August 16, 2013

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2700, P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: 2014 4th Generation Incentive Rate-setting Application by Algoma Power Inc. to Adjust Electricity Distribution Rates & Rural and Remote Rate Protection Funding, Effective January 1, 2014; EB-2013-0110

Please find accompanying this letter, two copies of an Application by Algoma Power Inc. to adjust Electricity Distribution Rates & Rural and Remote Rate Protection Funding, effective January 1, 2014. The Board has assigned case number EB-2013-0110 to this Application.

Electronic copies of the Application have been submitted via the Board's Regulatory Electronic Submission System and a CD containing electronic media accompany this submission.

Yours truly,

Original Signed by

Douglas Bradbury
Director Regulatory Affairs

2 Sackville Road, Suite A • Sault Ste. Marie, Ontario P6B 6J6
Tel: 705-759-7600 • Fax: 705-253-9896 • www.algomapower.com

An Application

By

Algoma Power Inc.

To Adjust

Electricity Distribution Rates

&

Rural and Remote Rate Protection Funding

Effective January 1, 2014

EB-2013-0110

Submitted: August 16, 2013

Index

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, C. S.O. 1998, c.15 (Sched. B);

AND IN THE MATTER OF an Application by Algoma Power Inc. for an Order or Orders pursuant to Section 78 of the *Ontario Energy Board Act, 1998* approving or fixing just and reasonable rates, Rural and Remote Rate Protection funding and other service charges for the distribution of electricity.

Application

1. The applicant is Algoma Power Inc. ("API" or the "Applicant"), a wholly-owned subsidiary of FortisOntario Inc. ("FortisOntario"). The Applicant, an Ontario corporation with its head office in Sault Ste. Marie, Ontario carries on the business of owning and operating electricity distribution facilities in the Algoma District of Ontario; Electricity Distribution Licence #ED-2009-0072.

2. API hereby applies to the Ontario Energy Board (the "Board" or the "OEB"), pursuant to section 78 of the *Ontario Energy Board Act, 1998* as amended (the "OEB Act") for an Order or Orders approving its proposed electricity distribution rates and other charges, effective January 1, 2014.

3. Effective January 1, 2013 in the matter of EB-2012-0104, the Board approved electricity distribution rates for API's electricity distribution customers; a listing of the electricity distribution rates effective January 1, 2013 is provided in Schedule "A" attached hereto.

4. The Ontario Energy Board issued file number EB-2013-0110 to API in respect

of a 2014 4th Generation Incentive Rate-Setting ("2014 4th IR") application.

5. This application has been prepared in a manner to facilitate the Board's expectation expressed in its Order and Decision in the matter of EB-2009-0278 in respect of the Rural and Remote Rate Protection ("RRRP") factor with an annual change in distribution rates and RRRP funding. And, to apply the principles of incentive regulation. The application of the principles of 2014 4th IR is the same as those approved by the Board in the matter of EB-2011-0152 and EB-2012-0104.

6. The persons affected by this Application are the ratepayers of API's service territory. It is impractical to set out their names and addresses because they are too numerous.

7. The Notice of Application will be published in the Sault Star, a paid local newspaper with a circulation of approximately 17,000. The Sault Star has the greatest readership in the service territory.

8. As signatory to this Application, I, R. Scott Hawkes, Vice President, Corporate Services and General Counsel do certify that the evidence filed in this Application is accurate, consistent and complete to the best of my knowledge.

All of Which is Respectfully Submitted

API's contact information for this Application is as follows:

The Applicant:

Mr. Douglas R. Bradbury P. Eng.
Director Regulatory Affairs
Algoma Power Inc.

Mailing Address:	1130 Bertie Street P. O. Box 1218 Fort Erie, Ontario L2A 5Y2
Telephone:	(905) 994-3634
Fax:	(905) 994-2207
Email Address:	doug.bradbury@fortisontario.com

The Applicant's counsel:

Mr. R. Scott Hawkes
Vice President, Corporate Services and General Counsel
Algoma Power Inc.

Mailing Address:	1130 Bertie Street P. O. Box 1218 Fort Erie, Ontario L2A 5Y2
Telephone:	(905) 994-3642
Fax:	(905) 994-2211
Email Address:	scott.hawkes@fortisontario.com

DATED at Fort Erie, Ontario this 16th day of August, 2013.

ALGOMA POWER INC.

By its counsel,

R. Scott Hawkes

Preamble

On November 11, 2010, the Ontario Energy Board (the "Board") issued its Decision and Order in the matter of EB-2009-0278; an application by Algoma Power Inc. ("API") for an order approving just and reasonable rates and other charges for the distribution of electricity to be effective July 1, 2010 and January 1, 2011. This Decision and Order was based on a 2011 Test Year.

On December 13, 2010, the Board issued its Rate Order with a Tariff of Rates and Charges effective and implemented on December 1, 2010. The Tariff of Rates and Charges was later amended on January 28, 2011 in EB-2010-0400, amending the Residential R – 2 customer class Rate Rider for the Deferral/Variance Account Disposition.

A key aspect of the Decision and Order in EB-2009-0278 was the Board's stated intention to calculate a Rural and Remote Rate Protection factor annually for API in order to calculate the annual change in distribution rates and RRRP funding. In its findings the Board stated,

> *"The Board intends to calculate an RRRP adjustment factor annually for Algoma Power, with rates and the RRRP amount for the rate year affected accordingly. Every year the Board will communicate the RRRP adjustment factor to Algoma Power to ensure that it is reflected in Algoma Power's rates application. Should Algoma Power not file either an IRM or a cost of service application, the Board will on its own motion initiate a proceeding in this regard."*[1]

In that context, API filed its first incentive regulation ("IR") application, EB-2011-0152, which proposed a form of incentive regulation ("IR") that combines aspects of the Incentive Regulation Mechanism ("IRM") with the adjustment of electricity distribution rates contemplated in O. Reg. 442/01. The Board issued its final Decision and Order in the matter of EB-2011-0152 on March 6, 2012.

[1] Decision and Order, EB-2009-0278, dated November 11, 2010, page 8

Again in 2012, API filed an IR application, EB-2012-0104, which was consistent with the principles established in EB-2011-0152. The Board issued its final Decision and Order in the matter of EB-2012-0104 on March 28, 2013.

This application is consistent with the Board's Decisions and in the matter of EB-2011-0152 and EB-2012-0104 and is compliant with the requirements of Chapter 3, 4th Generation Incentive Rate-setting and Annual Incentive Rate-setting Index, dated July 17, 2013.

API has four customer classifications:

i. Residential Service Classification

For the purposes of rates and charges, a residential service is defined in two ways:
i) a dwelling occupied as a residence continuously for at least eight months of the year and, where the residential premises is located on a farm, includes other farm premises associated with the residential electricity meter, and
ii) consumers who are treated as residential-rate class customers under Ontario Regulation 445/07 (Reclassifying Certain Classes of Consumers as Residential-Rate Class Customers: Section 78 of the *Ontario Energy Board Act, 1998*) made under the *Ontario Energy Board Act, 1998*.

RESIDENTIAL – R1

- This classification refers to a Residential service with a demand of less than, or is forecast to be less than, 50 kilowatts, and which is billed on an energy basis.

RESIDENTIAL – R2

- This classification refers to a Residential service with a demand equal to or greater than, or is forecast to be equal to or greater than, 50 kilowatts, and which is billed on a demand basis.

ii. Seasonal Customer Service Classification

This classification includes all services supplied to single-family dwelling units for domestic purposes, which are occupied on a seasonal/intermittent basis. A service is defined as Seasonal if occupancy is for a period of less than eight months of the year.

iii. Street Lighting Service Classification

This classification refers to an account for roadway lighting. The consumption for these unmetered accounts will be based on the calculated connection load times the calculated hours of use established in the approved OEB street lighting load shape template.

iv. microFIT Generator Service Classification

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

Price cap adjustment and the adjustment of electricity distribution rates contemplated in O. Reg. 442/01 do not apply to the microFIT Generator Service Classification.

API's electricity distribution rates for Residential Service Classification (both Residential R – 1 and Residential R – 2) are adjusted in accordance with O. Reg. 442/01. The electricity distribution rates for these classes are adjusted in line with the average of rate adjustments of select rate classes of other distributors in the most recent rate orders, as calculated by the Board; the RRRP adjustment Factor. API acknowledges that the Board will determine the actual RRRP adjustment factor for 2014 electricity distribution rates in due course. For purposes of presenting a RRRP adjustment factor for 2014, API is estimating a value of 2.20% in this Application.

The electricity distribution rates for the Seasonal Customer Service Classification and the Street Lighting Service Classification are not subject to the restrictions of O. Reg. 442/01 and will be determined in a manner consistent with a price cap form of incentive regulation.

Manager's Summary

In determining a price cap adjustment for the customer classes at API, two governing principles have to be considered:

1. The rates for Residential Service Classification (both Residential R – 1 and Residential R – 2) are adjusted in accordance with O. Reg. 442/01, as determined by the Board. The adjustment will be applied to the Monthly Service Charge and Distribution Volumetric Rate.

2. The rates for customer classifications that are not adjusted in accordance with O. Reg. 442/01 (Seasonal and Street Light customer classifications) are adjusted by the price cap adjustment index determined as the annual percentage change in inflation less the X-Factor.

API's 2014 rate adjustment application has to accommodate both of these considerations and therefore the conventional rate generating models produced by the Board are not suitable. API has used a series of electronic models in EXCEL format to generate 2014 electricity distribution rates; these models accompany this Application as Schedule "C".

The following is a discussion of API's Application.

1. Price Cap Index Adjustment

Where applicable, API has complied with Chapter 3 of the Board's Filing Requirements for Distribution Applications, dated July 17, 2013, in preparing this Application.

API is submitting a price cap adjustment of 0.48% as stipulated in Chapter 3 of the Board's Filing Requirements for Distribution Applications, dated July 17, 2013. This is based on the current default metrics; an inflation factor of 1.6%, a productivity factor of 0.72%, and a stretch factor of 0.4% (representing the middle cohort). API acknowledges that the Board may update API's 2014 IR Application with the final parameters to be established by the Board in its supplemental report on the Renewed Regulatory Framework for Electricity Distributors ("RRFE").

API is unique in the way its distribution rates are set by the Board. Pursuant to O. Reg. 442/01, and with the exception of the Seasonal and Street Lighting Service Classifications, API's rates are to be adjusted in line with the average of any adjustment to rates approved by the Board for other distributors for the same rate year. Any remaining revenue deficiency related to the revenue requirement of the Residential Class is recovered by API on behalf of its customers through the Rural and Remote Rate Protection ("RRRP"). The rates for the Residential – R1 and Residential – R2 will be determined using the RRRP Adjustment Factor for 2014 as determined by the Board and rates for the Seasonal and Street Light customer classes will be set by an IR adjustment factor as determined by the Board.

The methodology proposed to accomplish the price cap adjustment and rates is explained in detail and are provided in Schedule "C" attached.

2. Changes in Provincial and Federal Income Tax Rates

Under a 4th Generation IR, 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 applies[2].

In API's most recent cost of service electricity distribution rate application, EB-2009-0278, the Board approved recovery of $499,851 for federal and provincial income taxes in the rate requirement. There was no capital tax component and the corporate tax rate used in this determination was 28.25%. In this Application for a rate adjustment, API has determined the grossed up tax liability at the forecasted 2014 corporate tax rate of 26.5%.

API proposes that a 50/50 sharing of the impact of changes from the tax level reflected in the Board-approved base rates of 28.25% to the currently known legislated tax level for 2014 of 26.5%. API has calculated that the grossed up income taxes for the 2014 rate year is $457,723; a reduction of $42,128. Fifty per cent of these savings, $21,064, will be credited to the consumers in the form of a rate rider.

The details of the proposed Tax Change Rate Rider are provided in Schedule "D" attached and are provided in an EXCEL spreadsheet accompanying this Application. API's 2014 combined income tax rate of 26.5% does not reflect the Ontario Small Business Deduction ("OSBD") and therefore API has used an unlocked version of the Board's Tax Savings Workform. API is a wholly-owned subsidiary of FortisOntario which is wholly-owned by Fortis Inc. Fortis Inc.'s shares are listed on the Toronto Stock Exchange and traded under the symbol FTS and thus, Fortis Inc. is considered a public corporation under the Income Tax Act. API is considered a corporation controlled by a public corporation under the Income Tax Act. API is not considered a Canadian-controlled private corporation (CCPC) because it is owned indirectly by a public corporation. To be eligible for the OSBD a corporation must be a CCPC. API does not qualify for the OSBD.

API proposes a one year income tax rate rider with a sunset date of December 31, 2014; the rate riders are shown in the table below.

[2] Chapter 3, 4th Generation Incentive Rate-setting and Annual Incentive Rate-setting Index, July 17, 2013, Section 3.2.4 Tax Changes

Rate Class	Tax Changes by Rate Class	Rate Rider
Residential – R1	($13,240)	($0.0001)
Residential – R2	($1,894)	($0.0125)
Seasonal	($5,900)	($0.0005)
Street Lighting	($30)	n/a

API considers the outstanding balance of $30.00 in the Street Lighting customer classification to be insignificant and no accommodation is proposed in this application.

3. Revenue-to-Cost Ratios

In the matter of EB-2010-0278, the Board did not direct API to make changes to the revenue to cost ratios in its future IRM applications. API has not requested a change in the revenue to cost ratios in this Application.

4. Retail Transmission Service Rates

API has proposed Retail Transmission Service Rates ("RTSR") compliant with the Board's Guideline G-2008-0001, Revision 4.0, and dated June 28, 2012. The RTSR Adjustment Workform Version 4.0 accompanies this Application; a print version of the Workform is provided in Schedule "E" to this Application.

The proposed RTSR effective January 1, 2014 are shown below.

Service Classification	Board Approved	2014 Proposed	UOM
Residential - R1			
Retail Transmission Rate - Network Service Rate	0.0069	0.0066	per kWh
Retail Transmission Rate - Line and Conection Service Rate	0.0049	0.0047	per kWh
Residential - R2			
Retail Transmission Rate - Network Service Rate	2.5633	2.4575	per kW
Retail Transmission Rate - Line and Conection Service Rate	1.7423	1.6746	per kW
Retail Transmission Rate - Network Service Rate - Interval metered > 1,000 kW	2.7191	2.6069	per kW
Retail Transmission Rate - Line and Conection Service Rate - Interval metered > 1,000 kW	1.9255	1.8507	per kW
Seasonal Customers			
Retail Transmission Rate - Network Service Rate	0.0069	0.0066	per kWh
Retail Transmission Rate - Line and Conection Service Rate	0.0049	0.0047	per kWh
Street Lighting			
Retail Transmission Rate - Network Service Rate	1.9331	1.8533	per kW
Retail Transmission Rate - Line and Conection Service Rate	1.3469	1.2946	per kW

Comparison of the most recently reported RRR billing determinant data and the data presented in the "RRR Data" tab of the RTSR Adjustment Workform Version 4.0 accompanying this Application will reveal discrepancies. These discrepancies are the result of restrictive presentation and alignment of actual customer rate classes present in API's service territory. The following is a reconciliation of the most recently reported RRR billing determinant data and the RTSR Adjustment Workform.

API Customer Classes	RSTR Workfom, RRR Data		Most Recent RRR Reporting		RRR Customer Class Presentation
	kWh	kW	kW	kWh	
Residential - R1	**103,512,449**			**87,927,708**	Residential
				25,664,047	General Service < 50 kW
Seasonal	**10,136,343**			**57,038**	Unmetered Loads
Subtotal	113,648,793			113,648,793	Subtotal
Residential - R2	**16,561,356**	**53,633**	**185,948**	**79,423,076**	General Service > 50 kW
(Interval metered)	**62,861,720**	**132,315**	-	-	
Subtotal	79,423,076	185,948	185,948	79,423,076	Subtotal
Street Lighting	**728,404**	2,450		**728,404**	Street Lighting
Totals	193,800,273			193,800,273	Totals

API's Residential – R1 customer class reported in the RRR reports as generic customer classes including Residential, General Service < 50 kW and Unmetered Loads. API's Seasonal customer class is reported for RRR reporting purposes within the generic Residential class.

To properly allocate the RTSR charge, API's Residential – R2 customer class is disaggregated to provided interval and non-interval data. API does not report demand ("kW") associated with the Street Lighting customer class because distribution revenue is dependent upon the energy component.

5. Review and Disposition of Group 1 Deferral and Variance Accounts

In Chapter 3 of the Board's Filing Requirements for Electricity Distribution Rate Applications, Section 3.2.5, provides that under 4th Generation IR, the distributor's Group 1 audited account balances will be reviewed and disposed if the preset threshold of $0.001 per kWh (debit or credit) has been exceeded.

Accompanying this Application, API has filed a partially completed 2014 IRM Rate Generator model with Tabs 1, 3, 5 and 6 completed to provide the 2014 Continuity Schedule and Threshold Test. The relevant excerpts are provided in Schedule "F" attached.

In Tab 5, 2014 Continuity Schedule, the only discrepancies between the 2012 ending balances and the 2012 RRR filing is the 2012 fixed price and global adjustment true-ups completed in 2013. The true-up amounts are provided in the 'Other 1 Adjustments during Q4 2012' column of the continuity schedule.

In Tab 6, Billing Det. For Def-Var, the total claim for the threshold test is $105,489 and the metered kWh value is 190,140,490 from the approved forecast in API's last cost of service review, EB-2009-0278. The resultant is $0.0006 per kWh and does not meet the preset threshold of $0.001 per kWh.

API is not requesting disposition of its Group 1 Deferral Accounts in this Application.

6. LRAMVA Disposition

API is proposing to establish its 2011 LRAMVA, including its persistence into the 2012 rate year, in this Application. In support of API's 2011 LRAMVA, API has retained the services of Burman Energy Consultants Group Inc. ("Burman Energy"); a copy of the LRAMVA Support report prepared by Burman Energy and dated August 13, 2013 together with a copy of the OPA 2011 Final Report for API is provided in Schedule "G". The OPA 2011 Final Report is the basis of API's LRAMVA.

Burman Energy has determined that the total LRAMVA for 2011 is $4,954.99 with persistence into the 2012 rate year of $4,954.99 for a total of $9,908.98, exclusive of interest improvement.
API's last cost of service review, EB-2009-0278, established a cost of service for the 2011 rate year with an accepted 2011 customer and load forecast. This customer and load forecast predated the establishing API's Conservation and Demand Management ("CDM") Targets as a condition of its licence. There is no allowance in API's most recent customer and load forecast for CDM.

The 2011 allocation of CDM savings is entirely allocated to the Residential R – 1 customer class and the 2011 customer and load forecast parameters for the Residential R – 1 customer class has been used to determine a volumetric rate rider necessary to recover the balance. The table below provides details of this rate rider calculation.

Proposed 2014 LRAMVA for CDM Residential Programs pre 2011 and 2011
Price Cap Index 0.00%

2014 Distribution Price Indexed Electricity Distribution Rates											
			Billing Determinant		F/V Split		Distribution Rates		Revenues		
Customer Class	Metric	Average # of Customers	kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8039	106,119,297		0.0%	100.0%	-	0.0001	-	9,910	9,910
									-	**9,910**	**9,910**

The resultant rate rider for the 2014 rate year is less than $0.0001 per kWh; due to the significance of the resultant rate rider API proposes to defer disposition of the proposed account balance to a future rate proceeding. API proposes to establish an LRAMVA effective January 1, 2014 with an opening balance of $9,908.98.

7. Bill Impacts

The table shown below summarizes the bill impacts arising from the methodology and assumptions used in this Application.

Selected Delivery Charge and Bill Impacts Per Application
Algoma Power Inc. 2014

Customer Classification and Billing Type	Energy kWh	Demand kW	Monthly Delivery Charge Current	Per Application	Change $	Change %
Residential - R1	800		$ 72.20	$ 65.06	-$ 7.14	-9.9%
Residential - R1 (2000 kWh)	2,000		$ 145.85	$ 127.25	-$ 18.60	-12.8%
Residential - R2	90,000	225	$ 4,022.93	$ 2,860.70	-$ 1,162.24	-28.9%
Seasonal	287		$ 76.79	$ 74.19	-$ 2.61	-3.4%
Street Lighting	25,000	71	$ 5,005.91	$ 4,760.66	-$ 245.25	-4.9%

Customer Classification and Billing Type	Energy kWh	Demand kW	Total Bill Current	Per Application	Change $	Change %
Residential - R1	800		$ 148.54	$ 141.27	-$ 7.27	-4.9%
Residential - R1 (2000 kWh)	2,000		$ 335.72	$ 316.80	-$ 18.91	-5.6%
Residential - R2	90,000	225	$ 12,510.86	$ 11,328.86	-$ 1,182.00	-9.4%
Seasonal	287		$ 105.21	$ 102.56	-$ 2.65	-2.5%
Street Lighting	25,000	71	$ 7,538.52	$ 7,289.10	-$ 249.42	-3.3%

8. Other

In this application API is not applying for a Z-factor claim and is not applying for incremental capital.

THE FOLLOWING IS A LISTING OF THE EXCEL MODELS WHICH ACCOMPANY THIS APPLICATION:

- 2014 IRM4 Rate Generator Model for API
- 2014 IRM4 Tax Sharing Model for API
- 2014 RTSR Model for API
- 2014 Rate Design Model for API
- 2014 Bill Impact Model for API
- 2014 Proposed Tariff of Rates and Charges

Schedule "A"

Board Approved Tariff of Rates and Charges

EB-2012-0104

Algoma Power Inc.
TARIFF OF RATES AND CHARGES
Effective Date January 1, 2013
Implementation Date May 1, 2013

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

EB-2012-0104

RESIDENTIAL SERVICE CLASSIFICATION

For the purposes of rates and charges, a residential service is defined in two ways:
i) a dwelling occupied as a residence continuously for at least eight months of the year and, where the residential premises is located on a farm, includes other farm premises associated with the residential electricity meter, and
ii) consumers who are treated as residential-rate class customers under Ontario Regulation 445/07 (Reclassifying Certain Classes of Consumers as Residential-Rate Class Customers: Section 78 of the *Ontario Energy Board Act, 1998*) made under the *Ontario Energy Board Act, 1998*.

RESIDENTIAL – R1

This classification refers to a Residential service with a demand of less than, or is forecast to be less than, 50 kilowatts, and which is billed on an energy basis. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	22.32
Distribution Volumetric Rate	$/kWh	0.0313
Rate Rider for Foregone Revenue Recovery – effective until December 31, 2014	$/kWh	0.0004
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until May 31, 2013	$/kWh	0.0046
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until May 31, 2013	$/kWh	(0.0061)
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until December 31, 2013	$/kWh	(0.0052)
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until December 31, 2013	$/kWh	0.0150
Rate Rider for Tax Changes – effective until December 31, 2013	$/kWh	(0.0002)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0069
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0049

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge – effective on and after May 1, 2013	$/kWh	0.0012
Smart Metering Entity Charge	$	0.79
Standard Supply Service – Administration Charge (if applicable)	$	0.25

Algoma Power Inc.
TARIFF OF RATES AND CHARGES
Effective Date January 1, 2013
Implementation Date May 1, 2013

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

EB-2012-0104

RESIDENTIAL – R2

This classification refers to a Residential service with a demand equal to or greater than, or is forecast to be equal to or greater than, 50 kilowatts, and which is billed on a demand basis. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	596.12
Distribution Volumetric Rate	$/kW	2.8949
Rate Rider for Foregone Revenue Recovery – effective until December 31, 2014	$/kW	0.0373
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until May 31, 2013	$/kW	2.2664
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until May 31, 2013	$/kW	(2.8219)
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until December 31, 2013	$/kW	(1.3006)
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until December 31, 2013	$/kW	6.4235
Rate Rider for Tax Changes – effective until December 31, 2013	$/kW	(0.0300)
Retail Transmission Rate – Network Service Rate	$/kW	2.5633
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7423
Retail Transmission Rate – Network Service Rate – Interval Metered > 1,000 kW	$/kW	2.7191
Retail Transmission Rate – Line and Trans. Connection Service Rate – Interval Metered > 1,000 kW	$/kW	1.9255

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge – effective on and after May 1, 2013	$/kWh	0.0012
Standard Supply Service – Administration Charge (if applicable)	$	0.25

Algoma Power Inc.
TARIFF OF RATES AND CHARGES
Effective Date January 1, 2013
Implementation Date May 1, 2013

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

EB-2012-0104

SEASONAL CUSTOMERS SERVICE CLASSIFICATION

This classification includes all services supplied to single-family dwelling units for domestic purposes, which are occupied on a seasonal/intermittent basis. A service is defined as Seasonal if occupancy is for a period of less than eight months of the year. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	26.38
Distribution Volumetric Rate	$/kWh	0.1015
Rate Rider for Foregone Revenue Recovery – effective until December 31, 2014	$/kWh	0.0003
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until May 31, 2013	$/kWh	0.0046
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until May 31, 2013	$/kWh	(0.0061)
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until December 31, 2013	$/kWh	(0.0056)
Rate Rider for Deferral/Variance Account Disposition – effective until November 30, 2015	$/kWh	0.0307
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until December 31, 2013	$/kWh	0.0150
Smart Meter Deferred Revenue Rate Rider – effective until December 31, 2016	$	3.14
Smart Meter Incremental Revenue Rate Rider – effective until December 31, 2014	$	2.81
Rate Rider for Tax Changes – effective until December 31, 2013	$/kWh	(0.0003)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0069
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0049

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge – effective on and after May 1, 2013	$/kWh	0.0012
Smart Metering Entity Charge	$	0.79
Standard Supply Service – Administration Charge (if applicable)	$	0.25

Algoma Power Inc.
TARIFF OF RATES AND CHARGES
Effective Date January 1, 2013
Implementation Date May 1, 2013

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

EB-2012-0104

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting. The consumption for these unmetered accounts will be based on the calculated connection load times the calculated hours of use established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	0.97
Distribution Volumetric Rate	$/kWh	0.1557
Rate Rider for Foregone Revenue Recovery – effective until December 31, 2014	$/kWh	0.0003
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until May 31, 2013	$/kWh	0.0048
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until May 31, 2013	$/kWh	(0.0061)
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until December 31, 2013	$/kWh	(0.0045)
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until December 31, 2013	$/kWh	0.0150
Rate Rider for Tax Changes – effective until December 31, 2013	$/kWh	(0.0003)
Retail Transmission Rate – Network Service Rate	$/kW	1.9331
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3469

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge – effective on and after May 1, 2013	$/kWh	0.0012
Standard Supply Service – Administration Charge (if applicable)	$	0.25

Algoma Power Inc.
TARIFF OF RATES AND CHARGES
Effective Date January 1, 2013
Implementation Date May 1, 2013

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

EB-2012-0104

microFIT GENERATOR SERVICE CLASSIFICATION

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

APPLICATION

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

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

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.40

Algoma Power Inc.
TARIFF OF RATES AND CHARGES
Effective Date January 1, 2013
Implementation Date May 1, 2013

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EB-2012-0104

ALLOWANCES

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

SPECIFIC SERVICE CHARGES

APPLICATION

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

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

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

Customer Administration		
Arrears certificate (credit reference)	$	15.00
Statement of Account	$	15.00
Pulling Post Dated Cheques	$	15.00
Duplicate Invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Notification charge	$	15.00
Account History	$	15.00
Credit Reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheques	$	15.00
Legal letter charge	$	15.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection - during regular business hours	$	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00
Disconnect/Reconnect Charges - at meter during regular hours	$	65.00
Disconnect/Reconnect Charges - at meter after regular hours	$	185.00
Disconnect/Reconnect Charges at Pole - during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35
Service Call - customer owned equipment	$	30.00
Service Call - after regular hours	$	165.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - underground - no transformer	$	300.00
Temporary service install & remove - overhead - with transformer	$	1000.00

Algoma Power Inc.
TARIFF OF RATES AND CHARGES
Effective Date January 1, 2013
Implementation Date May 1, 2013

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

EB-2012-0104

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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

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

Retail Service Charges refer to services provided by Algoma Power Inc. to retailers or customers related to the supply of competitive electricity and are defined in the 2006 Electricity Distribution Rate Handbook.

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

LOSS FACTORS

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

Total Loss Factor – Secondary Metered Customer	1.0864
Total Loss Factor – Primary Metered Customer	1.0755

Schedule “B”

Proposed Tariff of Rates and Charges

File Number:	EB-2013-0110
Exhibit:	
Tab:	
Schedule:	A
Page:	
Date:	16-Aug-13

Proposed Tariff of Rates and Charges

Algoma Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2014

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

RESIDENTIAL - R1

For the purposes of rates and charges, a residential service is defined in two ways:
i) a dwelling occupied as a residence continuously for at least eight months of the year and, where the residential premises is located on a farm, includes other farm premises associated with the residential electricity meter, and
ii) consumers who are treated as residential-rate class customers under Ontario Regulation 445/07 (Reclassifying Certain Classes of Consumers as Residential-Rate Class Customers: Section 78 of the Ontario Energy Board Act, 1998) made under the Ontario Energy Board Act, 1998.

RESIDENTIAL – R1

This classification refers to a Residential service with a demand of less than, or is forecast to be less than, 50 kilowatts, and which is billed on an energy basis. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	22.81
Distribution Volumetric Rate	$/kWh	0.0320
Rate Rider for Foregone Revenue Recovery – effective until December 31, 2014	$/kWh	0.0004
Rate Rider for Tax Changes - effective until December 31, 2014	$/kWh	(0.0001)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0066
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0047

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Smart Meter Entity Charge		0.79
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

RESIDENTIAL - R2

This classification refers to a Residential service with a demand equal to or greater than, or is forecast to be equal to or greater than, 50 kilowatts, and which is billed on a demand basis. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	596.12
Distribution Volumetric Rate	$/kW	3.0083
Rate Rider for Foregone Revenue Recovery – effective until December 31, 2014	$/kW	0.0373
Rate Rider for Tax Changes - effective until December 31, 2014	$/kW	(0.0125)
Retail Transmission Rate – Network Service Rate	$/kW	2.4575
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6746
Retail Transmission Rate – Network Service Rate – Interval Metered > 1,000 kW	$/kW	2.6069
Retail Transmission Rate – Line and Trans. Connection Service Rate – Interval Metered > 1,000 kW	$/kW	1.8507

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

SEASONAL CUSTOMERS SERVICE CLASSIFICATION

This classification includes all services supplied to single-family dwelling units for domestic purposes, which are occupied on a seasonal/intermittent basis. A service is defined as Seasonal if occupancy is for a period of less than eight months of the year. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	26.51
Distribution Volumetric Rate	$/kWh	0.1019
Rate Rider for Foregone Revenue Recovery – effective until December 31, 2014	$/kWh	0.0003
Rate Rider for Deferral/Variance Account Disposition – effective until November 30, 2015	$/kWh	0.0307
Rate Rider for Tax Changes - effective until December 31, 2014	$/kWh	(0.0005)
Smart Meter Deferred Revenue Rate Rider – effective until December 31, 2016	$	3.14
Smart Meter Incremental Revenue Rate Rider – effective until December 31, 2014	$	2.81
Retail Transmission Rate – Network Service Rate	$/kWh	0.0066
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0047

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Smart Meter Entity Charge	$	0.79
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting. The consumption for these unmetered accounts will be based on the calculated connection load times the calculated hours of use established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	0.97
Distribution Volumetric Rate	$/kWh	0.1565
Rate Rider for Foregone Revenue Recovery – effective until December 31, 2014	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kW	1.8533
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2946

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

microFIT GENERATOR SERVICE CLASSIFICATION

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

APPLICATION

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

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

ALLOWANCES

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

SPECIFIC SERVICE CHARGES

APPLICATION

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

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Customer Administration

Arrears certificate (credit reference)	$	15.00
Statement of Account	$	15.00
Pulling Post Dated Cheques	$	15.00
Duplicate Invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Notification charge	$	15.00
Account History	$	15.00
Credit Reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheques	$	15.00
Legal letter charge	$	15.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection - during regular business hours	$	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00
Disconnect/Reconnect Charges - at meter during regular hours	$	65.00
Disconnect/Reconnect Charges - at meter after regular hours	$	185.00
Disconnect/Reconnect Charges at Pole - during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00

Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35
Service Call - customer owned equipment	$	30.00
Service Call - after regular hours	$	165.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - underground - no transformer	$	300.00
Temporary service install & remove - overhead - with transformer	$	1,000.00

RETAIL SERVICE CHARGES (if applicable)

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

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

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

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

LOSS FACTORS

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

Total Loss Factor – Secondary Metered Customer	1.0864
Total Loss Factor – Primary Metered Customer	1.0755

Schedule "C"

API 2014 Distribution Rate Indexing Methodology

The 2011 Board Approved Rate Design, EB-2009-0278

The starting point for 2012 electricity distribution rate design is the fully allocated Board Approved 2011 revenue requirement. The table shown below is the Board approved 2011 revenue requirement of $19,828,731[1].

Board Approved EB-2009-0278
Equivalent Distribution Rates

2011 Distribution Base Rate Determination											
			Billing Determinant		F/V Split		Distribution Rates		Revenues		
Customer Class	Metric	Average # of Customers	kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8039	106,119,297		13.6%	86.4%	20.41	0.1174	1,968,810	12,458,170	14,426,980
Residential - R2	kW	48		151,952	12.0%	88.0%	596.12	16.5559	343,365	2,515,702	2,859,067
Seasonal	kWh	3660	12,622,297		43.8%	56.2%	24.00	0.1073	1,054,008	1,354,803	2,408,811
Street Lighting	kWh	1052	791,996		0.0%	100.0%	-	0.1690	-	133,872	133,872
									3,366,183	**16,462,548**	**19,828,731**

The equivalent distribution rates shown in this table are those rates required to recover the revenue requirement in the absence of the RRRP funding and represent the full allocation to the customer classes.

Price Cap Indexing of Equivalent Distribution Rates

In the matter of the EB-2011-0152, the Board approved the following incentive regulation price cap metrics.

Board Approved 2012 Incentive Regulation Price Cap Metrics	
RRRP Adjustment Factor	2.81%
Implicit Price Index	1.70%
Productivity Factor	0.72%
Stretch Factor	0.60%
Price Cap Index	0.38%

These Board Approved 2012 incentive regulation price cap metrics were used to index the fully allocated Board Approved 2011 revenue requirement; the results are provided below.

[1] EB-2009-0278 Approved Draft Rate Order, November 22, 2010, Appendix B

Board Approved 2012 Application of Incentive Regulation Price Cap to Equivalent Distribution Rates
Price Cap Index 0.38%

2012 Distribution Price Indexed Electricity Distribution Rates											
			Billing Determinant		F/V Split		Distribution Rates		Revenues		
Customer Class	Metric	Average # of Customers	kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8039	106,119,297		13.6%	86.4%	20.49	0.1178	1,976,291	12,505,511	14,481,803
Residential - R2	kW	48		151,952	12.0%	88.0%	598.39	16.6188	344,670	2,525,262	2,869,932
Seasonal	kWh	3660	12,622,297		43.8%	56.2%	24.09	0.1077	1,058,013	1,359,951	2,417,965
Street Lighting	kWh	1052	791,996		0.0%	100.0%	-	0.1697	-	134,381	134,381
									3,378,974	**16,525,106**	**19,904,080**

These 2012 equivalent distribution rates then became the basis for the 2013 distribution rate design.

Shown below is the approved RRRP adjustment factor for the 2013 distribution rates and the final price cap index metrics for 2013 approved electricity distribution rates.

Actual 2013 Incentive Regulation Price Cap Metrics	
RRRP Adjustment Factor (Decision)	3.75%
Implicit Price Index	2.20%
Productivity Factor	0.72%
Stretch Factor	0.60%
Price Cap Index (Decision)	0.88%

These price cap metrics were applied to the 2012 equivalent electricity distribution rates to yield the fully allocated Board Approved 2013 revenue requirement with 2013 equivalent distribution rates; the results are provided below.

Actual 2013 Application of Incentive Regulation Price Cap to Equivalent Distribution Rates
Price Cap Index 0.88%

2013 Distribution Price Indexed Electricity Distribution Rates											
			Billing Determinant		F/V Split		Distribution Rates		Revenues		
Customer Class	Metric	Average # of Customers	kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8039	106,119,297		13.6%	86.4%	20.67	0.1189	1,993,683	12,615,560	14,609,242
Residential - R2	kW	48		151,952	12.0%	88.0%	603.65	16.7651	347,703	2,547,484	2,895,187
Seasonal	kWh	3660	12,622,297		43.8%	56.2%	24.30	0.1087	1,067,324	1,371,919	2,439,243
Street Lighting	kWh	1052	791,996		0.0%	100.0%	-	0.1712	-	135,564	135,564
									3,408,709	**16,670,527**	**20,079,236**

Shown below is the assumed RRRP adjustment factor for the 2014 electricity distribution rates and the preliminary price cap index metrics for 2014 electricity distribution rates.

Proposed 2014 Incentive Regulation	
RRRP Adjustment Factor (Estimated)	2.20%
Implicit Price Index (Estimated)	1.60%
Productivity Factor (Estimated)	0.72%
Stretch Factor (Estimated)	0.40%
Price Cap Index (Calculated)	0.48%

Applying these price cap metrics were to the approved 2013 equivalent electricity distribution rates yield the fully allocated 2014 revenue requirement with 2014 equivalent distribution rates; the results are provided below.

Proposed 2014 Application of Incentive Regulation Price Cap to Equivalent Distribution Rates

Price Cap Index 0.48%

2014 Distribution Price Indexed Electricity Distribution Rates											
			Billing Determinant		F/V Split		Distribution Rates		Revenues		
Customer Class	Metric	Average # of Customers	kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8039	106,119,297		13.6%	86.4%	20.77	0.1195	2,003,252	12,676,114	14,679,367
Residential - R2	kW	48		151,952	12.0%	88.0%	606.55	16.8455	349,372	2,559,712	2,909,084
Seasonal	kWh	3660	12,622,297		43.8%	56.2%	24.42	0.1092	1,072,447	1,378,504	2,450,951
Street Lighting	kWh	1052	791,996		0.0%	100.0%	-	0.1720	-	136,214	136,214
									3,425,071	**16,750,545**	**20,175,616**

Revenue to Cost Ratio Update

In EB-2009-0278, the Board approved the following class revenue to cost ratios.

Customer Class	Board Approved Revenue to Cost Ratio
Residential R - 1	114.1%
Residential R - 2	59.8%
Seasonal Customers	115.0%
Street Lighting	43%

There are no changes to the Board Approved revenue to cost ratios proposed in this Application. The following table shows the allocation of revenue requirement to the customer classes on the basis of the Board approved 2011 revenue to cost ratios.

No Adjustment Made to the 2011 Board Approved Revenue to Cost Ratios

2011 Cost Allocation Results								
	Cost Allocation Revenue Requirement	Revenue Requirement Allocation Percentage	Cost Allocation Misc.	Cost Allocation Misc. Percentage	2011 Service Revenue Requirement	2011 Misc. Revenue	2011 Base Revenue Requirement	
Residential - R1	12,066,293	63.7%	217,490	63.4%	12,876,372	234,623	12,641,749	
Residential - R2	4,569,290	24.1%	88,133	25.7%	4,876,052	95,075	4,780,977	
Seasonal	1,995,675	10.5%	32,431	9.5%	2,129,655	34,986	2,094,669	
Street Lighting	296,807	1.6%	5,003	1.5%	316,734	5,397	311,336	
	18,928,065	100.0%	343,057	100.0%	20,198,813	370,082	19,828,731	

Board Approved 2011 Base Distribution Rate Cost Allcation Design								
	2011 Approved Revenue @ 100% R|C	Revenue Proportions @ 100% R|C	Approved Proportion of Revenue	Base Revenue @ Approved Proportion	Over/(Under) Contributing	Approved Revenue to Cost Ratio	2011 Cost Allocation R|C	Board's Guideline
Residential - R1	12,641,749	63.8%	72.8%	14,426,980	1,785,231	114.1%	116.7%	85-115%
Residential - R2	4,780,977	24.1%	14.4%	2,859,067	(1,921,909)	59.8%	39.5%	80-180%
Seasonal	2,094,669	10.6%	12.1%	2,408,811	314,142	115.0%	149.9%	85-115%
Street Lighting	311,336	1.6%	0.7%	133,872	(177,464)	43.0%	15.9%	70-120%
	19,828,731	100.0%		19,828,731				

Actual 2012 Base Distribution Rate Cost Allocation Design								
	2012 Forecasted Revenue @ 100% R|C	Revenue Proportions @ 100% R|C	Proposed Proportion of Revenue	Base Revenue @ Proposed Proportion	Over/(Under) Contributing	Proposed Revenue to Cost Ratio	2010 Cost Allocation R|C	Board's Guideline
Residential - R1	12,689,787	63.8%	72.8%	14,481,803	1,792,015	114.1%	116.71%	85-115%
Residential - R2	4,799,145	24.1%	14.4%	2,869,932	(1,929,213)	59.8%	39.52%	80-180%
Seasonal	2,102,629	10.6%	12.1%	2,417,965	315,336	115.0%	149.94%	85-115%
Street Lighting	312,519	1.6%	0.7%	134,381	(178,138)	43.0%	15.92%	70-120%
	19,904,080	100.0%	100.0%	19,904,080				

Actual 2013 Base Distribution Rate Cost Allocation Design								
	2013 Forecasted Revenue @ 100% R|C	Revenue Proportions @ 100% R|C	Proposed Proportion of Revenue	Base Revenue @ Proposed Proportion	Over/(Under) Contributing	Proposed Revenue to Cost Ratio	2010 Cost Allocation R|C	Board's Guideline
Residential - R1	12,801,457	63.8%	72.8%	14,609,242	1,807,785	114.1%	0.00%	85-115%
Residential - R2	4,841,377	24.1%	14.4%	2,895,187	(1,946,190)	59.8%	0.00%	80-180%
Seasonal	2,121,132	10.6%	12.1%	2,439,243	318,111	115.0%	0.00%	85-115%
Street Lighting	315,270	1.6%	0.7%	135,564	(179,706)	43.0%	0.00%	70-120%
	20,079,236	100.0%	100.0%	20,079,236				

Proposed 2014 Base Distribution Rate Cost Allocation Design								
	2014 Forecasted Revenue @ 100% R|C	Revenue Proportions @ 100% R|C	Proposed Proportion of Revenue	Base Revenue @ Proposed Proportion	Over/(Under) Contributing	Proposed Revenue to Cost Ratio	2010 Cost Allocation R|C	Board's Guideline
Residential - R1	12,862,904	63.8%	72.8%	14,679,367	1,816,462	114.1%	0.00%	85-115%
Residential - R2	4,864,616	24.1%	14.4%	2,909,084	(1,955,531)	59.8%	0.00%	80-180%
Seasonal	2,131,313.53	10.6%	12.1%	2,450,951	319,637	115.0%	0.00%	85-115%
Street Lighting	316,783	1.6%	0.7%	136,214	(180,568)	43.0%	0.00%	70-120%
	20,175,616	100.0%	100.0%	20,175,616				

Smart Meter Cost Recovery – Rate Design

In its Decision, EB-2012-0104, the Board approved the recovery of API's smart meter costs. For purposes of recovery smart meter costs were allocated to the Residential – R1 and Seasonal customer classes. The Board approved recovery of the Residential – R1 allocation from RRRP funding over a two year period ending December 31, 2014. The approved Seasonal customer class allocation recovery was through a rate rider over a 44 month period ending December 31, 2016. In the tables shown below, the highlighted 50% of Net Deferred Revenue Requirement and the Incremental Revenue Requirement is allocated to the Residential – R1 customer class to simulate the two year recovery period stipulated in the Board Decision.

2013 Approved Methodology with Smart Meter Recovery, EB-2012-0104

RRRP Adjustment Factor	3.75%
Implicit Price Index (20121004) = A	2.20%
Productivity Factor = B	0.72%
Stretch Factor = C	0.60%
Price Cap Index = A - (B+C)	0.88%

	Total		Residential R1	Residential R2	Seasonal	Street Lighting
Price Index (October 4, 2012)			0.88%	0.88%	0.88%	0.88%
Revenue Requirement	$ 20,079,236		14,609,242	2,895,187	2,439,243	135,564
Smart Meter Cost Recovery						
Net Deferred Revenue Requirement	$ 1,752,033		1,245,917	-	506,116	-
Incremental Revenue Requirement	$ 708,415		502,406	-	206,009	-
Total Revenue Requirement for 2013	$ 22,539,684		16,357,565	2,895,187	3,151,368	135,564

In its Decision, EB-2012-0104, the Board has approved collection of the Residential R1 allocation from the RRRP funding over a two year period ending December 31, 2014. The Seasonal allocation is to be recovered through a rate rider over a 44 month period; May 1, 2012 to December 31 2016.

In the Table below and high-lighted, 50% of the Net Deferred Revenue Requirement and the Incremental Revenue Requirement is allocated to the Residential R1 class to simulate the two year recovery period stipulated in the Board's Decision.

	Total		Residential R1	Residential R2	Seasonal	Street Lighting
Price Index (October 4, 2012)			0.88%	0.88%	0.88%	0.88%
Revenue Requirement	$ 20,079,236		14,609,242	2,895,187	2,439,243	135,564
Smart Meter Cost Recovery						
Net Deferred Revenue Requirement	$ 622,959		622,959	-	-	-
Incremental Revenue Requirement	$ 251,203		251,203	-	-	-
Total Revenue Requirement per Decision	$ 20,953,398		$15,483,404	$2,895,187	$ 2,439,243	$ 135,564

2014 Continued Recovery of Smart Meter Costs Allocated to Residential - R1						
	Total		**Residential R1**	**Residential R2**	**Seasonal**	**Street Lighting**
Price Index (Estimated)			0.48%	0.48%	0.48%	0.48%
Revenue Requirement	$ 20,175,616		14,679,367	2,909,084	2,450,951	136,214
Smart Meter Cost Recovery						
Net Deferred Revenue Requirement	$ 622,959		622,959	-	-	-
Incremental Revenue Requirement	$ 251,203		251,203	-	-	-
Total Revenue Requirement per Decision	$ 21,049,778		$15,553,528	$2,909,084	$ 2,450,951	$ 136,214

Derivation of 2014 Proposed Distribution Rates and 2014 RRRP Funding Amount

By virtue of O. Reg. 442/01, the Residential R – 1 and Residential R – 2 electricity distribution rates are the currently approved rates adjusted by the RRRP Adjustment Factor, as determined by the Board.

In this rate design, API has assumed the RRRP Adjustment Factor for the 2014 rate year to be 2.20%. API acknowledges that the Board will apply the appropriate RRRP Adjustment Factor when the data becomes available.

Determination of Residential R1 & R2 2014 Electricity Distribution Rates and RRRP Funding

2014 Distribution Base Rate Determination											
			Billing Determinant		**F/V Split**		**Distribution Rates**		**Revenues**		
Customer Class	**Metric**	**Average # of Customers**	**kWh**	**kW**	**Fixed Allocation**	**Variable Allocation**	**Monthly Service Charge**	**Variable Charge**	**Fixed**	**Variable**	**Total Revenue**
Residential - R1	kWh	8039	106,119,297		13.6%	86.4%	22.00	0.1266	2,122,547	13,430,982	15,553,528
Residential - R2	kW	48		151,952	12.0%	88.0%	606.55	16.8455	349,372	2,559,712	2,909,084
									2,471,919	**15,990,694**	**18,462,612**
2014 Application of Rate Indexing Methodology											
Delivery Charges Indexed by Simple Average of Other LDC Increases in Current Year											
Simple Average Increase in Delivery Charge for 2014 using the Board Determination											**2.20%**
			Billing Determinant		**F/V Split**		**Distribution Rates**		**Revenues**		
Customer Class	**Metric**	**Average # of Customers**	**kWh**	**kW**	**Fixed Allocation**	**Variable Allocation**	**Monthly Service Charge**	**Variable Charge**	**Fixed**	**Variable**	**Total Revenue**
Residential - R1	kWh	8039	106,119,297		39.3%	60.7%	22.81	0.0320	2,200,535	3,394,608	5,595,143
Residential - R2	kW	48		151,952	43.8%	56.2%	609.23	2.9586	350,919	449,563	800,482
Hold Residential - R2 Fixed Charge at $596.12					42.9%	57.1%	596.12	3.0083	343,365	457,117	800,482
									2,543,901	**3,851,725**	**6,395,626**
The Rural and Remote Rate Protection Amount Required for 2014											**$12,066,987**

The fixed monthly charge for the Residential – R2 customer class is held at $596.12 in accordance with the proposed settlement agreement accepted in EB-2009-0278.

The RRRP Funding amount for 2014 has been calculated at $12,066,987. It is the difference between the revenue allocated to these classes and the revenue recovered at the proposed 2014 adjusted electricity distribution rates.

Rates for the Seasonal and Street Light customer classes are determined on the basis of the assumed Price Cap Index; calculated by API to be 0.48%. API acknowledges that the Board will apply the appropriate Price Cap when the data becomes available. The rate determination is shown below.

Determination of Seasonal and Street Lighting Distribution Rates

2014 Distribution Base Rate Determination											
			Billing Determinant		F/V Split		Distribution Rates		Revenues		
Customer Class	Metric	Average # of Customers	kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Seasonal	kWh	3660	12,622,297		47.5%	52.5%	26.51	0.1019	1,164,202	1,286,749	2,450,951
Street Lighting	kWh	1052	791,996		0.0%	100.0%	-	0.1720	-	136,214	136,214
Street Lighting					9.0%	91.0%	0.97	0.1565	12,304	123,910	136,214
									1,176,506	**1,410,660**	**2,587,165**

The fixed monthly charge for the Street Lighting customer class is set at $0.97 in accordance with the proposed settlement agreement accepted in EB-2009-0278.

Reconciliation

In the table provided below, the proposed 2014 electricity distribution rates have been reconciled with the indexed 2014 revenue requirement, including smart meter recovery, determined earlier and shown in the table captioned “2014 Continued Recovery of Smart Meter Costs Allocated to Residential - R1” to be $21,049,778.

	No. of Customers	Charge Determinant	2014 Monthly Service Charge	2014 Volumetric Distribution Charge	2014 Monthly Service Charge Revenue	2014 Volumetric Distribution Revenue	Total Service Revenue	Proposed 2014 RRRP	Total Service Revenue plus RRRP
Residential - R1	8,039	106,119,297	22.81	0.0320	2,200,535	3,394,608	5,595,143		
Residential - R2	48	151,952	596.12	3.0083	343,365	457,117	800,482		
Seasonal	3,660	12,622,297	26.51	0.1019	1,164,202	1,286,749	2,450,951		
Street Lighting	1,052	791,996	0.97	0.1565	12,304	123,910	136,214		
					3,720,406	5,262,385	8,982,791	12,066,987	21,049,778

The customer counts and volumes are those approved by the Board in API’s last cost of service review, EB-2009-0278.

The entire rate design module is provided on the following pages and an electronic copy accompanies this Application.

Algoma Power Inc.
Distribution Rate Design Module

2014 4th IR Electricity Distribution Rate Design
EB-2013-0110
Application

August 16, 2013

			Approved		2014 4th IR
			EB-2012-0104		EB-2013-0110
Delivery Charges			**Delivery Charges**		**Proposed Delivery Charges**
Monthly Rates and Charges	**Metric**		**Effective January 1, 2013 Implemented May 1, 2013**		**Effective January 1, 2014**
Residential - R1					
Monthly Service Charge	$		22.32		22.81
Distribution Volumetric Rate	$/kWh		0.0313		0.0320
Distribution Volumetric Rate Rate Rider, effective until December 31, 2014	$/kWh		0.0004		0.0004
Residential - R2					
Monthly Service Charge	$		596.12		596.12
Distribution Volumetric Rate	$/kW		2.8949		3.0083
Distribution Volumetric Rate Rate Rider, effective until December 31, 2014	$/kW		0.0373		0.0373
Seasonal					
Monthly Service Charge	$		26.38		26.51
Distribution Volumetric Rate	$/kWh		0.1015		0.1019
Distribution Volumetric Rate Rate Rider, effective until December 31, 2014	$/kWh		0.0003		0.0003
Smart Meter Cost Recovery Rate Rider - Net Deferred Revenue Requirement, effective until December 31, 2016	$/kWh		3.57		3.57
Smart Meter Cost Recovery Rate Rider - Incremental Revenue Requirement, effective until December 31, 2014	$/kWh		4.69		4.69
Street Lighting					
Monthly Service Charge	$		0.97		0.97
Distribution Volumetric Rate	$/kWh		0.1557		0.1565
Distribution Volumetric Rate Rate Rider, effective until December 31, 2014	$/kWh		0.0003		0.0003
Rural and Remote Rate Protection	$		12,117,516		12,066,987

Algoma Load and Customer Forecast Information - Board Approved EB-2009-0278										
	2003	2004	2005	2006	2007 Application	2007	2008	2009	2010 Test Year	2011 Test Year
R1										
Number of Customers	7,837	7,763	7,758	7,740	7,740	7,815	7,923	7,997	8,024	8,049
Change in Customer Count		(74)	(5)	(18)		75	109	74	27	25
Kilowatt-hours	108,693,027	105,879,912	103,661,767	99,478,516	104,428,306	100,674,579	103,691,076	103,761,012		
Weather Normalized Kilowatt-hours								103,317,932	104,754,767	106,119,297
Average per Customer - kWh	13,869	13,639	13,362	12,853	13,492	12,883	13,087	12,975		
Normalized Average per Customer - kWh								12,920	13,055	13,184
Seasonal										
Number of Customers	3,577	3,646	3,652	3,707	3,707	3,718	3,688	3,643	3,654	3,665
Change in Customer Count		69	6	55		11	(30)	(45)	11	11
Kilowatt-hours	11,867,258	11,692,754	11,678,117	11,746,043	11,746,043	11,665,351	11,591,418	12,341,792		
Weather Normalized Kilowatt-hours								12,289,090	12,459,994	12,622,297
Average per Customer - kWh	3,318	3,207	3,198	3,169	3,169	3,138	3,143	3,388		
Normalized Average per Customer - kWh								3,373	3,410	3,444
Residential - R2										
Number of Customers	49	49	47	45	47	47	48	48	48	48
Kilowatt-hours		30,337,868	66,360,103	68,290,099	50,139,889	75,340,938	66,017,652	69,931,763		
Kilowatts		163,453	182,693	180,802	197,392	191,492	159,280	150,499		
Weather Normalized Kilowatt-hours								69,808,980	70,228,773	70,606,900
Weather Normalized Kilowatts								150,235	151,138	151,952
Average per Customer - kWh		619,140	1,411,917	1,517,558	1,066,806	1,602,999	1,375,368	1,456,912		
Average per Customer - kW		3,336	3,887	4,018	4,200	4,074	3,318	3,135		
Normalized Average per Customer - kWh								1,454,354	1,463,099	1,470,977
Normalized Average per Customer - kW								3,130	3,149	3,166
Street Light										
Number of Customers	104	103	100	99	99	32	32	32	32	32
Kilowatt-hours	935,668	1,002,422	1,046,222	1,056,913	1,010,306	816,298	791,996	791,996	791,996	791,996
Kilowatts							2,304	2,304	2,304	2,304
Totals										
Number of Customers	11,567	11,561	11,557	11,591	11,593	11,611	11,691	11,720	11,758	11,794
Kilowatt-hours		148,912,956	182,746,209	180,571,571	167,324,544	188,497,166	182,092,142	186,826,563		
Kilowatts		163,453	182,693	180,802	197,392	191,492	161,584	152,803		
Weather Normal Kilowatt-hours								186,207,998	188,235,530	190,140,490
Weather Normal Kilowatts								152,539	153,442	154,256

Board Approved EB-2009-0278

2006 COST ALLOCATION INFORMATION FILING

Algoma Power Inc.

EB-2010-0278

June-01-10

Sheet O1 Revenue to Cost Summary Worksheet - First Run

Rate Base Assets			1	2	7	12
		Total	**R1**	**R2**	**Street Light**	**Seasonal**
crev	Distribution Revenue (sale)	$18,585,008	$13,865,405	$1,717,567	$42,237	$2,959,799
mi	Miscellaneous Revenue (mi)	$343,057	$217,490	$88,133	$5,003	$32,431
	Total Revenue	$18,928,065	$14,082,895	$1,805,700	$47,240	$2,992,230
	Expenses					
di	Distribution Costs (di)	$4,712,464	$2,835,059	$1,290,517	$87,388	$499,501
cu	Customer Related Costs (cu)	$1,693,808	$1,394,715	$91,659	$11,235	$196,199
ad	General and Administration (ad)	$2,632,964	$1,725,449	$583,912	$40,420	$283,183
dep	Depreciation and Amortization (dep)	$4,056,672	$2,563,128	$975,345	$70,644	$447,555
INPUT	PILs (INPUT)	$751,038	$456,888	$209,628	$11,219	$73,304
INT	Interest	$2,342,458	$1,425,014	$653,821	$34,991	$228,631
	Total Expenses	$16,189,405	$10,400,253	$3,804,882	$255,898	$1,728,372
	Direct Allocation	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$2,738,660	$1,666,040	$764,408	$40,910	$267,302
	Revenue Requirement (includes NI)	$18,928,065	$12,066,293	$4,569,290	$296,807	$1,995,675
		Revenue Requirement Input Does Not Equal Output				
	Rate Base Calculation					
	<u>Net Assets</u>					
dp	Distribution Plant - Gross	$101,557,858	$61,697,989	$27,444,170	$1,706,422	$10,709,276
gp	General Plant - Gross	$10,530,382	$6,406,067	$2,939,214	$157,302	$1,027,799
accum dep	Accumulated Depreciation	($46,509,937)	($28,210,059)	($12,079,334)	($884,122)	($5,336,422)
co	Capital Contribution	$0	$0	$0	$0	$0
	Total Net Plant	$65,578,302	$39,893,997	$18,304,050	$979,602	$6,400,653
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$17,166,389	$9,553,250	$6,404,606	$72,227	$1,136,306
	OM&A Expenses	$9,039,237	$5,955,223	$1,966,088	$139,043	$978,883
	Directly Allocated Expenses	$0	$0	$0	$0	$0
	Subtotal	*$26,205,626*	*$15,508,473*	*$8,370,694*	*$211,270*	*$2,115,188*
	Working Capital	$3,930,844	$2,326,271	$1,255,604	$31,691	$317,278
	Total Rate Base	$69,509,146	$42,220,268	$19,559,654	$1,011,293	$6,717,932
		Rate Base Input equals Output				
	Equity Component of Rate Base	$0	$0	$0	$0	$0
	Net Income on Allocated Assets	$2,738,660	$3,682,642	($1,999,182)	($208,657)	$1,263,858
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0
	Net Income	$2,738,660	$3,682,642	($1,999,182)	($208,657)	$1,263,858
	RATIOS ANALYSIS					
	REVENUE TO EXPENSES %	100.00%	116.71%	39.52%	15.92%	149.94%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$0	$2,016,602	($2,763,590)	($249,567)	$996,556
	RETURN ON EQUITY COMPONENT OF RATE BASE	0.00%	0.00%	0.00%	0.00%	0.00%

Board Approved EB-2009-0278

2011 Cost Allcoaction Results									
	Cost Allocation Revenue Requirement	Revenue Requirement Allocation Percentage	Cost Allocation Misc.	Cost Allocation Misc. Percentage	2011 Service Revenue Requirement	2011 Misc. Revenue	2011 Base Revenue Requirement		
Residential - R1	12,066,293	63.7%	217,490	63.4%	12,876,372	234,623	12,641,749		
Residential - R2	4,569,290	24.1%	88,133	25.7%	4,876,052	95,075	4,780,977		
Seasonal	1,995,675	10.5%	32,431	9.5%	2,129,655	34,986	2,094,669		
Street Lighting	296,807	1.6%	5,003	1.5%	316,734	5,397	311,336		
	18,928,065	100.0%	343,057	100.0%	20,198,813	370,082	19,828,731		

2011 Base Distribution Rate Cost Allcation Design									
	2011 Approved Revenue @ 100% R|C	Revenue Proportions @ 100% R|C	Approved Proportion of Revenue	Base Revenue @ Approved Proportion	Over/(Under) Contributing	Approved Revenue to Cost Ratio	2011 Cost Allocation R|C	Board's Guideline	Target R|C Ratio
Residential - R1	12,641,749	63.8%	72.8%	14,426,980	1,785,231	114.1%	116.71%	85-115%	Beneficary
Residential - R2	4,780,977	24.1%	14.4%	2,859,067	(1,921,909)	59.8%	39.52%	80-180%	59.8%
Seasonal	2,094,669	10.6%	12.1%	2,408,811	314,142	115.0%	149.94%	85-115%	115.0%
Street Lighting	311,336	1.6%	0.7%	133,872	(177,464)	43.0%	15.92%	70-120%	43.0%
	19,828,731	100.0%	100.0%	19,828,731					

No Adjustment Made to the 2011 Board Approved Revenue to Cost Ratios

2011 Cost Allocation Results								
	Cost Allocation Revenue Requirement	Revenue Requirement Allocation Percentage	Cost Allocation Misc.	Cost Allocation Misc. Percentage	2011 Service Revenue Requirement	2011 Misc. Revenue	2011 Base Revenue Requirement	
Residential - R1	12,066,293	63.7%	217,490	63.4%	12,876,372	234,623	12,641,749	
Residential - R2	4,569,290	24.1%	88,133	25.7%	4,876,052	95,075	4,780,977	
Seasonal	1,995,675	10.5%	32,431	9.5%	2,129,655	34,986	2,094,669	
Street Lighting	296,807	1.6%	5,003	1.5%	316,734	5,397	311,336	
	18,928,065	100.0%	343,057	100.0%	20,198,813	370,082	19,828,731	

Board Approved 2011 Base Distribution Rate Cost Allcation Design								
	2011 Approved Revenue @ 100% R|C	Revenue Proportions @ 100% R|C	Approved Proportion of Revenue	Base Revenue @ Approved Proportion	Over/(Under) Contributing	Approved Revenue to Cost Ratio	2011 Cost Allocation R|C	Board's Guideline
Residential - R1	12,641,749	63.8%	72.8%	14,426,980	1,785,231	114.1%	116.7%	85-115%
Residential - R2	4,780,977	24.1%	14.4%	2,859,067	(1,921,909)	59.8%	39.5%	80-180%
Seasonal	2,094,669	10.6%	12.1%	2,408,811	314,142	115.0%	149.9%	85-115%
Street Lighting	311,336	1.6%	0.7%	133,872	(177,464)	43.0%	15.9%	70-120%
	19,828,731	100.0%		19,828,731				

Actual 2012 Base Distribution Rate Cost Allocation Design								
	2012 Forecasted Revenue @ 100% R|C	Revenue Proportions @ 100% R|C	Proposed Proportion of Revenue	Base Revenue @ Proposed Proportion	Over/(Under) Contributing	Proposed Revenue to Cost Ratio	2010 Cost Allocation R|C	Board's Guideline
Residential - R1	12,689,787	63.8%	72.8%	14,481,803	1,792,015	114.1%	116.71%	85-115%
Residential - R2	4,799,145	24.1%	14.4%	2,869,932	(1,929,213)	59.8%	39.52%	80-180%
Seasonal	2,102,629	10.6%	12.1%	2,417,965	315,336	115.0%	149.94%	85-115%
Street Lighting	312,519	1.6%	0.7%	134,381	(178,138)	43.0%	15.92%	70-120%
	19,904,080	100.0%	100.0%	19,904,080				

Actual 2013 Base Distribution Rate Cost Allocation Design								
	2013 Forecasted Revenue @ 100% R|C	Revenue Proportions @ 100% R|C	Proposed Proportion of Revenue	Base Revenue @ Proposed Proportion	Over/(Under) Contributing	Proposed Revenue to Cost Ratio	2010 Cost Allocation R|C	Board's Guideline
Residential - R1	12,801,457	63.8%	72.8%	14,609,242	1,807,785	114.1%	0.00%	85-115%
Residential - R2	4,841,377	24.1%	14.4%	2,895,187	(1,946,190)	59.8%	0.00%	80-180%
Seasonal	2,121,132	10.6%	12.1%	2,439,243	318,111	115.0%	0.00%	85-115%
Street Lighting	315,270	1.6%	0.7%	135,564	(179,706)	43.0%	0.00%	70-120%
	20,079,236	100.0%	100.0%	20,079,236				

Proposed 2014 Base Distribution Rate Cost Allocation Design								
	2014 Forecasted Revenue @ 100% R|C	Revenue Proportions @ 100% R|C	Proposed Proportion of Revenue	Base Revenue @ Proposed Proportion	Over/(Under) Contributing	Proposed Revenue to Cost Ratio	2010 Cost Allocation R|C	Board's Guideline
Residential - R1	12,862,904	63.8%	72.8%	14,679,367	1,816,462	114.1%	0.00%	85-115%
Residential - R2	4,864,616	24.1%	14.4%	2,909,084	(1,955,531)	59.8%	0.00%	80-180%
Seasonal	2,131,313.53	10.6%	12.1%	2,450,951	319,637	115.0%	0.00%	85-115%
Street Lighting	316,783	1.6%	0.7%	136,214	(180,568)	43.0%	0.00%	70-120%
	20,175,616	100.0%	100.0%	20,175,616				

Board Approved EB-2009-0278
Equivalent Distribution Rates

2011 Distribution Base Rate Determination											
			Billing Determinant		F/V Split		Distribution Rates		Revenues		
Customer Class	Metric	Average # of Customers	kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8039	106,119,297		13.6%	86.4%	20.41	0.1174	1,968,810	12,458,170	14,426,980
Residential - R2	kW	48		151,952	12.0%	88.0%	596.12	16.5559	343,365	2,515,702	2,859,067
Seasonal	kWh	3660	12,622,297		43.8%	56.2%	24.00	0.1073	1,054,008	1,354,803	2,408,811
Street Lighting	kWh	1052	791,996		0.0%	100.0%	-	0.1690	-	133,872	133,872
									3,366,183	**16,462,548**	**19,828,731**

Board Approved 2012 Incentive Regulation Price Cap Metrics	
RRRP Adjustment Factor	2.81%
Implicit Price Index	1.70%
Productivity Factor	0.72%
Stretch Factor	0.60%
Price Cap Index	0.38%

Board Approved 2012 Application of Incentive Regulation Price Cap to Equivalent Distribution Rates
Price Cap Index 0.38%

2012 Distribution Price Indexed Electricity Distribution Rates											
			Billing Determinant		F/V Split		Distribution Rates		Revenues		
Customer Class	Metric	Average # of Customers	kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8039	106,119,297		13.6%	86.4%	20.49	0.1178	1,976,291	12,505,511	14,481,803
Residential - R2	kW	48		151,952	12.0%	88.0%	598.39	16.6188	344,670	2,525,262	2,869,932
Seasonal	kWh	3660	12,622,297		43.8%	56.2%	24.09	0.1077	1,058,013	1,359,951	2,417,965
Street Lighting	kWh	1052	791,996		0.0%	100.0%	-	0.1697	-	134,381	134,381
									3,378,974	**16,525,106**	**19,904,080**

Actual 2013 Incentive Regulation Price Cap Metrics	
RRRP Adjustment Factor (Decision)	3.75%
Implicit Price Index	2.20%
Productivity Factor	0.72%
Stretch Factor	0.60%
Price Cap Index (Decision)	0.88%

Actual 2013 Application of Incentive Regulation Price Cap to Equivalent Distribution Rates
Price Cap Index 0.88%

2013 Distribution Price Indexed Electricity Distribution Rates											
			Billing Determinant		F/V Split		Distribution Rates		Revenues		
Customer Class	Metric	Average # of Customers	kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8039	106,119,297		13.6%	86.4%	20.67	0.1189	1,993,683	12,615,560	14,609,242
Residential - R2	kW	48		151,952	12.0%	88.0%	603.65	16.7651	347,703	2,547,484	2,895,187
Seasonal	kWh	3660	12,622,297		43.8%	56.2%	24.30	0.1087	1,067,324	1,371,919	2,439,243
Street Lighting	kWh	1052	791,996		0.0%	100.0%	-	0.1712	-	135,564	135,564
									3,408,709	**16,670,527**	**20,079,236**

Proposed 2014 Incentive Regulation Price	
RRRP Adjustment Factor (Estimated)	2.20%
Implicit Price Index (Estimated)	1.60%
Productivity Factor (Estimated)	0.72%
Stretch Factor (Estimated)	0.40%
Price Cap Index (Calculated)	0.48%

Proposed 2014 Application of Incentive Regulation Price Cap to Equivalent Distribution Rates
Price Cap Index 0.48%

2014 Distribution Price Indexed Electricity Distribution Rates											
			Billing Determinant		F/V Split		Distribution Rates		Revenues		
Customer Class	Metric	Average # of Customers	kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8039	106,119,297		13.6%	86.4%	20.77	0.1195	2,003,252	12,676,114	14,679,367
Residential - R2	kW	48		151,952	12.0%	88.0%	606.55	16.8455	349,372	2,559,712	2,909,084
Seasonal	kWh	3660	12,622,297		43.8%	56.2%	24.42	0.1092	1,072,447	1,378,504	2,450,951
Street Lighting	kWh	1052	791,996		0.0%	100.0%	-	0.1720	-	136,214	136,214
									3,425,071	**16,750,545**	**20,175,616**

2013 Approved Methodology with Smart Meter Recovery, EB-2012-0104

RRRP Adjustment Factor	3.75%
Implicit Price Index (20121004) = A	2.20%
Productivity Factor = B	0.72%
Stretch Factor = C	0.60%
Price Cap Index = A - (B+C)	0.88%

	Total		Residential R1	Residential R2	Seasonal	Street Lighting
Price Index (October 4, 2012)			0.88%	0.88%	0.88%	0.88%
Revenue Requirement	$ 20,079,236		14,609,242	2,895,187	2,439,243	135,564
Smart Meter Cost Recovery						
Net Deferred Revenue Requirement	$ 1,752,033		1,245,917	-	506,116	-
Incremental Revenue Requirement	$ 708,415		502,406	-	206,009	-
Total Revenue Requirement for 2013	$ 22,539,684		16,357,565	2,895,187	3,151,368	135,564

In its Decision, EB-2012-0104, the Board has approved collection of the Residential R1 allocation from the RRRP funding over a two year period ending December 31, 2014. The Seasonal allocation is to be recovered through a rate rider over a 44 month period; May 1, 2012 to December 31 2016.

In the Table below and high-lighted, 50% of the Net Deferred Revenue Requirement and the Incremental Revenue Requirement is allocated to the Residential R1 class to simulate the two year recovery period stipulated in the Board's Decision.

	Total		Residential R1	Residential R2	Seasonal	Street Lighting
Price Index (October 4, 2012)			0.88%	0.88%	0.88%	0.88%
Revenue Requirement	$ 20,079,236		14,609,242	2,895,187	2,439,243	135,564
Smart Meter Cost Recovery						
Net Deferred Revenue Requirement	$ 622,959		622,959	-	-	-
Incremental Revenue Requirement	$ 251,203		251,203	-	-	-
Total Revenue Requirement per Decision	$ 20,953,398		$15,483,404	$ 2,895,187	$ 2,439,243	$ 135,564

2014 Continued Recovery of Smart Meter Costs Allocated to Residential - R1

	Total		Residential R1	Residential R2	Seasonal	Street Lighting
Price Index (Estimated)			0.48%	0.48%	0.48%	0.48%
Revenue Requirement	$ 20,175,616		14,679,367	2,909,084	2,450,951	136,214
Smart Meter Cost Recovery						
Net Deferred Revenue Requirement	$ 622,959		622,959	-	-	-
Incremental Revenue Requirement	$ 251,203		251,203	-	-	-
Total Revenue Requirement per Decision	$ 21,049,778		$15,553,528	$ 2,909,084	$ 2,450,951	$ 136,214

Determination of Residential R1 & R2 2014 Electricity Distribution Rates and RRRP Funding

2014 Distribution Base Rate Determination											
Customer Class	Metric	Average # of Customers	Billing Determinant		F/V Split		Distribution Rates		Revenues		
			kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8039	106,119,297		13.6%	86.4%	22.00	0.1266	2,122,547	13,430,982	15,553,528
Residential - R2	kW	48		151,952	12.0%	88.0%	606.55	16.8455	349,372	2,559,712	2,909,084
									2,471,919	**15,990,694**	**18,462,612**
2014 Application of Rate Indexing Methodology											
Delivery Charges Indexed by Simple Average of Other LDC Increases in Current Year											
Simple Average Increase in Delivery Charge for 2014 using the Board Determination											**2.20%**
Customer Class	Metric	Average # of Customers	Billing Determinant		F/V Split		Distribution Rates		Revenues		
			kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8039	106,119,297		39.3%	60.7%	22.81	0.0320	2,200,535	3,394,608	5,595,143
Residential - R2	kW	48		151,952	43.8%	56.2%	609.23	2.9586	350,919	449,563	800,482
Hold Residential - R2 Fixed Charge at $596.12					42.9%	57.1%	596.12	3.0083	343,365	457,117	800,482
									2,543,901	**3,851,725**	**6,395,626**
The Rural and Remote Rate Protection Amount Required for 2014											**$ 12,066,987**

Determination of Seasonal and Street Lighting Distribution Rates

2014 Distribution Base Rate Determination											
Customer Class	Metric	Average # of Customers	Billing Determinant		F/V Split		Distribution Rates		Revenues		
			kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Seasonal	kWh	3660	12,622,297		47.5%	52.5%	26.51	0.1019	1,164,202	1,286,749	2,450,951
Street Lighting	kWh	1052	791,996		0.0%	100.0%	-	0.1720	-	136,214	136,214
Street Lighting					9.0%	91.0%	0.97	0.1565	12,304	123,910	136,214
									1,176,506	**1,410,660**	**2,587,165**

Reconciliation of Proposed Distribution Revenue with Price Cap

	No. of Customers	Charge Determinant	2014 Monthly Service Charge	2014 Volumetric Distribution Charge	2014 Monthly Service Charge Revenue	2014 Volumetric Distribution Revenue	Total Service Revenue	Proposed 2014 RRRP	Total Service Revenue plus RRRP
Residential - R1	8,039	106,119,297	22.81	0.0320	2,200,535	3,394,608	5,595,143		
Residential - R2	48	151,952	596.12	3.0083	343,365	457,117	800,482		
Seasonal	3,660	12,622,297	26.51	0.1019	1,164,202	1,286,749	2,450,951		
Street Lighting	1,052	791,996	0.97	0.1565	12,304	123,910	136,214		
					3,720,406	5,262,385	8,982,791	12,066,987	21,049,778

Balanced? **Yes**

Schedule “D”

Tax Change Rate Rider

Incentive Regulation Shared Tax Savings Model for 2014 Filers

Version 1.1

Utility Name	Algoma Power Inc.
Service Territory Name	
Assigned EB Number	EB-2013-0110
Name and Title	Douglas Bradbury Director Regulatory Affairs
Phone Number	905 994 3634
Email Address	doug.bradbury@fortisontario.com
Date	August-16-13
Last COS Re-based Year	**2011**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

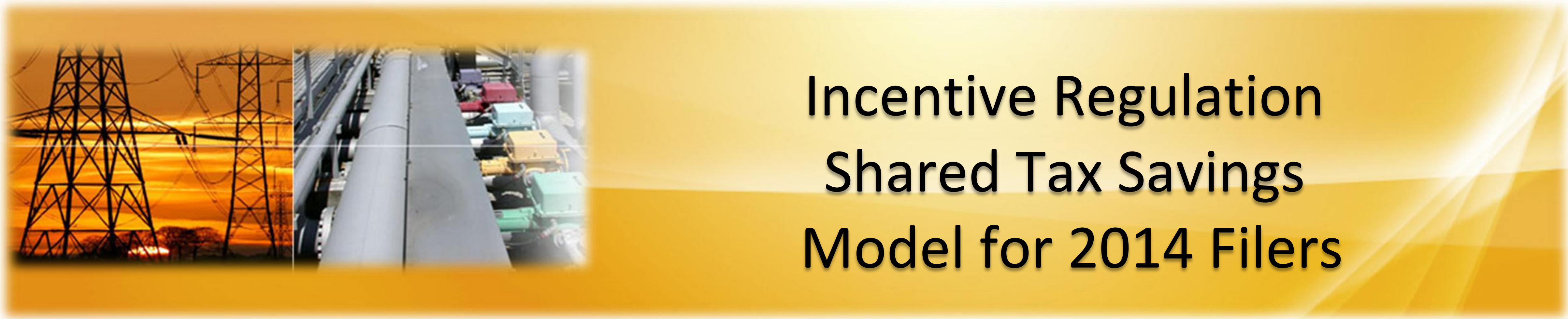
Incentive Regulation Shared Tax Savings Model for 2014 Filers

Incentive Regulation Shared Tax Savings Model for 2014 Filers

Enter your 2013 Base Monthly Fixed Charge and Distribution Volumetric Charge into columns labeled "Rate ReBal Base Service Charge" and "Rate ReBal Base Distribution Volumetric Rate kWh/kW" respectively.

Last COS Re-based Year was in 2011

Rate Group	Rate Class	Fixed Metric	Vol Metric	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Rate ReBal Base Service Charge D	Rate ReBal Base Distribution Volumetric Rate kWh E	Rate ReBal Base Distribution Volumetric Rate kW F
RES	Residential	Customer	kWh	8,039	106,119,297		22.32	0.0313	
GSGT50	General Service 50 to 499 kW	Customer	kW	48		151,952	596.12		2.8949
RES	Seasonal Residential – Normal Density [R4]	Customer	kWh	3,660	12,622,297		26.38	0.1015	
SL	Street Lighting	Connection	kW	1,052	791,996		0.97		0.1557
NA	Rate Class 5	NA	NA						
NA	Rate Class 6	NA	NA						
NA	Rate Class 7	NA	NA						
NA	Rate Class 8	NA	NA						
NA	Rate Class 9	NA	NA						
NA	Rate Class 10	NA	NA						
NA	Rate Class 11	NA	NA						
NA	Rate Class 12	NA	NA						
NA	Rate Class 13	NA	NA						
NA	Rate Class 14	NA	NA						
NA	Rate Class 15	NA	NA						
NA	Rate Class 16	NA	NA						
NA	Rate Class 17	NA	NA						
NA	Rate Class 18	NA	NA						
NA	Rate Class 19	NA	NA						
NA	Rate Class 20	NA	NA						
NA	Rate Class 21	NA	NA						
NA	Rate Class 22	NA	NA						
NA	Rate Class 23	NA	NA						
NA	Rate Class 24	NA	NA						
NA	Rate Class 25	NA	NA						



Calculating Re-Based Revenue from rates. No input required.

Last COS Re-based Year was in 2011

Rate Class	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Rate ReBal Base Service Charge D	Rate ReBal Base Distribution Volumetric Rate kWh E	Rate ReBal Base Distribution Volumetric Rate kW F	Service Charge Revenue G = A * D *12	Distribution Volumetric Rate Revenue kWh H = B * E	Distribution Volumetric Rate Revenue kW I = C * F	Revenue Requirement from Rates J = G + H + I
Residential	8,039	106,119,297	0	22.32	0.0313	0.0000	2,153,166	3,321,534	0	5,474,700
General Service 50 to 499 kW	48	0	151,952	596.12	0.0000	2.8949	343,365	0	439,886	783,251
Seasonal Residential – Normal Density [R	3,660	12,622,297	0	26.38	0.1015	0.0000	1,158,610	1,281,163	0	2,439,773
Street Lighting	1,052	791,996	0	0.97	0.0000	0.1557	12,245	0	0	12,245
							3,667,386	4,602,697	439,886	8,709,969

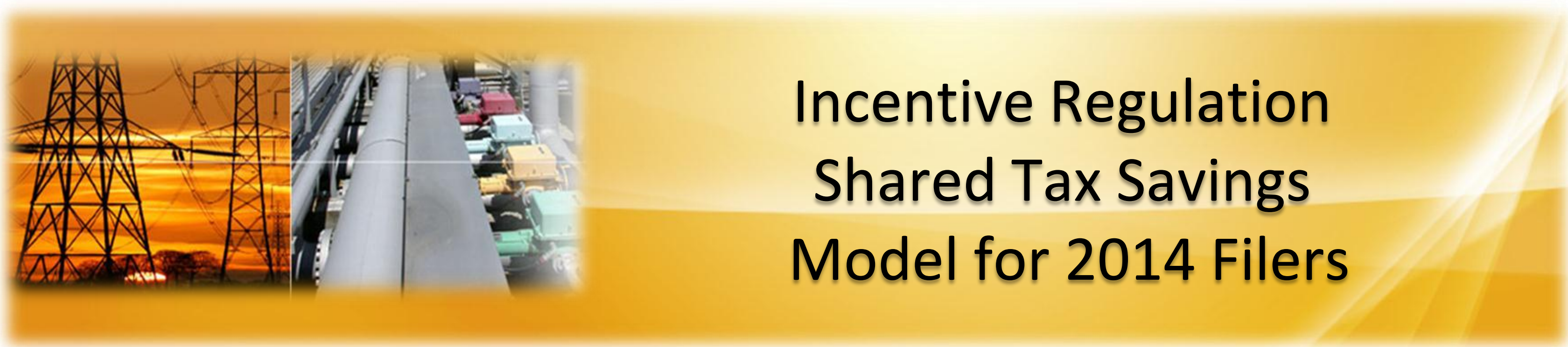
This worksheet calculates the tax sharing amount.

Step 1: Press the Update Button (this will clear all input cells and reveal your latest cost of service re-basing year).
Step 2: In the green input cells below, please enter the information related to the last Cost of Service Filing.

Summary - Sharing of Tax Change Forecast Amounts

For the 41502 year, enter any Tax Credits from the Cost of Service Tax Calculation (Positive #)

1. Tax Related Amounts Forecast from Capital Tax Rate Changes	**2011**	**2014**
Taxable Capital		$ -
Deduction from taxable capital up to $15,000,000		$ -
Net Taxable Capital	$ -	$ -
Rate	0.000%	0.000%
Ontario Capital Tax (Deductible, not grossed-up)	**$ -**	**$ -**
2. Tax Related Amounts Forecast from Income Tax Rate Changes	**2011**	**2014**
Regulatory Taxable Income	$ 1,269,534	$ 1,269,534
Corporate Tax Rate	28.25%	26.50%
Tax Impact	$ 358,643	$ 336,427
Grossed-up Tax Amount	**$ 499,851**	**$ 457,723**
Tax Related Amounts Forecast from Capital Tax Rate Changes	$ -	$ -
Tax Related Amounts Forecast from Income Tax Rate Changes	$ 499,851	$ 457,723
Total Tax Related Amounts	**$ 499,851**	**$ 457,723**
Incremental Tax Savings		**-$ 42,128**
Sharing of Tax Savings (50%)		**-$ 21,064**



This worksheet calculates a tax change volumetric rate rider. No input required. The outputs in column Q and S are to be entered into Sheet 11 "Proposed Rates" of the 2014 IRM Rate Generator Model. Rate description should be entered as "Rate Rider for Tax Change".

Rate Class	Total Revenue $ by Rate Class A	Total Revenue % by Rate Class B = A / $H	Total Z-Factor Tax Change$ by Rate Class C = $I * B	Billed kWh D	Billed kW E	Distribution Volumetric Rate kWh Rate Rider F = C / D	Distribution Volumetric Rate kW Rate Rider G = C / E
Residential	$5,474,700	62.86%	-$13,240	106,119,297	0	-$0.0001	
General Service 50 to 499 kW	$783,251	8.99%	-$1,894	0	151,952		-$0.0125
Seasonal Residential – Normal Density [R4]	$2,439,773	28.01%	-$5,900	12,622,297	0	-$0.0005	
Street Lighting	$12,245	0.14%	-$30	791,996	0		
	$8,709,969	100.00%	-$21,064				
	H		- I				

Schedule “E”

2014 Retail Transmission Service Rates

v 4.0

RTSR Workform for Electricity Distributors (2014 Filers)

Utility Name	Algoma Power Inc.
Service Territory	
Assigned EB Number	EB-2013-0110
Name and Title	Douglas R. Bradbury, Directory Regulatory Affairs
Phone Number	(905) 994-3634
Email Address	doug.bradbury@fortisontario.com
Date	16-Aug-13
Last COS Re-based Year	**2011**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

RTSR Workform for Electricity Distributors (2014 Filers)

RTSR Workform for Electricity Distributors (2014 Filers)

1. Select the appropriate rate classes that appear on your most recent Board-Approved Tariff of Rates and Charges.
2. Enter the RTS Network and Connection Rate as it appears on the Tariff of Rates and Charges

Rate Class	Unit	RTSR-Network	RTSR-Connection
Residential – High Density [R1]	kWh	$ 0.0069	$ 0.0049
General Service 50 to 4,999 kW	kW	$ 2.5633	$ 1.7423
General Service 1,000 to 4,999 kW - Interval Meters	kW	$ 2.7191	$ 1.9255
Seasonal Residential – Normal Density [R4]	kWh	$ 0.0069	$ 0.0049
Street Lighting	kW	$ 1.9331	$ 1.3469
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
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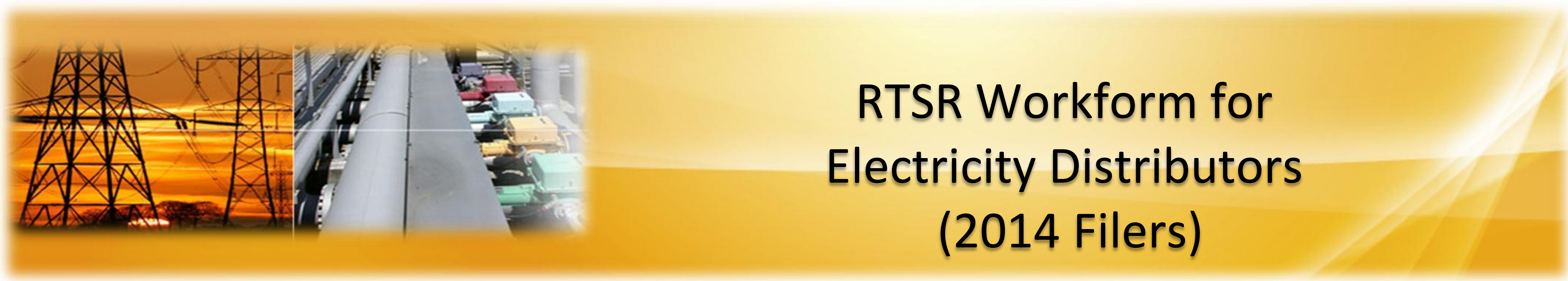
Choose Rate Class			



In the green shaded cells, enter the most recent reported RRR billing determinants. Please ensure that billing determinants are non-loss adjusted.

Rate Class	Unit	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor	Load Factor	Loss Adjusted Billed kWh	Billed kW
Residential – High Density [R1]	**kWh**	103,512,449		1.0864		112,455,925	-
General Service 50 to 4,999 kW	**kW**	16,561,356	53,633		**42.32%**	16,561,356	53,633
General Service 1,000 to 4,999 kW - Interval Meters	**kW**	62,861,720	132,315		**65.12%**	62,861,720	132,315
Seasonal Residential – Normal Density [R4]	**kWh**	10,136,343		1.0864		11,012,123	-
Street Lighting	**kW**	728,404	2,450		**40.75%**	728,404	2,450

RTSR Workform for Electricity Distributors (2014 Filers)

Uniform Transmission Rates	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.57	$ 3.63	$ 3.63
Line Connection Service Rate	kW	$ 0.80	$ 0.75	$ 0.75
Transformation Connection Service Rate	kW	$ 1.86	$ 1.85	$ 1.85

Hydro One Sub-Transmission Rates	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 2.65	$ 3.18	$ 3.18
Line Connection Service Rate	kW	$ 0.64	$ 0.70	$ 0.70
Transformation Connection Service Rate	kW	$ 1.50	$ 1.63	$ 1.63
Both Line and Transformation Connection Service Rate	kW	$ 2.14	$ 2.33	$ 2.33

If needed , add extra host here (I)	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

If needed , add extra host here (II)	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

Hydro One Sub-Transmission Rate Rider 9A	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
RSVA Transmission network – 4714 – which affects 1584	kW	$ -	$ 0.1465	$ 0.1465
RSVA Transmission connection – 4716 – which affects 1586	kW	$ -	$ 0.0667	$ 0.0667
RSVA LV – 4750 – which affects 1550	kW	$ -	$ 0.0475	$ 0.0475
RARA 1 – 2252 – which affects 1590	kW	$ -	$ 0.0419	$ 0.0419
RARA 1 – 2252 – which affects 1590 (2008)	kW	$ -	-$ 0.0270	-$ 0.0270
RARA 1 – 2252 – which affects 1590 (2009)	kW	$ -	-$ 0.0006	-$ 0.0006
Hydro One Sub-Transmission Rate Rider 9A	kW	$ -	$ 0.2750	$ 0.2750

		Historical 2012	Current 2013	Forecast 2014
Transformer Allowance Credit (if applicable, enter as a negative value)	$			

RTSR Workform for Electricity Distributors (2014 Filers)

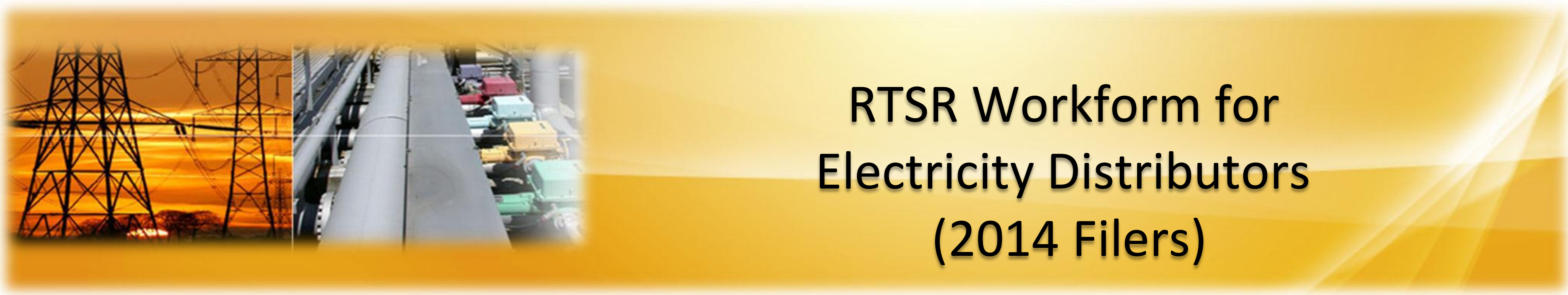
In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection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

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	37,653	$3.57	$ 134,421	19,084	$0.80	$ 15,267	41,062	$1.86	$ 76,375	$ 91,643
February	33,248	$3.57	$ 118,695	17,679	$0.80	$ 14,143	38,686	$1.86	$ 71,956	$ 86,099
March	36,432	$3.57	$ 130,062	20,971	$0.80	$ 16,777	41,347	$1.86	$ 76,905	$ 93,682
April	27,890	$3.57	$ 99,567	15,929	$0.80	$ 12,743	31,855	$1.86	$ 59,250	$ 71,994
May	28,248	$3.57	$ 100,845	18,191	$0.80	$ 14,553	33,682	$1.86	$ 62,649	$ 77,201
June	24,540	$3.57	$ 87,608	14,347	$0.80	$ 11,478	28,185	$1.86	$ 52,424	$ 63,902
July	25,625	$3.57	$ 91,481	13,977	$0.80	$ 11,182	29,066	$1.86	$ 54,063	$ 65,244
August	23,599	$3.57	$ 84,248	13,387	$0.80	$ 10,710	27,760	$1.86	$ 51,634	$ 62,343
September	23,881	$3.57	$ 85,255	13,379	$0.80	$ 10,703	28,336	$1.86	$ 52,705	$ 63,408
October	28,305	$3.57	$ 101,049	23,622	$0.80	$ 18,898	40,301	$1.86	$ 74,960	$ 93,857
November	33,430	$3.57	$ 119,345	16,852	$0.80	$ 13,482	35,321	$1.86	$ 65,697	$ 79,179
December	34,733	$3.57	$ 123,997	17,384	$0.80	$ 13,907	38,325	$1.86	$ 71,285	$ 85,192
Total	357,584	$ 3.57	$ 1,276,575	204,802	$ 0.80	$ 163,842	413,926	$ 1.86	$ 769,902	$ 933,744

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

Add Extra Host Here (I) (if needed)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

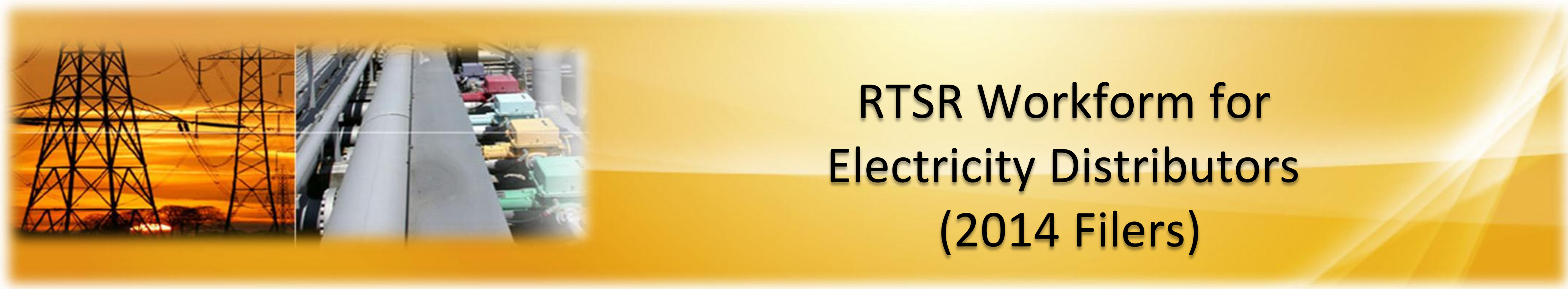
Add Extra Host Here (II) (if needed)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -



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

April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	37,653	$3.57	$ 134,421	19,084	$0.80	$ 15,267	41,062	$1.86	$ 76,375	$ 91,643
February	33,248	$3.57	$ 118,695	17,679	$0.80	$ 14,143	38,686	$1.86	$ 71,956	$ 86,099
March	36,432	$3.57	$ 130,062	20,971	$0.80	$ 16,777	41,347	$1.86	$ 76,905	$ 93,682
April	27,890	$3.57	$ 99,567	15,929	$0.80	$ 12,743	31,855	$1.86	$ 59,250	$ 71,994
May	28,248	$3.57	$ 100,845	18,191	$0.80	$ 14,553	33,682	$1.86	$ 62,649	$ 77,201
June	24,540	$3.57	$ 87,608	14,347	$0.80	$ 11,478	28,185	$1.86	$ 52,424	$ 63,902
July	25,625	$3.57	$ 91,481	13,977	$0.80	$ 11,182	29,066	$1.86	$ 54,063	$ 65,244
August	23,599	$3.57	$ 84,248	13,387	$0.80	$ 10,710	27,760	$1.86	$ 51,634	$ 62,343
September	23,881	$3.57	$ 85,255	13,379	$0.80	$ 10,703	28,336	$1.86	$ 52,705	$ 63,408
October	28,305	$3.57	$ 101,049	23,622	$0.80	$ 18,898	40,301	$1.86	$ 74,960	$ 93,857
November	33,430	$3.57	$ 119,345	16,852	$0.80	$ 13,482	35,321	$1.86	$ 65,697	$ 79,179
December	34,733	$3.57	$ 123,997	17,384	$0.80	$ 13,907	38,325	$1.86	$ 71,285	$ 85,192
Total	357,584	$ 3.57	$ 1,276,575	204,802	$ 0.80	$ 163,842	413,926	$ 1.86	$ 769,902	$ 933,744



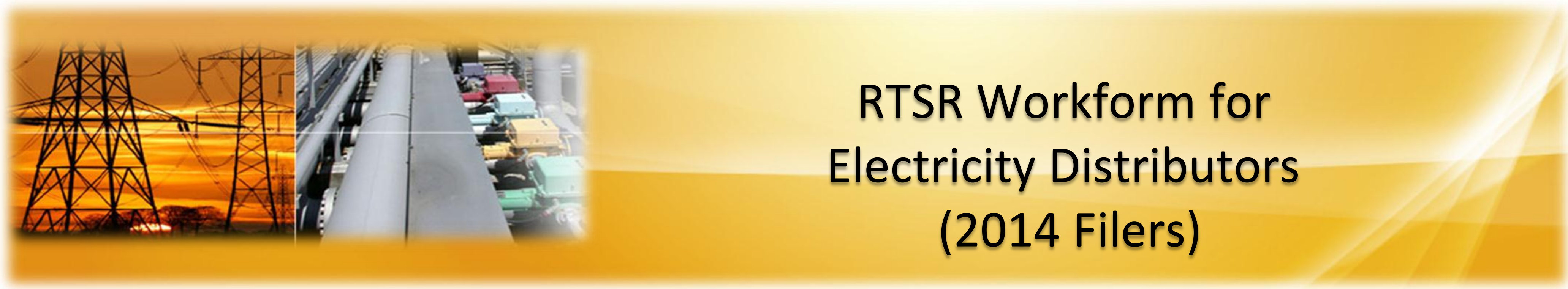
The purpose of this sheet is to calculate the expected billing when current 2013 Uniform Transmission Rates are applied against historical 2012 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	37,653	$ 3.6300	$ 136,680	19,084	$ 0.7500	$ 14,313	41,062	$ 1.8500	$ 75,965	$ 90,278
February	33,248	$ 3.6300	$ 120,690	17,679	$ 0.7500	$ 13,259	38,686	$ 1.8500	$ 71,569	$ 84,828
March	36,432	$ 3.6300	$ 132,248	20,971	$ 0.7500	$ 15,728	41,347	$ 1.8500	$ 76,492	$ 92,220
April	27,890	$ 3.6300	$ 101,241	15,929	$ 0.7500	$ 11,947	31,855	$ 1.8500	$ 58,932	$ 70,879
May	28,248	$ 3.6300	$ 102,540	18,191	$ 0.7500	$ 13,643	33,682	$ 1.8500	$ 62,312	$ 75,955
June	24,540	$ 3.6300	$ 89,080	14,347	$ 0.7500	$ 10,760	28,185	$ 1.8500	$ 52,142	$ 62,903
July	25,625	$ 3.6300	$ 93,019	13,977	$ 0.7500	$ 10,483	29,066	$ 1.8500	$ 53,772	$ 64,255
August	23,599	$ 3.6300	$ 85,664	13,387	$ 0.7500	$ 10,040	27,760	$ 1.8500	$ 51,356	$ 61,396
September	23,881	$ 3.6300	$ 86,688	13,379	$ 0.7500	$ 10,034	28,336	$ 1.8500	$ 52,422	$ 62,456
October	28,305	$ 3.6300	$ 102,747	23,622	$ 0.7500	$ 17,717	40,301	$ 1.8500	$ 74,557	$ 92,273
November	33,430	$ 3.6300	$ 121,351	16,852	$ 0.7500	$ 12,639	35,321	$ 1.8500	$ 65,344	$ 77,983
December	34,733	$ 3.6300	$ 126,081	17,384	$ 0.7500	$ 13,038	38,325	$ 1.8500	$ 70,901	$ 83,939
Total	357,584	$ 3.63	$ 1,298,030	204,802	$ 0.75	$ 153,602	413,926	$ 1.85	$ 765,763	$ 919,365

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
February	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
March	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
April	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
May	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
June	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
July	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
August	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
September	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
October	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
November	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
December	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -



The purpose of this sheet is to calculate the expected billing when current 2013 Uniform Transmission Rates are applied against historical 2012 transmission units.

November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	37,653	$3.63	$ 136,680	19,084	$0.75	$ 14,313	41,062	$1.85	$ 75,965	$ 90,278
February	33,248	$3.63	$ 120,690	17,679	$0.75	$ 13,259	38,686	$1.85	$ 71,569	$ 84,828
March	36,432	$3.63	$ 132,248	20,971	$0.75	$ 15,728	41,347	$1.85	$ 76,492	$ 92,220
April	27,890	$3.63	$ 101,241	15,929	$0.75	$ 11,947	31,855	$1.85	$ 58,932	$ 70,879
May	28,248	$3.63	$ 102,540	18,191	$0.75	$ 13,643	33,682	$1.85	$ 62,312	$ 75,955
June	24,540	$3.63	$ 89,080	14,347	$0.75	$ 10,760	28,185	$1.85	$ 52,142	$ 62,903
July	25,625	$3.63	$ 93,019	13,977	$0.75	$ 10,483	29,066	$1.85	$ 53,772	$ 64,255
August	23,599	$3.63	$ 85,664	13,387	$0.75	$ 10,040	27,760	$1.85	$ 51,356	$ 61,396
September	23,881	$3.63	$ 86,688	13,379	$0.75	$ 10,034	28,336	$1.85	$ 52,422	$ 62,456
October	28,305	$3.63	$ 102,747	23,622	$0.75	$ 17,717	40,301	$1.85	$ 74,557	$ 92,273
November	33,430	$3.63	$ 121,351	16,852	$0.75	$ 12,639	35,321	$1.85	$ 65,344	$ 77,983
December	34,733	$3.63	$ 126,081	17,384	$0.75	$ 13,038	38,325	$1.85	$ 70,901	$ 83,939
Total	357,584	$ 3.63	$ 1,298,030	204,802	$ 0.75	$ 153,602	413,926	$ 1.85	$ 765,763	$ 919,365

RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to calculate the expected billing when forecasted 2014 Uniform Transmission Rates are applied against historical 2012 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	37,653	$ 3.6300	$ 136,680	19,084	$ 0.7500	$ 14,313	41,062	$ 1.8500	$ 75,965	$ 90,278
February	33,248	$ 3.6300	$ 120,690	17,679	$ 0.7500	$ 13,259	38,686	$ 1.8500	$ 71,569	$ 84,828
March	36,432	$ 3.6300	$ 132,248	20,971	$ 0.7500	$ 15,728	41,347	$ 1.8500	$ 76,492	$ 92,220
April	27,890	$ 3.6300	$ 101,241	15,929	$ 0.7500	$ 11,947	31,855	$ 1.8500	$ 58,932	$ 70,879
May	28,248	$ 3.6300	$ 102,540	18,191	$ 0.7500	$ 13,643	33,682	$ 1.8500	$ 62,312	$ 75,955
June	24,540	$ 3.6300	$ 89,080	14,347	$ 0.7500	$ 10,760	28,185	$ 1.8500	$ 52,142	$ 62,903
July	25,625	$ 3.6300	$ 93,019	13,977	$ 0.7500	$ 10,483	29,066	$ 1.8500	$ 53,772	$ 64,255
August	23,599	$ 3.6300	$ 85,664	13,387	$ 0.7500	$ 10,040	27,760	$ 1.8500	$ 51,356	$ 61,396
September	23,881	$ 3.6300	$ 86,688	13,379	$ 0.7500	$ 10,034	28,336	$ 1.8500	$ 52,422	$ 62,456
October	28,305	$ 3.6300	$ 102,747	23,622	$ 0.7500	$ 17,717	40,301	$ 1.8500	$ 74,557	$ 92,273
November	33,430	$ 3.6300	$ 121,351	16,852	$ 0.7500	$ 12,639	35,321	$ 1.8500	$ 65,344	$ 77,983
December	34,733	$ 3.6300	$ 126,081	17,384	$ 0.7500	$ 13,038	38,325	$ 1.8500	$ 70,901	$ 83,939
Total	357,584	$ 3.63	$ 1,298,030	204,802	$ 0.75	$ 153,602	413,926	$ 1.85	$ 765,763	$ 919,365

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
February	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
March	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
April	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
May	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
June	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
July	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
August	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
September	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
October	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
November	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
December	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to calculate the expected billing when forecasted 2014 Uniform Transmission Rates are applied against historical 2012 transmission units.

November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	37,653	$ 3.63	$ 136,680	19,084	$ 0.75	$ 14,313	41,062	$ 1.85	$ 75,965	$ 90,278
February	33,248	$ 3.63	$ 120,690	17,679	$ 0.75	$ 13,259	38,686	$ 1.85	$ 71,569	$ 84,828
March	36,432	$ 3.63	$ 132,248	20,971	$ 0.75	$ 15,728	41,347	$ 1.85	$ 76,492	$ 92,220
April	27,890	$ 3.63	$ 101,241	15,929	$ 0.75	$ 11,947	31,855	$ 1.85	$ 58,932	$ 70,879
May	28,248	$ 3.63	$ 102,540	18,191	$ 0.75	$ 13,643	33,682	$ 1.85	$ 62,312	$ 75,955
June	24,540	$ 3.63	$ 89,080	14,347	$ 0.75	$ 10,760	28,185	$ 1.85	$ 52,142	$ 62,903
July	25,625	$ 3.63	$ 93,019	13,977	$ 0.75	$ 10,483	29,066	$ 1.85	$ 53,772	$ 64,255
August	23,599	$ 3.63	$ 85,664	13,387	$ 0.75	$ 10,040	27,760	$ 1.85	$ 51,356	$ 61,396
September	23,881	$ 3.63	$ 86,688	13,379	$ 0.75	$ 10,034	28,336	$ 1.85	$ 52,422	$ 62,456
October	28,305	$ 3.63	$ 102,747	23,622	$ 0.75	$ 17,717	40,301	$ 1.85	$ 74,557	$ 92,273
November	33,430	$ 3.63	$ 121,351	16,852	$ 0.75	$ 12,639	35,321	$ 1.85	$ 65,344	$ 77,983
December	34,733	$ 3.63	$ 126,081	17,384	$ 0.75	$ 13,038	38,325	$ 1.85	$ 70,901	$ 83,939
Total	357,584	$ 3.63	$ 1,298,030	204,802	$ 0.75	$ 153,602	413,926	$ 1.85	$ 765,763	$ 919,365

RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to re-align the current RTS Network Rates to recover current wholesale network costs.

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 – High Density [R1]	kWh	$ 0.0069	112,455,925	-	$ 775,946	57.3%	$ 743,914	$0.0066
General Service 50 to 4,999 kW	kW	$ 2.5633	16,561,356	53,633	$ 137,478	10.2%	$ 131,803	$2.4575
General Service 1,000 to 4,999 kW - Interval Meters	kW	$ 2.7191	62,861,720	132,315	$ 359,777	26.6%	$ 344,926	$2.6069
Seasonal Residential – Normal Density [R4]	kWh	$ 0.0069	11,012,123	-	$ 75,984	5.6%	$ 72,847	$0.0066
Street Lighting	kW	$ 1.9331	728,404	2,450	$ 4,736	0.3%	$ 4,541	$1.8533
					$ 1,353,921			

RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to re-align the current RTS Connection Rates to recover current wholesale connection costs.

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 – High Density [R1]	kWh	$ 0.0049	112,455,925	-	$ 551,034	57.6%	$ 529,635	$0.0047
General Service 50 to 4,999 kW	kW	$ 1.7423	16,561,356	53,633	$ 93,445	9.8%	$ 89,816	$1.6746
General Service 1,000 to 4,999 kW - Interval Meters	kW	$ 1.9255	62,861,720	132,315	$ 254,772	26.6%	$ 244,878	$1.8507
Seasonal Residential – Normal Density [R4]	kWh	$ 0.0049	11,012,123	-	$ 53,959	5.6%	$ 51,864	$0.0047
Street Lighting	kW	$ 1.3469	728,404	2,450	$ 3,300	0.3%	$ 3,172	$1.2946
					$ 956,511			

RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to update the re-align RTS Network Rates to recover forecast wholesale network costs.

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 – High Density [R1]	kWh	$0.0066	112,455,925	-	743,914.25	57.3%	$ 743,914	$0.0066
General Service 50 to 4,999 kW	kW	$2.4575	16,561,356	53,633	$ 131,803	10.2%	$ 131,803	$2.4575
General Service 1,000 to 4,999 kW - Interval Meters	kW	$2.6069	62,861,720	132,315	$ 344,926	26.6%	$ 344,926	$2.6069
Seasonal Residential – Normal Density [R4]	kWh	$0.0066	11,012,123	-	$ 72,847	5.6%	$ 72,847	$0.0066
Street Lighting	kW	$1.8533	728,404	2,450	$ 4,541	0.3%	$ 4,541	$1.8533
					$ 1,298,030			

RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to update the re-aligned RTS Connection Rates to recover forecast wholesale connection costs.

Rate Class	Unit	Adjusted RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Connection
Residential – High Density [R1]	kWh	$ 0.0047	112,455,925	-	$ 529,635	57.6%	$ 529,635	$ 0.0047
General Service 50 to 4,999 kW	kW	$ 1.6746	16,561,356	53,633	$ 89,816	9.8%	$ 89,816	$ 1.6746
General Service 1,000 to 4,999 kW - Interval Meters	kW	$ 1.8507	62,861,720	132,315	$ 244,878	26.6%	$ 244,878	$ 1.8507
Seasonal Residential – Normal Density [R4]	kWh	$ 0.0047	11,012,123	-	$ 51,864	5.6%	$ 51,864	$ 0.0047
Street Lighting	kW	$ 1.2946	728,404	2,450	$ 3,172	0.3%	$ 3,172	$ 1.2946
					$ 919,365			

RTSR Workform for Electricity Distributors (2014 Filers)

For Cost of Service Applicants, please enter the following Proposed RTS rates into your rates model.

For IRM applicants, please enter these rates into the 2013 IRM Rate Generator, Sheet 11 "Proposed Rates", column I.
Please note that the rate descriptions for the RTSRs are transfered automatically from Sheet 4 to Sheet 11, Column A.

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential – High Density [R1]	kWh	$ 0.0066	$ 0.0047
General Service 50 to 4,999 kW	kW	$ 2.4575	$ 1.6746
General Service 1,000 to 4,999 kW - Interval Meters	kW	$ 2.6069	$ 1.8507
Seasonal Residential – Normal Density [R4]	kWh	$ 0.0066	$ 0.0047
Street Lighting	kW	$ 1.8533	$ 1.2946

Schedule "F"

Deferral and Variance Account Continuity Schedule

Incentive Regulation Model for 2014 Filers

Version 2.3

Utility Name	Algoma Power Inc.
Service Territory	
Assigned EB Number	EB-2013-0110
Name of Contact and Title	Douglas R. Bradbury, Directory Regulatory Affairs
Phone Number	(905) 994-3634
Email Address	doug.bradbury@fortisontario.com
We are applying for rates effective	January-01-14
Rate-Setting Method	**Annual IR Index**
Please indicate in which Rate Year the Group 1 accounts were last cleared[1]	**2012**

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

Note:
1. Rate year of application

Incentive Regulation Model for 2014 Filers

Algoma Power Inc.

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, including the MicroFit Class.

How many classes are listed on your most recent Board-Approved Tariff of Rates and Charges? 4

Select Your Rate Classes from the **Blue Cells** below. Please ensure that a rate class is assigned to **each shaded cell.**

	Rate Class Classification
1	RESIDENTIAL - HIGH DENSITY [R1]
2	GENERAL SERVICE 50 TO 4,999 KW
3	SEASONAL RESIDENTIAL
4	STREET LIGHTING

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2014 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2013 EDR process (CoS or IRM) you received approval for the December 31, 2011 balances, the starting point for your entries below should be the adjustment column BQ for principal and column BV for interest. This will allow for the correct starting point for the 2012 opening balance columns for both principal and interest.

Please refer to the footnotes for further instructions.

Account Descriptions	Account Number
Group 1 Accounts	
LV Variance Account	1550
RSVA - Wholesale Market Service Charge	1580
RSVA - Retail Transmission Network Charge	1584
RSVA - Retail Transmission Connection Charge	1586
RSVA - Power (excluding Global Adjustment)	1588
RSVA - Global Adjustment	1589
Recovery of Regulatory Asset Balances	1590
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595
Disposition and Recovery/Refund of Regulatory Balances (2011)[5]	1595
Group 1 Sub-Total (including Account 1589 - Global Adjustment)	
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)	
RSVA - Global Adjustment	**1589**
Deferred Payments in Lieu of Taxes	1562
Total of Group 1 and Account 1562	
Special Purpose Charge Assessment Variance Account[4]	**1521**
LRAM Variance Account[6]	**1568**
Total including Accounts 1562 and 1568	

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

[1] Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

[2] For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

[3] If the LDC's 2013 rate year begins January 1, 2014, the projected interest is recorded from January 1, 2013 to December 31, 2013 on the December 31, 2012 balance adjusted for the disposed balances approved by the Board in the 2013 rate decision. If the LDC's 2014 rate year begins May 1, 2014 the projected interest is recorded from January 1, 2013 to April 30, 2014 on the December 31, 2012 balance adjusted for the disposed balances approved by the Board in the 2013 rate decision.

[4] Applicants that did not have the balance in Account 1521 cleared by the Board in the 2012 rate proceedings are expected to file to dispose of Account 1521 in the 2013 rate proceedings. No Account 1521 balance is to be filed for clearance in the 2013 rate proceedings for those distributors that had account 1521 cleared by the Board in the 2012 rate proceedings.

In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

[5] Include Account 1595 as part of Group 1 accounts (lines 31, 32, 33 and 34) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

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Group 1 Sub-Total (including Account 1589 - Global Adjustment)	
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RSVA - Global Adjustment	**1589**
Deferred Payments in Lieu of Taxes	1562
Total of Group 1 and Account 1562	
Special Purpose Charge Assessment Variance Account[4]	**1521**
LRAM Variance Account[6]	**1568**
Total including Accounts 1562 and 1568	

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Incentive Regulation Model for 2014 Filers

Algoma Power Inc.

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Group 1 Sub-Total (including Account 1589 - Global Adjustment)	
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RSVA - Global Adjustment	**1589**
Deferred Payments in Lieu of Taxes	1562
Total of Group 1 and Account 1562	
Special Purpose Charge Assessment Variance Account[4]	**1521**
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Total including Accounts 1562 and 1568	

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Group 1 Sub-Total (including Account 1589 - Global Adjustment)	
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)	
RSVA - Global Adjustment	**1589**
Deferred Payments in Lieu of Taxes	1562
Total of Group 1 and Account 1562	
Special Purpose Charge Assessment Variance Account[4]	**1521**
LRAM Variance Account[6]	**1568**
Total including Accounts 1562 and 1568	

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Incentive Regulation Model for 2014 Filers

Algoma Power Inc.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2014 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2013 EDR process (CoS or IRM) you received approval for the December 31, 2011 balances, the starting point for your entries below should be the adjustment column BQ for principal and column BV for interest. This will allow for the correct starting point for the 2012 opening balance columns for both principal and interest.

Please refer to the footnotes for further instructions.

Account Descriptions	**Account Number**
Group 1 Accounts	
LV Variance Account	1550
RSVA - Wholesale Market Service Charge	1580
RSVA - Retail Transmission Network Charge	1584
RSVA - Retail Transmission Connection Charge	1586
RSVA - Power (excluding Global Adjustment)	1588
RSVA - Global Adjustment	1589
Recovery of Regulatory Asset Balances	1590
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595
Disposition and Recovery/Refund of Regulatory Balances (2011)[5]	1595
Group 1 Sub-Total (including Account 1589 - Global Adjustment)	
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)	
RSVA - Global Adjustment	**1589**
Deferred Payments in Lieu of Taxes	1562
Total of Group 1 and Account 1562	
Special Purpose Charge Assessment Variance Account[4]	**1521**
LRAM Variance Account[6]	**1568**
Total including Accounts 1562 and 1568	

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

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

If the LDC's 2013 rate year begins January 1, 2014, the projected interest is recorded from January 1, 2013 to December 31, 2013 on the December 31, 2012 balance adjusted for the disposed balances approved by the Board in the 2013 rate decision. If the LDC's 2014 rate year begins May 1, 2014 the projected interest is recorded from January 1, 2013 to April 30, 2014 on the December 31, 2012 balance adjusted for the disposed balances approved by the Board in the 2013 rate decision.

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In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

Include Account 1595 as part of Group 1 accounts (lines 31, 32, 33 and 34) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Incentive Regulation Model for 2014 Filers

Algoma Power Inc.

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Account Descriptions	Account Number	2010 Closing Principal Balance as of Dec-31-10	2010 Closing Interest Amounts as of Dec-31-10
Group 1 Accounts			
LV Variance Account	1550		
RSVA - Wholesale Market Service Charge	1580		
RSVA - Retail Transmission Network Charge	1584		
RSVA - Retail Transmission Connection Charge	1586		
RSVA - Power (excluding Global Adjustment)	1588		
RSVA - Global Adjustment	1589		
Recovery of Regulatory Asset Balances	1590		
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595		
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595		
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595		
Disposition and Recovery/Refund of Regulatory Balances (2011)[5]	1595		
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		0	0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		0	0
RSVA - Global Adjustment	**1589**	0	0
Deferred Payments in Lieu of Taxes	1562		
Total of Group 1 and Account 1562		0	0
Special Purpose Charge Assessment Variance Account[4]	**1521**		
LRAM Variance Account[6]	**1568**		
Total including Accounts 1562 and 1568		0	0

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Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.
If the LDC's 2013 rate year begins January 1, 2014, the projected interest is recorded from January 1, 2013 to December 31, 2013 on the December 31, 2012 balance adjusted for the disposed balances approved by the Board in the 2013 rate decision. If the LDC's 2014 rate year begins May 1, 2014 the projected interest is recorded from January 1, 2013 to April 30, 2014 on the December 31, 2012 balance adjusted for the disposed balances approved by the Board in the 2013 rate decision.

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Account Descriptions	Account Number	2011									
		Opening Principal Amounts as of Jan-1-11	Transactions Debit / (Credit) during 2011 excluding interest and adjustments [2]	Board-Approved Disposition during 2011	Adjustments during 2011 - other [1]	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Adjustments during 2011 - other [2]	Closing Interest Amounts as of Dec-31-11
Group 1 Accounts											
LV Variance Account	1550	0				0	0				0
RSVA - Wholesale Market Service Charge	1580	0			(416,763)	(416,763)	0			(5,502)	(5,502)
RSVA - Retail Transmission Network Charge	1584	0			62,125	62,125	0			(167)	(167)
RSVA - Retail Transmission Connection Charge	1586	0			(109,426)	(109,426)	0			(2,417)	(2,417)
RSVA - Power (excluding Global Adjustment)	1588	0			(1,294,882)	(1,294,882)	0			11,462	11,462
RSVA - Global Adjustment	1589	0			830,898	830,898	0			(67,311)	(67,311)
Recovery of Regulatory Asset Balances	1590	0			(322,541)	(322,541)	0			122,448	122,448
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2011)[5]	1595	0				0	0				0
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		0	0	0	(1,250,589)	(1,250,589)	0	0	0	58,514	58,514
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		0	0	0	(2,081,487)	(2,081,487)	0	0	0	125,825	125,825
RSVA - Global Adjustment	**1589**	0	0	0	830,898	830,898	0	0	0	(67,311)	(67,311)
Deferred Payments in Lieu of Taxes	1562	0				0	0				0
Total of Group 1 and Account 1562		0	0	0	(1,250,589)	(1,250,589)	0	0	0	58,514	58,514
Special Purpose Charge Assessment Variance Account[4]	**1521**										
LRAM Variance Account[6]	**1568**					0					0
Total including Accounts 1562 and 1568		0	0	0	(1,250,589)	(1,250,589)	0	0	0	58,514	58,514

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		2012												
Account Descriptions	**Account Number**	**Opening Principal Amounts as of Jan-1-12**	**Transactions Debit / (Credit) during 2012 excluding interest and adjustments 2**	**Board-Approved Disposition during 2012**	**Other 1 Adjustments during Q1 2012**	**Other 1 Adjustments during Q2 2012**	**Other 1 Adjustments during Q3 2012**	**Other 1 Adjustments during Q4 2012**	**Closing Principal Balance as of Dec-31-12**	**Opening Interest Amounts as of Jan-1-12**	**Interest Jan-1 to Dec-31-12**	**Board-Approved Disposition during 2012**	**Adjustments during 2012 - other 1**
Group 1 Accounts													
LV Variance Account	1550	0							0	0			
RSVA - Wholesale Market Service Charge	1580	(416,763)	(303,315)	(205,889)					(514,189)	(5,502)	(6,561)	(4,006)	496
RSVA - Retail Transmission Network Charge	1584	62,125	(23,148)	(27,302)					66,280	(167)	1,268	(619)	66
RSVA - Retail Transmission Connection Charge	1586	(109,426)	(47,392)	(111,180)					(45,639)	(2,417)	(639)	(2,235)	268
RSVA - Power (excluding Global Adjustment)	1588	(1,294,882)	(819,069)	(1,049,240)				314,012	(750,699)	11,462	9,343	(17,787)	2,529
RSVA - Global Adjustment	1589	830,898	1,401,382					(677,525)	1,554,756	(67,311)	5,863		46,051
Recovery of Regulatory Asset Balances	1590	(322,541)	(0)						(322,542)	122,448	(4,739)		
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595	0							0	0			
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595	0							0	0			
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595	0							0	0			
Disposition and Recovery/Refund of Regulatory Balances (2011)[5]	1595	0							0	0			
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		(1,250,589)	208,458	(1,393,611)	0	0	0	(363,513)	(12,033)	58,514	4,536	(24,647)	49,410
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		(2,081,487)	(1,192,924)	(1,393,611)	0	0	0	314,012	(1,566,788)	125,825	(1,327)	(24,647)	3,359
RSVA - Global Adjustment	**1589**	830,898	1,401,382	0	0	0	0	(677,525)	1,554,756	(67,311)	5,863	0	46,051
Deferred Payments in Lieu of Taxes	1562	0							0	0			
Total of Group 1 and Account 1562		(1,250,589)	208,458	(1,393,611)	0	0	0	(363,513)	(12,033)	58,514	4,536	(24,647)	49,410
Special Purpose Charge Assessment Variance Account[4]	**1521**												
LRAM Variance Account[6]	**1568**	0							0	0			
Total including Accounts 1562 and 1568		(1,250,589)	208,458	(1,393,611)	0	0	0	(363,513)	(12,033)	58,514	4,536	(24,647)	49,410

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Account Descriptions	Account Number	Closing Interest Amounts as of Dec-31-12
Group 1 Accounts		
LV Variance Account	1550	0
RSVA - Wholesale Market Service Charge	1580	(7,562)
RSVA - Retail Transmission Network Charge	1584	1,787
RSVA - Retail Transmission Connection Charge	1586	(552)
RSVA - Power (excluding Global Adjustment)	1588	41,122
RSVA - Global Adjustment	1589	(15,397)
Recovery of Regulatory Asset Balances	1590	117,709
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595	0
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595	0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595	0
Disposition and Recovery/Refund of Regulatory Balances (2011)[5]	1595	0
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		137,107
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		152,504
RSVA - Global Adjustment	**1589**	(15,397)
Deferred Payments in Lieu of Taxes	1562	0
Total of Group 1 and Account 1562		137,107
Special Purpose Charge Assessment Variance Account[4]	**1521**	
LRAM Variance Account[6]	**1568**	0
Total including Accounts 1562 and 1568		137,107

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		2013				Projected Interest on Dec-31-12 Balances			2.1.7 RRR	
Account Descriptions	**Account Number**	**Principal Disposition during 2013 - instructed by Board**	**Interest Disposition during 2013 - instructed by Board**	**Closing Principal Balances as of Dec 31-12 Adjusted for Dispositions during 2013**	**Closing Interest Balances as of Dec 31-12 Adjusted for Dispositions during 2013**	**Projected Interest from Jan 1, 2013 to December 31, 2013 on Dec 31 -12 balance adjusted for disposition during 2013 [3]**	**Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 -12 balance adjusted for disposition during 2013 [3]**	**Total Claim**	**As of Dec 31-12**	**Variance RRR vs. 2012 Balance *(Principal + Interest)***
Group 1 Accounts										
LV Variance Account	1550			0	0	0		0		0
RSVA - Wholesale Market Service Charge	1580	(210,874)	(4,597)	(303,315)	(2,965)	(4,459)		(310,738)	(521,750)	0
RSVA - Retail Transmission Network Charge	1584	89,427	1,767	(23,148)	20	(340)		(23,468)	68,066	(0)
RSVA - Retail Transmission Connection Charge	1586	1,753	(156)	(47,392)	(396)	(697)		(48,485)	(46,191)	(0)
RSVA - Power (excluding Global Adjustment)	1588	(245,642)	25,638	(505,057)	15,484	(7,424)		(496,998)	(1,023,589)	(314,012)
RSVA - Global Adjustment	1589	830,898	(55,097)	723,857	39,700	10,641		774,198	2,216,883	677,524
Recovery of Regulatory Asset Balances	1590	(322,541)	117,707	(0)	2	(0)		2	(204,832)	0
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595			0	0	0		0		0
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595			0	0	0		0		0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595			0	0	0		0		0
Disposition and Recovery/Refund of Regulatory Balances (2011)[5]	1595			0	0	0		0		0
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		143,022	85,262	(155,055)	51,845	(2,279)	0	(105,489)	488,586	363,511
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		(687,876)	140,359	(878,912)	12,145	(12,920)	0	(879,687)	(1,728,297)	(314,012)
RSVA - Global Adjustment	**1589**	830,898	(55,097)	723,857	39,700	10,641	0	774,198	2,216,883	677,524
Deferred Payments in Lieu of Taxes	1562			0	0	0	0	0		0
										0
Total of Group 1 and Account 1562		143,022	85,262	(155,055)	51,845	(2,279)	0	(105,489)	488,586	363,511
Special Purpose Charge Assessment Variance Account[4]	**1521**									
LRAM Variance Account[6]	**1568**			0	0			0		0
Total including Accounts 1562 and 1568		143,022	85,262	(155,055)	51,845	(2,279)	0	(105,489)	488,586	363,511

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

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

Rate Class	Unit	Metered kWh	Metered kW	Billed kWh for Non-RPP Customers	Estimated kW for Non-RPP Customers	Distribution Revenue [1]	1590 Recovery Share Proportion*	1595 Recovery Share Proportion (2008) [2]	1595 Recovery Share Proportion (2009) [2]	1595 Recovery Share Proportion (2010) [2]	1595 Recovery Share Proportion (2011) [2]	1568 LRAM Variance Account Class Allocation ($ amounts)

Schedule “G”

LRAMVA Disposition

BURMAN ENERGY
CONSULTANTS GROUP INC

4309 Lloydtown Aurora Road, Kettleby, Ont. L7B 0E6 ● Phone: 1-877-662-5489 ● Fax: 905-939-4606 ● Email: info@burmanenergy.ca ● www.burmanenergy.ca

ALGOMA POWER

LRAMVA SUPPORT

AUGUST 13, 2013

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LRAMVA

With specific reference to the following:

13.2 LRAM Mechanism for 2011- 2014

The Board will adopt an approach for LRAM for the 2011-2014 CDM period that is similar to that adopted in relation to natural gas distributor DSM activities. The Board will authorize the establishment of an LRAM variance account ("LRAMVA") to capture, at the customer rate-class level, the difference between the following:

i. The results of actual, verified impacts of authorized CDM activities undertaken by electricity distributors between 2011-2014 for both Board-Approved CDM programs and OPA-Contracted Province-Wide CDM programs in relation to activities undertaken by the distributor and/or delivered for the distributor by a third party under contract (in the distributor's franchise area); and

ii. The level of CDM program activities included in the distributor's load forecast (i.e. the level embedded into rates).

Distributors will generally be expected to include a CDM component in their load forecast in cost of service proceedings to ensure that its customers are realizing the true effects of conservation at the earliest date possible date and to mitigate the variance between forecasted revenue losses and actual revenue losses. If the distributor has included a CDM load reduction in its distribution rates, the amount of the forecast that was adjusted for CDM at the rate class level would be compared to the actual DCM results verified by an independent third part for each year of the CDM program (i.e., 2011 to 2014) in accordance with the OPA's EM&V Protocols as set out in Section 6.1 of the CDM Code. The variance calculated from this comparison result in a credit or a debit to the ratepayers at the customer rate class level in the LRAMVA. The variance calculated from this comparison results in a credit or debit to the ratepayers at the customer rate class level in the LRAMVA. The LRAM amount is determined by applying, by customer class, the distributor's Board-approved variable distribution charge applicable to the class to the volumetric variance (positive or negative) described in the paragraph above. The calculated lost revenues will be recorded in the LRAMVA. Distributors will be expected to report the balance in the LRAMVA as part of the reporting and record-keeping requirements on an annual basis.

Burman Energy has prepared the following LRAMVA tables, representing the variance amount to be recorded in the LRAM Variance Account. The amount is the calculated result of the lost revenues by customer class based on the volumetric impact of the load reductions arising from the CDM measures implemented, multiplied by Algoma Power's Board-approved variable distribution changes applicable to the customer rate class in which the volumetric variance occurred. The calculations include only finalized 2011 Program results realized in 2011, and 2011 persistence into 2012. The calculations provided by Burman Energy do not include carrying charges.

ALGOMA POWER LRAMVA:

			2011				2012	
Initiative Name	Program Year	Results Status	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Gross Summer Peak Demand Savings (kW)	Gross Energy Savings (kWh)	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)
TOTAL LRAMVA - PRE-2011 PROGRAMS COMPLETED IN 2011			0.00	0	0.00	0	0.00	0.00
TOTAL LRAMVA - 2011 OPA PROGRAM RESULTS			24.00	168,537	34.00	212,237	168,537.00	34.00
			24.00	168,537	34.00	212,237	168,537	34

Initiative Name	Program Year	2011 LRAMVA	2012 LRAMVA	
TOTAL LRAMVA - PRE-2011 PROGRAMS COMPLETED IN 2011		$ -	$ -	
TOTAL LRAMVA - 2011 OPA PROGRAM RESULTS		$ 4,954.99	$ 4,954.99	
		$ 4,954.99	$ 4,954.99	$ 9,909.98

SUPPORTING ATTACHMENTS

Algoma Power
OPA Conservation & Demand Management Programs
Initiative Results at End-User Level

For: Algoma

Initiative Name	Program Year	Results Status	2011 Net Summer Peak Demand Savings (kW)	2011 Net Energy Savings (kWh)	2011 Gross Summer Peak Demand Savings (kW)	2011 Gross Energy Savings (kWh)	2012 Net Summer Peak Demand Savings (kW)	2012 Net Energy Savings (kWh)	2010 Rate (effective Dec 1)	2011 Rate (effective Feb 1)	2012 Rate (effective Jan 1)	2011 LRAMVA	2012 LRAMVA	
2011 OPA PROGRAM RESULTS														
Residential Service														
Appliance Retirement	2011	Final	6.00	41,532	12.00	80,205	41,532	12.00	0.0294	0.0294	0.0302	$ 1,221.04	$ 1,221.04	
Appliance Exchange	2011	Final	1.00	790	1.00	1,532	790	1.00	0.0294	0.0294	0.0302	$ 23.23	$ 23.23	
HVAC Incentives	2011	Final	10.00	19,936	16.00	33,546	19,936	16.00	0.0294	0.0294	0.0302	$ 586.12	$ 586.12	
Conservation Instant Coupon Booklet	2011	Final	3.00	41,414	2.00	37,581	41,414	2.00	0.0294	0.0294	0.0302	$ 1,217.57	$ 1,217.57	
Bi-Annual Retailer Event	2011	Final	4.00	64,865	3.00	59,373	64,865	3.00	0.0294	0.0294	0.0302	$ 1,907.03	$ 1,907.03	
RESIDENTIAL TOTAL			**24.00**	**168,537**	**34.00**	**212,237**	**168537.00**	**34**				**$ 4,954.99**	**$ 4,954.99**	
TOTAL LRAMVA - 2011 OPA PROGRAM RESULTS			**24.00**	**168,537**	**34.00**	**212,237**	**168537.00**	**34**				**$ 4,954.99**	**$ 4,954.99**	
TOTAL LRAMVA - PRE-2011 PROGRAMS COMPLETED IN 2011			**0.00**	**0**	**0.00**	**0**	**0.00**	**0.00**				**$ -**	**$ -**	
TOTAL LRAMVA - 2011 OPA PROGRAM RESULTS			**24.00**	**168,537**	**34.00**	**212,237**	**168,537.00**	**34.00**				**$ 4,954.99**	**$ 4,954.99**	
			24.00	**168,537**	**34.00**	**212,237**	**168,537**	**34**				**$ 4,954.99**	**$ 4,954.99**	**$ 9,909.98**

CNP / ALGOMA LRAMVA

METHODOLOGY

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program				
Gross Savings = Activity * Per Unit Assumption **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)				
1	Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection	Savings are considered to begin in the year and quarter that appliance has been picked up.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
2	Appliance Exchange	Results allocated based on average of 2008 & 2009 residential throughput when postal code information not provided by customer	Savings are considered to begin in the year and quarter that the exchange event occurred	
3	HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year and quarter that the installation occurred	
4	Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput	Data is provided to the OPA with the associated program year. Savings are considered to begin that specified program year. Currently, coupon redemption date is unavailable.	
5	Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the quarter and year in which the event occurs.	
6	Retailer Co-op	Results allocated based on average of 2008 & 2009 residential throughput when postal code information not provided by customer; Initiative was not evaluated in 2011, reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.	Savings are considered to begin in the year and quarter of the home visit and installation date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
7	Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year and quarter the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement. However all devices installed in 2011 and/or customers that have signed a peaksaver PLUS™ participant agreement as of December 31st are included in the ex ante savings estimate.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
8	Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year and quarter of the project completion date.	**Peak demand and energy savings** are determined using a measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.

METHODOLOGY

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Business Program				
Gross Savings = Reported Savings * Realization Rate **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)				
9	Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year and quarter of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
		Additional Note: project counts were derived by filtering out "Application Status" = "Post-Project Submission - Payment denied by LDC" and only including projects with an "Actual Project Completion Date" in 2011 and pulling both the "Application Name" field followed by the "Building Address 1" field from the Post Stage Retrofit Report and finally performing a count of the Building Addresses.		
10	Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order	Savings are considered to begin in the year and quarter of the actual project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
11	Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year and quarter of the actual project completion date.	**Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
12	New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, reported results are presented with reported assumptions (as per evaluated results in 2010 and consultation with OPA-LDC Work Groups)	Savings are considered to begin in the year and quarter of the actual project completion date.	**Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
13	Energy Audit	No resource savings results determined in 2011; Projects are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year and quarter of the audit date.	**Peak demand and energy savings** are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
14	Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year and quarter the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement. However all devices installed in 2011 and/or customers that have signed a peaksaver PLUS™ participant agreement as of December 31st are included in the ex ante savings estimate.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
15	Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year and quarter in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.

METHODOLOGY

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Industrial Program				
Gross Savings = Reported Savings * Realization Rate **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)				
16	Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year and quarter in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
17	Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year and quarter in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
18	Energy Manager	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year and quarter in which the project was completed by the energy manager. If no date is specified the savings will begin the year and quarter of the Quarterly Report submitted by the energy manager.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year and quarter of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
20	Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year and quarter in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Home Assistance Program				
Gross Savings = Activity * Per Unit Assumption **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)				
21	Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year and quarter in which the measures were installed.	**Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.

METHODOLOGY

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Pre-2011 Programs completed in 2011				
Gross Savings = Reported Savings * Realization Rate **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)				
22	Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation	Savings are considered to begin in the year and quarter in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
23	High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation	Savings are considered to begin in the year and quarter in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
24	Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation		
25	Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation		
26	Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation		
27	EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation	Savings are considered to begin in the year and quarter in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Algoma Power

Table 1: Participation[1]

#	Initiative	Unit	Uptake/ Participation Units
Consumer Program			
1	Appliance Retirement	Appliances	97
2	Appliance Exchange	Appliances	7
3	HVAC Incentives	Equipment	27
4	Conservation Instant Coupon Booklet	Products	1,107
5	Bi-Annual Retailer Event	Products	1,921
6	Retailer Co-op	Products	0
7	Residential Demand Response	Devices	0
8	Residential New Construction	Houses	0
Business Program			
9	Efficiency: Equipment Replacement	Projects	0
10	Direct Install Lighting	Projects	0
11	Existing Building Commissioning Incentive	Buildings	0
12	New Construction and Major Renovation Incentive	Buildings	0
13	Energy Audit	Audits	0
14	Commercial Demand Response (part of the Residential program schedule)	Devices	0
15	Demand Response 3 (part of the Industrial program schedule)	Facilities	0
Industrial Program			
16	Process & System Upgrades	Projects[2]	0
17	Monitoring & Targeting	Projects[3]	0
18	Energy Manager	Managers[2 3]	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Projects	0
20	Demand Response 3	Facilities	0
Home Assistance Program			
21	Home Assistance Program	Homes	0
Pre 2011 Programs Completed in 2011			
22	Electricity Retrofit Incentive Program	Projects	0
23	High Performance New Construction	Projects	0
24	Toronto Comprehensive	Projects	0
25	Multifamily Energy Efficiency Rebates	Projects	0
26	Data Centre Incentive Program	Projects	0
27	EnWin Green Suites	Projects	0

[1] *Please see "Methodology" tab for more information regarding attributing savings to LDCs*

[2] *Results are based on completed incentive projects (see "Methodology" tab for more information)*

[3] *Includes: Roving Energy Managers, Key Account Managers and Embedded Energy Managers if projects are completed in 2011*

Algoma Power

Table 5: Summarized Program Results

Program	Gross Savings: Incremental Peak Demand Savings (kW)	Gross Savings: Incremental Energy Savings (kWh)	Net Savings: Incremental Peak Demand Savings (kW)	Net Savings: Incremental Energy Savings (kWh)	Contribution to Targets: Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Contribution to Targets: Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program Total	35	212,237	23	168,537	22	673,545
Business Program Total	0	0	0	0	0	0
Industrial Program Total	0	0	0	0	0	0
Home Assistance Program Total	0	0	0	0	0	0
Pre-2011 Programs completed in 2011 Total	0	0	0	0	0	0
Total OPA Contracted Province-Wide CDM Programs	**35**	**212,237**	**23**	**168,537**	**22**	**673,545**

#	Initiative	Realization Rate		Gross Savings		Net-to-Gross Ratio		Net Savings		Contribution to Targets	
		Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program											
1	Appliance Retirement	100%	100%	12	80,205	51%	52%	6	41,532	6	165,927
2	Appliance Exchange	100%	100%	1	1,532	52%	52%	1	790	0	2,759
3	HVAC Incentives	100%	100%	16	33,546	59%	59%	10	19,936	10	79,744
4	Conservation Instant Coupon Booklet	100%	100%	2	37,581	114%	111%	3	41,414	3	165,655
5	Bi-Annual Retailer Event	100%	100%	3	59,373	113%	110%	4	64,865	4	259,461
6	Retailer Co-op	-	-	0	0	-	-	0	0	0	0
7	Residential Demand Response	0%	0%	0	0	-	-	0	0	0	0
8	Residential New Construction	-	-	0	0	-	-	0	0	0	0
Business Program											
9	Efficiency: Equipment Replacement	-	-	0	0	-	-	0	0	0	0
10	Direct Install Lighting	-	-	0	0	-	-	0	0	0	0
11	Existing Building Commissioning Incentive	-	-	0	0	-	-	0	0	0	0
12	New Construction and Major Renovation Incentive	-	-	0	0	-	-	0	0	0	0
13	Energy Audit	-	-	0	0	-	-	0	0	0	0
14	Commercial Demand Response (part of the Residential program schedule)	0%	0%	0	0	-	-	0	0	0	0
15	Demand Response 3 (part of the Industrial program schedule)	76%	100%	0	0	n/a	n/a	0	0	0	0
Industrial Program											
16	Process & System Upgrades	-	-	0	0	-	-	0	0	0	0
17	Monitoring & Targeting	-	-	0	0	-	-	0	0	0	0
18	Energy Manager	-	-	0	0	-	-	0	0	0	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	-	-	0	0	-	-	0	0	0	0
20	Demand Response 3	84%	100%	0	0	n/a	n/a	0	0	0	0
Home Assistance Program											
21	Home Assistance Program	-	-	0	0	-	-	0	0	0	0
Pre-2011 Programs completed in 2011											
22	Electricity Retrofit Incentive Program	-	-	0	0	-	-	0	0	0	0
23	High Performance New Construction	-	-	0	0	-	-	0	0	0	0
24	Toronto Comprehensive	-	-	0	0	-	-	0	0	0	0
25	Multifamily Energy Efficiency Rebates	-	-	0	0	-	-	0	0	0	0
26	Data Centre Incentive Program	-	-	0	0	-	-	0	0	0	0
27	EnWin Green Suites	-	-	0	0	-	-	0	0	0	0

Assumes demand response resources have a persistence of 1 year

saveONenergy

Message from the Vice President:

The OPA is pleased to provide you with the enclosed Final 2011 Results Report.

Despite some of the inertial challenges in 2011 with program start up, on average, year one province-wide forecasts were met and the year finished out with strong momentum which continues to build 2012. There are still challenges for LDCs of all sizes and we are committed to ensuring LDCs are successful in meeting their objectives. We look forward to further dialogue to discover opportunities to improve the current program suite with local program opportunities, best practices and successes to better reach our customers in the years to come.

This report was developed in collaboration with the OPA-LDC Reporting and Evaluation Working Group and is designed to help populate LDC annual report templates that will be submitted to the OEB in late September. Between the draft and final reports several improvements were made to improve clarity and transparency based on feedback provided by LDCs, such as: the addition of a glossary tab, total adjustments to savings are now broken out into both the realization rate and net-to-gross ratio for both peak demand and energy savings and modifications were made to the methodology tab. We invite you to continue to provide your feedback.

All results are now considered final for 2011. Any additional 2011 program activity not captured will be reported in the Final 2012 Results Report. Please continue to monitor saveONenergy E-blasts for any further updates and should you have any other questions or comments please contact LDC.Support@powerauthority.on.ca.

We appreciate your collaboration and cooperation throughout the reporting and evaluation process. We look forward to another successful year in 2012.

Sincerely,
Andrew Pride

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OPA-Contracted Province-Wide CDM Programs FINAL 2011 Results

LDC: Algoma Power Inc.

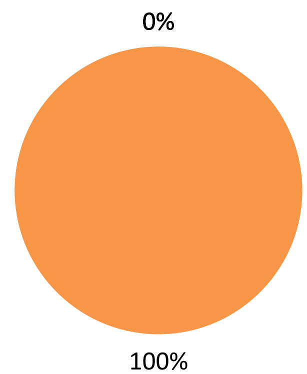
FINAL 2011 Progress to Targets	Incremental 2011	Scenario 1: % of Target Achieved	Scenario 2: % of Target Achieved
Net Annual Peak Demand Savings (MW)	0.0	**1.7%**	**1.8%**
Net Cumulative Energy Savings (GWh)	0.2	**9.1%**	**9.1%**

Scenario 1 = Assumes that demand resource resources have a persistence of 1 year

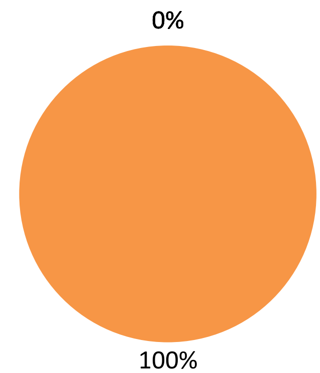
Scenario 2 = Assumes that demand response resources remain in your territory until 2014

Achievement by Sector

2011 Incremental Peak Demand Savings (MW)



2011 Incremental Energy Savings (GWh)

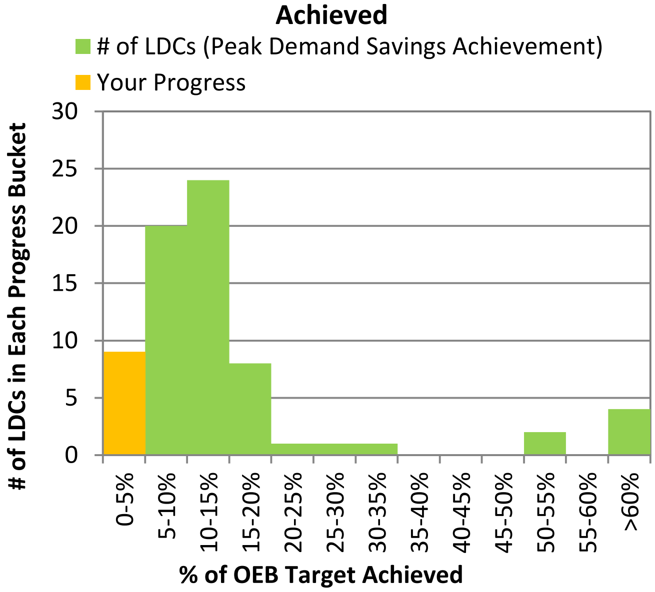


Consumer Program Total
Business Program Total
Industrial Program Total
Home Assistance Program Total
Pre-2011 Programs completed in 2011 Total

Comparison: Your Achievement vs. LDC Community Achievement

The following graphs assume that demand response resources remain in your territory until 2014 (aligns with Scenario 2)

% of OEB Peak Demand Savings Target Achieved



% of OEB Energy Savings Target Achieved

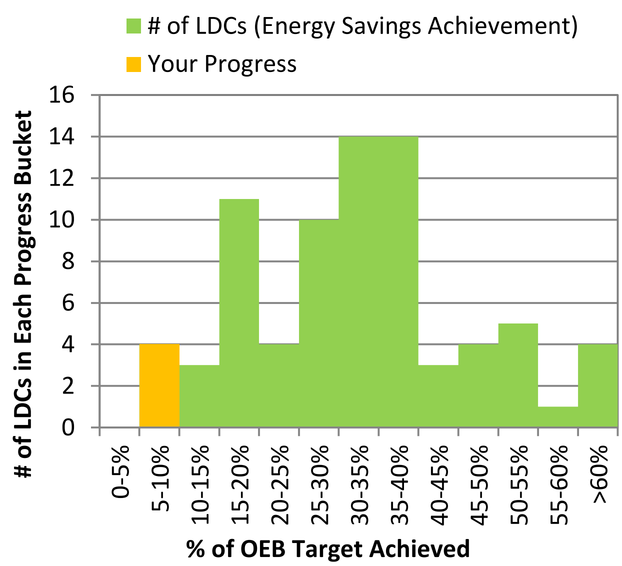


Table 1: Participation[1]

#	Initiative	Unit	Uptake/ Participation Units
Consumer Program			
1	Appliance Retirement	Appliances	97
2	Appliance Exchange	Appliances	7
3	HVAC Incentives	Equipment	27
4	Conservation Instant Coupon Booklet	Products	1,107
5	Bi-Annual Retailer Event	Products	1,921
6	Retailer Co-op	Products	0
7	Residential Demand Response	Devices	0
8	Residential New Construction	Houses	0
Business Program			
9	Efficiency: Equipment Replacement	Projects	0
10	Direct Install Lighting	Projects	0
11	Existing Building Commissioning Incentive	Buildings	0
12	New Construction and Major Renovation Incentive	Buildings	0
13	Energy Audit	Audits	0
14	Commercial Demand Response (part of the Residential program schedule)	Devices	0
15	Demand Response 3 (part of the Industrial program schedule)	Facilities	0
Industrial Program			
16	Process & System Upgrades	Projects[2]	0
17	Monitoring & Targeting	Projects[3]	0
18	Energy Manager	Managers[2 3]	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Projects	0
20	Demand Response 3	Facilities	0
Home Assistance Program			
21	Home Assistance Program	Homes	0
Pre 2011 Programs Completed in 2011			
22	Electricity Retrofit Incentive Program	Projects	0
23	High Performance New Construction	Projects	0
24	Toronto Comprehensive	Projects	0
25	Multifamily Energy Efficiency Rebates	Projects	0
26	Data Centre Incentive Program	Projects	0
27	EnWin Green Suites	Projects	0

[1] *Please see "Methodology" tab for more information regarding attributing savings to LDCs*

[2] *Results are based on completed incentive projects (see "Methodology" tab for more information)*

[3] *Includes: Roving Energy Managers, Key Account Managers and Embedded Energy Managers if projects are completed in 2011*

Table 3: OPA Province-Wide Evaluation Findings

#	Initiative	OPA Province-Wide Key Evaluation Findings
Consumer Program		

1	Appliance Retirement	* Overall participation continues to decline year over year
		  * Participation declined 17% from 2010 (from over 67,000 units in 2010 to over 56,000 units in 2011)
		* 97% of net resource savings achieved through the home pick-up stream
		  * Measure Breakdown: 66% refrigerators, 30% freezers, 4% Dehumidifiers and window air conditioners
		* 3% of net resource savings achieved through the Retailer pick-up stream
		  * Measure Breakdown: 90% refrigerators, 10% freezers
		* Net-to-Gross ratio for the initiative was 50%
		  * Measure-level free ridership ranges from 82% for the retailer pick-up stream to 49% for the home pick-up stream
		  * Measure-level spillover ranges from 3.7% for the retailer pick-up stream to 1.7% for the home pick-up stream

2	Appliance Exchange	* Overall eligible units exchanged declined by 36% from 2010 (from over 5,700 units in 2010 to
		  * Measure Breakdown: 75% window air conditioners, 25% dehumidifiers
		* Dehumidifiers and window air conditioners contributed almost equally to the net energy
		  * Dehumidifiers provide more than three times the energy savings per unit than window air conditioners
		* Window air conditioners contributed to 64% of the net peak demand savings achieved
		* Approximately 96% of consumers reported having replaced their exchanged units (as opposed to retiring the unit)
		* Net-to-Gross ratio for the initiative is consistent with previous evaluations (51.5%)

3	HVAC Incentives	* Total air conditioner and furnace installations increased by 14% (from over 95,800 units in 2010 to over 111,500 units in 2011)
		  * Measure Breakdown: 64% furnaces, 10% tier 1 air conditioners (SEER 14.5) and 26% tier 2 air conditioners (SEER 15)
		  * Measure breakdown did not change from 2010 to 2011
		* The HVAC Incentives initiative continues to deliver the majority of both the energy (45%) and demand (83%) savings in the consumer program
		  * Furnaces accounted for over 91% of energy savings achieved for this initiative
		* Net-to-Gross ratio for the initiative was 17% higher than 2010 (from 43% in 2010 to 60% in
		  * Increase due in part to the removal of programmable thermostats from the program, and an increase in the net-to-gross ratio for both Furnaces and Tier 2 air conditioners (SEER 15)

4	Conservation Instant Coupon Booklet	* Customers redeemed nearly 210,000 coupons, translating to nearly 560,000 products
		  * Majority of coupons redeemed were downloadable (~40%) or LDC-branded (~35%)
		  * Majority of coupons redeemed were for multi-packs of standard spiral CFLs (37%), followed by multi-packs of specialty CFLs (17%)
		* Per unit savings estimates and net-to-gross ratios for 2011 are based on a weighted average of 2009 and 2010 evaluation findings
		* Careful attention in the 2012 evaluation will be made for standard CFLs since it is believed that the market has largely been transformed

		* Customers redeemed nearly 370,000 coupons, translating to over 870,000 products * Majority of coupons redeemed were for multi-packs of standard spiral CFLs (49%), followed by multi-packs of specialty CFLs (16%)

#	Initiative	OPA Province-Wide Key Evaluation Findings

5	Bi-Annual Retailer Event	* Per unit savings estimates and net-to-gross ratios for 2011 are based on a weighted average of 2009 and 2010 evaluation findings
		  * Standard CFLs and heavy duty outdoor timers were reintroduced to the initiative in 2011 and contributed more than 64% of the initiative's 2011 net annual energy savings
		  * While the volume of coupons redeemed for heavy duty outdoor timers was relatively small (less than 1%), the measure accounted for 10% of net annual savings due to high per unit savings
		* Careful attention in the 2012 evaluation will be made for standard CFLs since it is believed that the market has largely been transformed.

6	Retailer Co-op	* Initiative was not evaluated in 2011 due to low uptake. Verified Bi-Annual Retailer Event per unit assumptions and free-ridership rates were used to calculate net resource savings

7	Residential Demand Response	* Approximately 20,000 new devices were installed in 2011
		  * 99% of the new devices enrolled controlled residential central AC (CAC)
		* 2011 only saw 1 atypical event (in both weather and timing) that had limited participation
		  * The ex ante impact developed through the 2009/2010 evaluations was maintained for 2011; residential CAC: 0.56 kW/device, commercial CAC: 0.64 kW/device, and Electric Water Heaters: 0.30 kW/device

8	Residential New Construction	* Initiative was not evaluated in 2011 due to limited uptake * Business case assumptions were used to calculate savings
Business Program		

9	Efficiency: Equipment Replacement	* Gross verified energy savings were boosted by lighting projects in the prescriptive and
		* Lighting projects overall were determined to have a realization rate of 112%; 116% when including interactive energy changes
		  * On average, the evaluation found high realization rates as a result of both longer operating hours and larger wattage reductions than initial assumptions
		  * Low realization rates for engineered lighting projects due to overstated operating hour assumptions
		* Custom non-lighting projects suffered from process issues such as: the absence of required M&V plans, the use of inappropriate assumptions , and the lack of adherence to the M&V plan
		* The final realization rate for summer peak demand was 94%
		  * 84% was a result of different methodologies used to calculate peak demand savings
		  * 10% due to the benefits from reduced air conditioning load in lighting retrofits
		* Overall net-to-gross ratios in the low 70's represent an improvement over the 2009 and Strict eligibility requirements and improvements in the pre-approval process contributed to the improvement in net-to-gross ratios

10	Direct Install Lighting	* Though overall performance is above expectations, participation continues to decline year over year as the initiative reaches maturity
		* 70% of province-wide resource savings persist to 2014
		  * Over 35% of the projects for 2011 included at least one CFL measure
		  * Resource savings from CFLs in the commercial sector only persist for the industry standard of 3 years
		* Since 2009 the overall realization rate for this program has improved
		  * 2011 evaluation recorded the highest energy realization rate to date at 89.5%

#	Initiative	OPA Province-Wide Key Evaluation Findings
		* The hours of use values were held constant from the 2010 evaluation and continue to be the main driver of energy realization rate * Lights installed in "as needed" areas (e.g., bathrooms, storage areas) were determined to have very low realization rates due to the difference in actual energy saved vs. reported savings
11	Existing Building Commissioning Incentive	* Initiative was not evaluated in 2011, no completed projects in 2011
12	New Construction and Major Renovation Incentive	* Initiative was not evaluated in 2011 due to low uptake * Assumptions used are consistent with preliminary reporting based on the 2010 Evaluation findings and consultation with the C&I Work Group (100% realization rate and 50% net-to-gross ratio)
13	Energy Audit	* The evaluation is ongoing. The sample size for 2011 was too small to draw reliable conclusions.
14	Commercial Demand Response (part of the Residential program schedule)	* See residential demand response (#7)
15	Demand Response 3 (part of the Industrial program schedule)	* See Demand Response 3 (#20)
Industrial Program		
16	Process & System Upgrades	* Initiative was not evaluated in 2011, no completed projects in 2011
17	Monitoring & Targeting	* Initiative was not evaluated in 2011, no completed projects in 2011
18	Energy Manager	* Initiative was not evaluated in 2011, no completed projects in 2011
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	* See Efficiency: Equipment Replacement (#9)
20	Demand Response 3	* Program performance for Tier 1 customers increased with DR-3 participants providing 75% * Industrial customers outperform commercial customers by provide 84% and 76% of contracted MW, respectively * Program continues to diversify but still remains heavily concentrated with less than 5% of * By increasing the number of contributors in each settlement account and implementation of the new baseline methodology the performance of the program is expected to increase
Home Assistance Program		
21	Home Assistance Program	* Initiative was not evaluated in 2011 due to low uptake * Business Case assumptions were used to calculate savings
Pre-2011 Programs completed in 2011		

#	Initiative	OPA Province-Wide Key Evaluation Findings
22	Electricity Retrofit Incentive Program	* Initiative was not evaluated * Net-to-Gross ratios used are consistent with the 2010 evaluation findings (multifamily buildings 99% realization rate and 62% net-to-gross ratio and C&I buildings 77% realization rate and 52% net-to-gross ratio)
23	High Performance New Construction	* Initiative was not evaluated * Net-to-Gross ratios used are consistent with the 2010 evaluation findings (realization rate of 100% and net-to-gross ratio of 50%)
24	Toronto Comprehensive	* Initiative was not evaluated * Net-to-Gross ratios used are consistent with the 2010 evaluation findings
25	Multifamily Energy Efficiency Rebates	* Initiative was not evaluated * Net-to-Gross ratios used are consistent with the 2010 evaluation findings
26	Data Centre Incentive Program	* Initiative was not evaluated
27	EnWin Green Suites	* Initiative was not evaluated

Table 5: Summarized Program Results

Program	Gross Savings: Incremental Peak Demand Savings (kW)	Gross Savings: Incremental Energy Savings (kWh)		Net Savings: Incremental Peak Demand Savings (kW)	Net Savings: Incremental Energy Savings (kWh)
Consumer Program Total	35	212,237		23	168,537
Business Program Total	0	0		0	0
Industrial Program Total	0	0		0	0
Home Assistance Program Total	0	0		0	0
Pre-2011 Programs completed in 2011 Total	0	0		0	0
Total OPA Contracted Province-Wide CDM Programs	**35**	**212,237**		**23**	**168,537**

#	Initiative	Realization Rate: Peak Demand Savings	Realization Rate: Energy Savings	Gross Savings: Incremental Peak Demand Savings (kW)	Gross Savings: Incremental Energy Savings (kWh)	Net-to-Gross Ratio: Peak Demand Savings	Net-to-Gross Ratio: Energy Savings	Net Savings: Incremental Peak Demand Savings (kW)	Net Savings: Incremental Energy Savings (kWh)
Consumer Program									
1	Appliance Retirement	100%	100%	12	80,205	51%	52%	6	41,532
2	Appliance Exchange	100%	100%	1	1,532	52%	52%	1	790
3	HVAC Incentives	100%	100%	16	33,546	59%	59%	10	19,936
4	Conservation Instant Coupon Booklet	100%	100%	2	37,581	114%	111%	3	41,414
5	Bi-Annual Retailer Event	100%	100%	3	59,373	113%	110%	4	64,865
6	Retailer Co-op	-	-	0	0	-	-	0	0
7	Residential Demand Response	0%	0%	0	0	-	-	0	0
8	Residential New Construction	-	-	0	0	-	-	0	0
Business Program									
9	Efficiency: Equipment Replacement	-	-	0	0	-	-	0	0
10	Direct Install Lighting	-	-	0	0	-	-	0	0
11	Existing Building Commissioning Incentive	-	-	0	0	-	-	0	0
12	New Construction and Major Renovation Incentive	-	-	0	0	-	-	0	0
13	Energy Audit	-	-	0	0	-	-	0	0
14	Commercial Demand Response (part of the Residential program schedule)	0%	0%	0	0	-	-	0	0
15	Demand Response 3 (part of the Industrial program schedule)	76%	100%	0	0	n/a	n/a	0	0
Industrial Program									
16	Process & System Upgrades	-	-	0	0	-	-	0	0
17	Monitoring & Targeting	-	-	0	0	-	-	0	0
18	Energy Manager	-	-	0	0	-	-	0	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	-	-	0	0	-	-	0	0
20	Demand Response 3	84%	100%	0	0	n/a	n/a	0	0
Home Assistance Program									
21	Home Assistance Program	-	-	0	0	-	-	0	0
Pre-2011 Programs completed in 2011									
22	Electricity Retrofit Incentive Program	-	-	0	0	-	-	0	0
23	High Performance New Construction	-	-	0	0	-	-	0	0
24	Toronto Comprehensive	-	-	0	0	-	-	0	0
25	Multifamily Energy Efficiency Rebates	-	-	0	0	-	-	0	0
26	Data Centre Incentive Program	-	-	0	0	-	-	0	0
27	EnWin Green Suites	-	-	0	0	-	-	0	0

Assumes demand response resources have a persistence of 1 year

Program	Contribution to Targets	
	Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program Total	22	673,545
Business Program Total	0	0
Industrial Program Total	0	0
Home Assistance Program Total	0	0
Pre-2011 Programs completed in 2011 Total	0	0
Total OPA Contracted Province-Wide CDM Programs	**22**	**673,545**

#	Initiative	Contribution to Targets	
		Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program			
1	Appliance Retirement	6	165,927
2	Appliance Exchange	0	2,759
3	HVAC Incentives	10	79,744
4	Conservation Instant Coupon Booklet	3	165,655
5	Bi-Annual Retailer Event	4	259,461
6	Retailer Co-op	0	0
7	Residential Demand Response	0	0
8	Residential New Construction	0	0
Business Program			
9	Efficiency: Equipment Replacement	0	0
10	Direct Install Lighting	0	0
11	Existing Building Commissioning Incentive	0	0
12	New Construction and Major Renovation Incentive	0	0
13	Energy Audit	0	0
14	Commercial Demand Response (part of the Residential program schedule)	0	0
15	Demand Response 3 (part of the Industrial program schedule)	0	0
Industrial Program			
16	Process & System Upgrades	0	0
17	Monitoring & Targeting	0	0
18	Energy Manager	0	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	0	0
20	Demand Response 3	0	0
Home Assistance Program			
21	Home Assistance Program	0	0
Pre-2011 Programs completed in 2011			
22	Electricity Retrofit Incentive Program	0	0
23	High Performance New Construction	0	0
24	Toronto Comprehensive	0	0
25	Multifamily Energy Efficiency Rebates	0	0
26	Data Centre Incentive Program	0	0
27	EnWin Green Suites	0	0

Assumes demand response resources have a persistence of 1 year

Progress Towards CDM Targets

Results are attributed to target using current OPA reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year. Please see methodology tab for more detailed information.

Yellow cells are intended for the LDC to input information to complete their OEB Reporting Template.

Table 6: Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	0.02	0.02	0.02	0.02
2012				
2013				
2014				0.00
Verified Net Annual Peak Demand Savings Persisting in 2014:				**0.02**
Algoma Power Inc. 2014 Annual CDM Capacity Target:				**1.28**
Verified Portion of Peak Demand Savings Target Achieved in 2014(%):				**1.72%**
LDC Milestone submitted for 2011				**24.65%**
Variance				-22.93%

Table 7: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	0.17	0.17	0.17	0.17	0.67
2012					
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					**0.67**
Algoma Power Inc. 2011-2014 Cumulative CDM Energy Target:					**7.37**
Verified Portion of Cumulative Energy Target Achieved (%):					**9.14%**
LDC Milestone submitted for 2011					**10.15%**
Variance					-1.01%

Table P1: Province-Wide Participation

#	Initiative	Activity Unit	Uptake/ Participation Units
Consumer Program			
1	Appliance Retirement	Appliances	56,110
2	Appliance Exchange	Appliances	3,688
3	HVAC Incentives	Equipment	111,587
4	Conservation Instant Coupon Booklet	Products[4]	559,462
5	Bi-Annual Retailer Event	Products[5]	870,332
6	Retailer Co-op	Products	152
7	Residential Demand Response	Devices	19,577
8	Residential New Construction	Houses	7
Business Program			
9	Efficiency: Equipment Replacement	Projects	2,516
10	Direct Installed Lighting	Projects	20,297
11	Existing Building Commissioning Incentive	Buildings	-
12	New Construction and Major Renovation Incentive	Buildings	10
13	Energy Audit	Audits	103
14	Commercial Demand Response (part of the Residential program schedule)	Devices	264
15	Demand Response 3 (part of the Industrial program schedule)	Facilities	148
Industrial Program			
16	Process & System Upgrades[2]	Projects	-
17	Monitoring & Targeting[2]	Projects	-
18	Energy Manager[2 3]	Managers	-
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)[1]	Projects	433
20	Demand Response 3	Facilities	134
Home Assistance Program			
21	Home Assistance Program	Homes	46
Pre 2011 Programs Completed in 2011			
22	Electricity Retrofit Incentive Program	Projects	2,023
23	High Performance New Construction	Projects	145
24	Toronto Comprehensive	Projects	553
25	Multifamily Energy Efficiency Rebates	Projects	110
26	Data Centre Incentive Program	Projects	5
27	EnWin Green Suites	Projects	3

[2] *Results are based on completed incentive projects (see "Methodology" tab for more information)*

[3] *Includes: Roving Energy Managers, Key Account Managers and Embedded Energy Managers with completed projects*

[4] *209,693 valid coupons redeemed*

[5] *369,446 valid coupons redeemed*

Table P2: Province-Wide Results

Program	Gross Savings: Incremental Peak Demand Savings (kW)	Gross Savings: Incremental Energy Savings (kWh)		Net Savings: Incremental Peak Demand Savings (kW)	Net Savings: Incremental Energy Savings (kWh)
Consumer Program Total	73,757	192,379,633		49,123	133,519,668
Business Program Total	78,048	251,304,448		64,594	198,124,227
Industrial Program Total	68,648	41,493,145		57,099	31,947,577
Home Assistance Program Total	4	56,119		2	39,283
Pre-2011 Programs completed in 2011 Total	87,169	460,822,079		44,833	241,853,020
Total OPA Contracted Province-Wide CDM Programs	**307,626**	**946,055,425**		**215,651**	**605,483,775**

#	Initiative	Realization Rate: Peak Demand Savings	Realization Rate: Energy Savings	Gross Savings: Incremental Peak Demand Savings (kW)	Gross Savings: Incremental Energy Savings (kWh)	Net-to-Gross Ratio: Peak Demand Savings	Net-to-Gross Ratio: Energy Savings	Net Savings: Incremental Peak Demand Savings (kW)	Net Savings: Incremental Energy Savings (kWh)
Consumer Program									
1	Appliance Retirement	100%	100%	6,750	45,971,627	51%	51%	3,299	23,005,812
2	Appliance Exchange	100%	100%	719	873,531	51%	51%	371	450,187
3	HVAC Incentives	100%	100%	53,209	99,413,430	60%	60%	32,037	59,437,670
4	Conservation Instant Coupon Booklet	100%	100%	1,184	19,192,453	114%	111%	1,344	21,211,537
5	Bi-Annual Retailer Event	100%	100%	1,504	26,899,265	112%	110%	1,681	29,387,468
6	Retailer Co-op	100%	100%	0	3,917	68%	68%	0	2,652
7	Residential Demand Response	n/a	n/a	10,390	23,597	n/a	n/a	10,390	23,597
8	Residential New Construction	100%	100%	0	1,813	41%	41%	0	743
Business Program									
9	Efficiency: Equipment Replacement	106%	91%	34,201	184,070,265	72%	74%	24,467	136,002,258
10	Direct Installed Lighting	108%	93%	22,155	65,777,197	108%	93%	23,724	61,076,701
11	Existing Building Commissioning Incentive	-	-	-	-	-	-	-	-
12	New Construction and Major Renovation Incentive	50%	50%	247	823,434	50%	50%	123	411,717
13	Energy Audit	-	-	-	-	-	-	-	-
14	Commercial Demand Response (part of the Residential program schedule)	n/a	n/a	55	131	n/a	n/a	55	131
15	Demand Response 3 (part of the Industrial program schedule)	76%	n/a	21,390	633,421	n/a	n/a	16,224	633,421
Industrial Program									
16	Process & System Upgrades	-	-	-	-	-	-	-	-
17	Monitoring & Targeting	-	-	-	-	-	-	-	-
18	Energy Manager	-	-	-	-	-	-	-	-
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	111%	91%	6,372	38,412,408	72%	75%	4,615	28,866,840
20	Demand Response 3	84%	n/a	62,276	3,080,737	n/a	n/a	52,484	3,080,737
Home Assistance Program									
21	Home Assistance Program	100%	100%	4	56,119	70%	70%	2	39,283
Pre-2011 Programs completed in 2011									
22	Electricity Retrofit Incentive Program	80%	80%	40,418	223,956,390	54%	54%	21,550	120,492,549
23	High Performance New Construction	100%	100%	10,197	52,371,183	49%	49%	5,098	26,185,591
24	Toronto Comprehensive	113%	113%	33,467	174,070,574	50%	52%	15,805	86,964,886
25	Multifamily Energy Efficiency Rebates	93%	93%	2,553	9,774,792	78%	78%	1,981	7,595,683
26	Data Centre Incentive Program	100%	100%	81	533,038	100%	100%	81	533,038
27	EnWin Green Suites	100%	100%	453	116,102	70%	70%	317	81,272

Assumes demand response resources have a persistence of 1 year

Program	Contribution to Targets	
	Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program Total	38,405	534,017,835
Business Program Total	41,048	767,657,790
Industrial Program Total	4,613	118,543,019
Home Assistance Program Total	2	157,134
Pre-2011 Programs completed in 2011 Total	44,833	967,412,079
Total OPA Contracted Province-Wide CDM Programs	**128,901**	**2,387,787,856**

#	Initiative	Contribution to Targets	
		Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program			
1	Appliance Retirement	3,160	91,903,303
2	Appliance Exchange	181	1,930,651
3	HVAC Incentives	32,037	237,750,681
4	Conservation Instant Coupon Booklet	1,344	84,846,148
5	Bi-Annual Retailer Event	1,681	117,549,874
6	Retailer Co-op	0	10,607
7	Residential Demand Response	0	23,597
8	Residential New Construction	0	2,973
Business Program			
9	Efficiency: Equipment Replacement	24,438	543,856,392
10	Direct Installed Lighting	16,486	221,520,977
11	Existing Building Commissioning Incentive	-	-
12	New Construction and Major Renovation Incentive	123	1,646,869
13	Energy Audit	-	-
14	Commercial Demand Response (part of the Residential program schedule)	0	131
15	Demand Response 3 (part of the Industrial program schedule)	0	633,421
Industrial Program			
16	Process & System Upgrades	-	-
17	Monitoring & Targeting	-	-
18	Energy Manager	-	-
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	4,613	115,462,282
20	Demand Response 3	0	3,080,737
Home Assistance Program			
21	Home Assistance Program	2	157,134
Pre-2011 Programs completed in 2011			
22	Electricity Retrofit Incentive Program	21,550	481,970,197
23	High Performance New Construction	5,098	104,742,366
24	Toronto Comprehensive	15,805	347,859,545
25	Multifamily Energy Efficiency Rebates	1,981	30,382,733
26	Data Centre Incentive Program	81	2,132,152
27	EnWin Green Suites	317	325,086

Assumes demand response resources have a persistence of 1 year

Summary - Provincial Progress

Table P3: Province-Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011	215.7	135.2	134.5	127.6
2012				
2013				
2014				
Verified Net Annual Peak Demand Savings in 2014:				127.6
2014 Annual CDM Capacity Target				1,330
Verified Peak Demand Savings Target Achieved - 2011 (%):				9.60%

Table P4: Province-Wide Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011	605.5	599.2	597.2	578.5	2,380
2012					0
2013					0
2014					0
Verified Net Cumulative Energy Savings 2011-2014:					2,380
2011-2014 Cumulative CDM Energy Target:					6,000
Verified Portion of Energy Target Achieved - 2011 (%):					39.67%

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS:

PRESCRIPTIVE MEASURES/PROJECTS:

Gross Savings = Activity * Per Unit Assumption

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

ENGINEERED/CUSTOM PROJECTS:

Gross Savings = Reported Savings * Realization Rate

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

DEMAND RESPONSE:

Peak Demand: Gross Savings = Net Savings = contracted MW at contributor level * Provincial contracted to ex ante ratio

Energy: Gross Savings = Net Savings = provincial ex post energy savings * LDC proportion of total provincial contracted MW

All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program				
1	Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection	Savings are considered to begin in the year the appliance is picked up.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
2	Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year that the exchange event occurred	
3	HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year that the installation occurred	

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
4	Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the coupon was redeemed.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Initiative was not evaluated in 2011, reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.
5	Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the event occurs.	
6	Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Initiative was not evaluated in 2011, reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
7	Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any “snapback” in energy consumption experienced after the event. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
8	Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	**Peak demand and energy savings** are determined using a measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program				

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
9	Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
		Additional Note: project counts were derived by filtering out "Application Status" = "Post-Project Submission - Payment denied by LDC" and only including projects with an "Actual Project Completion Date" in 2011 and pulling both the "Application Name" field followed by the "Building Address 1" field from the Post Stage Retrofit Report and finally performing a count of the Building Addresses.		
10	Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
11	Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
12	New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, reported results are presented with reported assumptions (as per evaluated results in 2010 and consultation with OPA-LDC Work Groups)	Savings are considered to begin in the year of the actual project completion date.	
13	Energy Audit	No resource savings results determined in 2011; Projects are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year of the audit date.	**Peak demand and energy savings** are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
14	Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
15	Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program				
16	Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
17	Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
18	Energy Manager	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
20	Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Home Assistance Program				
21	Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year in which the measures were installed.	**Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Pre-2011 Programs completed in 2011				
22	Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
23	High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	
24	Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation		

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
25	Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
26	Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation		
27	EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation		

ERII Sector (C&I vs. Industrial Mapping)	
Building Type	**Sector**
Agribusiness - Cattle Farm	C&I
Agribusiness - Dairy Farm	C&I
Agribusiness - Greenhouse	C&I
Agribusiness - Other	C&I
Agribusiness - Other,Mixed-Use - Office/Retail	C&I
Agribusiness - Other,Office,Retail,Warehouse	C&I
Agribusiness - Other,Office,Warehouse	C&I
Agribusiness - Poultry	C&I
Agribusiness - Poultry,Hospitality - Motel	C&I
Agribusiness - Swine	C&I
Convenience Store	C&I
Education - College / Trade School	C&I
Education - College / Trade School,Multi-Residential - Condominium	C&I
Education - College / Trade School,Multi-Residential - Rental Apartment	C&I
Education - College / Trade School,Retail	C&I
Education - Primary School	C&I
Education - Primary School,Education - Secondary School	C&I
Education - Primary School,Multi-Residential - Rental Apartment	C&I
Education - Primary School,Not-for-Profit	C&I
Education - Secondary School	C&I
Education - University	C&I
Education - University,Office	C&I
Hospital/Healthcare - Clinic	C&I
Hospital/Healthcare - Clinic,Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Clinic,Industrial	C&I
Hospital/Healthcare - Clinic,Retail	C&I
Hospital/Healthcare - Long-term Care	C&I
Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail,Office	C&I
Hospitality - Hotel	C&I
Hospitality - Hotel,Restaurant - Dining	C&I
Hospitality - Motel	C&I
Industrial	Industrial
Mixed-Use - Office/Retail	C&I
Mixed-Use - Office/Retail,Industrial	Industrial
Mixed-Use - Office/Retail,Mixed-Use - Other	C&I
Mixed-Use - Office/Retail,Mixed-Use - Other,Not-for-Profit,Warehouse	C&I
Mixed-Use - Office/Retail,Mixed-Use - Residential/Retail	C&I
Mixed-Use - Office/Retail,Office,Restaurant - Dining,Restaurant - Quick Serve,Retail,Warehouse	C&I

Mixed-Use - Office/Retail,Office,Warehouse	C&I
Mixed-Use - Office/Retail,Retail	C&I
Mixed-Use - Office/Retail,Warehouse	C&I
Mixed-Use - Office/Retail,Warehouse,Industrial	Industrial
Mixed-Use - Other	C&I
Mixed-Use - Other,Industrial	Industrial
Mixed-Use - Other,Not-for-Profit,Office	C&I
Mixed-Use - Other,Office	C&I
Mixed-Use - Other,Other: Please specify	C&I
Mixed-Use - Other,Retail,Warehouse	C&I
Mixed-Use - Other,Warehouse	C&I
Mixed-Use - Residential/Retail	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Condominium	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Rental Apartment	C&I
Mixed-Use - Residential/Retail,Retail	C&I
Multi-Residential - Condominium	C&I
Multi-Residential - Condominium,Multi-Residential - Rental Apartment	C&I
Multi-Residential - Condominium,Other: Please specify	C&I
Multi-Residential - Rental Apartment	C&I
Multi-Residential - Rental Apartment,Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Warehouse	C&I
Multi-Residential - Social Housing Provider	C&I
Multi-Residential - Social Housing Provider,Industrial	C&I
Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Not-for-Profit	C&I
Not-for-Profit,Office	C&I
Not-for-Profit,Other: Please specify	C&I
Not-for-Profit,Warehouse	C&I
Office	C&I
Office,Industrial	Industrial
Office,Other: Please specify	C&I
Office,Other: Please specify,Warehouse	C&I
Office,Restaurant - Dining	C&I
Office,Restaurant - Dining,Industrial	Industrial
Office,Retail	C&I
Office,Retail,Industrial	C&I
Office,Retail,Warehouse	C&I
Office,Warehouse	C&I
Office,Warehouse,Industrial	Industrial
Other: Please specify	C&I
Other: Please specify,Industrial	Industrial
Other: Please specify,Retail	C&I
Other: Please specify,Warehouse	C&I
Restaurant - Dining	C&I
Restaurant - Dining,Retail	C&I

Restaurant - Quick Serve	C&I
Restaurant - Quick Serve,Retail	C&I
Retail	C&I
Retail,Industrial	Industrial
Retail,Warehouse	C&I
Warehouse	C&I
Warehouse,Industrial	Industrial

Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Local Distribution Company	Allocation
Algoma Power Inc.	0.2%
Atikokan Hydro Inc.	0.0%
Attawapiskat Power Corporation	0.0%
Bluewater Power Distribution Corporation	0.6%
Brant County Power Inc.	0.2%
Brantford Power Inc.	0.7%
Burlington Hydro Inc.	1.4%
Cambridge and North Dumfries Hydro Inc.	1.0%
Canadian Niagara Power Inc.	0.5%
Centre Wellington Hydro Ltd.	0.1%
Chapleau Public Utilities Corporation	0.0%
COLLUS Power Corporation	0.3%
Cooperative Hydro Embrun Inc.	0.0%
E.L.K. Energy Inc.	0.2%
Enersource Hydro Mississauga Inc.	3.9%
ENTEGRUS	0.6%
ENWIN Utilities Ltd.	1.6%
Erie Thames Powerlines Corporation	0.4%
Espanola Regional Hydro Distribution Corporation	0.1%
Essex Powerlines Corporation	0.7%
Festival Hydro Inc.	0.3%
Fort Albany Power Corporation	0.0%
Fort Frances Power Corporation	0.1%
Greater Sudbury Hydro Inc.	1.0%
Grimsby Power Inc.	0.2%
Guelph Hydro Electric Systems Inc.	0.9%
Haldimand County Hydro Inc.	0.4%
Halton Hills Hydro Inc.	0.5%
Hearst Power Distribution Company Limited	0.1%
Horizon Utilities Corporation	4.0%
Hydro 2000 Inc.	0.0%
Hydro Hawkesbury Inc.	0.1%
Hydro One Brampton Networks Inc.	2.8%
Hydro One Networks Inc.	30.0%

Hydro Ottawa Limited	5.6%
Innisfil Hydro Distribution Systems Limited	0.4%
Kashechewan Power Corporation	0.0%
Kenora Hydro Electric Corporation Ltd.	0.1%
Kingston Hydro Corporation	0.5%
Kitchener-Wilmot Hydro Inc.	1.6%
Lakefront Utilities Inc.	0.2%
Lakeland Power Distribution Ltd.	0.2%
London Hydro Inc.	2.7%
Middlesex Power Distribution Corporation	0.1%
Midland Power Utility Corporation	0.1%
Milton Hydro Distribution Inc.	0.6%
Newmarket - Tay Power Distribution Ltd.	0.7%
Niagara Peninsula Energy Inc.	1.0%
Niagara-on-the-Lake Hydro Inc.	0.2%
Norfolk Power Distribution Inc.	0.3%
North Bay Hydro Distribution Limited	0.5%
Northern Ontario Wires Inc.	0.1%
Oakville Hydro Electricity Distribution Inc.	1.5%
Orangeville Hydro Limited	0.2%
Orillia Power Distribution Corporation	0.3%
Oshawa PUC Networks Inc.	1.2%
Ottawa River Power Corporation	0.2%
Parry Sound Power Corporation	0.1%
Peterborough Distribution Incorporated	0.7%
PowerStream Inc.	6.6%
PUC Distribution Inc.	0.9%
Renfrew Hydro Inc.	0.1%
Rideau St. Lawrence Distribution Inc.	0.1%
Sioux Lookout Hydro Inc.	0.1%
St. Thomas Energy Inc.	0.3%
Thunder Bay Hydro Electricity Distribution Inc.	0.9%
Tillsonburg Hydro Inc.	0.1%
Toronto Hydro-Electric System Limited	12.8%
Veridian Connections Inc.	2.4%
Wasaga Distribution Inc.	0.2%
Waterloo North Hydro Inc.	1.0%
Welland Hydro-Electric System Corp.	0.4%
Wellington North Power Inc.	0.1%
West Coast Huron Energy Inc.	0.1%
Westario Power Inc.	0.5%
Whitby Hydro Electric Corporation	0.9%
Woodstock Hydro Services Inc.	0.3%

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years).

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

Free-ridership: the percentage of participants who would have implemented the program measure or practice in the absence of the program.

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start' (please see table 5).

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net-to-Gross Ratio: The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

Program: a group of initiatives that target a particular market sector (i.e. Consumer, Industrial).

Realization Rate: A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.

Settlement Account: the grouping of demand response facilities (contributors) into one contractual agreement

Spillover: Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

Schedule “H”

Bill Impacts

Algoma Power Inc.
2014 Distribution Rate Impact Module
2014 Electricity Distribution Rate Application

EB-2013-0110

August 16, 2013

Electricity Distribution Impacts
Rates Effective January 1, 2014

Monthly Rates and Charges	Metric	Current Approved Rates	Proposed Rates
Residential - R1			
Monthly Service Charge	$	22.32	22.81
Smart Meter Rate Adder	$	-	-
Distribution Volumetric Rate	$/kWh	0.0313	0.0320
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2014	$/kWh	0.0004	0.0004
Rate Rider for Deferral/Variance Account Disposition (2010) - effective until May 31, 2013	$/kWh	0.0046	-
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until May 31, 2013	$/kWh	(0.0061)	-
Rate Rider for Deferral/Variance Account Disposition (2013) - effective until December 31, 2013	$/kWh	(0.0052)	-
Rate Rider for Global Adjustment Sub-Account Disposition (2013) - effective until December 31, 2013	$/kWh	0.0150	-
Rate Rider for Tax Changes - effective until December 31, 2013	$/kWh	(0.0002)	-
Rate Rider for Tax Changes - effective until December 31, 2014	$/kWh	-	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0069	0.0066
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0049	0.0047
Wholesale Market Service Rate	$/kWh	0.0044	0.0044
Rural Rate Protection Charge	$/kWh	0.0012	0.0012
Smart Meter Entity Charge - effective May 1, 2013 until October 31, 2018	$	0.79	0.79
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	0.25
Residential - R2			
Monthly Service Charge	$	596.12	596.12
Smart Meter Rate Adder	$	-	-
Distribution Volumetric Rate	$/kW	2.8949	3.0083
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2014	$/kW	0.0373	0.0373
Rate Rider for Deferral/Variance Account Disposition (2010) - effective until May 31, 2013	$/kW	2.2664	-
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until May 31, 2013	$/kW	(2.8219)	-
Rate Rider for Deferral/Variance Account Disposition (2013) - effective until December 31, 2013	$/kW	(1.3006)	-
Rate Rider for Global Adjustment Sub-Account Disposition (2013) - effective until December 31, 2013	$/kW	6.4235	-
Rate Rider for Tax Changes - effective until December 31, 2013	$/kW	(0.0300)	-
Rate Rider for Tax Changes - effective until December 31, 2014	$/kW	-	(0.0125)
Retail Transmission Rate - Network Service Rate	$/kW	2.5633	2.4575
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7423	1.6746
Retail Transmission Rate - Network Service Rate - Interval Meter > 1,000 kW	$/kW	2.7191	2.6069
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval > 1,000 kW	$/kW	1.9255	1.8507
Wholesale Market Service Rate	$/kWh	0.0044	0.0044
Rural Rate Protection Charge	$/kWh	0.0012	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	0.25
Seasonal			
Monthly Service Charge	$	26.38	26.51
Smart Meter Rate Adder	$	-	-
Distribution Volumetric Rate	$/kWh	0.1015	0.1019
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2014	$/kWh	0.0003	0.0003
Rate Rider for Deferral/Variance Account Disposition (2010) - effective until May 31, 2013	$/kWh	0.0046	-
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until May 31, 2013	$/kWh	(0.0061)	-
Rate Rider for Deferral/Variance Account Disposition - effective until November 30, 2015	$/kWh	0.0307	0.0307
Rate Rider for Deferral/Variance Account Disposition (2013) - effective until December 31, 2013	$/kWh	(0.0056)	-
Rate Rider for Global Adjustment Sub-Account Disposition (2013) - effective until December 31, 2013	$/kWh	0.0150	-
Smart Meter Cost Recovery Rate Rider - Net Deferred Revenue Requirement, effective until December 31, 2016	$	3.14	3.14
Smart Meter Cost Recovery Rate Rider - Incremental Revenue Requirement, effective until December 31, 2014	$	2.81	2.81
Rate Rider for Tax Changes - effective until December 31, 2013	$/kWh	(0.0003)	-
Rate Rider for Tax Changes - effective until December 31, 2014	$/kWh	-	(0.0005)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0069	0.0066
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0049	0.0047
Wholesale Market Service Rate	$/kWh	0.0044	0.0044
Rural Rate Protection Charge	$/kWh	0.0012	0.0012
Smart Meter Entity Charge - effective May 1, 2013 until October 31, 2018	$	0.79	0.79
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	0.25
Street Lighting			
Monthly Service Charge	$	0.97	0.97
Distribution Volumetric Rate	$/kWh	0.1557	0.1565
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2014	$/kWh	0.0003	0.0003
Rate Rider for Deferral/Variance Account Disposition (2010) - effective until May 31, 2013	$/kWh	0.0048	-
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until May 31, 2013	$/kWh	(0.0061)	-
Rate Rider for Deferral/Variance Account Disposition (2013) - effective until December 31, 2013	$/kWh	(0.0045)	-
Rate Rider for Global Adjustment Sub-Account Disposition (2013) - effective until December 31, 2013	$/kWh	0.0150	-
Rate Rider for Tax Changes - effective until December 31, 2013	$/kWh	(0.0003)	-
Retail Transmission Rate - Network Service Rate	$/kW	1.9331	1.8533
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3469	1.2946
Wholesale Market Service Rate	$/kWh	0.0044	0.0044
Rural Rate Protection Charge	$/kWh	0.0012	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	0.25
Other			
Debt Retirement Charge	$/kWh	0.0020	0.0020
Energy - First Tier	$/kWh	0.0750	0.0750
Energy - Second Tier	$/kWh	0.0880	0.0880
Loss Factor			
Total Loss Factor		1.0864	1.0864
TOU			
TOU - Off Peak	$/kWh	0.067	0.067
TOU - Mid Peak	$/kWh	0.104	0.104
TOU - On Peak	$/kWh	0.124	0.124
Energy Price	$/kWh	0.0839	0.0839
HST	%	13%	13%
OCEB	%	-10%	-10%
Energy Price	$/kWh	0.0839	0.0839

2014 Bill Impact

Monthly Rates and Charges
Residential - R1

Total Loss factor	1.0864
Number of Customers/Connections - Input Required	1
Consumption - kWh - Input Required	800
Demand - kW - Input Required	-
Load Factor - % - Calculated	n/a

Billing Component	Current Board Approved			Proposed			Impact	
	Rate	Volume / Demand	Charge	Rate	Volume / Demand	Charge	Change	Change
	$		$	$		$	$	%
Monthly Service Charge	22.32	1	22.32	22.81	1	22.81	0.49	2.2%
Distribution Volumetric Rate	0.0313	800	25.04	0.0320	800	25.60	0.56	2.2%
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2014	0.0004	800	0.32	0.0004	800	0.32	-	0.0%
Rate Rider for Tax Changes - effective until December 31, 2013	(0.0002)	800	(0.1600)	-	800	-	0.16	-100.0%
Rate Rider for Tax Changes - effective until December 31, 2014	-	800	-	(0.0001)	800	(0.08)	(0.08)	
Sub-Total A (excluding pass through)			47.52			48.65	1.13	2.4%
Line Losses on Cost of Power	0.0839	69	5.80	0.0839	69	5.80	-	0.0%
Rate Rider for Deferral/Variance Account Disposition (2010) - effective until May 31, 2013	-	800	-	-	800	-	-	
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until May 31, 2013	-	800	-	-	800	-	-	
Rate Rider for Deferral/Variance Account Disposition (2013) - effective until December 31, 2013	(0.0052)	800	(4.16)	-	800	-	4.16	-100.0%
Rate Rider for Global Adjustment Sub-Account Disposition (2013) - effective until December 31, 2013	0.0150	800	12.00	-	800	-	(12.00)	-100.0%
Smart Meter Entity Charge - effective May 1, 2013 until October 31, 2018	0.79	1	0.79	0.79	1	0.79	-	0.0%
Sub-Total B - Distribution (includes Sub-Total A)			61.95			55.24	(6.71)	-10.8%
Retail Transmission Rate - Network Service Rate	0.0069	869	6.00	0.0066	869	5.74	(0.26)	-4.3%
Retail Transmission Rate - Line and Transformation Connection Service Rate	0.0049	869	4.26	0.0047	869	4.08	(0.17)	-4.1%
Sub-Total C (includes Sub-Total B)			72.20			65.06	(7.14)	-9.9%
Wholesale Market Service Rate	0.0044	869	3.82	0.0044	869	3.82	-	0.0%
Rural Rate Protection Charge	0.0012	869	1.04	0.0012	869	1.04	-	0.0%
Standard Supply Service - Administrative Charge (if applicable)	0.25	1	0.25	0.25	1	0.25	-	0.0%
Debt Retirement Charge	0.0020	800	1.60	0.0020	800	1.60	-	0.0%
TOU - Off Peak	0.0670	512	34.30	0.0670	512	34.30	-	0.0%
TOU - Mid Peak	0.1040	144	14.98	0.1040	144	14.98	-	0.0%
TOU - On Peak	0.1240	144	17.86	0.1240	144	17.86	-	0.0%
Total Bill on TOU (before taxes)			146.06			138.91	(7.14)	-4.9%
HST	13%		18.99	13%		18.06	(0.93)	-4.9%
Total Bill including HST			165.05			156.97	(8.07)	-4.9%
OCEB	-10%		- 16.50	-10%		- 15.70	0.81	-4.9%
Total Bill on TOU (including OCEB)			148.54			141.27	(7.27)	-4.9%

2014 Bill Impact

Monthly Rates and Charges
Residential - R1

Total Loss factor	1.0864
Number of Customers/Connections - Input Required	1
Consumption - kWh - Input Required	2,000
Demand - kW - Input Required	-
Load Factor - % - Calculated	n/a

Billing Component	Current Board Approved			Proposed			Impact	
	Rate	Volume / Demand	Charge	Rate	Volume / Demand	Charge	Change	Change
	$		$	$		$	$	%
Monthly Service Charge	22.32	1	22.32	22.81	1	22.81	0.49	2.2%
Distribution Volumetric Rate	0.0313	2,000	62.60	0.0320	2,000	64.00	1.40	2.2%
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2014	0.0004	2,000	0.80	0.0004	2,000	0.80	-	0.0%
Rate Rider for Tax Changes - effective until December 31, 2013	(0.0002)	2,000	(0.4000)	-	2,000	-	0.40	-100.0%
Rate Rider for Tax Changes - effective until December 31, 2014	-	2,000	-	(0.0001)	2,000	(0.20)	(0.20)	
Sub-Total A (excluding pass through)			85.32			87.41	2.09	2.4%
Line Losses on Cost of Power	0.0839	173	14.50	0.0839	173	14.50	-	0.0%
Rate Rider for Deferral/Variance Account Disposition (2010) - effective until May 31, 2013	-	2,000	-	-	2,000	-	-	
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until May 31, 2013	-	2,000	-	-	2,000	-	-	
Rate Rider for Deferral/Variance Account Disposition (2013) - effective until December 31, 2013	(0.0052)	2,000	(10.40)	-	2,000	-	10.40	-100.0%
Rate Rider for Global Adjustment Sub-Account Disposition (2013) - effective until December 31, 2013	0.0150	2,000	30.00	-	2,000	-	(30.00)	-100.0%
Smart Meter Entity Charge - effective May 1, 2013 until October 31, 2018	0.79	1	0.79	0.79	1	0.79	-	0.0%
Sub-Total B - Distribution (includes Sub-Total A)			120.21			102.70	(17.51)	-14.6%
Retail Transmission Rate - Network Service Rate	0.0069	2,173	14.99	0.0066	2,173	14.34	(0.65)	-4.3%
Retail Transmission Rate - Line and Transformation Connection Service Rate	0.0049	2,173	10.65	0.0047	2,173	10.21	(0.43)	-4.1%
Sub-Total C (includes Sub-Total B)			145.85			127.25	(18.60)	-12.8%
Wholesale Market Service Rate	0.0044	2,173	9.56	0.0044	2,173	9.56	-	0.0%
Rural Rate Protection Charge	0.0012	2,173	2.61	0.0012	2,173	2.61	-	0.0%
Standard Supply Service - Administrative Charge (if applicable)	0.25	1	0.25	0.25	1	0.25	-	0.0%
Debt Retirement Charge	0.0020	2,000	4.00	0.0020	2,000	4.00	-	0.0%
TOU - Off Peak	0.0670	1,280	85.76	0.0670	1,280	85.76	-	0.0%
TOU - Mid Peak	0.1040	360	37.44	0.1040	360	37.44	-	0.0%
TOU - On Peak	0.1240	360	44.64	0.1240	360	44.64	-	0.0%
Total Bill on TOU (before taxes)			330.10			311.51	(18.60)	-5.6%
HST	13%		42.91	13%		40.50	(2.42)	-5.6%
Total Bill including HST			373.02			352.00	(21.01)	-5.6%
OCEB	-10%		- 37.30	-10%		- 35.20	2.10	-5.6%
Total Bill on TOU (including OCEB)			335.72			316.80	(18.91)	-5.6%

2014 Bill Impact

Monthly Rates and Charges
Residential - R2

Total Loss factor	1.0864
Number of Customers/Connections - Input Required	1
Consumption - kWh - Input Required	90,000
Demand - kW - Input Required	225
Load Factor - % - Calculated	55%

Billing Component	Current Board Approved			Proposed			Impact	
	Rate	Volume / Demand	Charge	Rate	Volume / Demand	Charge	Change	Change
	$		$	$		$	$	%
Monthly Service Charge	596.12	1	596.12	596.12	1	596.12	-	0.0%
Distribution Volumetric Rate	2.8949	225	651.35	3.0083	225	676.87	25.52	3.9%
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2014	0.0373	225	8.39	0.0373	225	8.39	-	0.0%
Rate Rider for Tax Changes - effective until December 31, 2013	(0.0300)	225	(6.75)	-	225	-	6.75	-100.0%
Rate Rider for Tax Changes - effective until December 31, 2014	-	225	-	(0.0125)	225	(2.81)	(2.81)	
						-	-	
Sub-Total A (excluding pass through)			1,249.12			1,278.57	29.45	2.4%
Line Losses on Cost of Power	0.0839	7,776	652.41	0.0839	7,776	652.41	-	0.0%
Rate Rider for Deferral/Variance Account Disposition (2010) - effective until May 31, 2013	-	225	-	-	225	-		
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until May 31, 2013	-	225	-	-	225	-		
Rate Rider for Deferral/Variance Account Disposition (2013) - effective until December 31, 2013	(1.3006)	225	(292.64)	-	225	-	292.64	-100.0%
Rate Rider for Global Adjustment Sub-Account Disposition (2013) - effective until December 31, 2013	6.4235	225	1,445.29	-	225	-	(1,445.29)	-100.0%
					-	-	-	
Sub-Total B - Distribution (includes Sub-Total A)			3,054.17			1,930.97	(1,123.20)	-36.8%
Retail Transmission Rate - Network Service Rate	2.5633	225	576.74	2.4575	225	552.94	(23.80)	-4.1%
Retail Transmission Rate - Line and Transformation Connection Service Rate	1.7423	225	392.02	1.6746	225	376.79	(15.23)	-3.9%
Sub-Total C (includes Sub-Total B)			4,022.93			2,860.70	(1,162.24)	-28.9%
Wholesale Market Service Rate	0.0044	97,776	430.21	0.0044	97,776	430.21	-	0.0%
Rural Rate Protection Charge	0.0012	97,776	117.33	0.0012	97,776	117.33	-	0.0%
Standard Supply Service - Administrative Charge (if applicable)	0.25	1	0.25	0.25	1	0.25	-	0.0%
Debt Retirement Charge	0.0020	90,000	180.00	0.0020	90,000	180.00	-	0.0%
Energy Price	0.0839	90,000	7,551.00	0.0839	90,000	7,551.00	-	0.0%
Total Bill on TOU (before taxes)			12,301.73			11,139.49	(1,162.24)	-9.4%
HST	13%		1,599.22	13%		1,448.13	(151.09)	-9.4%
Total Bill including HST			13,900.95			12,587.63	(1,313.33)	-9.4%
OCEB	-10%		- 1,390.10	-10%		- 1,258.76	131.33	-9.4%
Total Bill on TOU (including OCEB)			12,510.86			11,328.86	(1,182.00)	-9.4%

2014 Bill Impact

Monthly Rates and Charges
Residential - R2
Interval Metered

Total Loss factor	1.0864
Number of Customers/Connections - Input Required	1
Consumption - kWh - Input Required	90,000
Demand - kW - Input Required	225
Load Factor - % - Calculated	55%

Billing Component	Current Board Approved			Proposed			Impact	
	Rate	Volume / Demand	Charge	Rate	Volume / Demand	Charge	Change	Change
	$		$	$		$	$	%
Monthly Service Charge	596.12	1	596.12	596.12	1	596.12	-	0.0%
Distribution Volumetric Rate	2.8949	225	651.35	3.0083	225	676.87	25.52	3.9%
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2014	0.0373	225	8.39	0.0373	225	8.39	-	0.0%
Rate Rider for Tax Changes - effective until December 31, 2013	(0.0300)	225	(6.75)	-	225	-	6.75	-100.0%
Rate Rider for Tax Changes - effective until December 31, 2014	-	225	-	(0.0125)	225	(2.81)	(2.81)	
					-	-	-	
					-	-	-	
Sub-Total A (excluding pass through)			1,249.12			1,278.57	29.45	2.4%
Line Losses on Cost of Power	0.0839	7,776	652.41	0.0839	7,776	652.41	-	0.0%
Rate Rider for Deferral/Variance Account Disposition (2010) - effective until May 31, 2013	-	225	-	-	225	-	-	
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until May 31, 2013	-	225	-	-	225	-	-	
Rate Rider for Deferral/Variance Account Disposition (2013) - effective until December 31, 2013	(1.3006)	225	(292.64)	-	225	-	292.64	-100.0%
Rate Rider for Global Adjustment Sub-Account Disposition (2013) - effective until December 31, 2013	6.4235	225	1,445.29	-	225	-	(1,445.29)	-100.0%
Sub-Total B - Distribution (includes Sub-Total A)			3,054.17			1,930.97	(1,123.20)	-36.8%
Retail Transmission Rate - Network Service Rate	2.7191	225	611.80	2.6069	225	586.55	(25.25)	-4.1%
Retail Transmission Rate - Line and Transformation Connection Service Rate	1.9255	225	433.24	1.8507	225	416.41	(16.83)	-3.9%
Sub-Total C (includes Sub-Total B)			4,099.21			2,933.93	(1,165.28)	-28.4%
Wholesale Market Service Rate	0.0044	97,776	430.21	0.0044	97,776	430.21	-	0.0%
Rural Rate Protection Charge	0.0012	97,776	117.33	0.0012	97,776	117.33	-	0.0%
Standard Supply Service - Administrative Charge (if applicable)	0.25	1	0.25	0.25	1	0.25	-	0.0%
Debt Retirement Charge	0.0020	90,000	180.00	0.0020	90,000	180.00	-	0.0%
Energy Price	0.0839	90,000	7,551.00	0.0839	90,000	7,551.00	-	0.0%
Total Bill on TOU (before taxes)			12,378.00			11,212.73	(1,165.28)	-9.4%
HST	13%		1,609.14	13%		1,457.65	(151.49)	-9.4%
Total Bill including HST			13,987.15			12,670.38	(1,316.76)	-9.4%
OCEB	-10%		- 1,398.71	-10%		- 1,267.04	131.68	-9.4%
Total Bill on TOU (including OCEB)			12,588.43			11,403.35	(1,185.08)	-9.4%

2014 Bill Impact

Monthly Rates and Charges
Seasonal

Total Loss factor	1.0864
Number of Customers/Connections - Input Required	1
Consumption - kWh - Input Required	287
Demand - kW - Input Required	
Load Factor - % - Calculated	n/a

Billing Component	Current Board Approved			Proposed			Impact	
	Rate	Volume / Demand	Charge	Rate	Volume / Demand	Charge	Change	Change
	$		$	$		$	$	%
Monthly Service Charge	26.38	1	26.38	26.51	1	26.51	0.13	0.5%
Smart Meter Rate Adder	-	1	-	-	1	-	-	
Distribution Volumetric Rate	0.1015	287	29.13	0.1019	287	29.25	0.11	0.4%
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2014	0.0003	287	0.09	0.0003	287	0.09	-	0.0%
Smart Meter Cost Recovery Rate Rider - Net Deferred Revenue Requirement, effective until December 31, 2016	3.1400	1	3.14	3.1400	1	3.14	-	0.0%
Smart Meter Cost Recovery Rate Rider - Incremental Revenue Requirement, effective until December 31, 2014	2.8100	1	2.81	2.8100	1	2.81	-	0.0%
Rate Rider for Tax Changes - effective until December 31, 2013	(0.0003)	287	(0.09)	-	287	-	0.09	-100.0%
Rate Rider for Tax Changes - effective until December 31, 2014	-	287	-	(0.0005)	287	(0.14)	(0.14)	
Sub-Total A (excluding pass through)			58.74			58.98	0.24	0.4%
Line Losses on Cost of Power	0.0839	25	2.08	0.0839	25	2.08	-	0.0%
Rate Rider for Deferral/Variance Account Disposition (2010) - effective until May 31, 2013	-	287	-	-	287	-	-	
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until May 31, 2013	-	287	-	-	287	-	-	
Rate Rider for Deferral/Variance Account Disposition (2013) - effective until December 31, 2013	(0.0056)	287	(1.61)	-	287	-	1.61	-100.0%
Rate Rider for Global Adjustment Sub-Account Disposition (2013) - effective until December 31, 2013	0.0150	287	4.31	-	287	-	(4.31)	-100.0%
Rate Rider for Deferral/Variance Account Disposition - effective until November 30, 2015	0.0307	287	8.81	0.0307	287	8.81	-	0.0%
Smart Meter Entity Charge - effective May 1, 2013 until October 31, 2018	0.79	1	0.79	0.79	1	0.79	-	0.0%
Sub-Total B - Distribution (includes Sub-Total A)			73.12			70.66	(2.45)	-3.4%
Retail Transmission Rate - Network Service Rate	0.0069	312	2.15	0.0066	312	2.06	(0.09)	-4.3%
Retail Transmission Rate - Line and Transformation Connection Service Rate	0.0049	312	1.53	0.0047	312	1.47	(0.06)	-4.1%
Sub-Total C (includes Sub-Total B)			76.79			74.19	(2.61)	-3.4%
Wholesale Market Service Rate	0.0044	312	1.37	0.0044	312	1.37	-	0.0%
Rural Rate Protection Charge	0.0012	312	0.37	0.0012	312	0.37	-	0.0%
Standard Supply Service - Administrative Charge (if applicable)	0.25	1	0.25	0.25	1	0.25	-	0.0%
Debt Retirement Charge	0.0020	287	0.57	0.0020	287	0.57	-	0.0%
TOU - Off Peak	0.0670	184	12.31	0.0670	184	12.31	-	0.0%
TOU - Mid Peak	0.1040	52	5.37	0.1040	52	5.37	-	0.0%
TOU - On Peak	0.1240	52	6.41	0.1240	52	6.41	-	0.0%
Total Bill on TOU (before taxes)			103.45			100.84	(2.61)	-2.5%
HST	13%		13.45	13%		13.11	(0.34)	-2.5%
Total Bill including HST			116.90			113.95	(2.95)	-2.5%
OCEB	-10%		- 11.69	-10%		- 11.40	0.29	-2.5%
Total Bill on TOU (including OCEB)			105.21			102.56	(2.65)	-2.5%

2014 Bill Impact

Monthly Rates and Charges
Street Lighting

Total Loss factor	1.0864
Number of Customers/Connections - Input Required	428
Consumption - kWh - Input Required	25,000
Demand - kW - Input Required	71
Load Factor - % - Calculated	48%

Billing Component	Current Board Approved			Proposed			Impact	
	Rate	Volume / Demand	Charge	Rate	Volume / Demand	Charge	Change	Change
	$		$	$		$	$	%
Monthly Service Charge	0.97	428	415.16	0.97	428	415.16	-	0.0%
Distribution Volumetric Rate	0.1557	25,000	3,892.50	0.1565	25,000	3,912.50	20.00	0.5%
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2014	0.0003	25,000	7.50	0.0003	25,000	7.50	-	0.0%
Rate Rider for Tax Changes - effective until December 31, 2013	(0.0003)	25,000	(7.50)	-	25,000	-	7.50	-100.0%
			-		-	-	-	
Sub-Total A (excluding pass through)			4,307.66			4,335.16	27.50	0.6%
Line Losses on Cost of Power	0.0839	2,160	181.22	0.0839	2,160	181.22	-	0.0%
Rate Rider for Deferral/Variance Account Disposition (2010) - effective until May 31, 2013	-	25,000	-	-	25,000	-	-	
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until May 31, 2013	-	25,000	-	-	25,000	-	-	
Rate Rider for Deferral/Variance Account Disposition (2013) - effective until December 31, 2013	(0.0045)	25,000	(112.50)	-	25,000	-	112.50	-100.0%
Rate Rider for Global Adjustment Sub-Account Disposition (2013) - effective until December 31, 2013	0.0150	25,000	375.00	-	25,000	-	(375.00)	-100.0%
Sub-Total B - Distribution (includes Sub-Total A)			4,751.38			4,516.38	(235.00)	-4.9%
Retail Transmission Rate - Network Service Rate	1.9331	77.6	150.01	1.8533	77.6	143.82	(6.19)	-4.1%
Retail Transmission Rate - Line and Transformation Connection Service Rate	1.3469	77.6	104.52	1.2946	77.6	100.46	(4.06)	-3.9%
Sub-Total C (includes Sub-Total B)			5,005.91			4,760.66	(245.25)	-4.9%
Wholesale Market Service Rate	0.0044	27,160	119.50	0.0044	27,160	119.50	-	0.0%
Rural Rate Protection Charge	0.0012	27,160	32.59	0.0012	27,160	32.59	-	0.0%
Standard Supply Service - Administrative Charge (if applicable)	0.25	428	107.00	0.25	428	107.00	-	0.0%
Debt Retirement Charge	0.0020	25,000	50.00	0.0020	25,000	50.00	-	0.0%
Energy Price	0.0839	25,000	2,097.50	0.0839	25,000	2,097.50	-	0.0%
Total Bill on TOU (before taxes)			7,412.51			7,167.26	(245.25)	-3.3%
HST	13%		963.63	13%		931.74	(31.88)	-3.3%
Total Bill including HST			8,376.13			8,099.00	(277.13)	-3.3%
OCEB	-10%		- 837.61	-10%		- 809.90	27.71	-3.3%
Total Bill on TOU (including OCEB)			7,538.52			7,289.10	(249.42)	-3.3%

Selected Delivery Charge and Bill Impacts Per Application
Algoma Power Inc. 2014

Customer Classification and Billing Type	Energy kWh	Demand kW	Monthly Delivery Charge Current	Per Application	Change $	Change %
Residential - R1	800		$ 72.20	$ 65.06	-$ 7.14	-9.9%
Residential - R1 (2000 kWh)	2,000		$ 145.85	$ 127.25	-$ 18.60	-12.8%
Residential - R2	90,000	225	$ 4,022.93	$ 2,860.70	-$ 1,162.24	-28.9%
Seasonal	287		$ 76.79	$ 74.19	-$ 2.61	-3.4%
Street Lighting	25,000	71	$ 5,005.91	$ 4,760.66	-$ 245.25	-4.9%

Customer Classification and Billing Type	Energy kWh	Demand kW	Total Bill Current	Per Application	Change $	Change %
Residential - R1	800		$ 148.54	$ 141.27	-$ 7.27	-4.9%
Residential - R1 (2000 kWh)	2,000		$ 335.72	$ 316.80	-$ 18.91	-5.6%
Residential - R2	90,000	225	$ 12,510.86	$ 11,328.86	-$ 1,182.00	-9.4%
Seasonal	287		$ 105.21	$ 102.56	-$ 2.65	-2.5%
Street Lighting	25,000	71	$ 7,538.52	$ 7,289.10	-$ 249.42	-3.3%