ins Board	$4,125.22	$4,564.64	$4,689.65	WSIB Fees	Cost
Mearie-Vehicle Insurance Program	$3,388.00	$3,459.00	$3,494.00	Fleet Insurance	Contract
Pitney Bowes Global Credit Services	$3,076.80	$3,076.80	$3,076.80	Rental Fees	Contract
Shell Energy North America	$2,348.49	$-	$-	Retail Settlement Charges	Contract
L. Denis	$3,303.89	$3,421.40	$3,595.27	Janitorial Service	Cost
Universal Energy Corporation	$14,586.19	$75.05	$-	Retail Settlement Charges	Contract
Burlington Business Forms	$919.00	$7,625.08	$4,896.27	Billing Stationnary	Cost
Electrical Safety Authority	$2,771.47	$2,809.53	$2,865.91	Regulatory Oversight Cost & Licence Fee	Cost
I.G.S. Hawkesbury	$1,199.99	$1,199.99	$598.99	Internet Services	Contract
The Spi Group	$-	$-	$-		Contract

Tab 5 –Depreciation, Amortization and Depletion

E4.T5.S1 OVERVIEW OF DEPRECIATION

HHI's depreciation policy is described in Exhibit 2. The depreciation continuity schedule presented at the next section shows the calculation of annual depreciation expense with the half-year rule applied for rate-setting purposes, in accordance with the form prescribed in the Board' filing requirements. These expense amounts were used throughout Exhibit 2, in determining the net fixed asset values included in the rate base.

E4.T5.S2 DETAILS BY ASSET

The following pages show the depreciation calculation for 2012, 2013 Bridge Year and 2014 Test Year.

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Appendix 2-B
Fixed Asset Continuity Schedule

Year 2010

				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)		$ 113,796	$ 14,358		$ 128,153	$ (50,289)	$ (23,124)		$ (73,412)	$ 54,741
CEC	1612	Land Rights (Formally known as Account 1906)		$ 8,588	$ -		$ 8,588	$ (2,608)	$ -		$ (2,608)	$ 5,980
N/A	1805	Land		$ 10,000			$ 10,000	$ -	$ -		$ -	$ 10,000
47	1808	Buildings					$ -				$ -	$ -
13	1810	Leasehold Improvements					$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 349,917	$ 52,495		$ 402,412	$ (68,848)	$ (8,885)		$ (77,733)	$ 324,679
47	1820	Distribution Station Equipment <50 kV		$ 175,801	$ 9,059		$ 184,860	$ (88,861)	$ (10,597)		$ (99,458)	$ 85,402
47	1825	Storage Battery Equipment					$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 322,656	$ 28,411		$ 351,067	$ (171,009)	$ (18,316)		$ (189,325)	$ 161,742
47	1835	Overhead Conductors & Devices		$ 367,500	$ 34,806		$ 402,306	$ (198,824)	$ (22,294)		$ (221,118)	$ 181,188
47	1840	Underground Conduit		$ 113,708	$ 147		$ 113,855	$ (54,221)	$ (5,937)		$ (60,158)	$ 53,697
47	1845	Underground Conductors & Devices		$ 212,732	$ 47,660		$ 260,392	$ (84,447)	$ (11,544)		$ (95,991)	$ 164,401
47	1850	Line Transformers		$ 372,827	$ 24,321		$ 397,148	$ (170,766)	$ (16,654)		$ (187,420)	$ 209,728
47	1855	Services (Overhead & Underground)		$ 23,261	$ 3,574		$ 26,835	$ (5,121)	$ (1,001)		$ (6,122)	$ 20,713
47	1860	Meters		$ 246,912			$ 246,912	$ (140,473)	$ (15,656)		$ (156,129)	$ 90,783
47	1860	Meters (Smart Meters)					$ -				$ -	$ -
N/A	1905	Land		$ 28,300			$ 28,300	$ -	$ -		$ -	$ 28,300
47	1908	Buildings & Fixtures		$ 824,124			$ 824,124	$ (169,573)	$ (16,999)		$ (186,572)	$ 637,552
13	1910	Leasehold Improvements					$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 30,528	$ 2,126		$ 32,654	$ (12,211)	$ (2,616)		$ (14,827)	$ 17,827
8	1915	Office Furniture & Equipment (5 years)					$ -				$ -	$ -
10	1920	Computer Equipment - Hardware		$ 46,427	$ 3,691		$ 50,118	$ (35,048)	$ (4,725)		$ (39,773)	$ 10,345
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)					$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)					$ -				$ -	$ -
10	1930	Transportation Equipment		$ 205,346			$ 205,346	$ (188,730)	$ (2,556)		$ (191,286)	$ 14,060
8	1935	Stores Equipment					$ -				$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 13,960	$ 6,007		$ 19,966	$ (7,830)	$ (1,353)		$ (9,182)	$ 10,784
8	1945	Measurement & Testing Equipment					$ -				$ -	$ -
8	1950	Power Operated Equipment		$ 4,363			$ 4,363	$ (2,453)	$ (545)		$ (2,998)	$ 1,365
8	1955	Communications Equipment					$ -				$ -	$ -
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					$ -				$ -	$ -
47	1995	Contributions & Grants		$ (70,174)	$ (74,300)		$ (144,474)	$ 3,637	$ 4,291		$ 7,928	$ (136,546)
	etc.						$ -				$ -	$ -
		Total		**$ 3,400,571**	**$ 152,355**	**$ -**	**$ 3,552,926**	**$ (1,447,674)**	**$ (158,511)**	**$ -**	**$ (1,606,185)**	**$ 1,946,741**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ -

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Appendix 2-B
Fixed Asset Continuity Schedule

Year **2011**

				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)		$ 128,153	$ 8,639		$ 136,793	$ (73,412)	$ (23,439)		$ (96,851)	$ 39,941
CEC	1612	Land Rights (Formally known as Account 1906)		$ 8,588	$ -		$ 8,588	$ (2,608)	$ -		$ (2,608)	$ 5,980
N/A	1805	Land		$ 10,000			$ 10,000	$ -	$ -		$ -	$ 10,000
47	1808	Buildings		$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 402,412	$ 55,500		$ 457,912	$ (77,733)	$ (9,744)		$ (87,477)	$ 370,435
47	1820	Distribution Station Equipment <50 kV		$ 184,860	$ 66,691		$ 251,551	$ (99,458)	$ (11,860)		$ (111,318)	$ 140,233
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 351,067	$ 27,659		$ 378,725	$ (189,325)	$ (18,599)		$ (207,924)	$ 170,802
47	1835	Overhead Conductors & Devices		$ 402,306	$ 3,636		$ 405,943	$ (221,118)	$ (22,027)		$ (243,145)	$ 162,797
47	1840	Underground Conduit		$ 113,855	$ -		$ 113,855	$ (60,158)	$ (5,942)		$ (66,100)	$ 47,755
47	1845	Underground Conductors & Devices		$ 260,392	$ 585		$ 260,977	$ (95,991)	$ (12,507)		$ (108,498)	$ 152,479
47	1850	Line Transformers		$ 397,148	$ 6,025		$ 403,173	$ (187,420)	$ (15,567)		$ (202,987)	$ 200,186
47	1855	Services (Overhead & Underground)		$ 26,835	$ 3,350		$ 30,186	$ (6,122)	$ (1,140)		$ (7,262)	$ 22,923
47	1860	Meters		$ 246,912	$ 7,797		$ 254,709	$ (156,129)	$ (15,406)		$ (171,535)	$ 83,174
47	1860	Meters (Smart Meters)		$ -			$ -	$ -			$ -	$ -
N/A	1905	Land		$ 28,300	$ -		$ 28,300	$ -	$ -		$ -	$ 28,300
47	1908	Buildings & Fixtures		$ 824,124	$ -		$ 824,124	$ (186,572)	$ (16,999)		$ (203,571)	$ 620,553
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 32,654	$ 1,130		$ 33,784	$ (14,827)	$ (2,738)		$ (17,565)	$ 16,219
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 50,118	$ 2,103		$ 52,222	$ (39,773)	$ (4,392)		$ (44,165)	$ 8,056
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 205,346	$ -		$ 205,346	$ (191,286)	$ (2,556)		$ (193,842)	$ 11,504
8	1935	Stores Equipment		$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 19,966	$ 5,063		$ 25,029	$ (9,182)	$ (1,876)		$ (11,058)	$ 13,971
8	1945	Measurement & Testing Equipment		$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment		$ 4,363	$ -		$ 4,363	$ (2,998)	$ (545)		$ (3,543)	$ 820
8	1955	Communications Equipment		$ -			$ -	$ -			$ -	$ -
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		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		$ (144,474)	$ -		$ (144,474)	$ 7,928	$ 5,777		$ 13,705	$ (130,769)
	etc.			$ -			$ -	$ -			$ -	$ -
		Total		**$ 3,552,926**	**$ 188,179**	**$ -**	**$ 3,741,105**	**$ (1,606,185)**	**$ (159,560)**	**$ -**	**$ (1,765,745)**	**$ 1,975,359**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ -

Notes:

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Appendix 2-CA
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2015

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)	Smart Meter Additions (dd)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 136,793	$ (5,561)	$ 142,354	$ 2,683	$ 41,549	$ 143,695	5	20.00%	$ 28,739	$ 28,739	$ (0)
1612	Land Rights (Formally known as Account 1906)	$ 8,588	$ 8,588	$ -	$ -		$ -		0.00%	$ -		$ -
1805	Land	$ 10,000	$ 10,000	$ -	$ -		$ -		0.00%	$ -		$ -
1808	Buildings	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
1810	Leasehold Improvements	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ 457,912	$ 40,397	$ 417,515	$ 24,890		$ 429,960	40	2.50%	$ 10,749	$ 10,749	$ (0)
1820	Distribution Station Equipment <50 kV	$ 251,551	$ (137,573)	$ 389,124	$ 4,632		$ 391,440	30	3.33%	$ 13,048	$ 13,048	$ (0)
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
1830	Poles, Towers & Fixtures	$ 378,725	$ (100,074)	$ 478,799	$ 80,902		$ 519,250	25	4.00%	$ 20,770	$ 20,770	$ 0
1835	Overhead Conductors & Devices	$ 405,943	$ (124,489)	$ 530,432	$ 69,888		$ 565,375	25	4.00%	$ 22,615	$ 22,615	$ 0
1840	Underground Conduit	$ 113,855	$ (29,520)	$ 143,375	$ -		$ 143,375	25	4.00%	$ 5,735	$ 5,735	$ 0
1845	Underground Conductors & Devices	$ 260,977	$ (44,305)	$ 305,282	$ 4,936		$ 307,750	25	4.00%	$ 12,310	$ 12,310	$ (0)
1850	Line Transformers	$ 403,173	$ 14,383	$ 388,790	$ 5,620		$ 391,600	25	4.00%	$ 15,664	$ 15,664	$ (0)
1855	Services (Overhead & Underground)	$ 30,186		$ 30,186	$ 2,234		$ 31,303	25	4.00%	$ 1,252	$ 1,252	$ 0
1860	Meters	$ 254,709	$ (64,049)	$ 318,758	$ 135		$ 318,825	25	4.00%	$ 12,753	$ 12,753	$ 0
1860	Meters (Smart Meters)	$ -		$ 601,817	$ 17,082	$ 601,817	$ 610,358	15	6.67%	$ 40,691	$ 40,690	$ 1
1905	Land	$ 28,300	$ 28,300	$ (0)	$ -		$ (0)		0.00%	$ -		$ -
1908	Buildings & Fixtures	$ 824,124	$ (25,826)	$ 849,950	$ -		$ 849,950	50	2.00%	$ 16,999	$ 16,999	$ (0)
1910	Leasehold Improvements	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 33,784	$ 6,234	$ 27,550	$ -		$ 27,550	10	10.00%	$ 2,755	$ 2,755	$ (0)
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
1920	Computer Equipment - Hardware	$ 52,222	$ 35,355	$ 16,867	$ 2,656		$ 18,195	5	20.00%	$ 3,639	$ 3,639	$ (0)
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
1930	Transportation Equipment	$ 205,346	$ 184,898	$ 20,448	$ -		$ 20,448	8	12.50%	$ 2,556	$ 2,556	$ (0)
1935	Stores Equipment	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 25,029	$ 2,616	$ 22,413	$ 794	$ 2,173	$ 22,810	10	10.00%	$ 2,281	$ 2,281	$ 0
1945	Measurement & Testing Equipment	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
1950	Power Operated Equipment	$ 4,363		$ 4,363	$ -		$ 4,363	8	12.50%	$ 545	$ 545	$ 0
1955	Communications Equipment	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
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	$ -		$ -	$ -		$ -		0.00%	$ -		$ -
1995	Contributions & Grants	$ (144,474)		$ (144,474)	$ (110,041)		$ (199,494)	25	4.00%	$ (7,980)	$ (7,978)	$ (2)
etc.		$ -		$ -	$ -		$ -		0.00%	$ -		$ -
		$ -		$ -	$ -		$ -		0.00%	$ -		$ -
	Total	**$ 3,741,105**	**$ (200,626)**	**$ 4,543,547**	**$ 106,410**	**$ 645,539**	**$ 4,596,752**			**$ 205,121**	**$ 205,123**	**$ (1)**

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence

General **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

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Appendix 2-CA
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2015

Year 2013 **CGAAP**

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2013 (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)	Depreciation Expense (h) = (e) / (f)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)	
1611	Computer Software (Formally known as Account 1925)	$ 181,024	$ 81,389	$ 99,635	$ 28,000	$ 113,635	5	20.00%	$ 22,727	$ 22,727	$ 0	$ 0.00
1612	Land Rights (Formally known as Account 1906)	$ 8,588	$ 8,588	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	
1805	Land	$ 10,000	$ 10,000	$ -	$ -	$ -		0.00%	$ -	$ -	$ -	
1808	Buildings	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1815	Transformer Station Equipment >50 kV	$ 482,802	$ 40,402	$ 442,400	$ 1,547,900	$ 1,216,350	45	2.22%	$ 27,030	$ 27,030	$ (0)	
1820	Distribution Station Equipment <50 kV	$ 256,183	$ (137,564)	$ 393,747	$ 800,000	$ 793,747	45	2.22%	$ 17,639	$ 17,639	$ (0)	
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1830	Poles, Towers & Fixtures	$ 459,627	$ (95,988)	$ 555,615	$ 99,000	$ 605,115	45	2.22%	$ 13,447	$ 13,447	$ -	
1835	Overhead Conductors & Devices	$ 475,830	$ (124,390)	$ 600,220	$ 25,000	$ 612,720	60	1.67%	$ 10,212	$ 10,212	$ -	
1840	Underground Conduit	$ 113,855	$ (23,695)	$ 137,550	$ 500	$ 137,800	50	2.00%	$ 2,756	$ 2,756	$ -	
1845	Underground Conductors & Devices	$ 265,913	$ (35,217)	$ 301,130	$ 17,000	$ 309,630	30	3.33%	$ 10,321	$ 10,321	$ -	
1850	Line Transformers	$ 408,793	$ 22,313	$ 386,480	$ 28,000	$ 400,480	40	2.50%	$ 10,012	$ 10,012	$ 0	
1855	Services (Overhead & Underground)	$ 32,420	$ 20	$ 32,400	$ 3,000	$ 33,900	30	3.33%	$ 1,130	$ 1,130	$ -	
1860	Meters	$ 254,843	$ 28,468	$ 226,375	$ -	$ 226,375	25	4.00%	$ 9,055	$ 9,055	$ -	
1860	Meters (Smart Meters)	$ 618,899	$ -	$ 618,899	$ 3,500	$ 620,649	15	6.67%	$ 41,377	$ 41,377	$ (0)	
1905	Land	$ 28,300	$ -	$ 28,300	$ -	$ 28,300		0.00%	$ -		$ -	
1908	Buildings & Fixtures - **BUILDING ROOF**	$ 165,167	$ -	$ 165,167	$ 18,040	$ 174,187	25	4.00%	$ 6,967	$ 6,968	$ (1)	
1908	Buildings & Fixtures - **INTERIOR FIXTURES**	$ 246,041	$ -	$ 246,041	$ 19,460	$ 255,771	15	6.67%	$ 17,051	$ 17,053	$ (2)	
1908	Buildings & Fixtures - **STRUCTURE**	$ 412,916	$ -	$ 412,916	$ -	$ 412,916	50	2.00%	$ 8,258	$ 8,258	$ 0	
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1915	Office Furniture & Equipment (10 years)	$ 33,784	$ 6,224	$ 27,560	$ 5,700	$ 30,410	10	10.00%	$ 3,041	$ 3,041	$ -	
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1920	Computer Equipment - Hardware	$ 54,878	$ 41,508	$ 13,370	$ 3,000	$ 14,870	5	20.00%	$ 2,974	$ 2,974	$ (0)	
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1930	Transportation Equipment	$ 204,794	$ 184,346	$ 20,448	$ -	$ 20,448	8	12.50%	$ 2,556	$ 2,556	$ -	
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1940	Tools, Shop & Garage Equipment	$ 27,996	$ 5,066	$ 22,930	$ 3,000	$ 24,430	10	10.00%	$ 2,443	$ 2,443	$ -	
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1950	Power Operated Equipment	$ 4,363	$ 2,163	$ 2,200	$ 2,000	$ 3,200	8	12.50%	$ 400	$ 400	$ -	
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
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	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1995	Contributions & Grants - ACCT 1830	$ (77,570)	$ -	$ (77,570)	$ -	$ (77,570)	45	2.22%	$ (1,724)	$ (1,724)	$ 0	
1995	Contributions & Grants - ACCT 1835	$ (49,661)	$ -	$ (49,661)	$ -	$ (49,661)	60	1.67%	$ (828)	$ (828)	$ 0	
1995	Contributions & Grants - ACCT 1840	$ (220)	$ -	$ (220)	$ -	$ (220)	50	2.00%	$ (4)	$ (4)	$ (0)	
1995	Contributions & Grants - ACCT 1845	$ (80,350)	$ -	$ (80,350)	$ -	$ (80,350)	30	3.33%	$ (2,678)	$ (2,678)	$ (0)	
1995	Contributions & Grants - ACCT 1850	$ (46,713)	$ -	$ (46,713)	$ -	$ (46,713)	40	2.50%	$ (1,168)	$ (1,168)	$ 0	
				$ -		$ -		0.00%	$ -		$ -	
	Total	**$ 4,492,501**	**$ 13,634**	**$ 4,478,868**	**$ 2,603,100**	**$ 5,780,418**			**$ 202,995**	**$ 202,997**	**$ (2)**	

Notes:

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2 The applicant must provide an explanation of material variances in evidence

General **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	0
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Appendix 2-CA
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2015

Year 2014 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2014 (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)	Depreciation Expense (h) = (e) / (f)	2014 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)	
1611	Computer Software (Formally known as Account 1925)	$ 209,024	$ 113,414	$ 95,610	$ 17,000	$ 104,110	5	20.00%	$ 20,822	$ 20,822	$ 0	0.00
1612	Land Rights (Formally known as Account 1906)	$ 8,588	$ -	$ 8,588	$ -	$ 8,588		0.00%	$ -		$ -	
1805	Land	$ 10,000	$ -	$ 10,000	$ -	$ 10,000		0.00%	$ -		$ -	
1808	Buildings	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1815	Transformer Station Equipment >50 kV	$ 2,030,702	$ 40,387	$ 1,990,315	$ 25,000	$ 2,002,815	45	2.22%	$ 44,507	$ 44,507	$ -	
1820	Distribution Station Equipment <50 kV	$ 1,056,183	$ (137,592)	$ 1,193,775	$ 60,000	$ 1,223,775	45	2.22%	$ 27,195	$ 27,195	$ -	
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1830	Poles, Towers & Fixtures	$ 558,627	$ (32,768)	$ 591,395	$ 89,000	$ 635,895	45	2.22%	$ 14,131	$ 14,131	$ -	
1835	Overhead Conductors & Devices	$ 500,830	$ (124,450)	$ 625,280	$ 20,000	$ 635,280	60	1.67%	$ 10,588	$ 10,588	$ -	
1840	Underground Conduit	$ 114,355	$ (23,545)	$ 137,900	$ 500	$ 138,150	50	2.00%	$ 2,763	$ 2,763	$ -	
1845	Underground Conductors & Devices	$ 282,913	$ (33,447)	$ 316,360	$ 17,500	$ 325,110	30	3.33%	$ 10,837	$ 10,837	$ -	
1850	Line Transformers	$ 435,245	$ 31,495	$ 403,750	$ 12,500	$ 410,000	40	2.50%	$ 10,250	$ 10,250	$ 0	
1855	Services (Overhead & Underground)	$ 35,420	$ -	$ 35,420	$ 3,100	$ 36,970	30	3.33%	$ 1,232	$ 1,232	$ 0	
1860	Meters	$ 254,843	$ 254,843	$ -	$ -	$ -	25	4.00%	$ -	$ -	$ -	
1860	Meters (Smart Meters)	$ 622,399	$ -	$ 622,399	$ 3,500	$ 624,149	15	6.67%	$ 41,610	$ 41,610	$ (0)	
1905	Land	$ 28,300	$ -	$ 28,300	$ -	$ 28,300		0.00%	$ -		$ -	
1908	Buildings & Fixtures - **BUILDING ROOF**	$ 183,207	$ -	$ 183,207	$ -	$ 183,207	25	4.00%	$ 7,328	$ 7,329	$ (1)	
1908	Buildings & Fixtures - **INTERIOR FIXTURES**	$ 265,501	$ -	$ 265,501	$ 12,500	$ 271,751	15	6.67%	$ 18,117	$ 18,118	$ (1)	
1908	Buildings & Fixtures - **STRUCTURE**	$ 412,916	$ -	$ 412,916	$ -	$ 412,916	50	2.00%	$ 8,258	$ 8,258	$ 0	
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1915	Office Furniture & Equipment (10 years)	$ 39,484	$ 9,954	$ 29,530	$ 3,500	$ 31,280	10	10.00%	$ 3,128	$ 3,128	$ -	
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1920	Computer Equipment - Hardware	$ 57,878	$ 44,523	$ 13,355	$ 3,100	$ 14,905	5	20.00%	$ 2,981	$ 2,981	$ (0)	
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1930	Transportation Equipment	$ 204,794	$ 184,346	$ 20,448	$ -	$ 20,448	8	12.50%	$ 2,556	$ 2,556	$ -	
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1940	Tools, Shop & Garage Equipment	$ 30,996	$ 6,786	$ 24,210	$ 3,100	$ 25,760	10	10.00%	$ 2,576	$ 2,576	$ -	
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1950	Power Operated Equipment	$ 6,363	$ 4,363	$ 2,000	$ 2,000	$ 3,000	8	12.50%	$ 375	$ 375	$ -	
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
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	$ -	$ -	$ -	$ -	$ -		0.00%	$ -		$ -	
1995	Contributions & Grants - ACCT 1830	$ (77,570)	$ -	$ (77,570)	$ -	$ (77,570)	45	2.22%	$ (1,724)	$ (1,724)	$ 0	
1995	Contributions & Grants - ACCT 1835	$ (49,661)	$ -	$ (49,661)	$ -	$ (49,661)	60	1.67%	$ (828)	$ (828)	$ 0	
1995	Contributions & Grants - ACCT 1840	$ (220)	$ -	$ (220)	$ -	$ (220)	50	2.00%	$ (4)	$ (4)	$ (0)	
1995	Contributions & Grants - ACCT 1845	$ (80,350)	$ -	$ (80,350)	$ -	$ (80,350)	30	3.33%	$ (2,678)	$ (2,678)	$ (0)	
1995	Contributions & Grants - ACCT 1850	$ (46,713)	$ -	$ (46,713)	$ -	$ (46,713)	40	2.50%	$ (1,168)	$ (1,168)	$ 0	
						$ -		0.00%	$ -		$ -	
	Total	**$ 7,094,053**	**$ 338,310**	**$ 6,755,744**	**$ 272,300**	**$ 6,891,894**			**$ 222,853**	**$ 222,854**	**$ (1)**	

Notes:

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2 The applicant must provide an explanation of material variances in evidence

General **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

E4.T5.S3 COMPONENTIZATION.

In accordance with Board policy, HHI has adopted Kinectrics proposed useful lives and componentization (where applicable). HHI will continue to adopt CGAAP in and beyond 2014 and as such, there is not a requirement to re-state prior year balances as the change in accounting policy is made prospectively, not retroactively.

Table 13 –Depreciation Rates

Account	Description	Pre 2013	2013 and beyond
1611	Computer Software (Formally known as Account 1925)	5	5
1820	Distribution Station Equipment <50 kV	30	55
1830	Poles, Towers & Fixtures	25	40
1835	Overhead Conductors & Devices	25	60
1845	Underground Conductors & Devices	25	35
1850	Line Transformers	25	40
1855	Services (Overhead & Underground)	25	40
1860	Meters	25	25
1860	Meters (Smart Meters)	25	15
1915	Office Furniture & Equipment (10 years)	10	10
1920	Computer Equipment - Hardware	5	5
1935	Stores Equipment	10	10
1940	Tools, Shop & Garage Equipment	10	10
1945	Measurement & Testing Equipment	10	10
1995	Contributions & Grants	25	40

E4.T5.S4 ADOPTION OF HALF YEAR RULE

HHI and its accounting firm confirm that the half year rule has been applied according to Board policy.

E4.T5.S5 DEPRECIATION/AMORTIZATION POLICY, OR EQUIVALENT WRITTEN DESCRIPTION

HHI uses the straight line method of amortization which reflects a constant expense to the bottom line for the service as a function of time, based on the estimated average useful life of the asset. The estimated average useful lives of various asset categories are consistent with Board policy under CGAAP.

Table 14: Depreciation Rates prior to 2013

USoA Account	Account Description	Straight Line Life - Years	Straight Line Rate
1805	Distribution Plant - Land	N/A	N/A
1806	Distribution Plant - Land Rights/Easements	25	4.0%
1820	Distribution Plant - Distribution Stn. Equip. < 50KV	30	3.3%
1830	Distribution Plant - Poles, Towers and Fixtures	25	4.0%
1835	Distribution Plant - Overhead Conductors, Devices	25	4.0%
1840	Distribution Plant - Underground Conduit	25	4.0%
1845	Distribution Plant - Underground Conductors, Devices	25	4.0%
1850	Distribution Plant - Line Transformers	25	4.0%
1855	Distribution Plant - Services Underground	25	4.0%
1860	Distribution Plant - Meters	25	4.0%
1908	General Plant - Building/Fixtures	60	1.7%
1915	General Plant - Office Furniture/Equipment	10	10.0%
1920	Computer Equipment Hardware	5	20.0%
1925	Computer Software	5	20.0%
1930	General Plant - Transportation Equipment - heavy	8	12.5%
1930	General Plant - Transportation Equipment - light	5	20.0%
1935	General Plant - Stores Equipment	10	10.0%
1940	General Plant - Tools and Garage Equipment	10	10.0%
1945	General Plant - Measure and Testing Equipment	10	10.0%
1955	General Plant - Communication Equipment - FM	10	10.0%
1960	General Plant - Miscellaneous Equipment	5	20.0%
1970	General Plant - Load Mgt Customer Premises	10	10.0%
1980	General Plant - System Supervisory Equipment	25	4.0%

For all historical years up to 2012, the amortization rates used were the same as the rates found in Appendix B of the 2006 Distribution Rate Handbook. They reflected a rational and systematic allocation of cost over future periods appropriate to the nature of the property, plant and equipment. Acquisitions made during the year were amortized at half the normal rate.

E4.T5.S6 SUMMARY OF CHANGES TO DEPRECIATION/AMORTIZATION POLICY SINCE LAST COS

In accordance with the July 17, 2012 letter from the Board on Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies in 2012 and 2013, HHI completed an internal analysis which supports the revised average useful lives of various asset categories based on historical evidence and is within the typical useful life bands outlined in the Kinectrics Report "Asset Depreciation Study for the Ontario Energy Board". The impact of on the utility's net assets is discussed at Exhibit 2

E4.T5.S7 USEFUL LIVES STUDY

In accordance with Board policy, HHI has adopted Kinectrics proposed useful lives and componentization of certain asset categories as suggested in the report where applicable.

Tab 6 –PILs and Property Taxes

E4.T6.S1 OVERVIEW OF PILS

HHI is subject to the PILs regime, and therefore remits payments in lieu of corporate taxes to the Ontario Energy Financial Corporation.

HHI files Federal and Provincial tax returns annually. There have been no special circumstances that would require specific tax planning measures to minimize taxes payable.

There are no non-utility activities included in HHI's financial results, therefore the entire amount of PILs payable is considered in the proposed allowance to be included in the revenue requirement.

There are no outstanding audits, reassessments or disputes relating the tax returns filed by HHI.

E4.T5.S2 of this tab addresses the allowance for PILs to be included in the proposed revenue requirement for the 2014 test year. Please note that HHI is not claiming any Apprenticeship Training Tax Credits, education tax credits in its PILs calculation.

Deloitte completed the PILs model on behalf of HHI and confirms that it complies with the filing requirements.

E4.T6.S2 PILS MODEL

The income tax sheet from the Revenue Requirement Workform is presented at the next page and the PILs model is being filed in conjunction with this application

E4.T6.S3 MOST RECENT FEDERAL AND ONTARIO TAX RETURN

The latest tax returns are presented in the following pages,

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$253,737	$ -	$ -
2	Adjustments required to arrive at taxable utility income	$ -	$ -	$ -
3	Taxable income	$253,737	$ -	$ -
	Calculation of Utility income Taxes			
4	Income taxes	$15,447	$15,447	$15,447
6	Total taxes	$15,447	$15,447	$15,447
7	Gross-up of Income Taxes	$2,833	$2,833	$2,833
8	Grossed-up Income Taxes	$18,280	$18,280	$18,280
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$18,280	$18,280	$18,280
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	11.00%	11.00%	11.00%
12	Provincial tax (%)	4.50%	4.50%	4.50%
13	Total tax rate (%)	15.50%	15.50%	15.50%

Notes

Canada Revenue Agency Agence du revenu du Canada

INFORMATION RETURN FOR CORPORATIONS FILING ELECTRONICALLY

- You have to complete this return to allow your transmitter to electronically file your corporation income tax return to us at the Canada Revenue Agency. You have to complete this return for each tax year.
- By completing part B and signing part C, you acknowledge that, under the *Income Tax Act*, you have to keep all records used to prepare your corporation income tax return, and provide this information to us on request.
- Part D must be completed by either you or the electronic transmitter of your corporation income tax return.
- Give the signed original of this return to the transmitter and keep a copy for yourself. Under the Act, you have to keep your copy for six years.
- We are responsible for ensuring the confidentiality of your electronically filed tax information only after we have accepted it.

This return is for your records. Do not send it to us unless we ask for it.

Part A – Identification

Name of corporation
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.

Business Number	Tax year	From Y M D	To Y M D
89059 2611 RC0001		2012-01-01	2012-12-31

Part B – Declaration

Enter the following amounts, if applicable, from your corporation income tax return for the tax year noted above:

Net income or (loss) for income tax purposes from Schedule 1, financial statements or GIFI (line 300)	309,170
Part I tax payable (line 700)	
Part II surtax payable (line 708)	
Part III.1 tax payable (line 710)	
Part IV tax payable (line 712)	
Part IV.1 tax payable (line 716)	
Part VI tax payable (line 720)	
Part VI.1 tax payable (line 724)	
Part XIV tax payable (line 728)	
Net provincial and territorial tax payable (line 760)	
Provincial tax on large corporations (line 765)	

Part C – Certification and authorization

I, POULIN (Last name in block letters) MICHEL (First name in block letters) DIRECTEUR GÉNÉRAL (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined the corporation T2 income tax return, including accompanying schedules and statements, and that the information given on the T2 return and this T183 Corp information return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

I authorize the transmitter identified in Part D to electronically file the corporation income tax return identified in Part A. The transmitter can also modify the information originally filed in response to any errors Canada Revenue Agency identifies. This authorization expires when the Minister of National Revenue accepts the electronic return as filed.

2013-05-24 (Date (yyyy/mm/dd))
Signature of an authorized signing officer of the corporation
(613) 632-6689 (Telephone number)

Part D – Transmitter identification

The following transmitter has electronically filed the tax return of the corporation identified in Part A.

Name of person or firm DELOITTE LLP Electronic filer number A3491

Privacy Act, Personal Information Bank number CRA PPU 047

T183 CORP (11) Canada

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

055 **Do not use this area**

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business number (BN) **001** 89059 2611 RC0001

Corporation's name

002 HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.

Address of head office

Has this address changed since the last time we were notified? . . . . **010** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 011 to 018.)

011 850 TUPPER STREET

012

City	Province, territory, or state
015 HAWKESBURY	**016** ON
Country (other than Canada)	Postal code/Zip code
017	**018** K6A 3S7

Mailing address (if different from head office address)

Has this address changed since the last time we were notified? . . . . **020** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 021 to 028.)

021 c/o

022

023

City	Province, territory, or state
025	**026**
Country (other than Canada)	Postal code/Zip code
027	**028**

Location of books and records

Has the location of books and records changed since the last time we were notified? . . . . **030** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 031 to 038.)

031 850 TUPPER STREET

032

City	Province,territory, or state
035 HAWKESBURY	**036** ON
Country (other than Canada)	Postal code/Zip code
037	**038** K6A 3S7

040 Type of corporation at the end of the tax year

1 [X] Canadian-controlled private corporation (CCPC)

2 [ ] Other private corporation

3 [ ] Public corporation

4 [ ] Corporation controlled by a public corporation

5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. **043** ______ YYYY MM DD

To which tax year does this return apply?

Tax year start **060** 2012-01-01 (YYYY MM DD) Tax year-end **061** 2012-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . **063** 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . **065** ______ YYYY MM DD

Is the date on line 061 a deemed tax year-end according to:

subparagraph 88(2)(a)(iv)? . . . . **064** 1 Yes [ ] 2 No [X]

subsection 249(3.1)? . . . . **066** 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . **067** 1 Yes [ ] 2 No [X]

Is this the first year of filing after:

Incorporation? . . . . **070** 1 Yes [ ] 2 No [X]

Amalgamation? . . . . **071** 1 Yes [ ] 2 No [X]

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . **072** 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . **076** 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . **078** 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used **079**

Is the corporation a resident of Canada?

080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . **082** 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085 1 [ ] Exempt under paragraph 149(1)(e) or (l)

2 [ ] Exempt under paragraph 149(1)(j)

3 [ ] Exempt under paragraph 149(1)(t)

4 [ ] Exempt under other paragraphs of section 149

Do not use this area

095 **096**

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150		9
Is the corporation an associated CCPC?	160		23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233		
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234		
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

		1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution US

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	ELECTRICITY DISTRIBUTOR	285	100.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ____ YYYY MM DD

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes ☐ 2 No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.			300	309,170	A
Deduct: Charitable donations from Schedule 2	311				
Gifts to Canada, a province, or a territory from Schedule 2	312				
Cultural gifts from Schedule 2	313				
Ecological gifts from Schedule 2	314				
Gifts of medicine from Schedule 2	315				
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320				
Part VI.1 tax deduction*	325				
Non-capital losses of previous tax years from Schedule 4	331	309,170			
Net capital losses of previous tax years from Schedule 4	332				
Restricted farm losses of previous tax years from Schedule 4	333				
Farm losses of previous tax years from Schedule 4	334				
Limited partnership losses of previous tax years from Schedule 4	335				
Taxable capital gains or taxable dividends allocated from a central credit union	340				
Prospector's and grubstaker's shares	350				
Subtotal		309,170	►	309,170	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")					C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355		D
Taxable income (amount C **plus** amount D)			360		
Income exempt under paragraph 149(1)(t)			370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)					Z

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8. Use 3.2 for tax years ending before 2012.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	309,170	A
Taxable income from line 360 on page 3, **minus** 100/28* 3.57143 of the amount on line 632** on page 7, **minus** 1/(0.38 - X***) 4 times the amount on line 636**** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax	405		B
Business limit (see notes 1 and 2 below)	410	500,000	C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x 415 ***** ______ D / 11,250 = ______ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") 425 500,000 F

Small business deduction

Amount A, B, C, or F, whichever is the least ______ x 17 % = 430 ______ G

Enter amount G on line 1 on page 7.

* 10/3 for tax years ending before November 1, 2011. The result of the multiplication by line 632 has to be pro-rated based on the number of days in the tax year that are in each period: before November 1, 2011, and after October 31, 2011.

** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

*** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

**** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3*				A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27			B	
Amount QQ from Part 13 of Schedule 27			C	
Personal service business income**	432		D	
Amount used to calculate the credit union deduction from Schedule 17			E	
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			F	
Aggregate investment income from line 440 on page 6***			G	
Total of amounts B to G			▶	H
Amount A **minus** amount H (if negative, enter "0")				I

Amount I		x	Number of days in the tax year before January 1, 2011 / Number of days in the tax year	/ 366	x	10 %	=	J
Amount I		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 366	x	11.5 %	=	K
Amount I		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	366 / 366	x	13 %	=	L

General tax reduction for Canadian-controlled private corporations – Total of amounts J to L . . . M
Enter amount M on line 638 on page 7.

* For tax years ending after October 31, 2011, line 360 or amount Z, whichever applies.
** For tax years beginning after October 31, 2011.
*** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)				N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27			O	
Amount QQ from Part 13 of Schedule 27			P	
Personal service business income*	434		Q	
Amount used to calculate the credit union deduction from Schedule 17			R	
Total of amounts O to R			▶	S
Amount N **minus** amount S (if negative, enter "0")				T

Amount T		x	Number of days in the tax year before January 1, 2011 / Number of days in the tax year	/ 366	x	10 %	=	U
Amount T		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 366	x	11.5 %	=	V
Amount T		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	366 / 366	x	13 %	=	W

General tax reduction – Total of amounts U to W . . . X
Enter amount X on line 639 on page 7.

* For tax years beginning after October 31, 2011.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440** ________ x 26 2 / 3 % = ... ________ A

Foreign non-business income tax credit from line 632 on page 7 . . . . ________

Deduct:
Foreign investment income from Schedule 7 . . . . **445** ________ x 9 1 / 3 % = ________
(if negative, enter "0") ________ ▶ ________ B

Amount A **minus** amount B (if negative, enter "0") . . . . ________ C

Taxable income from line 360 on page 3 . . . . ________

Deduct:
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . ________

Foreign non-business income tax credit from line 632 on page 7 . . . ________ x 25/9* 100 / 35 = ________

Foreign business income tax credit from line 636 on page 7 . . . . ________ x 1(0.38 - X**) 4 = ________
________ ▶ ________
________ x 26 2 / 3 % = ________ D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . ________ E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least . . . . **450** ________ F

* 100/35 for tax years beginning after October 31, 2011.
** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . **460** ________
Deduct: Dividend refund for the previous tax year . . . . **465** ________
________ ▶ ________ G

Add the total of:
Refundable portion of Part I tax from line 450 above . . . . ________
Total Part IV tax payable from Schedule 3 . . . . ________
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . **480** ________
________ ▶ ________ H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H . . . . **485** ________

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . 84,467 x 1 / 3 28,156 I

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . ________ J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 on page 8) . . . . ________

Part I tax

Base amount of Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %			550	A
Recapture of investment tax credit from Schedule 31			602	B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			i
Taxable income from line 360 on page 3			
Deduct:			
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			
Net amount		▶	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii	604	C
Subtotal (**add** lines A to C)		D

Deduct:

Small business deduction from line 430 on page 4			1
Federal tax abatement	608		
Manufacturing and processing profits deduction from Schedule 27	616		
Investment corporation deduction	620		
Taxed capital gains 624			
Additional deduction – credit unions from Schedule 17	628		
Federal foreign non-business income tax credit from Schedule 21	632		
Federal foreign business income tax credit from Schedule 21	636		
General tax reduction for CCPCs from amount M on page 5	638		
General tax reduction from amount X on page 5	639		
Federal logging tax credit from Schedule 21	640		
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652		
Subtotal		▶	E

Part I tax payable – Line D **minus** line E	F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 ON

(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	
Provincial tax on large corporations (Nova Scotia Schedule 342)	765	
(The Nova Scotia tax on large corporations is eliminated effective July 2012.)		

Total tax payable 770 _____ A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund from page 6	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	

_____ B

Refund code 894 _____ Overpayment _____

Balance (line A **minus** line B) _____

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . . _____

Enclosed payment 898 _____

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 _____ Branch number

914 _____ Institution number 918 _____ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No ☒

Certification

I, 950 POULIN (Last name (print)) 951 MICHEL (First name (print)) 954 DIRECTEUR GÉNÉRAL (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2013-05-24 Date (yyyy/mm/dd) _____ Signature of the authorized signing officer of the corporation 956 (613) 632-6689 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . . 957 1 Yes ☒ 2 No ☐

958 _____ Name (print) 959 _____ Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 2

Privacy Act, Personal Information Bank number CRA PPU 047

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2012-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	3,185,346	4,017,463
	Total tangible capital assets	2008	+	4,502,503	3,751,105
	Total accumulated amortization of tangible capital assets	2009	–	2,039,628	1,765,746
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	1,785,641	1,587,188
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	7,433,862	7,590,010
	Liabilities				
	Total current liabilities	3139	+	2,939,457	3,730,376
	Total long-term liabilities	3450	+	1,239,890	879,950
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	4,179,347	4,610,326
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	3,254,515	2,979,684
	Total liabilities and shareholder equity	3640	=	7,433,862	7,590,010
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	1,565,169	1,290,338

***** Generic item

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2012-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	11,195,434	11,224,023
	Cost of sales	8518	–	9,546,720	9,895,593
	Gross profit/loss	8519	=	1,648,714	1,328,430
	Cost of sales	8518	+	9,546,720	9,895,593
	Total operating expenses	9367	+	1,406,779	1,178,885
	Total expenses (mandatory field)	9368	=	10,953,499	11,074,478
	Total revenue (mandatory field)	8299	+	11,378,704	11,397,853
	Total expenses (mandatory field)	9368	–	10,953,499	11,074,478
	Net non-farming income	9369	=	425,205	323,375
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	425,205	323,375
	Total other comprehensive income	9998	=		
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–		-214,218
	Future (deferred) income tax provision	9995	–	65,907	178,217
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	359,298	359,376

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 141

NOTES CHECKLIST

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2012-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . **095** 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . **097** 1 Yes [ ] 2 No [X]

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note: If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report . . . 1 [X]

Completed a review engagement report . . . 2 [ ]

Conducted a compilation engagement . . . 3 [ ]

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . **099** 1 Yes [ ] 2 No [X]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

Prepared the tax return (financial statements prepared by client) . . . 1 [ ]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . 2 [ ]

Were notes to the financial statements prepared? . . . **101** 1 Yes [ ] 2 No [X]

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . **104** 1 Yes [ ] 2 No [X]

Is re-evaluation of asset information mentioned in the notes? . . . **105** 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . **106** 1 Yes [ ] 2 No [X]

Is information regarding commitments mentioned in the notes? . . . **107** 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . **108** 1 Yes [ ] 2 No [X]

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . **200** 1 Yes [ ] 2 No [X]

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		In OCI Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year? . . . . . **250** 1 Yes [ ] 2 No [X]

Did the corporation apply hedge accounting during the tax year? . . . . . **255** 1 Yes [ ] 2 No [X]

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** 1 Yes [ ] 2 No [X]

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . **265** 1 Yes [ ] 2 No [X]

If **yes**, you have to maintain a separate reconciliation.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2012-12-31

Assets – lines 1000 to 2599

1000	216,704	1060	1,403,123	1061	-16,609
1122	111,022	1480	1,151,703	1483	222,147
1484	97,256	1599	3,185,346	1600	48,300
1601	8,588	1602	-2,608	1680	824,124
1681	-220,570	1742	237,154	1743	-213,581
1774	269,686	1775	-198,075	1783	3,114,651
1784	-1,404,794	2008	4,502,503	2009	-2,039,628
2424	1,785,641	2589	1,785,641	2599	7,433,862

Liabilities – lines 2600 to 3499

2620	2,342,183	2920	541,863	2960	55,411
3139	2,939,457	3140	722,761	3240	76,640
3320	354,318	3321	86,171	3450	1,239,890
3499	4,179,347				

Shareholder equity – lines 3500 to 3640

3500	1,689,346	3600	1,565,169	3620	3,254,515
3640	7,433,862				

Retained earnings – lines 3660 to 3849

3660	1,290,338	3680	359,298	3700	-84,467
3849	1,565,169				

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2012-12-31

Description

Sequence number **0003** 01

Revenue – lines 8000 to 8299

8000	11,195,434	**8089**	11,195,434	**8230**	183,270
8299	11,378,704				

Cost of sales – lines 8300 to 8519

8320	9,546,720	**8518**	9,546,720	**8519**	1,648,714

Operating expenses – lines 8520 to 9369

8670	274,433	**8714**	88,612	**8964**	253,130
9180	14,768	**9270**	24,546	**9284**	751,290
9367	1,406,779	**9368**	10,953,499	**9369**	425,205

Extraordinary items and taxes – lines 9970 to 9999

9970	425,205	**9995**	65,907	**9999**	359,298

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Net Income (Loss) for Income Tax Purposes

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2012-12-31

- 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*.
- All legislative references are to the *Income Tax Act*.

	Line	Amount		Amount	
Amount calculated on line 9999 from Schedule 125				359,298	A
Add:					
Provision for income taxes – deferred	102	65,907			
Amortization of tangible assets	104	274,433			
Subtotal of additions		340,340	▶	340,340	
Other additions:					
Resource amounts deducted	232				
Miscellaneous other additions:					
600 Montants collecté pour actifs règlementés	290	172,372			
604					
Total	294				
Subtotal of other additions	199	172,372	▶	172,372	
Total additions	500	512,712	▶	512,712	B
Amount A **plus** amount B				872,010	
Deduct:					
Capital cost allowance from Schedule 8	403	230,868			
Cumulative eligible capital deduction from Schedule 10	405	789			
Subtotal of deductions		231,657	▶	231,657	
Other deductions:					
Miscellaneous other deductions:					
700 Actifs règlementés capitalisés (débiteurs)	390	28,770			
701 Carrying charges	391	5,509			
702 Smart meters déjà taxés	392	296,904			
704					
Total	394				
Subtotal of other deductions	499	331,183	▶	331,183	
Total deductions	510	562,840	▶	562,840	
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				309,170	

T2 SCH 1 E (12)

Canada

Canada Revenue Agency / Agence du revenu du Canada

DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2012-12-31

- 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.

		Complete if payer corporation is connected			
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 (See note) 220	E Non-taxable dividend under section 83 230
				Total (enter on line 402 of Schedule 1)	

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.
For more details, consult the Help.

			Complete if payer corporation is connected		
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

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 Name of connected recipient corporation 400	B Business Number 410	C Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD (See note) 420	D Taxable dividends paid to connected corporations 430	D1 Eligible dividends (included in column D)
1	Corporation Ville de Hawkesbury	10698 4644 RC0001	2012-12-31	84,467	

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. For more details, consult the Help.

Total 84,467

Total taxable dividends paid in the tax year to other than connected corporations		450	
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	84,467

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)			84,467
Other dividends paid in the tax year (total of 510 to 540)			
Total dividends paid in the tax year		500	84,467
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			84,467

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SCHEDULE 4

CORPORATION LOSS CONTINUITY AND APPLICATION

Name of corporation	Business number	Tax year-end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2012-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending (TYE) before that time is deductible in computing taxable income in a TYE after that time. Also, no amount of capital loss incurred in a TYE after that time is deductible in computing taxable income of a TYE before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide.*
- File one completed copy of this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- Parts, sections, subsections, paragraphs, and subparagraphs mentioned in this schedule refer to the Act.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes				309,170	A
Deduct: (increase a loss)					
Net capital losses deducted in the year (enter as a positive amount)			a		
Taxable dividends deductible under sections 112, 113(1), or subsection 138(6)			b		
Amount of Part VI.1 tax deductible			c		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)			d		
Subtotal (total of amounts a to d)			▶		B
Subtotal (amount A **minus** amount B; if positive, enter "0")					C
Deduct: (increase a loss)					
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions					D
Subtotal (amount C **minus** amount D)					E
Add: (decrease a loss)					
Current-year farm loss (whichever is less: the net loss from farming or fishing included in the income, or the non-capital loss before deducting the farm loss. Enter amount F on line 310)					F
Current-year non-capital loss (amount E **plus** amount F; if positive, enter "0"; if negative, enter amount G on line 110 as a positive)					G

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year		462,157	e		
Deduct: Non-capital loss expired*	100		f		
Non-capital losses at the beginning of the tax year (amount e **minus** amount f)	102	462,157	▶	462,157	H
Add:					
Non-capital losses transferred on an amalgamation or the wind-up of a subsidiary corporation	105		g		
Current-year non-capital loss (amount G above)	110		h		
Subtotal (amount g **plus** amount h)			▶		I
Subtotal (amount H **plus** amount I)				462,157	J

* A non-capital loss expires as follows:
- after **7** tax years if it arose in a tax year ending before March 23, 2004;
- after **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss as follows:
- after **7** tax years if it arose in a tax year ending before March 23, 2004; and
- after **10** tax years if it arose in a tax year ending after March 22, 2004.

Part 1 – Non-capital losses (continued)

Amount J from page 1				462,157	
Deduct:					
Other adjustments (includes adjustments for an acquisition of control)	150		i		
Section 80 – Adjustments for forgiven amounts	140		j		
Subsection 111(10) – Adjustments for fuel tax rebate			j.1		
Non-capital losses of previous tax years applied in the current tax year (enter on line 331 of the T2 Return)	130	309,170	k		
Current and previous year non-capital losses applied against current-year taxable dividends subject to Part IV tax (enter on lines 330 and 335 of Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*, respectively)	135		l		
Subtotal (total of amounts i to l)		309,170	▶	309,170	K
Non-capital losses before any request for a carryback (amount J **minus** amount K)				152,987	L
Deduct – **Request to carry back non-capital loss to:**					
First previous tax year to reduce taxable income	901		m		
Second previous tax year to reduce taxable income	902		n		
Third previous tax year to reduce taxable income	903		o		
First previous tax year to reduce taxable dividends subject to Part IV tax	911		p		
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		q		
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		r		
Total of requests to carry back non-capital losses to previous tax years (total of amounts m to r)			▶		M
Closing balance of non-capital losses to be carried forward to future tax years (amount L **minus** amount M)	180			152,987	N

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200		a		
Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	205		b		
Subtotal (amount a **plus** amount b)			▶		A
Deduct:					
Other adjustments (includes adjustments for an acquisition of control)	250		c		
Section 80 – Adjustments for forgiven amounts	240		d		
Subtotal (amount c **plus** amount d)			▶		B
Subtotal (amount A **minus** amount B)					C
Add: Current-year capital loss (from the calculation on Schedule 6)	210				D
Unused non-capital losses that expired in the tax year*			e		
Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year**			f		
Enter amount e or f, whichever is less	215				
ABILs expired as non-capital loss: line 215 **divided** by 0.500000	220				E
Subtotal (total of amounts C to E)					F

Note

If there has been an amalgamation or a windup of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary. Add all these amounts and enter the total on line 220 above.

* If the losses were incurred in a tax year ending before March 23, 2004, enter the losses from the 8th previous tax year. If the losses were incurred in a tax year ending after March 22, 2004, and before 2006, enter the losses from the 11th previous tax year. Enter the losses from the 21st previous tax year if the losses were incurred in a tax year ending after 2005. Enter the part that was not used in previous years and the current year on line e.

** If the losses were incurred in a tax year ending before March 23, 2004, enter the losses from the 8th previous tax year. If the losses were incurred in a tax year ending after March 22, 2004, enter the losses from the 11th previous tax year. Enter the full amount on line f.

Part 2 – Capital losses (continued)

Amount F from page 2					
Deduct: Capital losses from previous tax years applied against the current-year net capital gain (see Note 1)				225	G
Capital losses before any request for a carryback (amount F **minus** amount G)					H

Deduct – **Request to carry back capital loss to** (see Note 2):

	Capital gain (100%)		Amount carried back (100%)		
First previous tax year		951		g	
Second previous tax year		952		h	
Third previous tax year		953		i	
Subtotal (total of amounts g to i)				▶	I
Closing balance of capital losses to be carried forward to future tax years (amount H **minus** amount I)				280	J

Note 1
To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the purpose of current-year tax, enter the amount from line 225 **multiplied** by 50% on line 332 of the T2 return.

Note 2
On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, **multiply** this amount by the 50% inclusion rate.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year			a		
Deduct: Farm loss expired*	300		b		
Farm losses at the beginning of the tax year (amount a **minus** amount b)	302		▶		A
Add:					
Farm losses transferred on the amalgamation or the windup of a subsidiary corporation	305		c		
Current-year farm loss	310		d		
Subtotal (amount c **plus** amount d)			▶		B
Subtotal (amount A **plus** amount B)					C
Deduct:					
Other adjustments (includes adjustments for an acquisition of control)	350		e		
Section 80 – Adjustments for forgiven amounts	340		f		
Farm losses of previous tax years applied in the current tax year (enter on line 334 of the T2 Return)	330		g		
Current and previous year farm losses applied against current-year taxable dividends subject to Part IV tax (enter on lines 340 and 345 of Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*, respectively)	335		h		
Subtotal (total of amounts e to h)			▶		D
Farm losses before any request for a carryback (amount C **minus** amount D)					E
Deduct – **Request to carry back farm loss to:**					
First previous tax year to reduce taxable income	921		i		
Second previous tax year to reduce taxable income	922		j		
Third previous tax year to reduce taxable income	923		k		
First previous tax year to reduce taxable dividends subject to Part IV tax	931		l		
Second previous tax year to reduce taxable dividends subject to Part IV tax	932		m		
Third previous tax year to reduce taxable dividends subject to Part IV tax	933		n		
Subtotal (total of amounts i to n)			▶		F
Closing balance of farm losses to be carried forward to future tax years (amount E **minus** amount F)			380		G

* A farm loss expires as follows:
- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business . . . . . 485 ______ A

Minus the deductible farm loss:

(amount A above ______ – $2,500) **divided** by 2 = ______ a

Amount a or $ 6,250 , whichever is less . . . . . ______ ▶ ______ b

2,500 c

Subtotal (amount b **plus** amount c) 2,500 ▶ 2,500 B

Current-year restricted farm loss (amount A **minus** amount B; enter amount C on line 410) ______ C

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year . . . . . ______ d

Deduct: Restricted farm loss expired* . . . . . 400 ______ e

Restricted farm losses at the beginning of the tax year (amount d **minus** amount e) . . . . . 402 ______ ▶ ______ D

Add:

Restricted farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation . . . . . 405 ______ f

Current-year restricted farm loss (enter on line 233 of Schedule 1) . . . . . 410 ______ g

Subtotal (amount f **plus** amount g) ______ ▶ ______ E

Subtotal (amount D **plus** amount E) ______ F

Deduct:

Restricted farm losses from previous tax years applied against current farming income (enter on line 333 of the T2 Return) . . . . . 430 ______ h

Section 80 – Adjustments for forgiven amounts . . . . . 440 ______ i

Other adjustments . . . . . 450 ______ j

Subtotal (total of amounts h to j) ______ ▶ ______ G

Restricted farm losses before any request for a carryback (amount F **minus** amount G) ______ H

Deduct – **Request to carry back restricted farm loss to:**

First previous tax year to reduce farming income . . . . . 941 ______ k

Second previous tax year to reduce farming income . . . . . 942 ______ l

Third previous tax year to reduce farming income . . . . . 943 ______ m

Subtotal (total of amounts k to m) ______ ▶ ______ I

Closing balance of restricted farm losses to be carried forward to future tax years (amount H **minus** amount I) 480 ______ J

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

* A restricted farm loss expires as follows:

- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year			a		
Deduct: Listed personal property loss expired after seven tax years	500		b		
Listed personal property losses at the beginning of the tax year (amount a **minus** amount b)	502		▶		A
Add: Current-year listed personal property loss (from Schedule 6)				510	B
Subtotal (amount A **plus** amount B)					C
Deduct:					
Previous year personal property losses applied in the current tax year against listed personal property gains (enter on line 655 of Schedule 6)	530		c		
Other adjustments	550		d		
Subtotal (amount c **plus** amount d)			▶		D
Listed personal property losses remaining before any request for a carryback (amount C **minus** amount D)					E
Deduct – **Request to carry back listed personal property loss to:**					
First previous tax year to reduce listed personal property gains	961		e		
Second previous tax year to reduce listed personal property gains	962		f		
Third previous tax year to reduce listed personal property gains	963		g		
Subtotal (total of amounts e to g)			▶		F
Closing balance of listed personal property losses to be carried forward to future tax years (amount E **minus** amount F)				580	G

Part 7 – Limited partnership losses

Current-year limited partnership losses

1	2	3	4	5	6	7
Partnership identifier	Tax year ending YYYY/MM/DD	Corporation's share of limited partnership loss	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Current-year limited partnership losses (column 3 **minus** 6)
600	602	604	606	608		620

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from previous tax years that may be applied in the current year

1	2	3	4	5	6	7
Partnership identifier	Tax year ending YYYY/MM/DD	Limited partnership losses at the end of the previous tax year	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6)
630	632	634	636	638		650

Continuity of limited partnership losses that can be carried forward to future tax years

1	2	3	4	5	6
Partnership identifier	Limited partnership losses at the end of the previous tax year	Limited partnership losses transferred on an amalgamation or the windup of a subsidiary	Current-year limited partnership losses (from column 620)	Limited partnership losses applied in the current year (cannot be more than column 650)	Current year limited partnership losses closing balance to be carried forward to future years (662 + 664 + 670 – 675)
660	662	664	670	675	680

Total (enter this amount on line 335 of the T2 return)

Note

If you have any current–or previous–year losses, enter your partnership identifier on line 600, 630, or 660.

Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . 190 Yes ☐

Further to a winding-up of a subsidiary, the portion of a non-capital loss, restricted farm loss, farm loss, or limited partnership loss from a wholly-owned subsidiary is deemed to be the loss of a parent from its tax year starting after the commencement of the winding-up.

Note

This election is only applicable for wind-ups under 88(1) that are reported on Schedule 24, *First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent*, and the deemed provision is only for the tax years that start after the commencement of the wind-up.

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses – losses that can be carried forward over 20 years

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce		Balance at end of year
					Taxable income	Part IV tax	
Current	N/A				N/A		
1st preceding taxation year 2011-12-31	462,157	N/A		N/A	309,170		152,987
2nd preceding taxation year 2010-12-31		N/A		N/A			
3rd preceding taxation year 2009-12-31		N/A		N/A			
4th preceding taxation year 2008-12-31		N/A		N/A			
5th preceding taxation year 2007-12-31		N/A		N/A			
6th preceding taxation year 2006-12-31		N/A		N/A			
7th preceding taxation year 2005-12-31		N/A		N/A			
8th preceding taxation year 2004-12-31		N/A		N/A			
9th preceding taxation year 2003-12-31		N/A		N/A			
10th preceding taxation year 2002-12-31		N/A		N/A			
11th preceding taxation year 2001-12-31		N/A		N/A			
12th preceding taxation year 2001-09-30		N/A		N/A			
13th preceding taxation year 2000-09-30		N/A		N/A			
14th preceding taxation year 1999-09-30		N/A		N/A			
15th preceding taxation year 1998-09-30		N/A		N/A			
16th preceding taxation year 1997-09-30		N/A		N/A			
17th preceding taxation year 1996-09-30		N/A		N/A			
18th preceding taxation year 1995-09-30		N/A		N/A			
19th preceding taxation year 1994-09-30		N/A		N/A			
20th preceding taxation year 1993-09-30		N/A		N/A			*
Total	462,157				309,170		152,987

* **This balance expires this year and will not be available next year.**

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2012-12-31

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	Transm + Distr 1988 and later	874,780			0		874,780	4	0	0	34,991	839,789
2.	2	Transm + Distr before 1988	325,942			0		325,942	6	0	0	19,557	306,385
3.	8	Office equipment	13,148	794		0	397	13,545	20	0	0	2,709	11,233
4.	10	Computer	702			0		702	30	0	0	211	491
5.	1	Building	542,963			0		542,963	4	0	0	21,719	521,244
6.	8	Equipment (Tools)	13,048			0		13,048	20	0	0	2,610	10,438
7.	10	Rolling stock	10,790			0		10,790	30	0	0	3,237	7,553
8.	45	Computer 22-03-04 to 18-03-07	752			0		752	45	0	0	338	414
9.	47	Transm + Distr Feb 22, 2005 an	987,981	970,563		0	485,282	1,473,262	8	0	0	117,861	1,840,683
10.	50	Computer > 18-03-07	1,789	2,656		0	1,328	3,117	55	0	0	1,714	2,731
11.	12	Software	24,580	2,683		0	1,342	25,921	100	0	0	25,921	1,342
		Totals	2,796,475	976,696			488,349	3,284,822				230,868	3,542,303

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.

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2012-12-31

- 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** 11,267 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** 11,267 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) . . . . 11,267 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 11,267

less amount from line 249 ______

Current year deduction . . . . 11,267 x 7.00 % = **250** 789 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 789 ▶ 789 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . **300** 10,478 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	

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2012-12-31

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: Business Number (If a corporation is not registered, enter "NR")	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
	100	200	300	350	400	500
1	THE CORPORATION OF THE TOWN OF HAWKESBURY	10698 4644 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2012-12-31

On: 2012-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the I*ncome Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . ☒ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . . ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC . . . . . ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation . . . . . ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary . . . . . ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

T2 SCH 53 E (09)

Canada

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year				**100**	752,306	A
Taxable income for the year (DICs enter "0") *		**110**		B		
Income for the credit union deduction * (amount E in Part 3 of Schedule 17)	**120**					
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less *	**130**					
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income *	**140**					
Subtotal (**add** lines 120, 130, and 140)		►		C		
Income taxable at the general corporate rate (line B **minus** line C) (if negative enter "0")		**150**				
After-tax income (line 150 x general rate factor for the tax year ** 0.72)				**190**		D
Eligible dividends received in the tax year		**200**				
Dividends deductible under section 113 received in the tax year		**210**				
Subtotal (**add** lines 200 and 210)				►		E
GRIP addition:						
Becoming a CCPC (line PP from Part 4)		**220**				
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)		**230**				
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)		**240**				
Subtotal (**add** lines 220, 230, and 240)				► **290**		F
Subtotal (**add** lines A, D, E, and F)					752,306	G
Eligible dividends paid in the previous tax year		**300**				
Excessive eligible dividend designations made in the previous tax year		**310**				
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.						
Subtotal (line 300 **minus** line 310)				►		H
GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative)				**490**	752,306	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)				**560**		
GRIP at the end of the tax year (line 490 **minus** line 560) Enter this amount on line 160 of Schedule 55.				**590**	752,306	

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2011-12-31

Taxable income before specified future tax consequences from the current tax year			J1	
Enter the following amounts before specified future tax consequences from the current tax year:				
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	L1			
Aggregate investment income (line 440 of the T2 return)	M1			
Subtotal (**add** lines K1, L1, and M1)	►		N1	
Subtotal (line J1 **minus** line N1) (if negative, enter "0")		►		O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R1

Aggregate investment income (line 440 of the T2 return) . . . . ______ S1

Subtotal (**add** lines Q1, R1, and S1) ______ ► ______ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ______ ► ______ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") ______ V1

GRIP adjustment for specified future tax consequences to the first previous tax year

(line V1 **multiplied by** the general rate factor for the tax year 0.72) . . . . **500** ______

Second previous tax year 2010-12-31

Taxable income before specified future tax consequences from the current tax year . . . . ______ J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L2

Aggregate investment income (line 440 of the T2 return) . . . . ______ M2

Subtotal (**add** lines K2, L2, and M2) ______ ► ______ N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") ______ ► ______ O2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R2

Aggregate investment income (line 440 of the T2 return) . . . . ______ S2

Subtotal (**add** lines Q2, R2, and S2) ______ ► ______ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ______ ► ______ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") ______ V2

GRIP adjustment for specified future tax consequences to the second previous tax year

(line V2 **multiplied by** the general rate factor for the tax year 0.72) . . . . **520** ______

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2009-12-31

Taxable income before specified future tax consequences from the current tax year J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L3

Aggregate investment income (line 440 of the T2 return) M3

Subtotal (**add** lines K3, L3, and M3) ▶ N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") ▶ O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R3

Aggregate investment income (line 440 of the T2 return) S3

Subtotal (**add** lines Q3, R3, and S3) ▶ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") ▶ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") V3

GRIP adjustment for specified future tax consequences to the third previous tax year
(line V3 **multiplied by** the general rate factor for the tax year 0.72) **540**

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . AA

Eligible dividends paid by the corporation in its last tax year . . . . BB

Excessive eligible dividend designations made by the corporation in its last tax year CC

Subtotal (line BB **minus** line CC) ▶ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)
(line AA **minus** line DD) . . . . EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . ☐ Post wind-up . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year			FF
The corporation's money on hand immediately before the end of its previous/last tax year			GG
Unused and unexpired losses at the end of the corporation's previous/last tax year:			
Non-capital losses			
Net capital losses			
Farm losses			
Restricted farm losses			
Limited partnership losses			
Subtotal		►	HH
Subtotal (**add** lines FF, GG, and HH)			II
All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year		JJ	
Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year		KK	
All the corporation's reserves deducted in its previous/last tax year		LL	
The corporation's capital dividend account immediately before the end of its previous/last tax year		MM	
The corporation's low rate income pool immediately before the end of its previous/last tax year		NN	
Subtotal (**add** lines JJ, KK, LL, MM, and NN)		►	OO
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0")			PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 5 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year.

0.68	x	number of days in the tax year before January 1, 2010 / number of days in the tax year	/ 366	. . . .	=		QQ
0.69	x	number of days in the tax year in 2010 / number of days in the tax year	/ 366	. . . .	=		RR
0.7	x	number of days in the tax year in 2011 / number of days in the tax year	/ 366	. . . .	=		SS
0.72	x	number of days in the tax year after December 31, 2011 / number of days in the tax year	366 / 366	. . . .	=	0.72000	TT

General rate factor for the tax year (total of lines QQ to TT) . . . . 0.72000 UU

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2012-12-31

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.
- All legislative references on this schedule are 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

	Line	Amount		Line	Amount	
Taxable dividends paid in the tax year **not included** in Schedule 3						
Taxable dividends paid in the tax year **included** in Schedule 3		84,467				
Total taxable dividends paid in the tax year	100	84,467				
Total eligible dividends paid in the tax year				150		A
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")				160	752,306	B
Excessive eligible dividend designation (line 150 **minus** line 160)						C
Deduct:						
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*				180		D
Subtotal (amount C **minus** amount D)						E
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount E **multiplied** by 20 %)				190		F

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

	Line	Amount		Line	Amount	
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)						G
Deduct:						
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*				280		H
Subtotal (amount G **minus** amount H)						I
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount I **multiplied** by 20 %)				290		J

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**.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	89059 2611 RC0001	2012-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	110 Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	120 Ontario Corporation No.
Ontario	2000-10-25	1436779

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	220 Street name/Rural route/Lot and Concession number	230 Suite number
850	Tupper Street	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	260 Province/state	270 Country	280 Postal/zip code
Hawkesbury	ON	CA	K6A 3S7

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 1 If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 POULIN (Last name) **451** MICHEL (First name)

454 ______________________, (Middle name(s))

460 1 Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

T2 SCH 546 E (10) Canada

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)		
520 Street number	**530** Street name/Rural route/Lot and Concession number	**540** Suite number
550 Additional address information if applicable (line 530 must be completed first)		

560 Municipality (e.g., city, town)	**570** Province/state	**580** Country	**590** Postal/zip code

Part 6 – Language of preference

600 Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Corporate Taxpayer Summary

Corporate information

Corporation's name . . . . HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.

Taxation Year . . . . 2012-01-01 to 2012-12-31

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* . . . .

* 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		309,170
Taxable income		
Donations		
Calculation of income from an active business carried on in Canada		309,170
Dividends paid		84,467
Dividends paid – Regular	84,467	
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		752,306
Balance of the general rate income pool at the end of the year		752,306
Part I tax (base amount)		

Summary of federal carryforward/carryback information

Carryforward balances

Non-capital losses that can be carried forward over 20 years	152,987
Unused surtax credit (Schedule 37)	23,404
Cumulative eligible capital	10,478

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	309,170		
Taxable income			
% Allocation	100.00		
Attributed taxable income			
Surtax		N/A	N/A
Tax payable before deduction*			
Deductions and credits			
Net tax payable			
Attributed taxable capital			N/A
Capital tax payable**			N/A
Total tax payable***			
Instalments and refundable credits			
Balance due/Refund (-)			
Logging tax payable (COZ-1179)			
Tax payable	N/A		N/A

* For Québec, this includes special taxes.

** 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 of provincial carryforward amounts

Other carryforward amounts

Ontario

Corporate minimum tax credit that can be carried forward over 20 years – Schedule 510 13,439

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
HYDRO HAWKESBURY INC. / HAWKESBURY HYDRO INC.	2,979,684	2,979,684	3,254,515	3,254,515
Total	2,979,684	2,979,684	3,254,515	3,254,515

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				

Five-Year Comparative Summary

Federal information (T2)

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Taxation year end	2012-12-31	2011-12-31	2010-12-31	2009-12-31	2008-12-31
Net income	309,170	-1,288,568	-399,166	-146,692	826,411
Taxable income					826,411
Active business income	309,170				826,411
Dividends paid	84,467	84,467	84,467	84,467	84,467
Dividends paid – Regular	84,467	84,467	84,467		
Dividends paid – Eligible					
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year	752,306	752,306	1,027,155	1,027,155	737,196
GRIP – end of the year	752,306	752,306	756,289	1,027,155	1,027,155
Donations					
Balance due/refund (-)			-54,000	-206,293	127,150

Federal taxes

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Part I before surtax					127,150
Surtax					
Part I.3					
Part IV					
Part I & Surtax					127,150
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Credits against part I tax

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Small business deduction					68,000
M&P deduction					
Foreign tax credit					
Political contribution					
Investment tax credit					
Abatement/other*					118,886

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Refunds/credits

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
ITC refund					
Dividend refund					
Instalments			54,000	214,220	
Surtax credit					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Ontario

Taxation year end	2012-12-31	2011-12-31	2010-12-31	2009-12-31	2008-12-31
Net income	309,170	-1,288,568	-399,166		826,411
Taxable income					826,411
% Allocation	100.00	100.00	100.00	100.00	100.00
Attributed taxable income					826,411
Surtax					13,872
Income tax payable before deduction					115,698
Income tax deductions /credits					42,500
Net income tax payable					87,070
Taxable capital			2,704,775	2,642,806	2,538,584
Capital tax payable					
Total tax payable*				7,927	87,070
Instalments and refundable credits					232,752
Balance due/refund**				7,927	-145,682

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, 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.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

Tab 7 –GEA Plan

E4.T7.S1 GEA PLAN

There is no proposed budget with respect to connection of renewable generation under the FIT program. HHI's GEA plan is presented at Exhibit 2.

Revised June 12, 2013.

E4.T7.S2 LRAMVA (2011-2014)

The Minimum Filing Requirement state that distributors must apply for the disposition of the balance in the LRAMVA as part of their COS applications. In compliance with the filing requirements, HHI is filing for LRAMVA related to the CDM programs delivered within the 2011 to 2014 term. In this proceeding, HHI seeks recovery of its 2011 LRAM with persistence up to 2012.

4 Year (2011-2014) kWh Target:	**9,280,000**

	2011	2012	2013	2014	Total
%					
2011 CDM Programs	7.76%	7.76%	7.76%	7.11%	30.39%
2012 CDM Programs		4.63%	4.63%	4.63%	13.90%
2013 CDM Programs			18.57%	18.57%	37.14%
2014 CDM Programs				18.57%	18.57%
Total in Year	**7.76%**	**12.39%**	**30.96%**	**48.89%**	**100.00%**

kWh					
2011 CDM Programs	720,000	720,000	720,000	660,000	2,820,000
2012 CDM Programs		430,000	430,000	430,000	1,290,000
2013 CDM Programs			1,723,333	1,723,333	3,446,667
2014 CDM Programs				1,723,333	1,723,333
Total in Year	**720,000**	**1,150,000**	**2,873,333**	**4,536,667**	**9,280,000**
				Check	9,280,000

HHI attests that it has used the most recent input assumptions available at the time of the program evaluation when calculating its LRAM amount;

HHI attests that has relied on the most recent and appropriate final evaluation report from the OPA in support of its LRAM calculation;

HHI has separate tables for each rate class that shows the LRAM amounts requested by the year they are associated with and the year the lost revenues took place; in Exhibit 9 Tab 1 Schedule 8.

In Exhibit 9 Tab 1 Schedule 8 HHI has included LRAM calculations, determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board-approved variable distribution charge appropriate to the class;

HHI is not requesting carrying charges on the LRAM amount;

Lastly, HHI attests that it does not have any Board approved programs

HHI is filing its final OPA Report on Contracted Province-Wide Programs in conjunction with this revision.

The following table shows each rate class by year the loss revenue took place and the derivations of the entry in account 1568.

The entry to account 1568 is being made in 2012. HHI is seeking to recover carrying charges on the above LRAM total claim up until December 31, 2013. Derivation of the rate rider is determined in the EDDVAR model and is detailed at Exhibit 9.

HHI attest that it does not use CDM Board-approved programs and as such, does not need a third party report.

	2011	2012	2013
LRAM Claim (kW):	150	150	
LRAM Claim (kWh):	720,000	720,000	

Per class allocation (kWh)	2011 Alloc by Class	2012 Alloc by Class	2011 LRAM (kWh)	2012 LRAM (kWh)	Total
Residential	**33.27%**	**34.27%**	239,513.51	246,733.25	486,246.76
General Service < 50 kW	**11.98%**	**12.42%**	86,220.48	89,420.06	175,640.54
General Service > 50 to 4999 kW	**53.68%**	**52.19%**	386,502.94	375,773.36	762,276.30
Unmetered Scattered Load	**0.14%**	**0.14%**	1,005.73	1,036.97	2,042.70
Sentinel Lighting	**0.07%**	**0.07%**	480.63	493.89	974.52
Street Lighting	**0.87%**	**0.91%**	6,276.71	6,542.46	12,819.17
	100%	**100%**	**720,000**	**720,000**	**1,440,000**

Per class allocation (kW)	2011 Alloc by Class	2012 Alloc by Class	kW	kW	Total
General Service > 50 to 4999 kW	**98.14%**	**98.09%**	147.22	147.13	294.34
Sentinel Lighting	**0.13%**	**0.13%**	0.19	0.20	0.40
Street Lighting	**1.73%**	**1.78%**	2.59	2.67	5.26
			2.59	**150.00**	**300.00**

LRAMVA Rate Rider	2011 Volumetric Rate	2012 Volumetric Rate	2011 LRAM	2012 LRAM	Entry to 1576
Residential	0.0079	0.0080	$1,892.16	$1,973.87	$3,866.02
General Service < 50 kW	0.0054	0.0055	$465.59	$491.81	$957.40
General Service > 50 to 4999 kW	1.5288	1.5453	$225.06	$227.36	$452.42
Unmetered Scattered Load	0.0021	0.0021	$2.11	$2.18	$4.29
Sentinel Lighting	3.1724	3.2067	$0.62	$0.65	$1.27
Street Lighting	6.6567	6.7286	$17.24	$17.95	$35.19
			$2,602.78	**$2,713.82**	**$5,316.60**

Tab 8 –CDM

E4.T8.S1 CDM COSTS

In the Board's Decision and Order issued on November 12, 2010 in the matter of the EB-2010-0215/0216 proceedings, HHI was assigned the following CDM targets for the 2011-2014 timeframe:

Peak Demand:	1.82 MW
Electricity Consumption:	9.82 MW

HHI is currently relying solely on Ontario Power Authority ("OPA") contracted Province Wide CDM programs to achieve its mandatory CDM targets. As a part of the planning process, HHI has outsourced all its CDM activities to Hydro Ottawa.

It is HHI's understanding that Hydro Ottawa utilized the OPA's Resource Planning Tool, taking into consideration HHI's service territory's residential profile and past CDM program results, to forecast its reductions in Peak Demand and Electricity Consumption.

To market the residential customers' programs, Hydro Ottawa will continue to utilize a customer-centric marketing approach, including elements ranging from bill inserts to attending community events. Hydro Ottawa's strategy for Commercial and Industrial customers will further build on developing and maintaining strong customer relationships in addition to traditional marketing approaches.

Tab 8 –CDM

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To market the residential customers' programs, Hydro Ottawa will continue to utilize a customer-centric marketing approach, including elements ranging from bill inserts to attending community events. Hydro Ottawa's strategy for Commercial and Industrial customers will further build on developing and maintaining strong customer relationships in addition to traditional marketing approaches.

At this time, HHI does not contemplate employing any Board-Approved programs. The intent is to meet demand and energy reduction requirements by delivering OPA-Contracted Province-Wide programs. HHI will not be applying for any OM&A costs related to the administration and delivery of CDM programs to be recovered through the revenue requirement.

HHI may, in the future, turn to Board-Approved CDM Programs, should the prescribed OPA funding model prove insufficient to deliver OPA-Contracted Province-Wide programs or the net results do not meet intended demand and energy savings.

Exhibit 5 – Cost of Capital

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EXHIBIT 5 – COST OF CAPITAL AND CAPITAL STRUCTURE

The evidence presented in this exhibit provides information supporting the various elements of HHI's proposed capital structure. The evidence herein is organized according to the following topics;

1) Capital Structure
2) Cost of Debt

Tab 1 – Capital Structure

E5.T1.S1 OVERVIEW OF CAPITAL STRUCTURE

HHI has followed the Report of the Board on Cost of Capital for Ontario's Regulated Utilities, December 11, 2009 in determining the cost of capital.

In calculating the cost of capital, HHI has used the deemed capital structure of 56% long-term debt, 4% short-term debt, and 40% equity, and the Cost of Capital parameters in the OEB letter of November 15, 2012, for the allowed return on equity and where appropriate for debt. HHI understands that the OEB will most likely update the ROE for 2014 at a later date, therefore the Applicant commits to updating its Capital Structure accordingly and as new information is issued.

HHI's cost of capital for 2014 has been calculated as 5.98%, as shown in Table 5.1.1 below.

Table 5.1.1 – Overview of Capital Structure

		2010 Board Approved			**2014 Test Year**	
	Deemed Capital Structure	**Rate**			**Rate**	
Short Term Debt	4%	2.07%			2.07%	
Long Term Debt	56%	5.87%			4.12%	
Equity	40%	9.85%			8.98%	
Total	100%		**7.31%**			**5.98%**

E5.T1.S2 CAPITAL STRUCTURE / COST OF CAPITAL - APPENDIX 2-OA

The following table shows the capital structure for historical years. Appendix 2-OA can be found at the next page

	2006	2007	2008	2009	2010	2011	2012 and
Cost of Capital							
Capital Structure[1]							
Deemed Short-term Debt Capitalization			0.0%	0.0%	4.0%	4.0%	4.0%
Deemed Long-term Debt Capitalization	50.0%	50.0%	53.3%	56.7%	56.0%	56.0%	56.0%
Deemed Equity Capitalization	50.0%	50.0%	46.7%	43.3%	40.0%	40.0%	40.0%
Preferred Shares							
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Cost of Capital Parameters							
Deemed Short-term Debt Rate			0.00%	0.00%	1.33%	1.33%	1.33%
Long-term Debt Rate (actual/embedded/deemed)[2]	6.25%	6.25%	6.25%	6.25%	7.62%	7.62%	7.62%
Target Return on Equity (ROE)	9.0%	9.00%	9.00%	9.00%	8.01%	8.01%	8.01%
Return on Preferred Shares							
WACC	7.63%	7.63%	7.53%	7.44%	7.52%	7.52%	7.52%
Working Capital Allowance							
Working Capital Allowance Rate *(% of the sum of Cost of Power + controllable expenses)*	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$3,955,804	4.12%	$162,979
2	Short-term Debt	4.00%	$282,557	2.07%	$5,849
3	**Total Debt**	60.00%	$4,238,361	3.98%	$168,828
	Equity				
4	Common Equity	40.00%	$2,825,574	8.98%	$253,737
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$2,825,574	8.98%	$253,737
7	**Total**	100.00%	$7,063,936	5.98%	$422,565

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$ -
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
4	Common Equity	0.00%	$ -	0.00%	$ -
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	$ -
7	**Total**	0.00%	$7,063,936	0.00%	$ -

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	0.00%	$ -	4.12%	$ -
9	Short-term Debt	0.00%	$ -	2.07%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	8.98%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$7,063,936	0.00%	$ -

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

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Appendix 2-OA
Capital Structure and Cost of Capital

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

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		Application				
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$3,955,804	4.12%	$162,979
2	Short-term Debt	4.00%	(1)	$282,557	2.07%	$5,849
3	**Total Debt**	60.0%		$4,238,361	3.98%	$168,828
	Equity					
4	Common Equity	40.00%		$2,825,574	8.98%	$253,737
5	Preferred Shares	0.00%		$ -	0.00%	$ -
6	**Total Equity**	40.0%		$2,825,574	8.98%	$253,737
7	**Total**	100.0%		$7,063,936	5.98%	$422,565

**Cost of Capital Parameter Updates for 2013 Cost of Service Applications for Rates Effective May 1, 2013*

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		2013 Application				
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$3,489,998	5.87%	$204,863
2	Short-term Debt	4.00%	(1)	$249,286	2.07%	$5,160
3	**Total Debt**	60.0%		$3,739,284	5.62%	$210,023
	Equity					
4	Common Equity	40.00%		$2,492,856	9.85%	$245,546
5	Preferred Shares	0.00%		$ -	0.00%	$ -
6	**Total Equity**	40.0%		$2,492,856	9.85%	$245,546
7	**Total**	100.0%		$6,232,140	7.31%	$455,569

** Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective May 1, 2012*

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		2012 Application				
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$2,126,369	5.87%	$124,818
2	Short-term Debt	4.00%	(1)	$151,884	2.07%	$3,144
3	**Total Debt**	60.0%		$2,278,253	5.62%	$127,962

	Equity						
4	Common Equity	40.00%		$1,518,835	9.85%		$149,605
5	Preferred Shares	0.00%		$ -	0.00%		$ -
6	**Total Equity**	40.0%		$1,518,835	9.85%		$149,605
7	**Total**	100.0%		$3,797,088	7.31%		$277,567

**Cost of Capital Parameter Updates for 2011 Cost of Service Applications for Rates Effective May 1 2011*

	2011 Application						
		(%)		($)	(%)		($)
	Debt						
1	Long-term Debt	56.00%		$2,005,983	5.87%		$117,751
2	Short-term Debt	4.00%	(1)	$143,285	2.07%		$2,966
3	**Total Debt**	60.0%		$2,149,268	5.62%		$120,717
	Equity						
4	Common Equity	40.00%		$1,432,845	9.85%		$141,135
5	Preferred Shares	0.00%		$ -	0.00%		$ -
6	**Total Equity**	40.0%		$1,432,845	9.85%		$141,135
7	**Total**	100.0%		$3,582,113	7.31%		$261,852

	2010 Application						
		(%)		($)	(%)		($)
	Debt						
1	Long-term Debt	56.00%		$2,023,375	5.87%		$118,772
2	Short-term Debt	4.00%	(1)	$144,527	2.07%		$2,992
3	**Total Debt**	60.0%		$2,167,902	5.62%		$121,764
	Equity						
4	Common Equity	40.00%		$1,445,268	9.85%		$142,359
5	Preferred Shares	0.00%		$ -	0.00%		$ -
6	**Total Equity**	40.0%		$1,445,268	9.85%		$142,359
7	**Total**	100.0%		$3,613,170	7.31%		$264,123

Tab 2 – Cost of Debt

E5.T2.S1 OVERVIEW OF EXISTING AND NEW DEBT

As directed in Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, dated June 28, 2012, HHI has completed the Board's Appendix 2-OB, which is included at the next page.

For rate setting purposes, the total cost of debt is calculated based on a weighting of 56% long term debt and 4% short-term debt. As per 2009 Board Report on Cost of Capital, the deemed short-term debt rate is used for the weighted Cost of Capital calculations. The calculation of weighted average long-term debt rate for rate setting purposes is performed in compliance with the policies documented in 2009 Board Report on the Cost of Capital.

Table 4 below summarizes HHI's debt position.

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

HHI's long-term debt comprises the following:

HHI has a convertible promissory note with the Town of Hawkesbury in the amount of $2,109,147. The payments towards the note began in 2001 and will be paid in full by the end of 2013. Interest rate in the amount of 5.5% was calculated in 2001, 4.25% for years 2002 and 2003, 6% for year 2004 and for the remaining term (ending in 2013) an interest rate of 6.5% per annum was calculated on the principle amount.

HHI has a non-revolving fixed rate loan in the aggregate maximum principal amount of $2,300,000 to support the construction of the 44KV and 110KV substations, for which HHI sought approval for in its 2012 ICM application. At December 31, 2012, the principal was $741,098 and the actual interest expense was in the amount of $14,702.

Details (Appendix 2-OB) of HHI historical and forecasted debt instrument are presented at the next page

HHI also pays dividends to its shareholder. The dividends are meant to provide shareholders with a steady income stream while providing the Corporation with an appropriate capital structure.

The key criteria for the determination of dividends:

- Cash position at the beginning of the year;
- Working capital requirements for the current year; and
- Net capital expenditures required for the current year.

E5.T2.S2 PROMISSORY NOTES

HHI 's promissory note is presented following Appendix 2-OB at the next page.

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Appendix 2-OB
Debt Instruments

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

Year **2010**

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	As of Dec. 31st Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	ACTUAL INTEREST EXPENSE
1	Convertible Promissory Note	Town of Hawkesbury	Third-Party	Fixed Rate	JANUARY 1, 2010	1	$ 731,715	6.50%	$ 47,561.44	$ 55,273.71
2									$ -	
3									$ -	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							**$ 731,715**	**0.065**	**$ 47,561.44**	**$ 55,273.71**

Year **2011**

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	As of Dec. 31st Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	ACTUAL INTEREST EXPENSE
1	Convertible Promissory Note	Town of Hawkesbury	Third-Party	Fixed Rate	JANUARY 1, 2011	1	$ 500,290	6.50%	$ 32,518.83	$ 40,747.61
2									$ -	
3									$ -	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							**$ 500,290**	**0.065**	**$ 32,518.83**	**$ 40,747.61**

Year **2012**

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	As of Dec. 31st Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	ACTUAL INTEREST EXPENSE
1	Convertible Promissory Note	Town of Hawkesbury	Third-Party	Fixed Rate	JANUARY 1, 2012	1	$ 253,366	6.50%	$ 16,468.79	$ 25,248.66
2	SUB 44KV Loan	Infrastructure Ontario	Third-Party	Fixed Rate	JULY 16, 2012	0.5	$ 741,098	3.94%	$ 29,199.28	$ 14,702.21
3									$ -	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							**$ 994,464**	**0.04592**	**$ 45,668.07**	**$ 39,950.87**

Year **2013**

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	As of Dec. 31st Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	ACTUAL INTEREST EXPENSE
1	Convertible Promissory Note	Town of Hawkesbury	Third-Party	Fixed Rate	JANUARY 1, 2013	1	$ -	6.50%	$ -	$ 8,711.72
2	SUB 44KV Loan	Town of Hawkesbury	Third-Party	Fixed Rate	JANUARY 1, 2013	1	$ 722,761	3.94%	$ 28,476.79	$ 28,870.54
3	SUB 110KV Loan	Town of Hawkesbury	Third-Party	Fixed Rate	JULY 1, 2013	1	$ 1,483,000	3.94%	$ 29,215.10	$ 28,900.00
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							**$ 2,205,761**	**0.02616**	**$ 57,691.89**	**$ 66,482.26**

Year **2014**

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

HYDRO HAWKESBURY INC./HAWKESBURY HYDRO INC.

Convertible promissory note

March 26, 2012

For value received, subject to the terms and conditions of this promissory note (the "Note"), HYDRO HAWKESBURY INC./HAWKESBURY HYDRO INC., a corporation incorporated under the laws of the Province of Ontario (the "Company"), hereby promises to pay on demand to the order of the Corporation of the Town of Hawkesbury (the "Holder") the principal sum of two million one hundred and nine thousand one hundred and forty-seven dollars ($2,109,147.00) in lawful money of Canada with the terms of payment stated below:

1. **Interest Rate** The principal amount shall bear interest at a rate of six and one half percent (6.5%) per annum calculated semi-annually not in advance and calculated from the first of January 2012.

2. **Terms of Payment** The principal sum due under this note shall be due and payable on the first of February 2009. Until payment in full of the principal sum, this note shall bear interest at the rate stipulated above which interest shall be paid by means of monthly payments commencing on the first of February 2012 until the principal amount is fully paid.

3. **Conversion** The principal amount of this Note together with the Interest is convertible in whole or in part at the option of the Holder by surrender of this Note at the registered office of the Company at any time prior to repayment into fully paid non-assessable common shares of the Company as presently constituted ("Shares") at a price of $1,691.94 (Canadian Dollars) per Share (the "Conversion Price") of principal amount and Interest then outstanding for each Share to be issued upon the conversion of this Note. The Conversion Price shall be adjusted to give effect to adjustments in the number of shares of the Company resulting from subdivisions, consolidations or reclassifications of the shares of the Company, the payment of stock dividends by the Company or other relevant changes in the capital stock of the Company.

4. **Issuance of Conversion Stock** As soon as practicable after conversion of this Note into Shares as provided herein, and the surrender of this Note to the Company at its principal office, the Company at its expense, will cause to be issued in the name and delivered to the Holder, a share certificate or certificates for the number of Shares to which the holder of this Note shall be entitled upon the conversion.

.../2

5. **Fully Paid Shares** All Shares issued upon the conversion of this Note shall be validly issued, fully paid and non-assessable.

6. **No Impairment** The Company will not willfully avoid or seek to avoid the observance or performance of any of the terms of this Note, but will act at all times in good faith to assist in the carrying out of all such terms and in the taking of all such action as may be necessary or appropriate in order to protect the rights of the Holder against impairment. Without limiting the generality of the foregoing, the Company will take all such action as may be necessary or appropriate in order that the Company may validly and legally issue fully paid and non-assessable Shares upon any conversion of this Note.

7. **Prepayment** The Company may at any time upon giving the Holder seven (7) days prior written notice (and during which notice period the Holder may exercise its right of conversion), without penalty, repay in whole or in part the principal amount and Interest outstanding under this Note. Any prepayment shall be applied first to the Interest until it has been paid and then to unpaid principal.

8. **Event of Default** The principal amount due hereunder together with the Interest will accelerate and become due if an Event of Default (as hereinafter defined) occurs. An "Event of Default" shall exist under this Note if the Company: (i) petitions or applies to any tribunal for or consents to the appointment of a receiver, trustee or liquidator of the Company or of all or any substantial part of its properties or assets, (ii) admits in writing its inability to pay its debts as they mature, (iii) makes a general assignment for the benefit of its creditors, (iv) is adjudicated bankrupt or insolvent; (v) files voluntarily or has filed against it a petition in bankruptcy or a petition seeking reorganization or an arrangement with creditors to take advantage of any bankruptcy, reorganization insolvency, readjustment of debts, dissolution or liquidation law or statute, or, (vi) breaches any of its obligations under this Note or the General Security Agreement made in favour of the Holder executed the date hereof by the Company.

9. **Amendment: Waiver** This Note may only be amended and the observance of any term of this Note may only be waived (either generally or in a particular instance and either retroactively or prospectively) by the written consent of the Company and the Holder of this Note. Any amendment or waiver effected in accordance with the previous sentence shall be binding upon each future holder or transferee of the Note and the Company.

.../3

10. **Assignment** This Note may be assigned by the Holder.

11. **Headings: References** The headings in this Note are for the purposes of convenience or reference only, and shall not be deemed to constitute a part of this Note. Unless otherwise expressly noted, all references herein to Sections refer to Sections of this Note.

12. **Notices** All notices given by the Company or Holder pursuant to this Note shall be in writing and shall be served by either personal service, facsimile transmission, nationally recognized overnight courier service or mail at the notice of address of the receiving party set forth below. All notices served by personal service shall be deemed to have been given upon actual delivery to the receiving party, all notices served by facsimile transmission or nationally recognized overnight courier shall be deemed to have been given on the next business day following their dispatch, and all notices given by mail shall be by certified or registered mail, return receipt requested, and shall be deemed to have been given (5) days after deposit into the Canadian mail, postage paid. The Company's notice of address shall be its principal office and the Noteholder's notice of address shall be the last address for notice furnished to the Company by Noteholder in writing.

13. **Law Governing** This Note shall be construed and enforced in accordance with, and governed by, the laws of Ontario.

14. **Lawyers' Fees: Waiver of Presentment** The Company promises to pay the Holder hereof, without demand, all reasonable lawyers' fees, costs and other expenses incurred by such holder in enforcing any provisions of this Note and hereby waives presentment, notice of nonpayment, notice of dishonour, protest, demand and diligence.

IN WITNESS WHEREOF, the Company has caused this Note to be signed in its name the date first written above.

THE CORPORATION OF THE TOWN OF HAWKESBURY

Réné Berthiaume, Mayor

Christine Groulx, Clerk

HYDRO HAWKESBURY INC./
HAWKESBURY HYDRO INC.

Michel Poulin, Manager

Linda

LINDA PARISIEN, Assistant Manager/CFO

THE CORPORATION OF THE TOWN OF HAWKESBURY

By-law N° 31-2012

A by-law to authorize
the Mayor and the Clerk
to execute a promissory note between
the Corporation of the Town of Hawkesbury
and
Hawkesbury Hydro Inc.

WHEREAS on October 24, 2000, the Municipal Council of the Town of Hawkesbury adopted By-law N° 74-2000 which transfers the assets of the Hawkesbury Hydro-Electric Commission associated with the distribution of electricity to Hydro Hawkesbury Inc./Hawkesbury Hydro Inc. ("Hawkesbury Hydro");

AND WHEREAS pursuant to paragraph 4.02 of By-law N° 74-2000, the balance of the purchase price, after deduction of the value of the debts transferred by Hawkesbury Hydro, should be shared by a promissory note and common shares of the Hawkesbury Hydro according to proportions to be determined by the Council;

AND WHEREAS that, after an audit conducted by the auditors of the Corporation of the Town of Hawkesbury, it has been determined that the balance of the purchase price in the amount of $3,798,493.00 was shared by the issuance and delivery of a promissory note and capital stock as follows:

Promissory Note:	$2,109,147.00
Capital stock (999 common shares):	$1,689,346.00

AND WHEREAS that the amount of the promissory note from Hawkesbury Hydro Inc. to the Corporation of the Town of Hawkesbury as of December 31, 2011 is $500,290.49.

NOW THEREFORE, the council of the Corporation of the Town of Hawkesbury enacts as follows:

1. **THAT** the Council confirms the allocation of a promissory note.

2. **THAT** the Mayor and Clerk of the Corporation of the Town of Hawkesbury be authorized to sign the said promissory note.

3. **THAT** this by-law shall come into effect and force upon the date of its adoption.

READ A FIRST, SECOND AND ADOPTED UPON THIRD READING THIS 26st DAY OF MARCH 2012.

René Berthiaume, Mayor

Christine Groulx, Clerk

Copie certifiée conforme/Certified a true copy
Ce/This April 3, 2012

Christine Groulx, greffière/Clerk
Ville de/Town of HAWKESBURY

Exhibit 6 – Revenue Deficit

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EXHIBIT 6 – REVENUE DEFICIT

The evidence presented in this exhibit provides information supporting the utility's expected deficit at existing rates for the 2014 Test year. The evidence herein is organized according to the following topics;

1) Utility Revenue at Existing Rates
2) Revenue Deficit

Tab 1 – Utility Revenue

E6.T1.S1 REVENUE FROM EXISTING RATES

The current rates are based on Board approved rates effective May 1, 2013 through an IRM proceeding (EB-2012-0134). Existing and projected revenues based on existing Board approved rates, which are used in calculating utility income, are comprised of distribution revenue and other revenues.

Details on existing and projected distribution revenue at existing rates are presented in Exhibit 3, Tab 1. Other revenue is presented in Exhibit 3, Tab 2.

E6.T1.S2 OVERVIEW OF REVENUE REQUIREMENT

A utility's revenue requirement represents the amount of money that a utility must receive from its customers to cover its costs, operating expenses, taxes, interest paid on debts owed to investors and, if applicable, a deemed return (profit).

The proposed Base Revenue Requirement, representing the revenue to be recovered from base distribution rates, is equal to the total Service Revenue Requirement, less Revenue Offsets derived from other revenue sources in 2014. Table 2 below shows the proposed revenue requirement for the 2014 test year.

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$1,126,665		$1,126,665		$1,126,665	
2	Amortization/Depreciation	$222,854		$222,854		$222,854	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$18,280		$18,280		$18,280	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$168,828		$ -		$ -	
	Return on Deemed Equity	$253,737		$ -		$ -	
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	$ -		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$1,790,364		$1,367,799		$1,367,799	
9	Revenue Offsets	$157,139		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$1,633,225		$1,367,799		$1,367,799	
11	Distribution revenue	$1,633,224		$ -		$ -	
12	Other revenue	$157,139		$ -		$ -	
13	**Total revenue**	$1,790,363		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($1)	(1)	($1,367,799)	(1)	($1,367,799)	(1)

Notes

(1) Line 11 - Line 8

Tab 2 – Utility Deficit

E6.T2.S1 CALCULATION OF REVENUE DEFICIT

HHI's net revenue deficiency under the proposed rates is $297,828. This deficiency is calculated as the difference between the 2014 Test Year Revenue Requirement and the Forecast 2014 Test Year Revenue Requirement at the Applicant's 2013 approved distribution rates.

The Table of Revenue Deficit presented at E6.T2.S2 shows the revenue deficiency calculations for the 2014 Test Year at Existing 2013 rates.

The drivers of the revenue deficiency are detailed in E6.T2.S3.

E6.T2.S2 TABLE OF REVENUE DEFICIT

The Revenue Deficiency sheet from the Revenue Requirement Work Form is presented at the next page.

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application				Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$297,828		($14,141)		$1,349,519
2	Distribution Revenue	$1,363,660	$1,335,397	$1,363,660	$1,647,366	$ -	($1,349,519)
3	Other Operating Revenue Offsets - net	$157,139	$157,139	$ -	$ -	$ -	$ -
4	**Total Revenue**	$1,520,799	$1,790,363	$1,363,660	$1,633,224	$ -	$ -
5	Operating Expenses	$1,349,519	$1,349,519	$1,349,519	$1,349,519	$1,349,519	$1,349,519
6	Deemed Interest Expense	$168,828	$168,828	$ -	$ -	$ -	$ -
7	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	$ - **(2)**	$ -	$ - **(2)**	$ -	$ - **(2)**	$ -
8	**Total Cost and Expenses**	$1,518,347	$1,518,347	$1,349,519	$1,349,519	$1,349,519	$1,349,519
9	**Utility Income Before Income Taxes**	$2,452	$272,016	$14,141	$283,705	($1,349,519)	($1,349,519)
10	Tax Adjustments to Accounting Income per 2013 PILs model	$ -	$ -	$ -	$ -	$ -	$ -
11	**Taxable Income**	$2,452	$272,016	$14,141	$283,705	($1,349,519)	($1,349,519)
12	Income Tax Rate	15.50%	15.50%	15.50%	15.50%	15.50%	15.50%
13	**Income Tax on Taxable Income**	$380	$42,162	$2,192	$43,974	($209,175)	($209,175)
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$2,072	$253,736	$11,950	($1,367,799)	($1,140,344)	($1,367,799)
16	**Utility Rate Base**	$7,063,936	$7,063,936	$7,063,936	$7,063,936	$7,063,936	$7,063,936
17	Deemed Equity Portion of Rate Base	$2,825,574	$2,825,574	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	0.07%	8.98%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.98%	8.98%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-8.91%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	2.42%	5.98%	0.17%	0.00%	-16.14%	0.00%
22	Requested Rate of Return on Rate Base	5.98%	5.98%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-3.56%	0.00%	0.17%	0.00%	-16.14%	0.00%
24	Target Return on Equity	$253,737	$253,737	$ -	$ -	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$251,664	($1)	($11,950)	$ -	$1,140,344	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$297,828 **(1)**		($14,141) **(1)**		$1,349,519 **(1)**	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

(2) Treated as an adjustment pre-tax to avoid an impact on taxes/PILs and hence on revenue sufficiency deficiency

E6.T2.S3 CAUSES OF REVENUE DEFICIT

HHI's existing rates are based on the Board-approved rates in 2010 following a cost of service rate application, and adjustments to its base distribution rates in 2011-2013 under the Board's third Generation Incentive Regulation Mechanism.

As shown in Table of Revenue Deficit at the previous section, the Revenue Deficiency is determined to be $297,828K. The deficiency is due to the increase in the rate base and OM&A. The proposed rate base for 2014 is $2.8 million higher than the 2010 Board-approved amount, an increase of 66%. Based on a 5.98% overall cost of capital, the increase in the rate base drives an increase to the revenue requirement. The factors contributing to the change in the rate base are discussed in detail at Exhibit 2 but for the most part, are due to investments in the distribution system to accommodate growth and the inclusion to smart meters into rate base.

The increased expense for Operations, Maintenance and Administration (OM&A) is another reason for the revenue deficiency. Projected OM&A for 2014 is $181K higher than the 2010 Board-approved amount, an increase of 19.5%. The cost drivers underlying this increase are presented in Exhibit 4.

Exhibit 7 – Cost Allocation

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EXHIBIT 7 – COST ALLOCATION

The evidence presented in this exhibit provides information supporting the various elements of HHI's proposed cost allocation. The evidence herein is organized according to the following topics;

1) Overview Cost Allocation

Tab 1 – Cost Allocation

E5.T1.S1 OVERVIEW OF COST ALLOCATION

HHI has prepared and is filling a cost allocation information filing consistent with the utility's understanding of the Directions, the Guidelines, the Model and the Instructions issued by the Board back in November of 2006 and all subsequent updates.

The main objectives of the original information filing back in 2006, was to provide information on any apparent cross-subsidization among a distributor's rate classifications and to eventually be used in future rate applications. As part of its 2010 Cost of Service Rate Application, HHI updated the cost allocation revenue to cost ratios with 2010 base revenue requirement information. The revenue to cost ratios from the 2010 application is presented below.

Table 1: Previously Approved Ratios (2010 COS)

	%
Residential	111
GS < 50 kW	111
GS > 50	80
Street Lighting	70
Sentinel Lights	120
Unmetered Scattered Load (USL)	80

HHI has prepared a Cost Allocation Study for 2014 based on an allocation of the 2014 test year costs (i.e., the 2014 forecast revenue requirement) to the various customer classes using allocators that are based on the forecast class loads (kW and kWh) by class, customer counts, etc.

HHI has used the updated Board-approved Cost Allocation Model and followed the instructions and guidelines issued by the Board to enter the 2014 data into this model.

HHI populated the information on Sheet I3, Trial Balance Data with the 2014 forecasted data, Target Net Income, PILs, Deemed interest on long term debt, and the targeted Revenue Requirement and Rate Base.

On Sheet I4, Break-out of Assets, HHI updated the allocation of the accounts based on 2014 values.

In Sheet I5.1, Miscellaneous data, HHI updated the deemed equity component of rate base, km of roads where distribution lines exist, working capital allowance, the proportion of pole rent revenue from secondary poles, and the monthly service charges.

In Sheet I5.2, Weighting Factors, HHI has used LDC specific factors versus the use of default factors as instructed by the Board. The utility has applied service and billing & collecting weightings for each customer classification. These weightings are based on a review of time and costs incurred in servicing these particular customer classes:

- Residential: weighted for services and for billing and collecting as “1” per Cost Allocation instruction sheet

- General Service less than 50 kW: weighted “1” for billing & collecting. HHI feels that no more time, attention and costs are spent on these customers as the residential class. The weighting factor for services requires slightly more planning and monitoring for general service class than the residential class.

- The Weighted factor for the General Service greater than 50 kW also resulted in 1 for billing and collecting: Billing this particular class requires no more time, effort and cost than any other class. HHI selected a weighting factor of “1” for services. The reason for selecting “1” is that as per the ESA, HHI is not allowed to service the equipment for this particular class. The general service customer will hire an external contractor to perform the work. The only additional time spent on servicing this class is to ensure that the demand data is programmed and monitored appropriately.

- A Weighting factor of 1 is also used for the billing and collecting of the Sentinel and Unmetered Scattered Load class as it requires no more time and effort to bill these classes than the residential class. Services Weighting factors is not applicable for Street Lights.

<u>In Sheet I6.1</u> Revenue has been populated with the 2014 Test year forecast data as well as existing rates.

Sheet I6.2 has been updated with the required Bad Debt and Late Payment revenue data as well as customer/connection number information devices.

HHI updated the capital cost meter information on Sheet I7.1 and the meter reading information on I7.2 in accordance with the recent update to smart meters.

On sheet I8, Due to the lack of growth in the area and the, the utility's demand data has not changed since 2010 and as such, HHI deemed it appropriate to use the co-incident and non-co-incident peaks from the previous cost of service allocation.

No Direct Allocations on Sheet I9 were used.

The revenue to cost ratios calculated on Sheet O1 and O2 of the Cost Allocation model for the 2014 updated study is provided at the next page.

2013 Cost Allocation Model

Sheet O1 Revenue to Cost Summary Worksheet -

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

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	4	5	6	7	8	9
Rate Base Assets		Total	Residential	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$1,443,257	$780,598	$209,021	$421,273	$0	$0	$0	$30,203	$1,328	$834
mi	Miscellaneous Revenue (mi)	$157,139	$124,578	$16,848	$11,589	$0	$0	$0	$3,929	$100	$95
		Miscellaneous Revenue Input equals Output									
	Total Revenue at Existing Rates	**$1,600,396**	**$905,176**	**$225,869**	**$432,862**	**$0**	**$0**	**$0**	**$34,132**	**$1,428**	**$929**
	Factor required to recover deficiency (1 + D)	1.1316									
	Distribution Revenue at Status Quo Rates	$1,633,225	$883,344	$236,533	$476,723	$0	$0	$0	$34,178	$1,502	$944
	Miscellaneous Revenue (mi)	$157,139	$124,578	$16,848	$11,589	$0	$0	$0	$3,929	$100	$95
	Total Revenue at Status Quo Rates	**$1,790,364**	**$1,007,922**	**$253,381**	**$488,312**	**$0**	**$0**	**$0**	**$38,108**	**$1,602**	**$1,039**
	Expenses										
di	Distribution Costs (di)	$274,050	$133,182	$38,036	$92,620	$0	$0	$0	$9,634	$454	$125
cu	Customer Related Costs (cu)	$454,515	$395,283	$50,624	$8,120	$0	$0	$0	$70	$70	$348
ad	General and Administration (ad)	$398,100	$284,876	$48,431	$58,924	$0	$0	$0	$5,326	$285	$257
dep	Depreciation and Amortization (dep)	$222,854	$103,658	$26,452	$88,603	$0	$0	$0	$3,901	$137	$103
INPUT	PILs (INPUT)	$18,280	$7,316	$2,202	$8,501	$0	$0	$0	$242	$10	$10
INT	Interest	$168,828	$67,565	$20,336	$78,510	$0	$0	$0	$2,234	$93	$91
	Total Expenses	**$1,536,628**	**$991,880**	**$186,082**	**$335,278**	**$0**	**$0**	**$0**	**$21,406**	**$1,048**	**$935**
	Direct Allocation	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$253,737	$101,546	$30,563	$117,994	$0	$0	$0	$3,357	$139	$137
	Revenue Requirement (includes NI)	$1,790,364	$1,093,425	$216,645	$453,272	$0	$0	$0	$24,762	$1,187	$1,073
		Revenue Requirement Input equals Output									
	Rate Base Calculation										
	Net Assets										
dp	Distribution Plant - Gross	$5,889,645	$2,489,598	$707,967	$2,563,524	$0	$0	$0	$121,493	$4,114	$2,949
gp	General Plant - Gross	$1,467,653	$589,401	$176,880	$677,212	$0	$0	$0	$22,509	$869	$782
accum dep	Accumulated Depreciation	($2,287,115)	($1,042,842)	($273,794)	($901,227)	$0	$0	$0	($66,241)	($1,982)	($1,030)
co	Capital Contribution	($223,229)	($95,379)	($27,177)	($88,187)	$0	$0	$0	($12,091)	($312)	($83)
	Total Net Plant	**$4,846,954**	**$1,940,779**	**$583,876**	**$2,251,322**	**$0**	**$0**	**$0**	**$65,670**	**$2,689**	**$2,619**
	Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$15,927,063	$5,500,577	$1,978,075	$8,299,233	$0	$0	$0	$115,987	$10,678	$22,514
	OM&A Expenses	$1,126,665	$813,341	$137,092	$159,665	$0	$0	$0	$15,029	$808	$730
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$17,053,728***	***$6,313,917***	***$2,115,167***	***$8,458,898***	***$0***	***$0***	***$0***	***$131,016***	***$11,486***	***$23,244***
	Working Capital	**$2,216,985**	**$820,809**	**$274,972**	**$1,099,657**	**$0**	**$0**	**$0**	**$17,032**	**$1,493**	**$3,022**
	Total Rate Base	**$7,063,939**	**$2,761,588**	**$858,848**	**$3,350,979**	**$0**	**$0**	**$0**	**$82,702**	**$4,182**	**$5,640**
		Rate Base Input equals Output									
	Equity Component of Rate Base	**$2,825,575**	**$1,104,635**	**$343,539**	**$1,340,391**	**$0**	**$0**	**$0**	**$33,081**	**$1,673**	**$2,256**
	Net Income on Allocated Assets	**$253,737**	**$16,042**	**$67,299**	**$153,034**	**$0**	**$0**	**$0**	**$16,702**	**$555**	**$104**
	Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$253,737**	**$16,042**	**$67,299**	**$153,034**	**$0**	**$0**	**$0**	**$16,702**	**$555**	**$104**
	RATIOS ANALYSIS										
	REVENUE TO EXPENSES STATUS QUO%	**100.00%**	**92.18%**	**116.96%**	**107.73%**	**0.00%**	**0.00%**	**0.00%**	**153.89%**	**135.05%**	**96.86%**
	EXISTING REVENUE MINUS ALLOCATED COSTS	($189,968)	($188,250)	$9,224	($20,410)	$0	$0	$0	$9,370	$241	($143)
		Deficiency Input Does Not Equal Output									
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($85,503)	$36,736	$35,040	$0	$0	$0	$13,345	$416	($34)
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.98%	1.45%	19.59%	11.42%	0.00%	0.00%	0.00%	50.49%	33.18%	4.60%

2013 Cost Allocation Model

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

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7	8	9
	Residential	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$6.98	$7.03	$10.26	$0.00	$0.28	$5.81
Customer Unit Cost per month - Directly Related	$10.54	$10.61	$14.88	$0.01	$0.43	$8.96
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$13.89	$15.59	$29.66	$1.57	$3.01	$12.12
Existing Approved Fixed Charge	$5.99	$13.84	$97.35	$0.62	$1.63	$6.39

Per the Filing Requirements for Transmission and Distribution Applications dated June 22, 2011, HHI has completed OEB Appendix 2-P with the results of the 2014 cost allocation study and proposed adjustments. The Allocated cost table (2), calculated class revenues (2) and Rebalancing Revenue-to-Cost (R/C) Ratios (3) are summarized at the next few pages.

Table 2: Allocated Costs

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$774,573	52%	$1,093,425	61.16%
GS < 50 kW	$211,822	14%	$216,645	12.10%
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	$471,811	32%	$453,272	25.23%
GS > xxx kW, if applicable		0%		0.00%
Large User, if applicable		0%		0.00%
Street Lighting	$29,336	2%	$24,762	1.38%
Sentinel Lighting	$1,498	0%	$1,187	0.07%
Unmetered Scattered Load (USL)	$849	0%	$1,073	0.06%
Other class, if applicable		0%		0.00%
		0%		0.00%
Embedded distributor class		0%		0.00%
Total	$1,489,889	100%	$1,790,364	100.00%

Table 3: Class Revenues

Classes (same as previous table)	Column 7B	Column 7C	Column 7D	Column 7E
	Load Forecast (LF) X current approved rates	L.F. X current approved rates X (1 + d)	LF X proposed rates	Miscellaneous Revenue
Residential	$780,598	$883,344	$928,876	$124,578
GS < 50 kW	$209,021	$236,533	$211,515	$16,848
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	$307,750	$476,723	$464,628	$11,589
GS > xxx kW, if applicable				
Large User, if applicable				
Street Lighting	$30,200	$34,178	$25,897	$3,929
Sentinel Lighting	$1,329	$1,502	$1,330	$100
Unmetered Scattered Load (USL)	$834	$944	$978	$95
Other class, if applicable				
Embedded distributor class				
Total	$1,329,732	$1,633,225	$1,633,224	$157,139

Table 4: Rebalancing Revenue to Cost Ratios

Class	Previously Approved Ratios Most Recent Year: 20XX	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	111.00	92.18	96.34	85 - 115
GS < 50 kW	111.00	116.96	105.41	80 - 120
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	80.00	107.73	105.06	80 - 120
GS > xxx kW, if applicable				80 - 120
Large User, if applicable				85 - 115
Street Lighting	70.00	153.89	120.45	70 - 120
Sentinel Lighting	120.00	135.04	120.50	80 - 120
Unmetered Scattered Load (USL)	80.00	96.86	100.08	80 - 120
Other class, if applicable				
Embedded distributor class				

Table 5 below provides a breakdown of the proposed revenue allocation based on the results of the updated Cost Allocation Study (Sheet O2). The first column shows the allocated costs from the proposed service revenue requirement while the second column shows the per class allocation of the proposed service revenue requirement. The third and fourth column show the breakdown of the revenue offsets as calculated in the cost allocation model. Columns 7-8-9-10 show the results of the cost allocation model and the last column calculates the maximum charge per class.

Table 5: Cost Allocation Results

Cost Allocation Results	REVENUE ALLOCATION (sheet O1)							CUSTOMER UNIT COST PER MONTH (sheet O2)			
Customer Class Name	Service Rev Req (row40)		Misc. Revenue (mi) (row19)		Base Rev Req		Rev2Cost Expenses %	Avoided Costs (Minimum Charge)	Directly Related	Minimum System with PLCC * adjustment	Maximum Charge
Residential	1,093,425	61.07%	124,578	79.28%	968,847	59.32%	84.94%	$7.90	$11.46	$14.82	$14.82
General Service < 50 kW	216,645	12.10%	16,848	10.72%	199,797	12.23%	122.41%	$7.70	$11.28	$16.26	$16.26
General Service > 50 to 4999 kW	453,272	25.32%	11,589	7.37%	441,683	27.04%	122.86%	$10.26	$14.88	$29.66	$97.35
Unmetered Scattered Load	1,073	0.06%	95	0.06%	978	0.06%	96.08%	$5.81	$8.96	$12.12	$12.12
Sentinel Lighting	1,187	0.07%	100	0.06%	1,087	0.07%	142.55%	$0.28	$0.43	$3.01	$3.01
Street Lighting	24,762	1.38%	3,929	2.50%	20,833	1.28%	148.72%	$0.00	$0.01	$1.57	$1.57
TOTAL	**1,790,364**	**100.00%**	**157,139**	**100.00%**	**1,633,225**	**100.00%**					

Table 6: Cost Allocation of Revenue Requirement

Revenue Reallocation - Service Revenue Requirement

Customer Class Name	Base Revenue Requirement %						Revenue Offsets		Service Revenue Requirement $		
	Cost Allocation Results		Existing Rates		Proposed Allocation		%	$	Cost Allocation	Existing Rates	Rate Application
Residential	59.32%	968,847	58.70%	958,758	56.87%	928,876	79.28%	124,578	1,093,425	1,083,336	1,053,454
General Service < 50 kW	12.23%	199,797	15.72%	256,727	12.95%	211,515	10.72%	16,848	216,645	273,575	228,363
General Service > 50 to 4999 kW	27.04%	441,683	23.14%	377,990	28.45%	464,628	7.37%	11,589	453,272	389,579	476,217
Unmetered Scattered Load	0.06%	978	0.06%	1,025	0.06%	978	0.06%	95	1,073	1,120	1,073
Sentinel Lighting	0.07%	1,087	0.10%	1,632	0.08%	1,330	0.06%	100	1,187	1,732	1,430
Street Lighting	1.28%	20,833	2.27%	37,093	1.59%	25,897	2.50%	3,929	24,762	41,022	29,826
TOTAL		**1,633,224**		**1,633,224**	**100.00%**	**1,633,224**		**157,139**	**1,790,363**	**1,790,363**	**1,790,363**

Table 7: Revenue to Cost Ratios

Customer Class Name	Calculated R/C Ratio	Proposed R/C Ratio	Variance
Residential	0.92	0.96	0.04
General Service < 50 kW	1.17	1.05	-0.12
General Service > 50 to 4999 kW	1.08	1.05	-0.03
Unmetered Scattered Load	0.97	1.00	0.03
Sentinel Lighting	1.35	1.20	-0.15
Street Lighting	1.54	1.20	-0.33

Target Range	
Floor	Ceiling
0.85	1.15
0.80	1.20
0.80	1.20
0.70	1.20
0.70	1.20
0.70	1.20

The reason for the significant difference in the calculated ratios and proposed ratios, especially where the Sentinel and Street Lights are concerned, is due to the utility specific weighting factors. The default factors used in the previous cost allocation did not accurately reflect the actual billing, collecting and services at HHI. How the proposed revenues to cost ratios are used to determine rates is discussed in detail at Exhibit 8.

2013 Cost Allocation Model

Sheet I6.1 Revenue Worksheet -

Total kWhs from Load Forecast	151,851,313
Total kWs from Load Forecast	200,599
Deficiency from RRWF	296,046
Miscellaneous Revenue	157,139

			1	2	3	7	8	9
Billing Data	**ID**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Forecast kWh	**CEN**	151,851,313	52,443,428	18,859,305	79,126,290	1,105,837	101,802	214,651
Forecast kW	**CDEM**	200,599			197,191	3,124	284	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		-						
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**	151,851,313	52,443,428	18,859,305	79,126,290	1,105,837	101,802	214,651
kWh - 30 year weather normalized amount		314,660,565	52,443,428	52,443,428	52,443,428	52,443,428	52,443,428	52,443,428

Existing Monthly Charge			$5.99	$13.84	$97.35	$0.62	$1.63	$6.39
Existing Distribution kWh Rate			$0.0081	$0.0055				$0.0021
Existing Distribution kW Rate					$1.5558	$6.7744	$3.2285	
Existing TFOA Rate					$0.60	$0.60	$0.60	
Additional Charges								
Distribution Revenue from Rates		$1,443,257	$780,598	$209,021	$421,273	$30,203	$1,328	$834
Transformer Ownership Allowance		$0	$0	$0	$0	$0	$0	$0
Net Class Revenue	**CREV**	$1,443,257	$780,598	$209,021	$421,273	$30,203	$1,328	$834
Data Mismatch Analysis								
Revenue with 30 year weather normalized kWh		3,961,140	780,598	581,239	279,212	1,432,345	683,943	203,803

Weather Normalized Data from Hydro One

	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
kWh - 30 year weather normalized amount	331,683,702	55,280,617	55,280,617	55,280,617	55,280,617	55,280,617	55,280,617
Loss Factor		**1.0541**	**1.0541**	**1.0541**	**1.0541**	**1.0541**	**1.0541**

2013 Cost Allocation Model

Sheet I6.2 Customer Data Worksheet -

	ID	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
Billing Data								
Bad Debt 3 Year Historical Average	BDHA	$13,275	$11,713	$1,562	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$29,189	$26,708	$2,481				
Number of Bills	CNB	68,268	59,400	7,608	1,176	12	12.00	60
Number of Devices								
Number of Connections (Unmetered)	CCON	1,236				1,215	21	
Total Number of Customers	CCA	5,689	4,950	634	98	1	1	5
Bulk Customer Base	CCB	-						
Primary Customer Base	CCP	6,923	4,950	634	98	1,215	21	5
Line Transformer Customer Base	CCLT	6,923	4,950	634	98	1,215	21	5
Secondary Customer Base	CCS	6,923	4,950	634	98	1,215	21	5
Weighted - Services	CWCS	6,342	4,950	1,268	98	-	21	5
Weighted Meter -Capital	CWMC	1,746,480	1,485,000	181,380	80,100	-	-	-
Weighted Meter Reading	CWMR	425	-	-	425	-	-	-
Weighted Bills	CWNB	68,268	59,400	7,608	1,176	12	12	60

Bad Debt Data

		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Historic Year:	2010	19,528	17,420	2,108				
Historic Year:	2011	17,497	15,280	2,217				
Historic Year:	2012	2,800	2,440	360				
Three-year average		**13,275**	**11,713**	**1,562**	**-**	**-**	**-**	**-**

Sheet I8 Demand Data Worksheet -

This is an input sheet for demand allocators.

CP TEST RESULTS	12 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

Customer Classes		Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	34,067	11,916	4,373	17,451	296	22	9
Bulk Delivery CP	BCP1	34,067	11,916	4,373	17,451	296	22	9
Total Sytem CP	DCP1	34,067	11,916	4,373	17,451	296	22	9
4 CP								
Transformation CP	TCP4	130,808	42,220	16,067	71,588	832	64	37
Bulk Delivery CP	BCP4	130,808	42,220	16,067	71,588	832	64	37
Total Sytem CP	DCP4	130,808	42,220	16,067	71,588	832	64	37
12 CP								
Transformation CP	TCP12	345,243	101,941	41,872	200,155	1,080	85	110
Bulk Delivery CP	BCP12	345,243	101,941	41,872	200,155	1,080	85	110
Total Sytem CP	DCP12	345,243	101,941	41,872	200,155	1,080	85	110
NON CO_INCIDENT PEAK								
1 NCP								
Classification NCP from Load Data Provider	DNCP1	38,671	12,902	5,197	20,220	309	33	10
Primary NCP	PNCP1	38,671	12,902	5,197	20,220	309	33	10
Line Transformer NCP	LTNCP1	38,308	12,781	5,148	20,030	306	33	10
Secondary NCP	SNCP1	38,323	12,786	5,150	20,038	306	33	10
4 NCP								
Classification NCP from Load Data Provider	DNCP4	146,479	48,656	19,430	77,094	1,137	125	37
Primary NCP	PNCP4	146,479	48,656	19,430	77,094	1,137	125	37
Line Transformer NCP	LTNCP4	145,102	48,199	19,247	76,369	1,126	124	37
Secondary NCP	SNCP4	145,161	48,218	19,255	76,400	1,127	124	37
12 NCP								
Classification NCP from Load Data Provider	DNCP12	380,501	119,812	46,944	210,181	3,148	306	110
Primary NCP	PNCP12	380,501	119,812	46,944	210,181	3,148	306	110
Line Transformer NCP	LTNCP12	376,924	118,686	46,503	208,205	3,118	303	109
Secondary NCP	SNCP12	377,077	118,734	46,522	208,289	3,120	303	109

Exhibit 8 – Rate Design

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EXHIBIT 8 – RATE DESIGN

The evidence presented in this exhibit provides information supporting the utility's development of electricity prices for various customer classes to meet revenue requirements dictated by operating needs and costs. The evidence herein is organized according to the following topics;

1) Fixed/Variable Proportions
2) Retail Transmission Service Rates
3) Retail Service Charges
4) Wholesale Market Service Charges
5) Specific Service Charges
6) Low voltage Charges
7) Loss Adjustment Factor
8) Rate Schedule
9) Bill Impacts

Tab 1 – Fixed Variable Proportion

E8.T1.S1 OVERVIEW OF EXISTING RATES

The existing rate schedule is presented at E8.T1.S2. The current rates were approved as part of the proceeding EB-2012-0117. HHI applied for distribution rate adjustments pursuant to the IRM process. Notice of HHI's rate application was given through newspaper publication in HHI's service area, and advising how interested parties may intervene in the proceeding or comment on the application. No intervention requests or comments were received.

The Board found that HHI's rate application was filed in compliance with Chapter 3 of the Board's Filing Requirements for Transmission and Distribution Applications (the "Filing Requirements"), which outlines the application filing requirements for IRM applications based on the policies in the Reports.

The following matters were addressed in the decision.

- Rates were adjusted by a price escalator less a productivity factor. The Board established the price escalator to be 1.60% with a stretch factor of 0.2%.
- On March 28, 2013, the Board issued a Decision and Order (EB-2012-0100/EB-2012-0211) establishing a Smart Metering Entity charge of $0.79 per month for Residential and General Service < 50kW customers for those distributors identified in the Board's annual Yearbook of Electricity Distributors.

The following matters were addressed in the decision.

- Rate Riders and Rate Adders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural or Remote Rate Protection Charge;
- Standard Supply Service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Loss Factors;
- Specific Service, MicroFit and Retail Service Charges.

HHI's rates were approved by the Board and rendered effective May 1, 2013 and will remain in effect until December 31, 2013.

Table 1 below summarizes these revenue projections, showing the proportions attributable to fixed (monthly service) charges and variable (distribution volumetric) charges. Table 2 which follows the Revenues from Existing Fixed and Variable Charges shows the current customer classes. HHI is not proposing any changes to its customer class at this time.

Table 1: Revenues from Existing Fixed and Variable Charges

Bridge Year

Customer Class Name	Bridge Year Projected Revenue from Existing Variable Charges							
	Variable Distribution Rate	per	Bridge Year Volume	Gross Variable Revenue	Transform. Allowance Rate	Transform. Allowance kW's	Transform. Allowance $'s	Net Variable Revenue
Residential	$0.0081	kWh	54,711,762	443,165			0	443,165
General Service < 50 kW	$0.0055	kWh	20,128,592	110,707			0	110,707
General Service > 50 to 4999 kW	$1.5558	kW	206,144	320,719	($0.60)	189,205	-113,523	207,196
Unmetered Scattered Load	$0.0021	kWh	224,238	471			0	471
Sentinel Lighting	$3.2285	kW	297	959	($0.60)		0	959
Street Lighting	$6.7744	kW	3,250	22,017	($0.60)		0	22,017
Total Variable Revenue			**75,274,283**	**898,038**		**189,205**	**-113,523**	**784,515**

Bridge Year

Customer Class Name	Bridge Year Projected Revenue from Existing Fixed Charges							
	Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Revenue	TOTAL	% Fixed Revenue	% Variable Revenue	% Total Revenue
Residential	$5.9900	4,905	352,571	443,165	795,737	44.31%	55.69%	58.35%
General Service < 50 kW	$13.8400	630	104,630	110,707	215,338	48.59%	51.41%	15.79%
General Service > 50 to 4999 kW	$97.3500	96	112,147	207,196	319,343	35.12%	64.88%	23.42%
Unmetered Scattered Load	$6.3900	5	383	471	854	44.88%	55.12%	0.06%
Sentinel Lighting	$1.6300	21	411	959	1,370	29.99%	70.01%	0.10%
Street Lighting	$0.6200	1,210	9,002	22,017	31,019	29.02%	70.98%	2.27%
Total Fixed Revenue		**6,867**	**579,146**	**784,515**	**1,363,660**			

Table 2: Rate Classes

Customer Class Name	Existing	Proposed	Status	MSCMetric	Usage Metric	USA #
Residential	YES	YES	Continued	Customer	kWh	
General Service < 50 kW	YES	YES	Continued	Customer	kWh	
General Service > 50 to 4999 kW	YES	YES	Continued	Customer	kW	
Unmetered Scattered Load	YES	YES	Continued	Customer	kWh	
Sentinel Lighting	YES	YES	Continued	Connection	kW	
Street Lighting	YES	YES	Continued	Connection	kW	
MicroFit	YES	YES	Continued	Customer	Monthly	

E8.T1.S2 Current Rate Schedule

The current rates is presented at the next page

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Current Tariff Sheet

Loss Factor	
Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0446
Total Loss Factor – Secondary Metered Customer > 5,000 kW	
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0342
Total Loss Factor – Primary Metered Customer > 5,000 KW	

Residential	Effective Until mm/dd/yy	rate	Connection Type
Service Charge		5.99	$
Distribution Volumetric Rate		0.0081	kWh
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until April 30, 2014		-1.35	kWh
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement - in effective until the effective date of the next cost of service-based rate order		1.39	kWh
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018		0.79	kWh
Low Voltage Service Rate		0.0004	kWh
Rate Rider for Recovery of Incremental Capital Costs		0.0024	kWh
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014		0.0011	kWh
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014 Applicable only for Non-RPP Customers		0.0060	kWh
Retail Transmission Rate – Network Service Rate		0.0069	kWh
Retail Transmission Rate – Line and Transformation Connection Service Rate		0.0031	kWh
Wholesale Market Service Rate		0.0044	kWh
Rural Rate Protection Charge		0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)		0.25	$

General Service < 50 kW	Effective Until mm/dd/yy	rate	Connection Type
Service Charge		13.84	$
Distribution Volumetric Rate		0.0055	kWh
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until April 30, 2014		-0.09	kWh
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement - in effective until the effective date of the next cost of service-based rate order		2.46	kWh
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018		0.79	kWh
Low Voltage Service Rate		0.0004	kWh
Rate Rider for Recovery of Incremental Capital Costs		0.0017	kWh
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014		0.0011	kWh
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014 Applicable only for Non-RPP Customers		0.0060	kWh
Retail Transmission Rate – Network Service Rate		0.0063	kWh
Retail Transmission Rate – Line and Transformation Connection Service Rate		0.0027	kWh
Wholesale Market Service Rate		0.0044	kWh
Rural Rate Protection Charge		0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)		0.25	$

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Current Tariff Sheet

General Service > 50 to 4999 kW	Effective Until mm/dd/yy	rate	Connection Type
Service Charge		97.35	$
Distribution Volumetric Rate		1.5558	kW
Low Voltage Service Rate		0.1369	kW
Rate Rider for Recovery of Incremental Capital Costs		0.3270	kW
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014		0.4219	kW
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014 Applicable only for Non-RPP Customers		2.3612	kW
			kW
Retail Transmission Rate – Network Service Rate		2.5533	kW
Retail Transmission Rate – Line and Transformation Connection Service Rate		1.1197	kW
Wholesale Market Service Rate		0.0044	kWh
Rural Rate Protection Charge		0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)		0.25	$

Unmetered Scattered Load	Effective Until mm/dd/yy	rate	Connection Type
Service Charge		6.39	$
Distribution Volumetric Rate		0.0021	kWh
Low Voltage Service Rate		0.0004	kWh
Rate Rider for Recovery of Incremental Capital Costs		0.0006	kWh
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014		0.0011	kWh
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014 Applicable only for Non-RPP Customers		0.0060	kWh
Retail Transmission Rate – Network Service Rate		0.0063	kWh
Retail Transmission Rate – Line and Transformation Connection Service Rate		0.0027	kWh
Wholesale Market Service Rate		0.0044	kWh
Rural Rate Protection Charge		0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)		0.25	$

Sentinel Lighting	Effective Until mm/dd/yy	rate	Connection Type
Service Charge		1.63	$
Distribution Volumetric Rate		3.2285	kW
Low Voltage Service Rate		0.2162	kW
Rate Rider for Recovery of Incremental Capital Costs		0.7496	kW
Retail Transmission Rate – Network Service Rate		1.9264	kW
Retail Transmission Rate – Line and Transformation Connection Service Rate		1.7674	kW
Wholesale Market Service Rate		0.0044	kWh
Rural Rate Protection Charge		0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)		0.25	$

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Street Lighting	Effective Until mm/dd/yy	rate	Connection Type
Service Charge		0.62	$
Distribution Volumetric Rate		6.7744	kW
Low Voltage Service Rate		0.1059	kW
Rate Rider for Recovery of Incremental Capital Costs		1.5987	kW
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014		0.3889	kW
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014 Applicable only for Non-RPP Customers		2.1767	kW
Retail Transmission Rate – Network Service Rate		1.9258	kW
Retail Transmission Rate – Line and Transformation Connection Service Rate		0.8656	kW
Wholesale Market Service Rate		0.0044	kWh
Rural Rate Protection Charge		0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)		0.25	$

Certain classes fell within the minimum and maximum boundaries while others fell outside the boundaries. The utility has adjusted the fixed charge taking into consideration various factors such as equity between the fixed and variable rate, impact on the customers as well as revenue stability.

Under the current rates and split, the fixed charge rates for the Unmetered Scattered Load resulted in a 45% fixed to 54% variable. The utility felt that the split should be rebalanced so as to get as close as possible to a 50% fixed to 50% split. The resulting Monthly Service Charge ("MSC") of $8.50 instead of the existing $6.39 falls within the boundaries produced by the 2014 Cost Allocation ("CA") model. The revenue recovered from this class is $978.

The fixed charge rates for the Street Lighting classes were set so as to get as close as possible to a 50% fixed to 50% variable split. The resulting Monthly Service Charge ("MSC") is a slight increase from the currently approved rates and fall well within the boundaries produced by the 2014 Cost Allocation ("CA") model. The MSC was set at $1.00. The revenue recovered from this class is $25,891.

The fixed charge rates for the Sentinel Lights class were also rebalanced so as to get as closer to a 50% fixed to 50% variable split. The resulting Monthly Service Charge ("MSC") is a slight increase from the currently approved rates and fall well within the boundaries produced by the 2014 Cost Allocation ("CA") model. The MSC was set at $3.00. The revenue recovered from this class is $1,329.

The split at current rates is for the General Service 50 – 4,999 kW rate class is 37% fixed to 63% variable. Since the calculated rates at current split fell outside the maximum boundary, HHI opted to use the maximum MSC of $97.35 which results in a split of 24% fixed to 66% variable.

For the General Service less than 50kW rate class, the split at current rates is 50% fixed to 50% variable. The resulting MSC chosen by HHI is $15.00 instead $14.00 and falls within the minimum and maximum boundaries.

HHI's current MSC of $5.99 is lowest in Ontario and has been for many years. The utility's variable charge is the second lowest in Ontario. With Hawkesbury's lack of growth, aging population and high level of unemployment, HHI feels that an increase in MSC is necessary to ensure a level of revenue stability for the utility. The proposed fixed to variable split is 64% fixed to 36% variable. The resulting MSC of $10.00 still falls well below the average MSC in Ontario. Details are presented at the next page.

Table 4: List of Ontario MSC's in 2011

Average	**13.87**	**0.00152**
Applicant	**MSC**	**VC**
Hydro Hawkesbury Inc.	5.89	0.0079
Oshawa PUC Networks Inc.	8.45	0.0123
Hydro 2000 Inc.	8.53	0.0060
Hydro Ottawa Limited	8.54	0.0207
PUC Distribution Inc.	8.73	0.0151
COLLUS Power Corporation	8.94	0.0169
Hearst Power Distribution Company Limited	9.00	0.0156
Lakefront Utilities Inc.	9.29	0.0134
Kitchener-Wilmot Hydro Inc.	9.59	0.0170
Hydro One Brampton Networks Inc.	9.75	0.0142
Tillsonburg Hydro Inc.	9.82	0.0168
Thunder Bay Hydro Electricity Distribution Inc.	9.88	0.0124
Cambridge and North Dumfries Hydro Inc.	9.95	0.0161
Espanola Regional Hydro Distribution Corporation	9.96	0.0120
Veridian Connections Inc. - Gravenhurst	9.97	0.0192
Rideau St. Lawrence Distribution Inc.	10.28	0.0117
ENWIN Utilities Ltd.	10.70	0.0200
Ottawa River Power Corporation	10.95	0.0149
Brant County Power Inc.	11.00	0.0237
Veridian Connections Inc.	11.08	0.0156
E.L.K. Energy Inc.	11.13	0.0079
Westario Power Inc.	11.24	0.0141
Brantford Power Inc.	11.36	0.0137
St. Thomas Energy Inc.	11.50	0.0160
Midland Power Utility Corporation	11.68	0.0194
Enersource Hydro Mississauga Inc.	11.77	0.0118
Peterborough Distribution Incorporated	11.81	0.0115
Wasaga Distribution Inc.	11.82	0.0147
Fort Frances Power Corporation	11.89	0.0087
PowerStream Inc. - South	11.89	0.0134
Middlesex Power Distribution Corporation - Newbury	11.94	0.0120
Kingston Hydro Corporation	12.06	0.0148
Burlington Hydro Inc.	12.12	0.0165
Festival Hydro Inc. - Hensall	12.49	0.0134
Essex Powerlines Corporation	12.57	0.0148
London Hydro Inc.	12.61	0.0142
Woodstock Hydro Services Inc.	12.72	0.0218
Middlesex Power Distribution Corporation - Dutton	12.82	0.0121
Halton Hills Hydro Inc.	12.94	0.0121

Oakville Hydro Electricity Distribution Inc.	13.10	0.0143
Guelph Hydro Electric Systems Inc.	13.41	0.0164
Orillia Power Distribution Corporation	13.49	0.0162
Cooperative Hydro Embrun Inc.	13.51	0.0126
Bluewater Power Distribution Corporation	13.68	0.0186
Middlesex Power Distribution Corporation	13.76	0.0139
Centre Wellington Hydro Ltd.	13.79	0.0127
Wellington North Power Inc.	13.88	0.0139
West Coast Huron Energy Inc.	14.08	0.0182
Haldimand County Hydro Inc.	14.10	0.0311
Renfrew Hydro Inc.	14.11	0.0146
Erie Thames Powerlines Corporation	14.19	0.0126
North Bay Hydro Distribution Limited	14.21	0.0127
Welland Hydro-Electric System Corp.	14.24	0.0143
Horizon Utilities Corporation	14.45	0.0142
Waterloo North Hydro Inc.	14.56	0.0184
Festival Hydro Inc.	14.78	0.0164
Milton Hydro Distribution inc.	14.80	0.0138
Grimsby Power Inc.	15.11	0.0086
PowerStream Inc. - Barrie	15.21	0.0136
Lakeland Power Distribution Ltd.	15.22	0.0137
Canadian Niagara Power Inc. - Port Colborne Hydro Inc.	15.46	0.0219
Niagara Peninsula Energy Inc. - Niagara Falls	15.62	0.0157
Niagara Peninsula Energy Inc. - Peninsula West	15.62	0.0157
Greater Sudbury Hydro Inc.	16.00	0.0123
Orangeville Hydro Limited	16.14	0.0139
Veridian Connections Inc. - Gravenhurst	16.42	0.0226
Whitby Hydro Electric Corporation	17.24	0.0141
Northern Ontario Wires Inc.	17.64	0.0134
Canadian Niagara Power Inc. - Eastern Ontario Power	18.01	0.0151
Canadian Niagara Power Inc. - Fort Erie	18.01	0.0151
Niagara-on-the-Lake Hydro Inc.	18.06	0.0127
Chatham-Kent Hydro Inc.	18.10	0.0084
Toronto Hydro-Electric System Limited	18.25	0.0152
Chapleau Public Utilities Corporation	18.46	0.0102
Kenora Hydro Electric Corporation Ltd.	18.77	0.0137
Innisfil Hydro Distribution Systems Limited	19.05	0.0186
Norfolk Power Distribution Inc.	20.77	0.0190
Algoma Power Inc.	20.92	0.0294
Parry Sound Power Corporation	21.55	0.0172
Sioux Lookout Hydro Inc.	24.05	0.0103
Veridian Connections Inc. - Gravenhurst	26.49	0.0327
Atikokan Hydro Inc.	30.58	0.0121

E8.T1.S4 FIXED/VARIABLE REVENUE SPLIT

Table 5 at the next page shows the Current fixed/variable proportion for each rate class, along with the proposed fixed/variable proportion for each rate class.

Table 5: Rate Design – Fixed to Variable Split

Cost Allocation Results

	Cost Allocation - Minimum Fixed Rate (b)			Cost Allocation - Maximun Fixed Rate (b)		
Customer Class Name	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**
Residential	$7.90	50.52%	49.48%	$14.82	94.77%	5.23%
General Service < 50 kW	$7.70	27.70%	72.30%	$16.26	58.49%	41.51%
General Service > 50 to 4999 kW	$10.26	2.60%	97.40%	$97.35	24.64%	75.36%
Unmetered Scattered Load	$5.81	35.63%	64.37%	$12.12	74.32%	25.68%
Sentinel Lighting	$0.28	5.31%	94.69%	$3.01	57.04%	42.96%
Street Lighting	$0.00	0.00%	100.00%	$1.57	88.39%	11.61%

Existing Rates

	Current Rates and Split			Calculated Rates at Current Split		
Customer Class Name	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**
Residential	$5.99	45.58%	54.42%	$7.13	45.58%	54.42%
General Service < 50 kW	$13.84	50.38%	49.62%	$14.01	50.38%	49.62%
General Service > 50 to 4999 kW	$97.35	37.20%	62.80%	$146.97	37.20%	62.80%
Unmetered Scattered Load	$6.39	45.96%	54.04%	$7.50	45.96%	54.04%
Sentinel Lighting	$1.63	30.92%	69.08%	$1.63	30.92%	69.08%
Street Lighting	$0.62	29.93%	70.07%	$0.53	29.93%	70.07%

Rate Design

	Proposed Fixed Charge			Resulting Variable		
Customer Class Name	Fixed Rate	Fixed %	Variable %	**Variable (h)**	**Rate (i)**	**per**
Residential	$10.00	63.95%	36.05%	334,876	$0.0064	kWh
General Service < 50 kW	$15.00	53.95%	46.05%	97,395	$0.0052	kWh
General Service > 50 to 4999 kW	$97.35	24.64%	75.36%	463,667	$2.3514	kW
Unmetered Scattered Load	$8.50	52.12%	47.88%	468	$0.0022	kWh
Sentinel Lighting	$3.00	56.85%	43.15%	574	$2.0183	kW
Street Lighting	$1.00	56.30%	43.70%	11,317	$3.6230	kW
				908,298		

	Transf. Allowance ($/kW):		($0.60)	Base Revenue Requirement $		
Customer Class Name	**kW**	**Rate**	**Total $ (g)**	Total (d)	Fixed	Variable
Residential	0	$0.00	0	928,876	594,000	334,876
General Service < 50 kW	0	$0.00	0	211,515	114,120	97,395
General Service > 50 to 4999 kW	189,205	$0.60	113,523	464,628	114,484	350,144
Unmetered Scattered Load	0	$0.00	0	978	510	468
Sentinel Lighting	0	$0.00	0	1,330	756	574
Street Lighting	0	$0.00	0	25,897	14,580	11,317
				1,633,224	**838,450**	**794,775**

E8.T1.S5 RECONCILIATION TO BASE REVENUE REQUIREMENT APPENDIX 2-V

Appendix 2-V presented at the next page, shows the reconciliation of the revenues from fixed and variable distribution charges to the Base Revenue Requirement.

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Appendix 2-V
Revenue Reconciliation

Rate Class	Customers/ Connections	Number of Customers/Connections: Start of Test Year	End of Test Year	Average	Test Year Consumption: kWh	kW	Proposed Rates: Monthly Service Charge	Volumetric kWh	Volumetric kW	Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
Residential	Customers	4,950.00	4,950.00	4,950.00	52,443,428		$ 10.00	$ 0.0064		$ 928,876.34	$ 928,876		$ 928,876	$ -
GS < 50 kW	Customers	634.00	634.00	634.00	18,859,305		$ 15.00	$ 0.0052		$ 211,514.73	$ 211,515		$ 211,515	$ -
GS > 50 to 4,999 kW	Customers	98.00	98.00	98.00	-	197,191	$ 97.35		$ 2.3514	$ 578,151.02	$ 464,628	$ 113,523	$ 578,151	$ -
				-						$ -			$ -	$ -
Streetlighting	Connections	1,215.00	1,215.00	1,215.00		3,124	$ 1.00		$ 3.6230	$ 25,896.86	$ 25,897		$ 25,897	$ -
Sentinel Lighting	Connections	21.00	21.00	21.00		284	$ 3.00		$ 2.0183	$ 1,329.78	$ 1,330		$ 1,330	$ -
Unmetered Scattered Load	Customers	5.00	5.00	5.00	214,651		$ 8.50	$ 0.0022		$ 978.46	$ 978		$ 978	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
Total										$ 1,746,747.19	$ 1,633,224	$ 113,523	$ 1,746,747	$ -

Note

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

Tab 2 – Retail Transmission Service Rates

E8.T2.S1 RETAIL TRANSMISSION SERVICE RATES (RTSR)

Electricity distributors are charged for transmission costs at the wholesale level and subsequently pass these charges on to their distribution customers through the RTSRs. Variance accounts are used to capture timing differences and differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers

HHI completed its 2014 proposed RTSR in accordance with the Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates, October 22, 2008 (and any subsequent updates). The RTSR model provided by the Board is being filed in conjunction with this application.

The trend indicates that the current rates result in over-collection of transmission charges for both Network Service and Connection Service. This conclusion is consistent with the accumulation of credit balances in variance accounts 1584-RSVA/NW and 1586-RSVA/CN during the last year period. HHI therefore proposes to adjust its RTSRs to offset the over-collection bias in its existing retail rates. The Power accounts (1588) have seen a trend of under-collection.

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

E8.T2.S2 PROPOSED RETAIL TRANSMISSION SERVICE RATES (RTSR)

Table 6 below presents the Applicant's proposed RTSR for the Test Year. The proposed rates are reflected in the Applicant's projected power supply expense for 2014 as shown in Exhibit 3.

Table 6 Proposed RTSR

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	0.0063	0.0030
General Service Less Than 50 kW	kWh	0.0057	0.0026
General Service 50 to 4,999 kW	kW	2.3286	1.0753
Unmetered Scattered Load	kWh	0.0057	0.0026
Sentinel Lighting	KW	1.7569	1.6973
Street Lighting	kW	1.7564	0.8313

Table 7: Adjusted Network to Current WS

Rate Class	Unit	Current RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Network
Residential Regular	kWh	0.0069	53,413,358	0	$368,552.17	36%	336,124	0.0063
General Service Less Than 50 kW	kWh	0.0063	19,357,851	0	$121,954.46	12%	111,224	0.0057
General Service 50 to 4,999 kW	kW	2.5533	77,875,017	206640	$527,613.91	51%	481,190	2.3286
Unmetered Scattered Load	kWh	0.0063	224,486	0	$1,414.26	0%	1,290	0.0057
Sentinel Lighting	kW	1.9264	102,354	284	$547.10	0%	499	1.7569
Street Lighting	kW	1.9258	1,355,854	3751	$7,223.68	1%	6,588	1.7564

Table 8: Adjusted Network to Forecasted WS

Rate Class	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Network
Residential Regular	kWh	0.0063	53,413,358	0	$336,123.72	36%	336,124	0.0063
General Service Less Than 50 kW	kWh	0.0057	19,357,851	0	$111,223.84	12%	111,224	0.0057
General Service 50 to 4,999 kW	kW	2.3286	77,875,017	206640	$481,189.81	51%	481,190	2.3286
Unmetered Scattered Load	kWh	0.0057	224,486	0	$1,289.82	0%	1,290	0.0057
Sentinel Lighting	kW	1.7569	102,354	284	$498.96	0%	499	1.7569
Street Lighting	kW	1.7564	1,355,854	3751	$6,588.07	1%	6,588	1.7564

Table 9: Adjusted Connection to Current WS

Rate Class	Unit	Current RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Connection
Residential Regular	kWh	0.0031	53,413,358	0	$165,581.41	37%	159,011	0.0030
General Service Less Than 50 kW	kWh	0.0027	19,357,851	0	$52,266.20	12%	50,192	0.0026
General Service 50 to 4,999 kW	kW	1.1197	77,875,017	206640	$231,374.81	51%	222,194	1.0753
Unmetered Scattered Load	kWh	0.0027	224,486	0	$606.11	0%	582	0.0026
Sentinel Lighting	kW	1.7674	102,354	284	$501.94	0%	482	1.6973
Street Lighting	kW	0.8656	1,355,854	3751	$3,246.87	1%	3,118	0.8313

Table 10: Adjusted Connection to Forecasted WS

Rate Class	Unit	Current RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Connection
Residential Regular	kWh	0.0030	53,413,358	0	$159,010.90	37%	159,011	0.0030
General Service Less Than 50 kW	kWh	0.0026	19,357,851	0	$50,192.20	12%	50,192	0.0026
General Service 50 to 4,999 kW	kW	1.0753	77,875,017	206640	$222,193.52	51%	222,194	1.0753
Unmetered Scattered Load	kWh	0.0026	224,486	0	$582.06	0%	582	0.0026
Sentinel Lighting	kW	1.6973	102,354	284	$482.02	0%	482	1.6973
Street Lighting	kW	0.8313	1,355,854	3751	$3,118.03	1%	3,118	0.8313

Tab 3 – Retail Service Charges and Specific Service Charges

E8.T3.S1 OVERVIEW OF RETAIL AND SPECIFIC SERVICE CHARGE

Retail services refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity as set out in the Retail Settlement Code ("RSC"). HHI proposes to maintain most of its current Retail Service Charges and Specific Service Charges in this application with the exception of four service charges as described at Exhibit 3 section E3.T3.S5 and described below.

Table 11 - Change of occupancy charge

CURRENT FEE:	$30.00
ADJUSTED FEE REQUESTED:	**$40.00**
ACTUAL COSTS	
Lineman out in field for meter disconnection:	$11.00
(Average time - 15 minutes)	
Fuel costs:	$3.00
CSR at counter to complete "Demand of Service" contract:	$8.00
(Average time - 15 minutes)	
Billing clerk to complete the opening of account in CIS:	$15.00
(Average time - 20 minutes)	
TOTAL COSTS:	**$37.00**

Table 12 - Disconnect/Reconnect at meter – after regular hours

CURRENT FEE:	$130.00
ADJUSTED FEE REQUESTED:	**$170.00**
ACTUAL COSTS	
Lineman out in field for meter disconnection:	$159.56
(Paid 4 hours as per Union contract)	
Fuel costs:	$3.00
TOTAL COSTS:	**$162.56**

Table 13 - Install / remove load control device – after regular hours

CURRENT FEE:	$130.00
ADJUSTED FEE REQUESTED:	**$170.00**
ACTUAL COSTS	
Lineman out in field for installation of load control device:	$159.56
(Paid 4 hours as per Union contract)	
Fuel costs:	$3.00
TOTAL COSTS:	**$162.56**

Table 14 - Service call – after regular hours

CURRENT FEE:	$130.00
ADJUSTED FEE REQUESTED:	**$170.00**
ACTUAL COSTS	
Lineman out in field for service call:	$159.56
(Paid 4 hours as per Union contract)	
Fuel costs:	$3.00
TOTAL COSTS:	**$162.56**

HHI is proposing to maintain all other existing retail service charges which are consistent with the OEB's Standard Rates and consistent with all other utilities in Ontario.

The final schedule of specific service charges is presented at E8.T3.S2.

E8.T3.S2 PROPOSED RETAIL AND SPECIFIC SERVICE CHARGES

Arrears Certificate	$15.00
Statement of Account	$15.00
Duplicate invoices for previous billing	$15.00
Credit reference/credit check (plus credit agency costs)	$15.00
Returned cheque charge (plus bank charges)	$20.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$40.00
Notification charge	$30.00
Late Payment - per month	1.50%
Late Payment - per annum	19.56%
Collection of account charge – no disconnection	$5.00
Disconnect/Reconnect at meter – during regular hours	$30.00
Disconnect/Reconnect at meter – after regular hours	$170.00
Disconnect/Reconnect at pole - during regular hours	$100.00
Disconnect/Reconnect at pole – after regular hours	$300.00
Install/Remove load control device – during regular hours	$30.00
Install/Remove load control device – after regular hours	$170.00
Service call – after regular hours	$170.00
Temporary service install & remove – overhead – no transformer	$500.00
Temporary service install & remove – overhead – with transformer	$1,000.00
Specific charge for access to the power pole – per pole/year	$22.35
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

Tab 4 – Wholesale Market Service Charges

E8.T4.S1 OVERVIEW OF WHOLESALE MARKET SERVICE CHARGES

On March 21, 2013, the Board issued a Decision with Reasons and Rate Order (EB-2013-0067) establishing that the Wholesale Market Service rate ("WMS rate") used by rate regulated distributors to bill their customers shall be $0.0044 per kilowatt hour effective May 1, 2013. HHI is proposing to maintain its existing Wholesale Market Service Charges at $0.0044.

Tab 5 – Low Voltage Charges

E8.T5.S1 OVERVIEW OF LOW VOLTAGE CHARGES

Table 1 presents the derivation of proposed retail rates for Low Voltage ("LV") service. The 2013-2014 estimates of total LV charges were calculated based on an average of the last 2 years and adjusted upwards to reflect the projected load growth in 2014.

The projections were allocated to customer classes, according to each class' share of projected Transmission-Connection revenue, in accordance with Board policy. The resulting allocated LV charges for each class were divided by the applicable 2014 volumes from the load forecast, as presented in Exhibit 3.

Current LV revenues are recovered through a separate rate adder and therefore are not embedded within the approved Distribution Volumetric rate. 2014 LV rates appear on a distinct line item on the proposed schedule of rates.

E8.T5.S2 DERIVATION OF PROPOSED LOW VOLTAGE CHARGES

Table 15: Derivation of Low Voltage Charges

Low Voltage Charges
(not loss adjusted)

	2013 PROPOSED LOW VOLTAGE CHARGES & RATES				
Customer Class Name	% Allocation	Charges	Not Uplifted Volumes	Rate	per
Residential	38.28%	38,125	52,443,428	$0.0007	kWh
General Service < 50 kW	11.93%	11,882	18,859,305	$0.0006	kWh
General Service > 50 to 4999 kW	48.94%	48,744	197,191	$0.2472	kW
Unmetered Scattered Load	0.14%	135	214,651	$0.0006	kWh
Sentinel Lighting	0.11%	111	284	$0.3902	kW
Street Lighting	0.60%	597	3,124	$0.1911	kW
TOTAL	100.00%	99,595	71,717,983		

				Bridge Year 2013			Test Year 2014		
Customer		Revenue	Expense		2013			2014	
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	4075	4750	54,711,762	$0.0004	$21,885	52,443,428	$0.0007	$36,710.40
General Service < 50 kW	kWh	4075	4750	20,128,592	$0.0004	$8,051	18,859,305	$0.0006	$11,315.58
General Service > 50 to 4999 kW	kW	4075	4750	206,144	$0.1369	$28,221	197,191	$0.2472	$48,745.62
Unmetered Scattered Load	kWh	4075	4750	224,238	$0.0004	$90	214,651	$0.0006	$128.79
Sentinel Lighting	kW	4075	4750	297	$0.2162	$64	284	$0.3902	$110.93
Street Lighting	kW	4075	4750	3,250	$0.1059	$344	3,124	$0.1911	$596.93
TOTAL		0	0	75,274,283		$58,655	71,717,983		$97,608.25
Projected Power Supply Expense						$16,062,015			$15,927,063

Tab 6 – Loss Adjustment Factors

E8.T6.S1 OVERVIEW OF LOSS ADJUSTMENT FACTOR

Table 1 at the next page presents the determination of the Applicant's loss adjustment factor.

HHI proposes a Total Loss Factor ("TLF") 1.0541, using the historical average of the last five years as presented at E8.T6.S2. The proposed TLF represents a marginal increase from HHI's currently approved TLF of 1.0446.

HHI is an embedded distributor with Hydro One Networks Inc. ("HONI") as its host distributor. As reflected in Attachment 1 (Appendix 2-R, Loss Factor) the total losses in HHI's distribution system are only 1.0480 while the supply facility loss represents 1.0058. HHI is committed to continuing its effort to minimize its distribution system losses.

E8.T6.S2 DERIVATION OF PROPOSED LOSS ADJUSTMENT FACTOR

Appendix 2-R Loss Factor is presented at the next page.

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Appendix 2-R
Loss Factors

		Historical Years					5-Year Average
		2008	2009	2010	2011	2012	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	195,587,930	180,790,858	159,288,614	161,859,215	155,160,223	170,537,368
A(2)	"Wholesale" kWh delivered to distributor (lower value)	194,402,877	179,654,626	158,412,711	160,929,367	154,311,135	169,542,143
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	26,758,704	-	-	-	-	5,351,741
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	167,644,173	179,654,626	158,412,711	160,929,367	154,311,135	164,190,402
D	"Retail" kWh delivered by distributor	185,032,775	169,624,607	152,090,908	154,131,709	149,212,313	162,018,462
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	26,758,704	-	-	-	-	5,351,741
F	Net "Retail" kWh delivered by distributor = **D - E**	158,274,071	169,624,607	152,090,908	154,131,709	149,212,313	156,666,722
G	Loss Factor in Distributor's system = **C / F**	1.05920	1.05913	1.04157	1.04410	1.03417	1.04802
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.00605892	1.0062848	1.0054988	1.0057448	1.0054723	1.005811924
	Total Losses						
I	Total Loss Factor = **G x H**	1.065619369	1.065787108	1.047293312	1.05010108	1.039830887	1.05411451

Notes

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

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

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

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

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

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

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

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

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

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

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

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

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

Tab 7 – Stranded Meter Rate Rider

E8.T7.S1 CALCULATION OF STRANDED METER RATE RIDER

In the minimum filing requirements , The Board's states that the Smart Meter Funding and Cost Recovery (G-2008-0002) provides two options to distributors regarding the accounting treatment for stranded meters related to the installation of smart meters:

- (Scenario A) If the stranded meter costs were transferred to "Sub-account Stranded Meter Costs" of Account 1555;.or
- (Scenario B) If the stranded meter costs remained recorded in Account 1860.

HHI attests that its utility falls under Scenario B as the stranded meters have, until now, resided in Account 1860 - Meters.

The table below (excerpt from Appendix 2-R of the Board's Appendices) shows the net book value of HHI's stranded smart meters.

Table 16: Net Book Value of Stranded Meters

Year	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
	(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006	$221,805.19	$95,458.19		$126,347.00		$126,347.00
2007	$222,885.19	$110,272.19		$112,613.00		$112,613.00
2008	$224,821.63	$125,119.63		$99,702.00		$99,702.00
2009	$246,912.13	$140,473.13		$106,439.00		$106,439.00
2010	$246,912.13	$156,129.13		$90,783.00		$90,783.00
2011	$254,708.77	$171,535.13		$83,173.64		$83,173.64
2012	$254,843.38	$184,288.13		$70,555.25		$70,555.25
2013	$254,843.38	$193,343.13		$61,500.25		**$61,500.25**

Appendix 2-S requests that utilities complete the following information relating to the treatment of the utility's stranded meters.

1. A description of the accounting treatment followed by the applicant on stranded meter costs for financial accounting and reporting purposes.

Thus far, stranded meters were included in account 1860 and therefore were treated accordance with CGAAP with the same accounting rules as standard meters.

2. The amount of the pooled residual net book value of the removed from service stranded meters, less any contributed capital (net of accumulated amortization), and less any net proceeds from sales, as of December 31, 2012.

The amount of pooled residual net book value as of December 31st, 2013 is in the amount of $61,500

3. A statement as to whether or not the recording of depreciation expenses continued in order to reduce the net book value through accumulated depreciation. If so, provision of the total (cumulative) depreciation expense for the period from the time that the meters became stranded to December 31, 2013.

Smart meters were fully installed by the end of 2012. The 2010 depreciation expense was for $15,656, 2011 was for $15,406, 2012 was for 12,753 and 2013 is in the amount of $9,055.

4. If no depreciation expenses were recorded to reduce the net book value of stranded meters through accumulated depreciation, the total (cumulative) depreciation

expense amount that would have been applicable for the period from the time that the meters became stranded to December 31, 2012.

N/A Please see question #3 above.

5. The estimated amount of the pooled residual net book value of the removed from service meters, less any net proceeds from sales and contributed capital, at the time when smart meters will have been fully deployed. If the smart meters have been fully deployed, please provide the actual amount.

The estimated net amount at end of 2013 was $61,500

6. A description as to how the applicant intends to recover in rates the costs for stranded meters, including the proposed accounting treatment, the proposed disposition period and the associated bill impacts.

The applicant intends to recover the cost of the Stranded Meters through a Rate Rider. The proposed recovery period is 2 years. Calculations of the proposed rate rider are presented at Table 1 below.

Table 9: Stranded Meter Rate Rider

Customer Class Name	**Net Book Value**	**Smart Meters Installed**	**% share**	**Annual $**	**Customer**	**Rate**	**per month**
Residential	$54,894.20	4803	89.26%	27,447.10	4950	$5.54	$0.46
General Service < 50 kW	$6,606.05	578	10.74%	3,303.02	168	$19.66	$1.64
General Service > 50 to 4999 kW							
	TOTAL	**5381**					

Total for Recovery				**61,500**
Recovery Period (years)			**2**	
Annual Recovery				**30,750**

Tab 8 – Rate Schedule

E8.T7.S1 OVERVIEW OF PROPOSED RATE SCHEDULE

The schedule at the next page shows the current and proposed 2014 tariff rates.

E8.T7.S2 PROPOSED RATE SCHEDULE

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TESI-10
Existing and Proposed Rate Schedule

Current Rates

Residential	**rate**	**Connection Type**
Service Charge	5.99	$
Distribution Volumetric Rate	0.0081	kWh
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until April 30, 2014	-1.35	kWh
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement - in effective until the effective date of the next cost of service-based rate order	1.39	kWh
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	0.79	kWh
Low Voltage Service Rate	0.0004	kWh
Rate Rider for Recovery of Incremental Capital Costs	0.0024	kWh
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	0.0011	kWh
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014 Applicable only for Non-RPP Customers	0.0060	kWh
Retail Transmission Rate – Network Service Rate	0.0069	kWh
Retail Transmission Rate – Line and Transformation Connection Service Rate	0.0031	kWh
Wholesale Market Service Rate	0.0044	kWh
Rural Rate Protection Charge	0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)	0.25	$

General Service < 50 kW	**rate**	**Connection Type**
Service Charge	13.84	$
Distribution Volumetric Rate	0.0055	kWh
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until April 30, 2014	-0.09	kWh
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement - in effective until the effective date of the next cost of service-based rate order	2.46	kWh
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	0.79	kWh
Low Voltage Service Rate	0.0004	kWh
Rate Rider for Recovery of Incremental Capital Costs	0.0017	kWh
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	0.0011	kWh
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014 Applicable only for Non-RPP Customers	0.006	kWh
Retail Transmission Rate – Network Service Rate	0.0063	kWh
Retail Transmission Rate – Line and Transformation Connection Service Rate	0.0027	kWh
Wholesale Market Service Rate	0.0044	kWh
Rural Rate Protection Charge	0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)	0.25	$

Proposed Rates

Residential	**rate**	**Connection Type**
Service Charge	10.00	$
Distribution Volumetric Rate	0.0064	kWh
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	0.79	kWh
Low Voltage Service Rate	0.0007	kWh
Rate Rider for Disposition of Deferral/Variance Account (2014) - effective until December 31, 2013	-0.0010	kWh
Rate Rider for Disposition of Global Adjustment Sub-Account (2014) - effective until December 31, 2013 Applicable only for Non-RPP Customers	0.0033	kWh
Stranded Meter Rate Rider	0.46	$
Retail Transmission Rate – Network Service Rate	0.0063	kWh
Retail Transmission Rate – Line and Transformation Connection Service Rate	0.0030	kWh
Wholesale Market Service Rate	0.0044	kWh
Rural Rate Protection Charge	0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)	0.25	$

General Service < 50 kW	**rate**	**Connection Type**
Service Charge	15.00	$
Distribution Volumetric Rate	0.0052	kWh
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	0.79	kWh
Low Voltage Service Rate	0.0006	kWh
Rate Rider for Disposition of Deferral/Variance Account (2014) - effective until December 31, 2013	-0.0011	kWh
Rate Rider for Disposition of Global Adjustment Sub-Account (2014) - effective until December 31, 2013 Applicable only for Non-RPP Customers	0.0033	kWh
Stranded Meter Rate Rider	1.64	$
Retail Transmission Rate – Network Service Rate	0.0057	kWh
Retail Transmission Rate – Line and Transformation Connection Service Rate	0.0026	kWh
Wholesale Market Service Rate	0.0044	kWh
Rural Rate Protection Charge	0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)	0.25	$

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Existing and Proposed Rate Schedule

General Service > 50 to 4999 kW	**rate**	**Connection Type**	**General Service > 50 to 4999 kW**	**rate**	**Connection Type**
Service Charge	97.35	$	Service Charge	97.35	$
Distribution Volumetric Rate	1.5558	kW	Distribution Volumetric Rate	2.3514	kW
Low Voltage Service Rate	0.1369	kW	Low Voltage Service Rate	0.2472	kW
Rate Rider for Recovery of Incremental Capital Costs	0.327	kW			
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	0.4219	kW	Rate Rider for Disposition of Deferral/Variance Account (2014) - effective until December 31, 2013	-0.4328	kW
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014 Applicable only for Non-RPP Customers	2.3612	kW	Rate Rider for Disposition of Global Adjustment Sub-Account (2014) - effective until December 31, 2013 Applicable only for Non-RPP Customers	1.2501	kW
		kW			
Retail Transmission Rate – Network Service Rate	2.5533	kW	Retail Transmission Rate – Network Service Rate	2.3286	kW
Retail Transmission Rate – Line and Transformation Connection Service Rate	1.1197	kW	Retail Transmission Rate – Line and Transformation Connection Service Rate	1.0753	kW
Wholesale Market Service Rate	0.0044	kWh	Wholesale Market Service Rate	0.0044	kWh
Rural Rate Protection Charge	0.0012	kWh	Rural Rate Protection Charge	0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)	0.25	$	Standard Supply Service – Administrative Charge (if applicable)	0.25	$

Unmetered Scattered Load	**rate**	**Connection Type**	**Unmetered Scattered Load**	**rate**	**Connection Type**
Service Charge	6.39	$	Service Charge	8.50	$
Distribution Volumetric Rate	0.0021	kWh	Distribution Volumetric Rate	0.0022	kWh
Low Voltage Service Rate	0.0004	kWh	Low Voltage Service Rate	0.0006	kWh
Rate Rider for Recovery of Incremental Capital Costs	0.0006	kWh			
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	0.0011	kWh	Rate Rider for Disposition of Deferral/Variance Account (2014) - effective until December 31, 2013	-0.0011	kWh
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014 Applicable only for Non-RPP Customers	0.006	kWh	Rate Rider for Disposition of Global Adjustment Sub-Account (2014) - effective until December 31, 2013 Applicable only for Non-RPP Customers	0.0033	kWh
Retail Transmission Rate – Network Service Rate	0.0063	kWh	Retail Transmission Rate – Network Service Rate	0.0057	kWh
Retail Transmission Rate – Line and Transformation Connection Service Rate	0.0027	kWh	Retail Transmission Rate – Line and Transformation Connection Service Rate	0.0026	kWh
Wholesale Market Service Rate	0.0044	kWh	Wholesale Market Service Rate	0.0044	kWh
Rural Rate Protection Charge	0.0012	kWh	Rural Rate Protection Charge	0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)	0.25	$	Standard Supply Service – Administrative Charge (if applicable)	0.25	$

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Existing and Proposed Rate Schedule

Sentinel Lighting	**rate**	**Connection Type**		**Sentinel Lighting**	**rate**	**Connection Type**
Service Charge	1.63	$		Service Charge	3.00	$
Distribution Volumetric Rate	3.2285	kW		Distribution Volumetric Rate	2.0183	kW
Low Voltage Service Rate	0.2162	kW		Low Voltage Service Rate	0.3902	kW
Rate Rider for Recovery of Incremental Capital Costs	0.7496	kW				kW
				Rate Rider for Disposition of Deferral/Variance Account (2014) - effective until December 31, 2013	-0.2757	kW
				Rate Rider for Disposition of Global Adjustment Sub-Account (2014) - effective until December 31, 2013 Applicable only for Non-RPP Customers	1.1955	kW
Retail Transmission Rate – Network Service Rate	1.9264	kW		Retail Transmission Rate – Network Service Rate	1.7569	kW
Retail Transmission Rate – Line and Transformation Connection Service Rate	1.7674	kW		Retail Transmission Rate – Line and Transformation Connection Service Rate	1.6973	kW
Wholesale Market Service Rate	0.0044	kWh		Wholesale Market Service Rate	0.0044	kWh
Rural Rate Protection Charge	0.0012	kWh		Rural Rate Protection Charge	0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)	0.25	$		Standard Supply Service – Administrative Charge (if applicable)	0.25	$

Street Lighting	**rate**	**Connection Type**		**Street Lighting**	**rate**	**Connection Type**
Service Charge	0.62	$		Service Charge	1.00	$
Distribution Volumetric Rate	6.7744	kW		Distribution Volumetric Rate	3.6230	kW
Low Voltage Service Rate	0.1059	kW		Low Voltage Service Rate	0.1911	kW
Rate Rider for Recovery of Incremental Capital Costs	1.5987	kW				kW
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	0.3889	kW		Rate Rider for Disposition of Deferral/Variance Account (2014) - effective until December 31, 2013	0.1393	kW
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014 Applicable only for Non-RPP Customers	2.1767	kW		Rate Rider for Disposition of Global Adjustment Sub-Account (2014) - effective until December 31, 2013 Applicable only for Non-RPP Customers	1.1991	kW
Retail Transmission Rate – Network Service Rate	1.9258	kW		Retail Transmission Rate – Network Service Rate	1.7564	kW
Retail Transmission Rate – Line and Transformation Connection Service Rate	0.8656	kW		Retail Transmission Rate – Line and Transformation Connection Service Rate	0.8313	kW
Wholesale Market Service Rate	0.0044	kWh		Wholesale Market Service Rate	0.0044	kWh
Rural Rate Protection Charge	0.0012	kWh		Rural Rate Protection Charge	0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)	0.25	$		Standard Supply Service – Administrative Charge (if applicable)	0.25	$

Tab 9 – Bill Impact

E8.T8.S1 OVERVIEW OF BILL IMPACTS

Total bill impacts for all class have gone down and vary by customer class, ranging from a decrease of **26.54**% for GS> 50 Class and to a decrease of **2.91**% for Residential Class. The reason for the overall decrease in rates is mainly due to the expiration of many rate riders such as the SMDR and SMIRR. The impact is further reduced by overall credit rate riders to dispose of the significant balances owed to ratepayers that have accumulated in certain variance accounts. Decreases in rates for retail transmission service and wholesale market service also contribute to further reduce the utility's distribution rates.

Although the overall bill impacts have been reduced for all classes, HHI's increase in revenue requirement is needed to remain in compliance with its regulators and meet its mandate and commitment to provide safe, reliable cost-effective services and products achieving sustainable growth while respecting the community and the environment.

E8.T8.S2 BILL IMPACTS

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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

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

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 5.99	1	$ 5.99	$ 10.00	1	$ 10.00	$ 4.01	66.94%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -	$ 0.46	1	$ 0.46	$ 0.46	
SMIRR	Monthly	$ 1.39	1	$ 1.39		1	$ -	-$ 1.39	-100.00%
SMDR	Monthly	-$ 1.35	1	-$ 1.35		1	$ -	$ 1.35	-100.00%
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0081	800	$ 6.48	$ 0.0064	800	$ 5.11	-$ 1.37	-21.17%
Smart Meter Disposition Rider	per kWh		800	$ -		800	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		800	$ -		800	$ -	$ -	
	per kWh		800	$ -		800	$ -	$ -	
Incremental Capital Rate Rider	per kWh	$ 0.0024	800	$ 1.92		800	$ -	-$ 1.92	-100.00%
			800	$ -		800	$ -	$ -	
	Monthly		800	$ -		1	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Low Voltage	per kWh		800	$ -	$ 0.0007	800	$ 0.56	$ 0.56	
Sub-Total A				$ 14.43			$ 16.13	**$ 1.70**	**11.78%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0011	800	$ 0.88	-$ 0.0009	800	-$ 0.69	-$ 1.57	-178.22%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0004	800	$ 0.32		800	$ -	-$ 0.32	-100.00%
Smart Meter Entity Charge	Monthly	$ 0.79	1	$ 0.79	$ 0.79	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 15.63**			**$ 15.44**	**-$ 0.19**	**-1.20%**
RTSR - Network	per kWh	$ 0.0069	808	$ 5.58	$ 0.0063	808	$ 5.13	-$ 0.45	-8.11%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	808	$ 2.51	$ 0.0030	808	$ 2.43	-$ 0.08	-3.22%
Sub-Total C - Delivery (including Sub-Total B)				**$ 23.71**			**$ 22.99**	**-$ 0.72**	**-3.04%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	808	$ 3.56	$ 0.0044	808	$ 3.56	$ 0.00	0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	808	$ 0.97	$ 0.0012	808	$ 0.97	$ 0.00	0.01%
Standard Supply Service Charge	Monthly	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			808	$ -		808	$ -	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	208	$ 18.34	$ 0.0880	208	$ 18.34	$ 0.01	0.04%
TOU - Off Peak	per kWh	$ 0.0650	517	$ 33.63	$ 0.0650	517	$ 33.63	$ 0.00	0.01%
TOU - Mid Peak	per kWh	$ 0.1000	146	$ 14.55	$ 0.1000	146	$ 14.55	$ 0.00	0.01%
TOU - On Peak	per kWh	$ 0.1170	146	$ 17.02	$ 0.1170	146	$ 17.03	$ 0.00	0.01%
Total Bill on RPP (before Taxes)				**$ 91.83**			**$ 91.11**	**-$ 0.71**	**-0.78%**
HST		13%		$ 11.94	13%		$ 11.84	-$ 0.09	-0.78%
Total Bill (including HST)				$ 103.76			$ 102.96	-$ 0.81	-0.78%
Ontario Clean Energy Benefit [1]				-$ 10.38			-$ 10.30	$ 0.08	-0.77%
Total Bill on RPP (including OCEB)				**$ 93.38**			**$ 92.66**	**-$ 0.73**	**-0.78%**
Total Bill on TOU (before Taxes)				**$ 93.69**			**$ 92.98**	**-$ 0.71**	**-0.76%**
HST		13%		$ 12.18	13%		$ 12.09	-$ 0.09	-0.76%
Total Bill (including HST)				$ 105.87			$ 105.07	-$ 0.81	-0.76%
Ontario Clean Energy Benefit [1]				-$ 10.59			-$ 10.51	$ 0.08	-0.76%
Total Bill on TOU (including OCEB)				**$ 95.28**			**$ 94.56**	**-$ 0.73**	**-0.76%**
Loss Factor (%)		1.04%			1.05%				

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

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

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

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

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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

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

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 5.99	1	$ 5.99	$ 10.00	1	$ 10.00	$ 4.01	66.94%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -	$ 0.46	1	$ 0.46	$ 0.46	
SMIRR	Monthly	$ 1.39	1	$ 1.39		1	$ -	-$ 1.39	-100.00%
SMDR	Monthly	-$ 1.35	1	-$ 1.35		1	$ -	$ 1.35	-100.00%
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0081	800	$ 6.48	$ 0.0064	800	$ 5.11	-$ 1.37	-21.17%
Smart Meter Disposition Rider	per kWh		800	$ -		800	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		800	$ -		800	$ -	$ -	
	per kWh		800	$ -		800	$ -	$ -	
Incremental Capital Rate Rider	per kWh	$ 0.0024	800	$ 1.92		800	$ -	-$ 1.92	-100.00%
			800	$ -		800	$ -	$ -	
	Monthly		800	$ -		1	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Low Voltage	per kWh		800	$ -	$ 0.0007	800	$ 0.56	$ 0.56	
Sub-Total A				$ 14.43			$ 16.13	**$ 1.70**	**11.78%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0011	800	$ 0.88	-$ 0.0009	800	-$ 0.69	-$ 1.57	-178.22%
Global Adj DVA	per kWh	$ 0.0060	800	$ 4.80	$ 0.0033	800	$ 2.65	-$ 2.15	-44.71%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Low Voltage Service Charge		$ 0.0004	800	$ 0.32		800	$ -	-$ 0.32	-100.00%
Smart Meter Entity Charge	Monthly	$ 0.79	1	$ 0.79	$ 0.79	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 20.43**			**$ 18.10**	**-$ 2.33**	**-11.42%**
RTSR - Network	per kWh	$ 0.0069	808	$ 5.58	$ 0.0063	808	$ 5.13	-$ 0.45	-8.11%
RTSR - Line and Transformation Connection	per kWh	$ 0.0031	808	$ 2.51	$ 0.0030	808	$ 2.43	-$ 0.08	-3.22%
Sub-Total C - Delivery (including Sub-Total B)				**$ 28.51**			**$ 25.65**	**-$ 2.87**	**-10.05%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	808	$ 3.56	$ 0.0044	808	$ 3.56	$ 0.00	0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	808	$ 0.97	$ 0.0012	808	$ 0.97	$ 0.00	0.01%
Standard Supply Service Charge	Monthly	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			808	$ -		808	$ -	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	208	$ 18.34	$ 0.0880	208	$ 18.34	$ 0.01	0.04%
TOU - Off Peak	per kWh	$ 0.0650	517	$ 33.63	$ 0.0650	517	$ 33.63	$ 0.00	0.01%
TOU - Mid Peak	per kWh	$ 0.1000	146	$ 14.55	$ 0.1000	146	$ 14.55	$ 0.00	0.01%
TOU - On Peak	per kWh	$ 0.1170	146	$ 17.02	$ 0.1170	146	$ 17.03	$ 0.00	0.01%
Total Bill on RPP (before Taxes)				**$ 96.63**			**$ 93.77**	**-$ 2.86**	**-2.96%**
HST		13%		$ 12.56	13%		$ 12.19	-$ 0.37	-2.96%
Total Bill (including HST)				$ 109.19			$ 105.96	-$ 3.23	-2.96%
Ontario Clean Energy Benefit [1]				-$ 10.92			-$ 10.60	$ 0.32	-2.93%
Total Bill on RPP (including OCEB)				**$ 98.27**			**$ 95.36**	**-$ 2.91**	**-2.96%**
Total Bill on TOU (before Taxes)				**$ 98.49**			**$ 95.63**	**-$ 2.86**	**-2.90%**
HST		13%		$ 12.80	13%		$ 12.43	-$ 0.37	-2.90%
Total Bill (including HST)				$ 111.30			$ 108.06	-$ 3.23	-2.90%
Ontario Clean Energy Benefit [1]				-$ 11.13			-$ 10.81	$ 0.32	-2.88%
Total Bill on TOU (including OCEB)				**$ 100.17**			**$ 97.25**	**-$ 2.91**	**-2.91%**

	Current	Proposed
Loss Factor (%)	1.04%	1.05%

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

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

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

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

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Appendix 2-W
Bill Impacts

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

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

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 13.84	1	$ 13.84	$ 15.00	1	$ 15.00	$ 1.16	8.38%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -	$ 1.64	1	$ 1.64	$ 1.64	
SMIRR	Monthly	$ 2.46	1	$ 2.46		1	$ -	-$ 2.46	-100.00%
SMDR	Monthly	-$ 0.09	1	-$ 0.09		1	$ -	$ 0.09	-100.00%
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0055	2000	$ 11.00	$ 0.0052	2000	$ 10.33	-$ 0.67	-6.10%
Smart Meter Disposition Rider			2000	$ -		2000	$ -	$ -	
LRAM & SSM Rate Rider			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Incremental Capital Rate Rider	per kW	$ 0.0017	2000	$ 3.40		2000	$ -	-$ 3.40	-100.00%
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Sub-Total A				$ 30.61			$ 26.97	**-$ 3.64**	**-11.90%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0011	2000	$ 2.20	-$ 0.0010	2000	-$ 2.02	-$ 4.22	-191.68%
Global Adj DVA	per kWh	$ 0.0060	2000	$ 12.00	$ 0.0033	2000	$ 6.63	-$ 5.37	-44.71%
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0004	2000	$ 0.80	$ 0.0006	2000	$ 1.20	$ 0.40	50.00%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.79	2000	$ 1,580.00	$ 1,579.21	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 45.61**			**$ 32.78**	**-$ 12.83**	**-28.12%**
RTSR - Network	per kWh	$ 0.0063	2021	$ 12.73	$ 0.0057	2021	$ 11.52	-$ 1.21	-9.52%
RTSR - Line and Transformation Connection	per kWh	$ 0.0027	2021	$ 5.46	$ 0.0026	2021	$ 5.25	-$ 0.20	-3.69%
Sub-Total C - Delivery (including Sub-Total B)				**$ 63.80**			**$ 49.56**	**-$ 14.24**	**-22.32%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2021	$ 8.89	$ 0.0044	2021	$ 8.89	$ 0.00	0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2021	$ 2.43	$ 0.0012	2021	$ 2.43	$ 0.00	0.01%
Standard Supply Service Charge	Monthly	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			2021	$ -		2021	$ -	$ -	
Energy - RPP - Tier 1	per kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0880	1421	$ 125.04	$ 0.0880	1421	$ 125.06	$ 0.02	0.01%
TOU - Off Peak	per kWh	$ 0.0650	1293	$ 84.07	$ 0.0650	1293	$ 84.08	$ 0.01	0.01%
TOU - Mid Peak	per kWh	$ 0.1000	364	$ 36.38	$ 0.1000	364	$ 36.38	$ 0.00	0.01%
TOU - On Peak	per kWh	$ 0.1170	364	$ 42.56	$ 0.1170	364	$ 42.56	$ 0.00	0.01%
Total Bill on RPP (before Taxes)				**$ 245.40**			**$ 231.18**	**-$ 14.22**	**-5.79%**
HST		13%		$ 31.90	13%		$ 30.05	-$ 1.85	-5.79%
Total Bill (including HST)				$ 277.31			$ 261.24	-$ 16.07	-5.79%
Ontario Clean Energy Benefit [1]				-$ 27.73			-$ 26.12	$ 1.61	-5.81%
Total Bill on RPP (including OCEB)				**$ 249.58**			**$ 235.12**	**-$ 14.46**	**-5.79%**
Total Bill on TOU (before Taxes)				**$ 238.37**			**$ 224.15**	**-$ 14.22**	**-5.97%**
HST		13%		$ 30.99	13%		$ 29.14	-$ 1.85	-5.97%
Total Bill (including HST)				$ 269.36			$ 253.29	-$ 16.07	-5.97%
Ontario Clean Energy Benefit [1]				-$ 26.94			-$ 25.33	$ 1.61	-5.98%
Total Bill on TOU (including OCEB)				**$ 242.42**			**$ 227.96**	**-$ 14.46**	**-5.97%**
Loss Factor (%)		1.04%			1.05%				

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

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

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

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

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Appendix 2-W
Bill Impacts

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

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

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 97.3500	1	$ 97.35	$ 97.3500	1	$ 97.35	$ -	0.00%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 1.5558	240	$ 373.39	$ 2.3514	240	$ 564.33	$ 190.93	51.14%
Smart Meter Disposition Rider			240	$ -		240	$ -	$ -	
LRAM & SSM Rate Rider			240	$ -		240	$ -	$ -	
			240	$ -		240	$ -	$ -	
Incremental Capital Rate Rider	per kW	$ 1.3270	240	$ 318.48		240	$ -	-$ 318.48	-100.00%
			240	$ -		240	$ -	$ -	
			240	$ -		240	$ -	$ -	
			240	$ -		240	$ -	$ -	
			240	$ -		240	$ -	$ -	
			240	$ -		240	$ -	$ -	
Sub-Total A				$ 789.22			$ 661.68	**-$ 127.55**	**-16.16%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ 0.4219	240	$ 101.26	-$ 0.4300	240	-$ 103.20	-$ 204.46	-201.92%
Global Adj DVA	per kW	$ 2.3612	240	$ 566.69	$ 1.2501	240	$ 300.03	-$ 266.65	-47.05%
			240	$ -		240	$ -	$ -	
			240	$ -		240	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.1369	240	$ 32.86	$ 0.2472	240	$ 59.33	$ 26.47	80.57%
Smart Meter Entity Charge						240	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,490.02**			**$ 917.84**	**-$ 572.18**	**-38.40%**
RTSR - Network		$ 2.5533	243	$ 619.19	$ 2.3286	243	$ 564.75	-$ 54.44	-8.79%
RTSR - Line and Transformation Connection		$ 1.1197	243	$ 271.54	$ 1.0753	243	$ 260.79	-$ 10.74	-3.96%
Sub-Total C - Delivery (including Sub-Total B)				**$ 2,380.75**			**$ 1,743.39**	**-$ 637.36**	**-26.77%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	243	$ 1.07	$ 0.0044	243	$ 1.07	$ 0.00	0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	243	$ 0.29	$ 0.0012	243	$ 0.29	$ 0.00	0.01%
Standard Supply Service Charge	Monthly	$ 0.25	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			243	$ -		243	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	243	$ 18.19	$ 0.0750	243	$ 18.19	$ 0.00	0.01%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	155	$ 10.09	$ 0.0650	155	$ 10.09	$ 0.00	0.01%
TOU - Mid Peak		$ 0.1000	44	$ 4.37	$ 0.1000	44	$ 4.37	$ 0.00	0.01%
TOU - On Peak		$ 0.1170	44	$ 5.11	$ 0.1170	44	$ 5.11	$ 0.00	0.01%
Total Bill on RPP (before Taxes)				**$ 2,400.55**			**$ 1,763.18**	**-$ 637.36**	**-26.55%**
HST		13%		$ 312.07	13%		$ 229.21	-$ 82.86	-26.55%
Total Bill (including HST)				$ 2,712.62			$ 1,992.40	-$ 720.22	-26.55%
Ontario Clean Energy Benefit [1]				-$ 271.26			-$ 199.24	$ 72.02	-26.55%
Total Bill on RPP (including OCEB)				**$ 2,441.36**			**$ 1,793.16**	**-$ 648.20**	**-26.55%**
Total Bill on TOU (before Taxes)				**$ 2,401.92**			**$ 1,764.56**	**-$ 637.36**	**-26.54%**
HST		13%		$ 312.25	13%		$ 229.39	-$ 82.86	-26.54%
Total Bill (including HST)				$ 2,714.17			$ 1,993.95	-$ 720.22	-26.54%
Ontario Clean Energy Benefit [1]				-$ 271.42			-$ 199.39	$ 72.03	-26.54%
Total Bill on TOU (including OCEB)				**$ 2,442.75**			**$ 1,794.56**	**-$ 648.19**	**-26.54%**

	Current Board-Approved	Proposed
Loss Factor (%)	1.04%	1.05%

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

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

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

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

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Appendix 2-W
Bill Impacts

Customer Class: **Sentinel Lighting**

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

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 1.63	1	$ 1.63	$ 1.0000	1	$ 1.00	-$ 0.63	-38.65%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 3.2285	1.3	$ 4.20	$ 3.6230	1.3	$ 4.71	$ 0.51	12.22%
Smart Meter Disposition Rider			1.3	$ -		1.3	$ -	$ -	
LRAM & SSM Rate Rider			1.3	$ -		1.3	$ -	$ -	
			1.3	$ -		1.3	$ -	$ -	
Incremental Capital Rate Rider	per kW	$ 0.7496	1.3	$ 0.97		1.3	$ -	-$ 0.97	-100.00%
			1.3	$ -		1.3	$ -	$ -	
			1.3	$ -		1.3	$ -	$ -	
			1.3	$ -		1.3	$ -	$ -	
			1.3	$ -		1.3	$ -	$ -	
			1.3	$ -		1.3	$ -	$ -	
Sub-Total A				$ 6.80			$ 5.71	**-$ 1.09**	**-16.05%**
Deferral/Variance Account Disposition Rate Rider	per kW		1.3	$ -	$ 0.1513	1.3	$ 0.20	$ 0.20	
Global Adj DVA	per kW		1.3	$ -	$ 1.1991	1.3	$ 1.56	$ 1.56	
			1.3	$ -		1.3	$ -	$ -	
			1.3	$ -		1.3	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.2162	1.3	$ 0.28	$ 0.1911	1.3	$ 0.25	-$ 0.03	-11.61%
Smart Meter Entity Charge						1.3	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 7.08**			**$ 7.71**	**$ 0.63**	**8.91%**
RTSR - Network	per kW	$ 1.9264	1	$ 2.53	$ 1.7564	1	$ 2.31	-$ 0.22	-8.82%
RTSR - Line and Transformation Connection	per kW	$ 1.7674	1	$ 2.32	$ 0.8313	1	$ 1.09	-$ 1.23	-52.96%
Sub-Total C - Delivery (including Sub-Total B)				**$ 11.93**			**$ 11.11**	**-$ 0.82**	**-6.88%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1	$ 0.01	$ 0.0044	1	$ 0.01	$ 0.00	0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	1	$ 0.00	$ 0.0012	1	$ 0.00	$ 0.00	0.01%
Standard Supply Service Charge	Monthly	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1	$ -		1	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	1	$ 0.10	$ 0.0750	1	$ 0.10	$ 0.00	0.01%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	1	$ 0.05	$ 0.0650	1	$ 0.05	$ 0.00	0.01%
TOU - Mid Peak		$ 0.1000	0	$ 0.02	$ 0.1000	0	$ 0.02	$ 0.00	0.01%
TOU - On Peak		$ 0.1170	0	$ 0.03	$ 0.1170	0	$ 0.03	$ 0.00	0.01%
Total Bill on RPP (before Taxes)				**$ 12.29**			**$ 11.47**	**-$ 0.82**	**-6.68%**
HST		13%		$ 1.60	13%		$ 1.49	-$ 0.11	-6.68%
Total Bill (including HST)				$ 13.89			$ 12.96	-$ 0.93	-6.68%
Ontario Clean Energy Benefit [1]				-$ 1.39			-$ 1.30	$ 0.09	-6.47%
Total Bill on RPP (including OCEB)				**$ 12.50**			**$ 11.66**	**-$ 0.84**	**-6.71%**
Total Bill on TOU (before Taxes)				**$ 12.30**			**$ 11.48**	**-$ 0.82**	**-6.68%**
HST		13%		$ 1.60	13%		$ 1.49	-$ 0.11	-6.68%
Total Bill (including HST)				$ 13.90			$ 12.97	-$ 0.93	-6.68%
Ontario Clean Energy Benefit [1]				-$ 1.39			-$ 1.30	$ 0.09	-6.47%
Total Bill on TOU (including OCEB)				**$ 12.51**			**$ 11.67**	**-$ 0.84**	**-6.70%**

Loss Factor (%)	1.04%	1.05%

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

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

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

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

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Appendix 2-W
Bill Impacts

Customer Class: **Street Lighting**

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

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 0.6200	1	$ 0.62	$ 1.0000	1	$ 1.00	$ 0.38	61.29%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 6.7744	0.23	$ 1.56	$ 3.6230	0.23	$ 0.83	-$ 0.72	-46.52%
Smart Meter Disposition Rider			0.23	$ -		0.23	$ -	$ -	
LRAM & SSM Rate Rider			0.23	$ -		0.23	$ -	$ -	
			0.23	$ -		0.23	$ -	$ -	
Incremental Capital Rate Rider	per kW	$ 1.5987	0.23	$ 0.37		0.23	$ -	-$ 0.37	-100.00%
			0.23	$ -		0.23	$ -	$ -	
			0.23	$ -		0.23	$ -	$ -	
			0.23	$ -		0.23	$ -	$ -	
			0.23	$ -		0.23	$ -	$ -	
			0.23	$ -		0.23	$ -	$ -	
Sub-Total A				$ 2.55			$ 1.83	**-$ 0.71**	**-27.99%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ 0.3898	0.23	$ 0.09	$ 0.1513	0.23	$ 0.03	-$ 0.05	-61.19%
Global Adj DVA	per kW	$ 2.1767	0.23	$ 0.50	$ 1.1991	0.23	$ 0.28	-$ 0.22	-44.91%
			0.23	$ -		0.23	$ -	$ -	
			0.23	$ -		0.23	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.1059	0.23	$ 0.02	$ 0.1911	0.23	$ 0.04	$ 0.02	80.45%
Smart Meter Entity Charge						0.23	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 3.16**			**$ 2.19**	**-$ 0.97**	**-30.78%**
RTSR - Network	per kW	$ 1.9258	0	$ 0.45	$ 1.7564	0	$ 0.41	-$ 0.04	-8.79%
RTSR - Line and Transformation Connection	per kW	$ 0.8656	0	$ 0.20	$ 0.8313	0	$ 0.19	-$ 0.01	-3.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 3.81**			**$ 2.79**	**-$ 1.02**	**-26.78%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	0	$ 0.00	$ 0.0044	0	$ 0.00	$ 0.00	0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	0	$ 0.00	$ 0.0012	0	$ 0.00	$ 0.00	0.01%
Standard Supply Service Charge	Monthly	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			0	$ -		0	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	0	$ 0.02	$ 0.0750	0	$ 0.02	$ 0.00	0.01%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	0	$ 0.01	$ 0.0650	0	$ 0.01	$ 0.00	0.01%
TOU - Mid Peak		$ 0.1000	0	$ 0.00	$ 0.1000	0	$ 0.00	$ 0.00	0.01%
TOU - On Peak		$ 0.1170	0	$ 0.00	$ 0.1170	0	$ 0.00	$ 0.00	0.01%
Total Bill on RPP (before Taxes)				**$ 4.08**			**$ 3.06**	**-$ 1.02**	**-25.01%**
HST		13%		$ 0.53	13%		$ 0.40	-$ 0.13	-25.01%
Total Bill (including HST)				$ 4.61			$ 3.46	-$ 1.15	-25.01%
Ontario Clean Energy Benefit [1]				-$ 0.46			-$ 0.35	$ 0.11	-23.91%
Total Bill on RPP (including OCEB)				**$ 4.15**			**$ 3.11**	**-$ 1.04**	**-25.13%**
Total Bill on TOU (before Taxes)				**$ 4.08**			**$ 3.06**	**-$ 1.02**	**-25.00%**
HST		13%		$ 0.53	13%		$ 0.40	-$ 0.13	-25.00%
Total Bill (including HST)				$ 4.61			$ 3.46	-$ 1.15	-25.00%
Ontario Clean Energy Benefit [1]				-$ 0.46			-$ 0.35	$ 0.11	-23.91%
Total Bill on TOU (including OCEB)				**$ 4.15**			**$ 3.11**	**-$ 1.04**	**-25.12%**

Loss Factor (%) 1.04% 1.05%

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

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

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

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

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Appendix 2-W
Bill Impacts

Customer Class: **Unmetered Scattered Load**

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

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 6.39	1	$ 6.39	$ 8.50	1	$ 8.50	$ 2.11	33.02%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0021	4600	$ 9.66	$ 0.0022	4600	$ 10.04	$ 0.38	3.93%
Smart Meter Disposition Rider			4600	$ -		4600	$ -	$ -	
LRAM & SSM Rate Rider			4600	$ -		4600	$ -	$ -	
			4600	$ -		4600	$ -	$ -	
Incremental Capital Rate Rider	per kWh	$ 0.0006	4600	$ 2.76		4600	$ -	-$ 2.76	-100.00%
			4600	$ -		4600	$ -	$ -	
			4600	$ -		4600	$ -	$ -	
			4600	$ -		4600	$ -	$ -	
			4600	$ -		4600	$ -	$ -	
			4600	$ -		4600	$ -	$ -	
Sub-Total A				$ 18.81			$ 18.54	**-$ 0.27**	**-1.44%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0011	4600	$ 5.06	-$ 0.0011	4600	-$ 5.00	-$ 10.06	-198.73%
Global Adj DVA	per kWh	$ 0.0060	4600	$ 27.60	$ 0.0033	4600	$ 15.26	-$ 12.34	-44.71%
			4600	$ -		4600	$ -	$ -	
			4600	$ -		4600	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0004	4600	$ 1.84	$ 0.0006	4600	$ 2.76	$ 0.92	50.00%
Smart Meter Entity Charge						4600	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 53.31**			**$ 31.56**	**-$ 21.75**	**-40.79%**
RTSR - Network	per kWh	$ 0.0063	4648	$ 29.28	$ 0.0057	4648	$ 26.50	-$ 2.79	-9.52%
RTSR - Line and Transformation Connection	per kWh	$ 0.0027	4648	$ 12.55	$ 0.0026	4648	$ 12.09	-$ 0.46	-3.69%
Sub-Total C - Delivery (including Sub-Total B)				**$ 95.14**			**$ 70.15**	**-$ 25.00**	**-26.27%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	4648	$ 20.45	$ 0.0044	4648	$ 20.45	$ 0.00	0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	4648	$ 5.58	$ 0.0012	4648	$ 5.58	$ 0.00	0.01%
Standard Supply Service Charge	per kWh	$ 0.25	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			4648	$ -		4648	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	4048	$ 356.23	$ 0.0880	4048	$ 356.27	$ 0.04	0.01%
TOU - Off Peak		$ 0.0650	2975	$ 193.36	$ 0.0650	2975	$ 193.38	$ 0.02	0.01%
TOU - Mid Peak		$ 0.1000	837	$ 83.66	$ 0.1000	837	$ 83.67	$ 0.01	0.01%
TOU - On Peak		$ 0.1170	837	$ 97.89	$ 0.1170	837	$ 97.90	$ 0.01	0.01%
Total Bill on RPP (before Taxes)				**$ 522.65**			**$ 497.69**	**-$ 24.96**	**-4.77%**
HST		13%		$ 67.94	13%		$ 64.70	-$ 3.24	-4.77%
Total Bill (including HST)				$ 590.59			$ 562.39	-$ 28.20	-4.77%
Ontario Clean Energy Benefit [1]				-$ 59.06			-$ 56.24	$ 2.82	-4.77%
Total Bill on RPP (including OCEB)				**$ 531.53**			**$ 506.15**	**-$ 25.38**	**-4.77%**
Total Bill on TOU (before Taxes)				**$ 496.33**			**$ 471.37**	**-$ 24.96**	**-5.03%**
HST		13%		$ 64.52	13%		$ 61.28	-$ 3.24	-5.03%
Total Bill (including HST)				$ 560.86			$ 532.65	-$ 28.20	-5.03%
Ontario Clean Energy Benefit [1]				-$ 56.09			-$ 53.27	$ 2.82	-5.03%
Total Bill on TOU (including OCEB)				**$ 504.77**			**$ 479.38**	**-$ 25.38**	**-5.03%**
Loss Factor (%)		1.04%			1.05%				

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

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

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

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

Exhibit 9 – Deferral and Variance Acct

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EXHIBIT 9 – DEFERRAL AND VARIANCE ACCOUNT

The evidence presented in this exhibit provides information on a distributor's variance and deferral accounts. Specifically, amounts recorded in the deferral and variance accounts that should be reflected in rates. The evidence herein is organized according to the following topics;

1) Status and Disposition of Deferral and Variance Accounts

Tab 1 – Status and disposition of Deferral and Variance Accounts

E9.T1.S1 DESCRIPTION OF DVA USED BY THE APPLICANT

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

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

At December 31, 2012, HHI has balances in the following Board-approved deferral and variance accounts:

Group 1 Accounts

1550 – LV Variance Account

Account Description: This account is used to record the variances arising from low voltage transactions which are not part of the electricity wholesale market.

Account 1550: Low Voltage (LV) Variance Account

This account captures the difference between the amounts included in rates and billed to customers and the cost to HHI of Hydro One's charges for using its LV lines to transmit electricity from its transformer stations to HHI's distribution system. The low voltage costs forecast for 2014 are proposed to be collected through a rate rider consistent with past practice. The details supporting this calculation can be found in Exhibit 8.

For 2014, HHI is requesting disposition of the December 31, 2012 audited balance, plus the forecasted interest through December 30, 2013 for account 1550. The December 31, 2012 audited balance reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a debit of $48,843.

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

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

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

For 2014, HHI is requesting disposition of the December 31, 2012 audited balance, plus the forecasted interest through December 30, 2013 for account 1580. The December 31, 2012 audited reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a credit of $116,610.

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

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

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

For 2014, HHI is requesting disposition of the December 31, 2012 audited balance, plus the forecasted interest through December 30, 2013 for account 1584. The December 31, 2012 audited balance reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a credit of $-7433.

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

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

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

For 2014, HHI is requesting disposition of the December 31, 2012 audited balance, plus the forecasted interest through December 30, 2013 for account 1586. The December 31, 2012 audited balance reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a credit of $21,499

1588 – Retail Settlement Variance Account– Power (“RSVAPOWER”)

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

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

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

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

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

For 2014, HHI is requesting disposition of the December 31, 2012 audited balance, plus the forecasted interest through December 30, 2013 for account 1588 RSVA. The December 31, 2012 audited balance reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a debit of 117,602

1589– Retail Settlement Variance Account – Global Adjustment (“RSVA$_{GA}$”)

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

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

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

For 2014, HHI is requesting disposition of the December 31, 2012 audited balance, plus the forecasted interest through December 30, 2013 for account 1588GA. The December 31, 2012 audited balance reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a debit of $271,751

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

Account Description: This account is used to record the disposition and recoveries of deferral and variance account balances for electricity distributors receiving approval to recover (or refund) account balances in rates as part of the regulatory process.

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. Since disposal/recovery of 1595 is only eligible once the rate rider has expired, only 2008 has been included in this application.

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

For 2014, HHI is requesting disposition of the December 31, 2012 audited balance. The December 31, 2012 audited balance reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a credit of $-$195,709

Group 2 Accounts

1508 – Other Regulatory Assets – Sub-Account - Incremental Capital Charges

Account Description: Account Description: The new incremental capital. The Board has approved a sub-account of account 1508, Other Regulatory Assets, "Sub-account Incremental Capital Charges", for distributors to record the charges arising *from the capital rate relief rider. ("Rider 5") charge arises from an incremental capital module approved for Hydro One (EB-2008-0187), which was effective on May 1, 2009 but was implemented on June 1, 2009.*

For 2014, HHI is requesting disposition of the December 31, 2012 audited balance, plus the forecasted interest through December 30, 2013 for account 1508. The December 31, 2012 audited balance reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a debit of $3,359

1518 - Retail Cost Variance Account – Retail

Account Description: This account shall be used to record the net of :

i) revenues derived from the following services described in the Rates Handbook:

a) Establishing Service Agreements;

b) Distributor-Consolidated Billing;

c) Retailer-Consolidated Billing; and

d) Split Billing;

AND

ii) the costs of entering into Service Agreements, and related contract administration, monitoring, and other expenses necessary to maintain the contract, as well as the incremental costs incurred to provide the services in (b) and (d) above, as applicable, and the avoided cost credit arising from Retailer-Consolidated Billing.

For 2014, HHI is requesting disposition of the December 31, 2012 audited balance, plus the forecasted interest through December 30, 2013 for account 11518. The December 31, 2012 audited balance reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a debit of $1,857

1535 - Smart Grid OM&A Deferral Account

Operating, maintenance, amortization and administrative expenses directly related to the following smart grid development activities will be recorded in this operating deferral account:

- *smart grid studies or demonstration projects;*
- *smart grid planning; and*
- *smart grid education and training.*

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

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

HHI is requesting disposition of the December 31, 2012 audited balance, plus the forecasted interest through December 30, 2013 for account 1535. The December 31, 2012 audited balance reconciles with filing 2.1.7 of the RRR. The balance requested for disposal, including carrying charges is a debit of $1,901.

1548 - Retail Cost Variance Account – STR

Account Description: This account shall be used to record the net of:

i) revenues derived from the Service Transaction Request services described in the Rates

Handbook and charged by the distributor, as prescribed, in the form of a:

a) Request fee;

b) Processing fee;

c) Information Request fee;

d) Default fee; and

e) Other Associated Costs fee;

AND

ii) the incremental cost of labour, internal information system maintenance costs, and delivery costs related to the provision of the services associated with the above items.

HHI is requesting disposition of the December 31, 2012 audited balance, plus the forecasted interest through December 30, 2013 for account 1548. The December 31, 2012 audited balance reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a debit of $9,590

Group 2 Accounts not sought for disposal

1508 – Other Regulatory Assets – Sub-Account - Incremental Capital Charges-Rate Rider

1508 – Other Regulatory Assets – Sub-Account - Incremental Capital Charges-Sub 115KV Expenses

1508 – Other Regulatory Assets – Sub-Account - Incremental Capital Charges- Sub 44KV Expenses

Account Description: ICM Accounting Treatment; As per section 2.2.7 of the Chapter 3 of the Filing Requirements for Transmission and Distribution Applications which states;

> *"The distributor will record eligible ICM amounts in Account 1508, Other Regulatory Asset, sub-account Incremental Capital Expenditures, subject to the assets being used and useful. For incremental capital assets under construction, the normal accounting treatment will continue in the construction work in progress ("CWIP") prior to these assets going into service and hence eligible for recording in the 1508 sub-account. The amortization of capital assets for the relevant accounting period will be recorded in a separate amortization account of the sub-account, Incremental Capital Expenditures. In addition, the revenues collected from the rate rider will be recorded in Account 1508, Other Regulatory Asset, sub-account, Incremental Capital Expenditures rate rider.*
>
> *The distributor shall also record monthly carrying charges in sub-accounts Incremental Capital Expenditures and Incremental Capital Expenditures rate rider. Carrying charges amounts are calculated using simple interest applied to the monthly opening balances in the account and recorded in a separate sub-account of account 1508. The rate of interest shall be the rate prescribed by the Board for deferral and*

variance accounts for the respective quarterly period published in the Board's web site."

Due to the lack of instructions regarding the treatment of ICM related variance accounts, HHI is not seeking at this time disposition of the December 31, 2012 audited balance, plus the forecasted interest through December 30, 2013 for the 3 sub-account of 1508. Instead, HHI seeks clarification from the Board on how to treat these balances.

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

Although HHI has incurred costs related to the costs of transition to IFRS, in view of the fact that HHI has opted to remain on the CGAAP accounting, the utility is not seeking to dispose of its transition costs in this proceeding and instead requests that the balances be disposed of at a later time.

Table 1 – Balances not sought disposal

Account Name	Balance as of Dec,31,2012
Other Regulatory Assets - Sub-Account - Incremental Capital Charges - RATE RIDER	$(119,792)
Other Regulatory Assets - Sub-Account - Incremental Capital Expenditures - SUB 115KV EXPENSES	$ 85,233
Other Regulatory Assets - Sub-Account - Incremental Capital Expenditures - SUB 44KV EXPENSES	$792,934
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	$ 3,312

E9.T1.S2 DVA BALANCES AND CONTINUITY SCHEDULE

Table 1 below presents the list of deferral and variance accounts, with the proposed selection of balances for disposition. All account balances selected for disposition are as at December 31, 2012 being the most recent date the balances was subject to audit.

Board policy states: 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. In accordance with the above statement, HHI proposes to dispose of all its balances

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

Table 2: Deferral and Variance Balances proposed for disposition

		Amounts from Sheet 2
LV Variance Account	1550	48,843
RSVA - Wholesale Market Service Charge	1580	(116,610)
RSVA - Retail Transmission Network Charge	1584	(7,433)
RSVA - Retail Transmission Connection Charge	1586	(21,499)
RSVA - Power (excluding Global Adjustment)	1588	117,602
RSVA - Power - Sub-account - Global Adjustment	1588	271,751
Recovery of Regulatory Asset Balances	1590	(0)
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	(195,709)
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	0
Total of Group 1 Accounts (excluding 1588 sub-account)		**(174,807)**

Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	0
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	(0)
Other Regulatory Assets - Sub-Account - Incremental Capital Charges - RATE RIDER	1508	
Other Regulatory Assets - Sub-Account - Incremental Capital Expenditures - SUB 115KV EXPENSES	1508	
Other Regulatory Assets - Sub-Account - Incremental Capital Expenditures - SUB 44KV EXPENSES	1508	
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	3,359
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	0
Other Regulatory Assets - Sub-Account - Other	1508	0
Retail Cost Variance Account - Retail	1518	1,857
Misc. Deferred Debits	1525	(0)
Renewable Generation Connection Capital Deferral Account	1531	0
Renewable Generation Connection OM&A Deferral Account	1532	0
Renewable Generation Connection Funding Adder Deferral Account	1533	0
Smart Grid Capital Deferral Account	1534	0
Smart Grid OM&A Deferral Account	1535	1,901
Smart Grid Funding Adder Deferral Account	1536	0
Retail Cost Variance Account - STR	1548	9,590
Board-Approved CDM Variance Account	1567	0
Extra-Ordinary Event Costs	1572	0
Deferred Rate Impact Amounts	1574	0
RSVA - One-time	1582	0
Other Deferred Credits	2425	0
Total of Group 2 Accounts		**16,708**

Deferred Payments in Lieu of Taxes	1562	(0)
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	0
Total of Account 1562 and Account 1592		**(0)**

Special Purpose Charge Assessment Variance Account	1521	(0)
LRAM Variance Account **(Enter dollar amount for each class)**	1568	6,819
(Account 1568 - total amount allocated to classes)	6,819	
Variance	0	

Total Balance Allocated to each class (excluding 1588 sub-account)	**(151,280)**
Total Balance in Account 1588 - sub account	**271,751**
Total Balance Allocated to each class (including 1588 sub-account)	**120,471**

E9.T1.S3 INTEREST RATES APPLIED

Table 2 below provides the interest rates by quarter that are applied to calculate actual and forecast carrying charges for each regulatory and variance account.

Table 2: Interest Rates Applied to Deferral and Variance Accounts (%)

Q2 2013	1.47		Q4 2009	0.55
Q1 2013	1.47		Q3 2009	0.55
Q4 2012	1.47		Q2 2009	1
Q3 2012	1.47		Q1 2009	2.45
Q2 2012	1.47		Q3 2008	3.35
Q1 2012	1.47		Q4 2008	3.35
Q4 2011	1.47		Q2 2008	4.08
Q3 2011	1.47		Q1 2008	5.14
Q2 2011	1.47		Q4 2007	5.14
Q1 2011	1.47		Q3 2007	4.59
Q4 2010	1.2		Q2 2007	4.59
Q3 2010	0.89		Q1 2007	4.59
Q2 2010	0.55		Q4 2006	4.59
Q1 2010	0.55		Q3 2006	4.59

E9.T1.S4 CALCULATION OF RATE RIDER

HHI is proposing to dispose of these balances over a period one year. The rate rider calculations are presented at the next page.

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

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

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1588 sub-account)	Rate Rider for Deferral/Variance Accounts	
Residential	kWh	51,132,834	-$ 43,993	- 0.0009	$/kWh
GS<50	kWh	18,531,353	-$ 18,688	- 0.0010	$/kWh
GS>50	kW	206,640	-$ 88,857	- 0.4300	$/kW
USL	kWh	214,901	-$ 233	- 0.0011	$/kWh
Sentinel	kW	284	-$ 77	- 0.2700	$/kW
Street Lights	kW	3,751	$ 567	0.1513	$/kW
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
Total			**-$ 151,280**		

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

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

E9.T1.S5 DEPARTURE FROM BOARD APPROVED BALANCES

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

E9.T1.S6 RECONCILIATION OF ENERGY SALES AND COST OF POWER EXPENSES TO FINANCIAL STATEMENTS

The filing requirements state that a breakdown of energy sales and cost of power expenses, as reported in the 2011 audited financial statements is requested. Please refer to Table 2 below for an excerpt from the model that HHI used to calculate its projected rates.

Table 2: Energy Sales and Cost of Power Expenses

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

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

E9.T1.S7 PRO-RATA OF GLOBAL ADJUSTMENT INTO RPP/NON-RPP

HHI confirms that it pro-rated the IESO Global Adjustment

Charge into the RPP and non-RPP portions and that Global Adjustment is only being applied to customers that are non-RPP.

E9.T1.S8 REQUEST FOR NEW VARIANCE ACCOUNT

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

E9.T1.S9 LRAMVA

At this time, the applicant is not including an LRAM Variance Account (LRAMVA); however, HHI may request for application of this account in a future application. This is consistent with the information disclosed in the "Ontario Energy Board Accounting Procedures Handbook Frequently Asked Questions" dated July 2012.

Revised June 12, 2013. The total balance of $6,818 sought for disposition includes $1,423 ($1,231 + $192 in carrying charges) in residual balances from the previous LRAM Rate Rider (EB-2011-0173)

For 2014, HHI is requesting disposition of the December 31, 2012 audited balance, plus forecasted interest through December 30, 2013. The requested amount is a debit balance of $ 5,316.60 as detailed at Section E4.T7.S2 of Exhibit 4. Carrying charges up to December 31, 2013 are calculated at $78. The determination of the class specific rate rider is presented below.

LRAMVA Calculations

	2011	2012	2013	
LRAM Claim (kW):	150	150		tab 3.1.1 of Final 2011 OPA report
LRAM Claim (kWh):	720,000	720,000		tab 3.1.1 of Final 2011 OPA report

Per class allocation (kWh)	**2011 Alloc by Class**	**2012 Alloc by Class**	**2011 LRAM (kWh)**	**2012 LRAM (kWh)**	**Total**
Residential	**33.27%**	**34.27%**	239,513.51	246,733.25	486,246.76
General Service < 50 kW	**11.98%**	**12.42%**	86,220.48	89,420.06	175,640.54
General Service > 50 to 4999 kW	**53.68%**	**52.19%**	386,502.94	375,773.36	762,276.30
Unmetered Scattered Load	**0.14%**	**0.14%**	1,005.73	1,036.97	2,042.70
Sentinel Lighting	**0.07%**	**0.07%**	480.63	493.89	974.52
Street Lighting	**0.87%**	**0.91%**	6,276.71	6,542.46	12,819.17
	100%	**100%**	**720,000**	**720,000**	**1,440,000**

Per class allocation (kW)	**2011 Alloc by Class**	**2012 Alloc by Class**	**kW**	**kW**	**Total**
General Service > 50 to 4999 kW	**98.14%**	**98.09%**	147.22	147.13	294.34
Sentinel Lighting	**0.13%**	**0.13%**	0.19	0.20	0.40
Street Lighting	**1.73%**	**1.78%**	2.59	2.67	5.26
			2.59	**150.00**	**300.00**

LRAMVA Rate Rider	**2011 Volumetric Rate**	**2012 Volumetric Rate**	**2011 LRAM**	**2012 LRAM**	**Entry to 1576**
Residential	0.0079	0.0080	$1,892.16	$1,973.87	$3,866.02
General Service < 50 kW	0.0054	0.0055	$465.59	$491.81	$957.40
General Service > 50 to 4999 kW	1.5288	1.5453	$225.06	$227.36	$452.42
Unmetered Scattered Load	0.0021	0.0021	$2.11	$2.18	$4.29
Sentinel Lighting	3.1724	3.2067	$0.62	$0.65	$1.27
Street Lighting	6.6567	6.7286	$17.24	$17.95	$35.19
			$2,602.78	**$2,713.82**	**$5,316.60**

		Class Share	Residual from previous rider incl. carrying charges	2014 Claim including Carrying Charges	Total Claim (EDDVAR model)
Residential		73%	$1,035.34	$3,922.85	4958.19
General Service < 50 kW		18%	$256.40	$971.47	1227.87
General Service > 50 to 4999 kW		9%	$121.16	$459.07	580.23
Unmetered Scattered Load		0%	$1.15	$4.35	5.50
Sentinel Lighting		0%	$0.34	$1.28	1.62
Street Lighting		1%	$9.43	$35.71	45.14
			$1,423.81	$5,394.75	6818.56