ATIKOKAN HYDRO INC.

117 Gorrie Street, Box 1480
Atikokan, Ontario P0T 1C0

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September 30, 2011

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

Dear Ms. Walli:

Re: Atikokan Hydro Inc.
2012 Cost of Service Rate Application (EB-2011-0293)

Atikokan Hydro Inc. is pleased to submit its 2012 Cost of Service Rate Application (the "Application"). The Application is based on Chapter 2 of the Board's "Filing Requirements for Transmission and Distribution Rate Applications", dated June 22, 2011.

The Application includes the following Exhibits found in file Atikokan_APPL_CoS_30092011

Exhibit 1 - Administrative Documents
Exhibit 2 - Rate Base
Exhibit 3 - Operating Revenue
Exhibit 4 - Operating Costs
Exhibit 5 - Cost of Capital and Capital Structure
Exhibit 6 - Revenue Deficiency/Sufficiency
Exhibit 7 - Cost Allocation
Exhibit 8 - Rate Design
Exhibit 9 - Deferral and Variance Accounts

The Application has been filed electronically with the Board today and two (2) paper copies will be delivered to the Board Secretary.

If you require further information please contact me.

Regards,

Wilf Thorburn

Wilf Thorburn
CEO Secretary/Treasurer
Atikokan Hydro Inc

ATIKOKAN HYDRO INC

APPLICATION FOR APPROVAL OF ELECTRICITY DISTRIBUTION RATES EFFECTIVE MAY 1, 2012

INDEX

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Atikokan Hydro Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity commencing May 1, 2012.

APPLICATION

Introduction

The Applicant is Atikokan Hydro Incorporated (referred to in this Application as the "Applicant" or "Atikokan Hydro"). The Applicant is a corporation incorporated pursuant to the Ontario Business Corporations Act with its head office in the Town of Atikokan

The Applicant hereby applies to the Ontario Energy Board (the "OEB") pursuant to section 78 of the Ontario Energy Board Act, 1998 as amended (the "OEB Act") for approval of its proposed distribution rates and other charges, effective May 1, 2012.

In the preparation of the Application, the Applicant followed Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 22, 2011 (the "Filing Requirements") in preparing this Application.

Proposed Distribution Rates and Other Charges

The detailed Tariff of Rates and Charges proposed in this Application is identified in Exhibit 8 Tab 1, Schedule 6. A summary of the proposed Tariff of Rates and Charges is provided in Appendix A of this tab. The material being filed in support of this Application sets out Atikokan Hydro's approach to its 2012 distribution rates and charges.

Proposed Effective Date of Rate Order

The Applicant requests that the OEB make its Rate Order effective May 1, 2012 in accordance with the Filing Requirements**.**

The Proposed Distribution Rates and Other Charges are Just and Reasonable

The Applicant submits the proposed distribution rates contained in this Application as just and as reasonable as can be expected on the following grounds:

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

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

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

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

Relief Sought

The Applicant applies for an Order or Orders approving the proposed distribution rates and other charges set out in this Application as just and reasonable rates and charges pursuant to section 78 of the OEB Act, to be effective May 1, 2012, or as soon as possible thereafter. If delays are expected in processing the application and issuing a rate order, Atikokan Hydro is asking for interim rates effective May 1, 2012.

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

Form of Hearing Requested

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

DATED at Atikokan, Ontario, this 30th day of September, 2011.

Atikokan Hydro
117 Gorrie Street
Atikokan, ON
P0T 1C0

Appendix A

RESIDENTIAL SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	41.01
Smart Meter Cost Recovery Rider – effective until April 30, 2015	$	3.54
Stranded Meter Rate Rider - effective until April 30, 2015	$	0.39
Distribution Volumetric Rate	$/kWh	0.0162
Rate Mitigation Rate Rider - effective until April 30, 2013	$/kWh	(0.0034)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0056
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0035

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	82.46
Smart Meter Cost Recovery Rider – effective until April 30, 2015	$	3.54
Stranded Meter Rate Rider - effective until April 30, 2015	$	0.39
Distribution Volumetric Rate	$/kWh	0.0105
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0030

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	587.88
Smart Meter Cost Recovery Rider – effective until April 30, 2015	$	3.54
Stranded Meter Rate Rider - effective until April 30, 2015	$	0.39
Distribution Volumetric Rate	$/kW	2.2261
Retail Transmission Rate – Network Service Rate	$/kW	2.0445
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.1690
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2016
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.3281

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

STREET LIGHTING SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	14.67
Distribution Volumetric Rate	$/kW	18.0955
Retail Transmission Rate – Network Service Rate	$/kW	1.5421
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9288

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

microFIT GENERATOR SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

ALLOWANCES

Transformer Allowance for Ownership – per kW of billing demand/month – customer shall be credited at a rate of 10% of the applicable Distribution Volumetric Rate		
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

Customer Administration	
Returned Cheque charge (plus bank charges)	$ 25.00
Account set up charge / change of occupancy charge (plus credit agency costs if applicable)	$ 25.00
Special Meter reads	$ 25.00
Non-Payment of Account	
Late Payment - per month	% 1.50
Late Payment - per annum	% 19.56
Collection of account charge – no disconnection	$ 25.00
Disconnect/Reconnect at Meter – during regular hours	$ 28.00
Disconnect/Reconnect at Meter – after regular hours	$ 315.00
Disconnect/Reconnect at Pole – during regular hours	$ 28.00
Disconnect/Reconnect at Pole – after regular hours	$ 315.00
Specific Charge for Access to the Power Poles – per pole/year	$ 22.35

RETAIL SERVICE CHARGES

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

LOSS FACTORS

Total Loss Factor – Secondary Metered Customers	1.0778
Total Loss Factor – Primary Metered Customers	1.0671

CONTACT INFORMATION AND PUBLICATION OF NOTICES:

CONTACT INFORMATION

Atikokan Hydro Inc.

Wilf Thorburn
CEO / Sec / Treas
Atikokan Hydro Inc
117 Gorrie Street
Atikokan, ON P0T 1C0
Phone: (807)597-6600
Fax: (807)597-6988
E-mail: wilf.thorburn@athydro.com

PUBLICATION OF NOTICES :

Atikokan Hydro intends to publish all required notices in the Atikokan Progress a local newspaper. This local newspaper is distributed as a paid circulation with approximately 1600 distributed within Atikokan. [There are no unpaid newspapers in Atikokan]

SPECIFIC APPROVALS REQUESTED:

In this proceeding, Atikokan Hydro is requesting the following approvals:

- Approval to charge rates effective May 1, 2012 to recover a revenue requirement of $1,579,603 which includes a revenue deficiency of $ 364,011, as set out in Exhibit 6, Schedule 1, Tab 1; the proposed tariff of rates and charges is set out in Exhibit 8 Tab 1 Schedule 6

- Approval of the proposed loss factor as set out in Exhibit 8, Tab 1, Schedule 3;

- Approval to charge a Retail Transmission Network Service rate and a Retail Transmission Connection Rate as proposed and described in Exhibit 8, Tab 1, Schedule 2;

- Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the OEB Decision and Order in the matter of Atikokan Hydro's 2011 Distribution Rates (EB-2010-0064);

- Approval to continue the Specific Service Charges and Transformer Allowance approved in the OEB Decision and Order in the matter of Atikokan Hydro's 2011 Distribution Rates (EB-2010-0064);

- Approval for a smart meter cost recovery rate rider for the difference between the smart meter adder collected from May 1, 2006 until April 30, 2012 and the revenue requirement related to these smart meters up to December 31, 2011, through a rider of $3.54 per month per metered customer, for three years;

- Approval for a stranded meter rate rider of $0.39 per month per metered customer, for three years to recover the net book value of $23,375 for stranded meters as at December 31, 2011;

- Approval to include smart meter capital deployed as of December 31, 2011 in the 2012 rate base that supports the 2012 revenue requirement and distribution rates which is the subject of this rate application;

- Approval to include smart meter operation and maintenance expenses in the 2012 revenue requirement associated with the smart meters deployed;
- Approval to discontinue the Smart Meter rate adder;
- Approval to implement a rate mitigation plan which includes a rate migration rate rider to address bill impacts above 10% for the Residential class and deferring the disposition of the 2010 Group 1 and 2 deferral and variance account balances until the 2013 IRM application. Further details of the rate mitigation plan are provided in Exhibit 8, Tab 1, Schedule 4;
- Approval to discontinue the Sentinel Light and Unmetered Scattered Load classes since there are no longer any customers in these rate classes;
- Approval of the Basic Green Energy Plan as set out in Exhibit 2.

PROPOSED ISSUES LIST:

GENERAL (Exhibit 1)

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

2. RATE BASE (Exhibit 2)

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

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

- Is the load forecast methodology including weather normalization appropriate?

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

4. OPERATING COSTS (Exhibit 4)

- Is the overall OM&A forecast for the test year appropriate?
- Are the methodologies used to allocate shared services and other costs appropriate?
- Is the proposed level of depreciation/amortization expense for the test year appropriate?
- Are the 2012 compensation costs and employee levels appropriate?
- Is the test year forecast of PILs appropriate?

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

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

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

- Is the calculation of Revenue Deficiency accurate?

7. COST ALLOCATION (Exhibit 7)

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

8. RATE DESIGN (Exhibit 8)

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

9. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit 9)

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

PROCEDURAL ORDERS/MOTIONS/NOTICES:

March 1, 2011 the Board issued its list of distributors that it anticipates will be filing a Cost of Service Applications for 2012. Atikokan Hydro was included on that list.

ACCOUNTING ORDERS REQUESTED:

Atikokan Hydro is not requesting any change in Accounting Orders in this proceeding.

COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS:

Atikokan Hydro has followed the accounting principles and main categories of accounts as stated in the OEB’s Accounting Procedures Handbook (the “APH”) and the Uniform System of Accounts (“USoA”) in the preparation of this Application.

DISTRIBUTION SERVICE TERRITORY AND DISTRIBUTION SYSTEM:

Description of Distributor:

COMMUNITY SERVED:	Urban and Rural areas of Town of Atikokan
TOTAL SERVICE AREA:	380 sq km
DISTRIBUTION TYPE	Electricity distribution
MUNICIPAL POPULATION:	3000

Map 1 shows Atikokan Hydro's Distribution Service Territory including the two 44 kV lines and is attached to this Schedule as Appendix B.

Map 2 Shows the Town of Atikokan [formerly Township of Atikokan], and indicates the area where the majority of our feeders are, and is displayed as Appendix C.

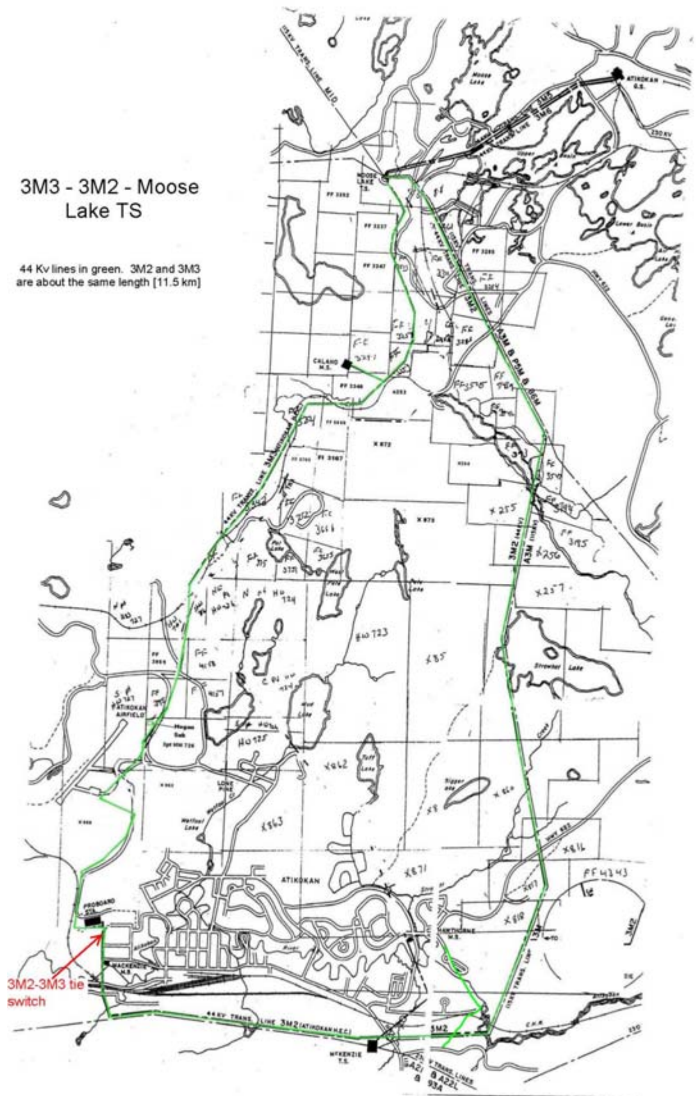
Appendix D is a map of 5 of our distribution feeders.

A schematic diagram of Atikokan Hydro's distribution system is attached as Appendix E

Appendix B

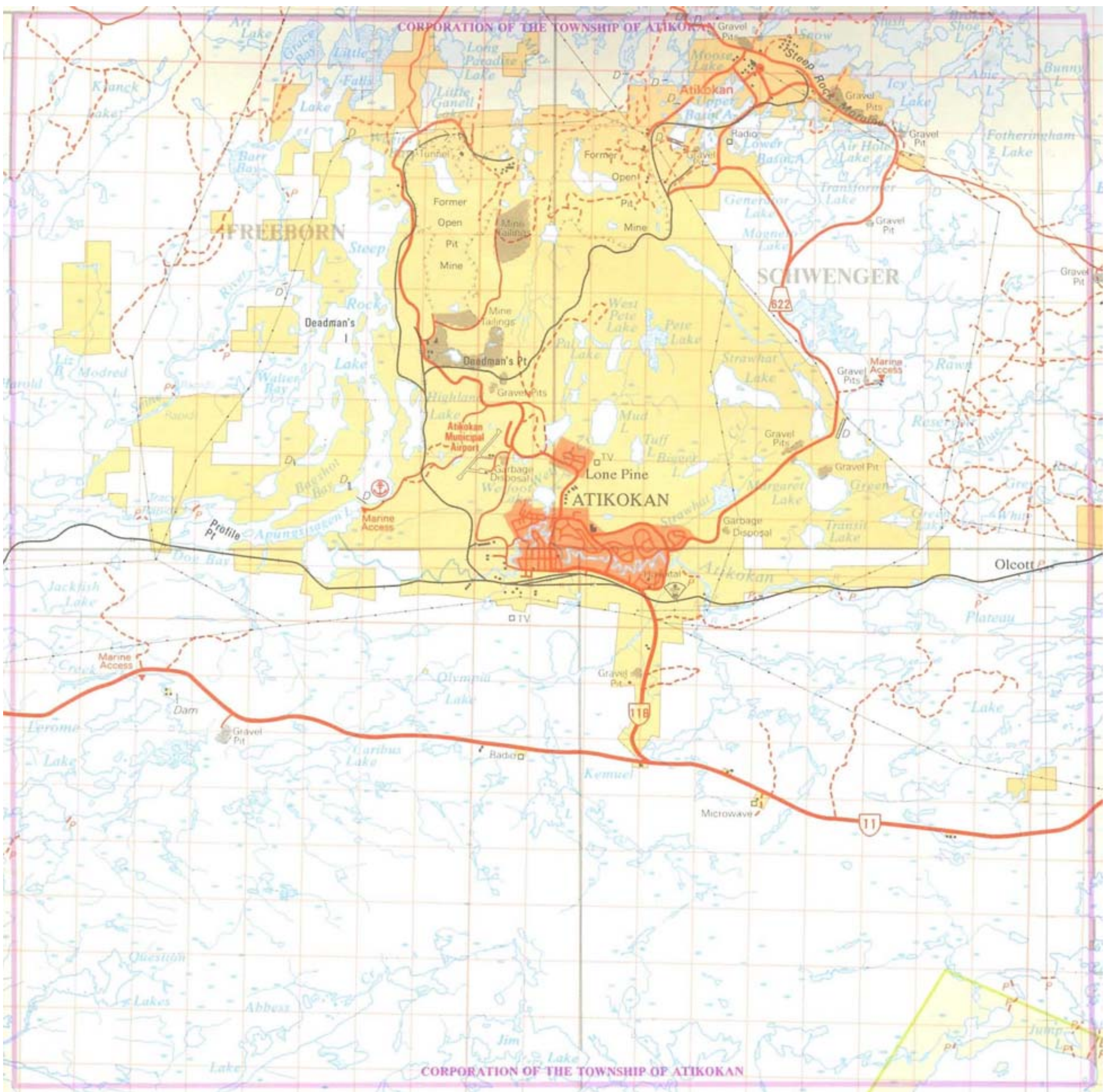
MAP1 OF DISTRIBUTION SERVICE TERRITORY:

The map below shows Atikokan Hydro's service area. The lines in green are the 44 kV lines The most concentrated area of customers is near the bottom of the map.



APPENDIX C

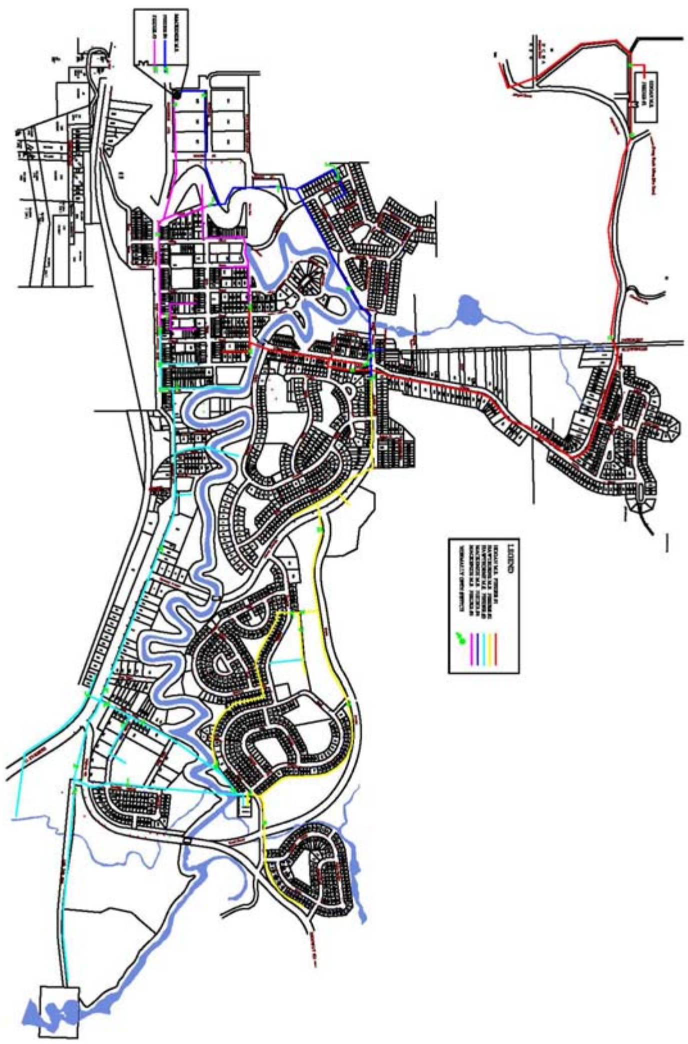
MAP 2 OF DISTRIBUTION SERVICE TERRITORY



APPENDIX D

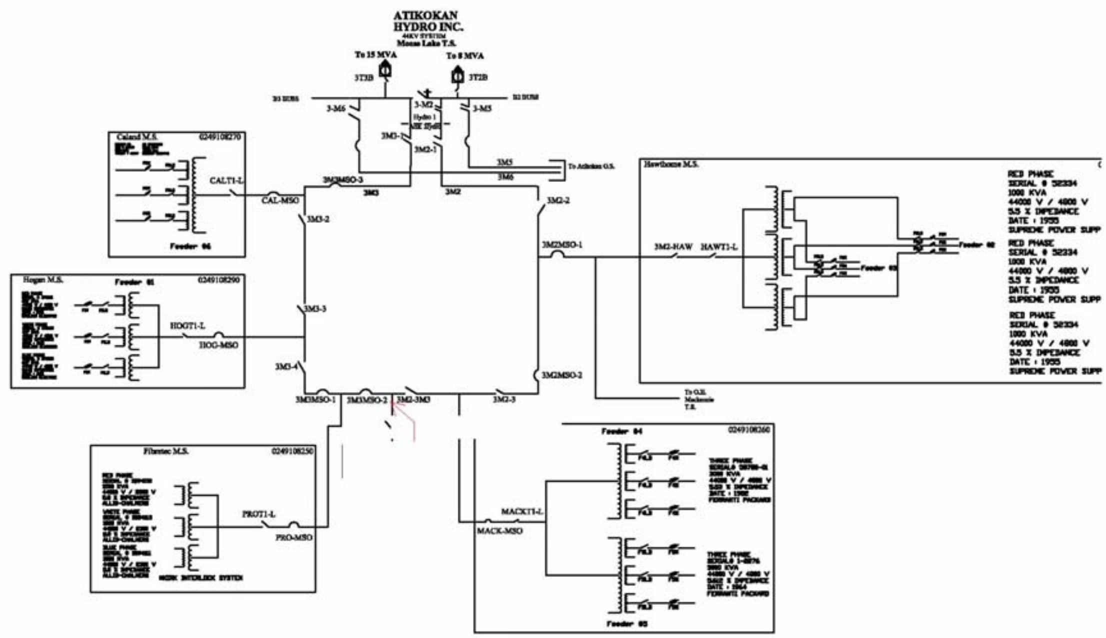
MAP OF DISTRIBUTION SYSTEM

Feeders 1 to 5 are displayed on this map



Appendix E

Schematic of Atikokan Hydro's Distribution System



LIST OF NEIGHBOURING UTILITIES:

Atikokan Hydro is bounded by one Hydro One single phase radial feeder on the eastern side. There is a 32 km buffer zone of no service to the west, and Hydro One have another single phase radial feeder. There are no Utilities to the south before the US border, and Hydro One has a feeder along the TransCanada highway 140 km to the north. Atikokan Hydro is relatively remote and isolated from neighboring LDCs

EXPLANATION OF HOST AND EMBEDDED UTILITIES:

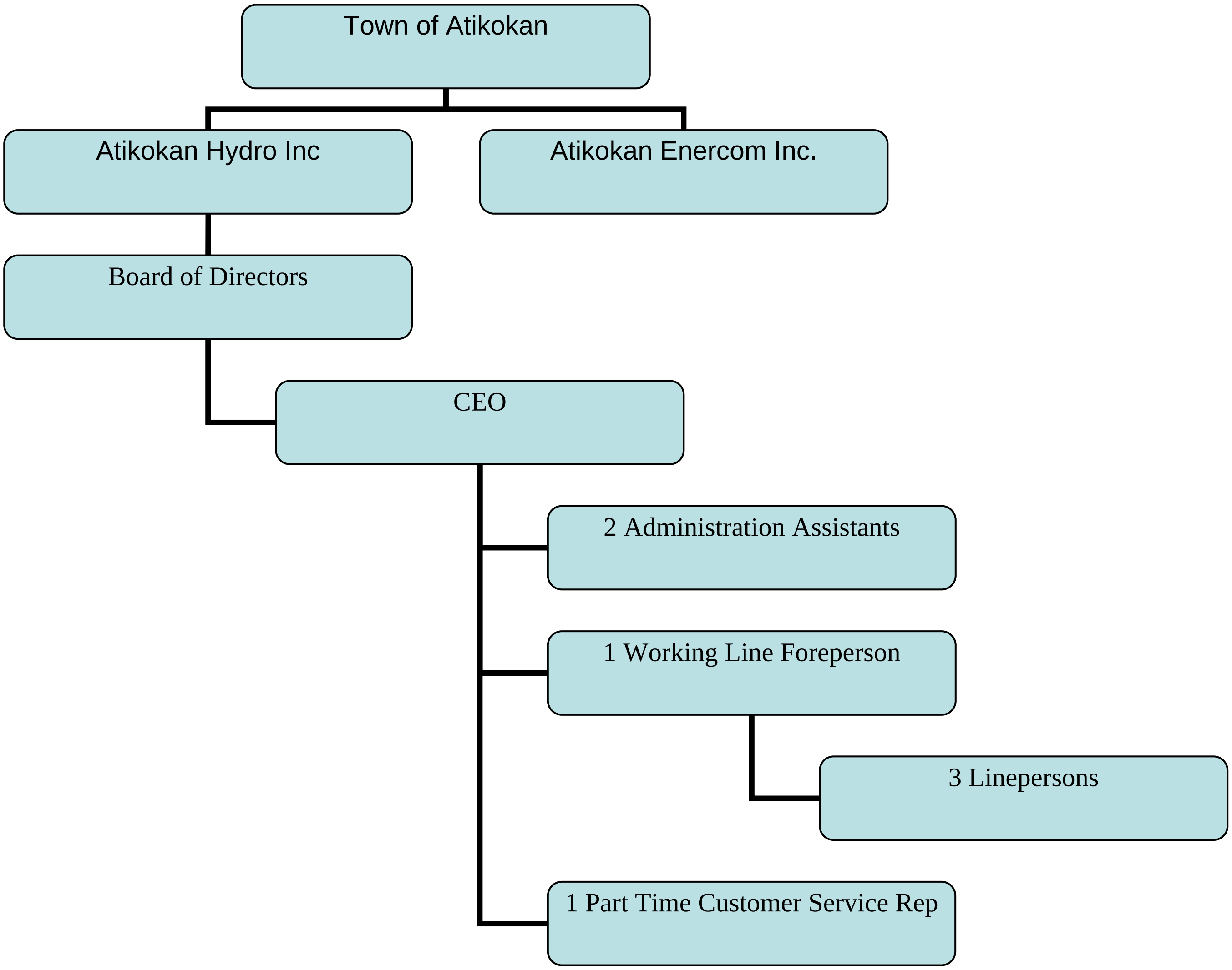
Atikokan Hydro is neither embedded nor is it a host to another Utility.

UTILITY ORGANIZATIONAL STRUCTURE:

A chart illustrating Atikokan Hydro's corporate family is provided on the following page. Atikokan Hydro has only the Town of Atikokan as its shareholder. Atikokan Enercom Inc was created by the Town of Atikokan as an affiliate to Atikokan Hydro Inc.

Atikokan Enercom was the shareholders representative in Norwest Mobility, which brought cell phone service to the more remote parts of North Western Ontario. Atikokan Enercom is a cell phone dealer for TBay Tel. Atikokan Enercom owns a communications tower that rents space to various entities. Atikokan Enercom holds an electrical contractors license and does line construction in the outlying areas for private individuals. Atikokan Enercom was able to take on the street light maintenance when ESA refused to renew Atikokan Hydro's contract license. The intercompany agreement can be found as an attachment in Exhibit 4.

1


Town of Atikokan
Atikokan Hydro Inc
Atikokan Enercom Inc.
Board of Directors
CEO
2 Administration Assistants
1 Working Line Foreperson
3 Linepersons
1 Part Time Customer Service Rep

CORPORATE ENTITIES RELATIONSHIP CHART:

There are no additional corporate entities.

PLANNED CHANGES IN CORPORATE AND OPERATIONAL STRUCTURE:

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

STATUS OF BOARD DIRECTIVES FROM PREVIOUS BOARD DECISIONS:

There are no directives from previous Board Decisions

PRELIMINARY LIST OF WITNESSES:

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

SUMMARY OF THE APPLICATION:

Preamble

Atikokan Hydro has submitted this Application in order to meet its Corporate Mission and Corporate Goals as outlined below. Current rates will result in actual Return on Equity in 2011 and 2012 well below levels currently approved by the OEB. The increased rates are required to:

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

Atikokan Hydro's Mission Statement

Atikokan Hydro is committed to:

- efficiently deliver a reliable supply of electrical energy to our customers at competitive distribution rates in the Town of Atikokan
- provide a safe and rewarding work environment for our employees
- assure that future supply is available to meet Atikokan's changing needs
- be a good corporate citizen within the Town of Atikokan

Atikokan Hydro's priorities are defined in its Corporate Goals:

In pursuit of our goals, Atikokan Hydro holds certain core values in the operation of the utility and as it relates to its customer, staff and shareholder.

Atikokan Hydro values its employees, customers, partners, and our community. We provide our employees with a safe, healthy environment with fair remuneration and opportunities for learning.

We value our customers and work hard to win their trust and support. We strive for excellence and continuous improvement in all aspects of our business. At all times we will act with integrity and respect. We value the long term health and sustainability of Atikokan Hydro and work to create value for our shareholder by focusing on core business strengths and pursuing appropriate business opportunities.

Atikokan Hydro has consistently exceeded the OEB's Service Quality Indicators and, as set out in Table 1 below, has targeted to maintain its performance at levels equal to or above the OEB's standards in 2011 and 2012.

Table 1-1

SQI's

AVERAGE PERFORMANCE FOR 2010

Appointments Met - at the appointed time		
SQI Standard: 90% of the time		
2010 Actual	**2011 Target**	**2012 Target**
100%	95%	95%
Telephone Accessibility - answered in person within 30 seconds		
SQI Standard: 65% of the time		
2010 Actual	**2011 Target**	**2012 Target**
92%	80%	80%
Connection of New Services -within 5 working days		
SQI Standard: 90% of the time		
2010 Actual	**2011 Target**	**2012 Target**
100%	95%	95%
Emergency Response - Urban within 60 minutes		
SQI Standard: 80% of the time		
2010 Actual	**2011 Target**	**2012 Target**
100%	95%	95%

Written Responses to Inquiries - within 10 working days		
SQI Standard: 80% of the time		
2010 Actual	**2011 Target**	**2012 Target**
100%	95%	95%

Purpose and Need

Atikokan Hydro's requested revenue requirement for 2012 in the amount of $1,579,603 includes the recovery of its costs to provide distribution services, its permitted Return on Equity ["ROE"] and the funds necessary to service its debt.

When forecasted energy and demand levels for 2012 are considered, Atikokan Hydro estimates that its present rates will produce a deficiency in gross distribution revenue of $364,011 for the 2012 Test Year.

Therefore, Atikokan Hydro seeks the OEB's approval to revise its electricity distribution rates. The rates proposed to recover its projected revenue requirement and other relief sought are set out in the Exhibit.

Atikokan Hydro is mindful that the full revenue requirement has created a significant bill impact on customers, and has proposes the following solution for rate mitigation:

1. Introduce a rate rider for Residential customers for one year from May 1, 2012 to April 30, 2013 of $0.0034 per kWh to reduce the overall bill impact on the Residential 800 kWh per month customer to under 10%.

2. Defer the disposal of all deferral and variance accounts until 2013 IRM filing

The information presented in this Application represents Atikokan Hydro's forecasted results for its 2012 Test Year. Atikokan Hydro is also presenting the forecasted results for 2011 Bridge Year and audited financial information for fiscal 2009 and 2010. For 2012, Atikokan Hydro has determine the proposed revenue requirement under modified IFRS. However, the adjustment needed to move the 2012 revenue requirement from CGAAP to modified IFRS was only a reduction of $32,832 in depreciation to reflect a longer useful life for Distribution Stations, Poles, Conductors and Line Transformers. As outlined in Exhibit 2, Atikokan Hydro revised its capitalization policy in 2010 to not capitalize any expense that was not directly related to the installation of the capital. This change in capitalization policy is consistent with IFRS standards which means there is no adjustment in 2012 needed resulting from a revised capitalization policy since the required adjustment was made in the actual results for 2010 under CGAAP.

Timing

The financial information supporting the Test Year for this Application will be Atikokan Hydro's fiscal year ending December 31, 2012 (the "2012 Test Year"). However, Atikokan Hydro is requesting rates effective May 1, 2012, continuing through April 30, 2012.

Customer Impact

In preparing this application, Atikokan Hydro has considered the impacts on its customers, with a goal of minimizing those impacts. With respect to cost allocation, the revenue cost ratios resulting from the 2012 cost allocation study have been adjusted in order to bring each rate class revenue to cost ratio within the acceptable range defined by the Board.

Customer impacts including the percentage average Total Bill Impact and Average Dollar Impact, which include revised distribution rates [monthly service charge and volumetric rates], revised retail transmission rates and revised loss factors requested in this Application are set out in Table 1-2 below, for typical Residential (800 kWh per month) and Commercial (2000 kWh per month) customers. A complete listing of bill impacts for all customer classes at various levels of consumption is provided in Exhibit 8, Tab 1, Schedule 2.

Table 1-2: Bill Impact: Residential and Commercial

RESIDENTIAL

Consumption	2011 BILL			2012 BILL			IMPACT		
800 kWh	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			30.58			41.01	10.43	34.11%	26.73%
Distribution (kWh)	800	0.0121	9.68	800	0.0162	12.96	3.28	33.88%	8.45%
Late Payment Rate Rider			0.29			0.00	(0.29)	(100.00%)	0.00%
Smart Meter Rider (per month)			3.50			3.54	0.04	1.28%	2.31%
Rate Mitigation Rider (kWh)	800	0.0000	0.00	800	(0.0034)	(2.72)	(2.72)	#DIV/0!	(1.77%)
Stranded Meter Rider (per month)			0.00			0.39	0.39	#DIV/0!	0.25%
Deferrral & Variance Acct (kWh)	800	(0.0018)	(1.44)	800	0.0000	0.00	1.44	(100.00%)	0.00%
Distribution Sub-Total			**42.61**			**55.18**	**12.57**	**29.51%**	**35.96%**
Retail Transmisssion (kWh)	860	0.0097	8.34	862	0.0091366	7.88	(0.47)	(5.59%)	5.13%
Delivery Sub-Total			**50.95**			**63.06**	**12.11**	**23.76%**	**41.10%**
Other Charges (kWh)	860	0.0130	11.19	862	0.0130	11.20	0.01	0.12%	7.30%
Cost of Power Commodity (kWh)	600	0.0680	40.80	600	0.0680	40.80	0.00	0.00%	26.59%
Cost of Power Commodity (kWh)	260	0.0790	20.56	262	0.0790	20.72	0.16	0.78%	13.50%
SPC (kWh)	860	0.0000	0.00	860	0.0000	0.00	0.00	#DIV/0!	0.00%
Total Bill Before Taxes			**123.50**			**135.78**	**12.28**	**9.94%**	**88.50%**
HST		13.00%	16.06		13.00%	17.65	1.60	9.94%	11.50%
Total Bill			**139.56**			**153.44**	**13.88**	**9.94%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption	2011 BILL			2012 BILL			IMPACT		
2000 kWh	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			70.02			82.46	12.44	17.77%	23.05%
Distribution (kWh)	2,000	0.0089	17.80	2,000	0.0105	21.00	3.20	17.98%	5.87%
Late Payment Rate Rider			0.71			0.00	(0.71)	(100.00%)	0.00%
Smart Meter Rider (per month)			3.50			3.54	0.04	1.28%	0.99%
LRAM & SSM Rider (kWh)	2,000	0.0000	0.00	2,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Stranded Meter Rider (per month)			0.00			0.39	0.39	#DIV/0!	0.11%
Deferrral & Variance Acct (kWh)	2,000	(0.0018)	(3.60)	2,000	0.0000	0.00	3.60	(100.00%)	0.00%
Distribution Sub-Total			**88.43**			**107.39**	**18.96**	**21.44%**	**30.02%**
Retail Transmisssion (kWh)	2,151	0.0086	18.50	2,156	0.0081001	17.46	(1.03)	(5.59%)	4.88%
Delivery Sub-Total			**106.93**			**124.85**	**17.93**	**16.77%**	**34.90%**
Other Charges (kWh)	2,151	0.0130	27.98	2,156	0.0130	28.01	0.03	0.12%	7.83%
Cost of Power Commodity (kWh)	600	0.0680	40.80	600	0.0680	40.80	0.00	0.00%	11.41%
Cost of Power Commodity (kWh)	1,551	0.0790	122.50	1,556	0.0790	122.90	0.40	0.33%	34.36%
SPC (kWh)	2,151	0.0000	0.00	2,151	0.0000	0.00	0.00	#DIV/0!	0.00%
Total Bill Before Taxes			**298.20**			**316.56**	**$18.36**	**6.16%**	**88.50%**
HST		13.00%	38.77		13.00%	41.15	2.39	6.16%	11.50%
Total Bill			**336.97**			**357.72**	**$20.75**	**6.16%**	**100.00%**

Smart Meters:

Atikokan Hydro is requesting disposition of its December 31, 2010 smart meter account balances and the discontinuation of the smart meter funding adder, as outlined in Exhibit 9 of this Application.

Capital Structure

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

Return on Equity

Atikokan Hydro has assumed a return on equity of 9.58% consistent with the Cost of Capital Parameter Updates for 2011 Cost of Service Applications issued by the OEB on March 3, 2011. Atikokan Hydro understands the Board will be finalizing the cost of capital parameters for 2012 rates based on January 2012 market interest rate information, and that adjustments to the Application may be required as a result.

Capital Expenditures

Atikokan Hydro continues to expand and reinforce its distribution system in order to maintain a reliable distribution system for the customers in its service territory. Expenditures are also being made to maintain the system as well as meet regulations set out by both the OEB and the IESO including smart meters

Operating, Maintenance and Administration (OM&A) Costs

The need to support the smart meter program and revise the capitalization policy to be inline with modified IFRS along with the standard increases in staff cost resulting from such items as the collective agreements since 2008 have put upward pressure on the 2012 OM&A costs. This upward pressure is the main driver for the need for increased rates in this application. In Atikokan Hydro's view it has done everything within its ability to control these cost but recognizes these costs will most likely be the focus of this application.

BUDGET OVERVIEW:

Atikokan Hydro compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budget forecast. This budget information is compiled for both the 2011 Bridge Year and the 2012 Test Year.

Revenue Forecast

Atikokan Hydro's load forecasting model was used to prepare the revenues sales and throughput volume and revenue forecast at existing rates for 2012. The load forecast is weather normalized as outlined in Exhibit 3 and considers such factors as average weather conditions and economic conditions in the area serviced by Atikokan Hydro.

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

The OM&A expenses for the 2011 Bridge Year and the 2012 Test Year have been based on an review of operating priorities and requirements and is strongly influenced by prior year experience, year-to-date results and expected changes for the forecast periods. Each item is reviewed account by account for each of the forecast years.

Capital Budget

The capital budget forecast 2011 and 2012 is influenced by, among other factors, the highest priority capital requirements and Atikokan Hydro's capacity to finance capital projects. All proposed capital projects are assessed within the framework of their capital budget priority and are outlined in Exhibit 2.

CHANGES IN METHODOLOGY:

Atikokan Hydro is not requesting any changes in methodology in the current proceeding.

REVENUE DEFICIENCY:

In Exhibit 6, Atikokan Hydro has provided the justification to support its 2012 revenue deficiency. As shown on the follow page Atikokan Hydro's 2012 revenue deficiency is $364,011

1 # Calculation of Revenue Deficiency

ATIKOKAN HYDRO INC
Revenue Deficiency Determination

Description	2012 Test Existing Rates	2012 Test - Required Revenue
Revenue		
Revenue Deficiency		364,011
Distribution Revenue	1,090,357	1,090,357
Other Operating Revenue (Net)	125,235	125,235
Total Revenue	1,215,592	1,579,603
Costs and Expenses		
Administrative & General, Billing & Collecting	703,625	703,625
Operation & Maintenance	471,526	471,526
Depreciation & Amortization	197,456	197,456
Deemed Interest	77,426	77,426
Total Costs and Expenses	1,450,033	1,450,033
Less OCT Included Above	0	0
Total Costs and Expenses Net of OCT	1,450,033	1,450,033
Utility Income Before Income Taxes	-234,441	129,570
Income Taxes:		
Corporate Income Taxes	-38,508	17,914
Total Income Taxes	-38,508	17,914
Utility Net Income	-195,933	111,656
Capital Tax Expense Calculation:		
Total Rate Base	2,913,786	2,913,786
Exemption	0	0
Deemed Taxable Capital	2,913,786	2,913,786
Ontario Capital Tax	0	0
Income Tax Expense Calculation:		
Accounting Income	-234,441	129,570
Tax Adjustments to Accounting Income	-13,997	-13,997
Taxable Income	-248,438	115,573
Income Tax Expense	-38,508	17,914
Tax Rate Refecting Tax Credits	15.50%	15.50%
Actual Return on Rate Base:		
Rate Base	2,913,786	2,913,786
Interest Expense	77,426	77,426
Net Income	-195,933	111,656
Total Actual Return on Rate Base	-118,507	189,083
Actual Return on Rate Base	-4.07%	6.49%
Required Return on Rate Base:		
Rate Base	2,913,786	2,913,786
Return Rates:		
Return on Debt (Weighted)	4.43%	4.43%
Return on Equity	9.58%	9.58%
Deemed Interest Expense	77,426	77,426
Return On Equity	111,656	111,656
Total Return	189,083	189,083
Expected Return on Rate Base	6.49%	6.49%
Revenue Deficiency After Tax	307,589	-0
Revenue Deficiency Before Tax	364,011	-0

CAUSES OF REVENUE DEFICIENCY:

Atikokan Hydro notes that main contributor to the net revenue deficiency of $307,589 for the 2012 Test Year is a result of an increase in OM&A expenses from the 2008 Board approved amount of $809,045 to $1,175,151 in the 2012 Test Year. This represents an increase of $336,106 which explains more the net revenue deficiency. As outlined in Exhibit 4, the rationale for the increase of $336,106 can be summarized into the following categories

- Smart meter related OM&A costs $107,573
- Change in capitalization policy in 2010 to be aligned with MIFRS $169,035
- ¼ of the costs to prepare and support this application $50,000
- Staff changes $39,498
- Total $366,106

FINANCIAL STATEMENTS – 2009 and 2010:

Atikokan Hydro's Audited Financial Statements accompany this Schedule as Appendix F.

Appendix F

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

Contents

Tel: 807 274 9848
Fax: 807 274 5142
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BDO Canada LLP
375 Scott Street
Fort Frances ON P9A 1H1 Canada

Auditors' Report

To the Shareholder of
Atikokan Hydro Inc.

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

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

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

BDO CANADA LLP

Chartered Accountants, Licensed Public Accountants

Fort Frances, Ontario
March 19, 2010

Atikokan Hydro Inc.
Balance Sheet

December 31	2009	2008
Assets		
Current		
Cash	$ 46,801	$ 296,407
Accounts receivable (Note 2)	324,082	98,329
Unbilled revenue	367,149	375,354
Inventory	102,578	93,894
Prepaids	349,297	25,874
	1,189,907	889,858
Property, plant and equipment (Note 3)	2,048,801	1,929,990
Regulatory assets (Note 9)	541,959	134,020
Other assets (Note 4)	7,819	10,664
Future income tax assets (Note 11)	83,742	96,819
	$ 3,872,228	$ 3,061,351
Liabilities		
Current		
Accounts payable	$ 440,272	$ 482,108
Customer deposits	10,836	8,232
Payments in lieu of corporate taxes payable	22,229	-
Current portion of long-term debt (Note 5)	49,559	36,194
Deferred revenue	5,121	-
	528,017	526,534
Regulatory liabilities (Note 9)	169,638	328,981
Customer deposits	97,529	74,083
Long-term debt (Note 5)	2,065,270	1,293,286
	2,860,454	2,222,884
Shareholders' equity		
Share capital (Note 6)	1,277,900	1,277,900
Deficit	(266,126)	(439,433)
	1,011,774	838,467
	$ 3,872,228	$ 3,061,351

On behalf of the Board:

______________________ Director

______________________ Director

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

Atikokan Hydro Inc.
Statement of Operations and Deficit

For the year ended December 31	2009	2008
Revenue		
Sale of energy	$ 1,806,595	$ 1,857,645
Distribution revenue	1,234,365	922,462
Rent from electric property	38,196	35,045
Late payment charges	7,043	5,624
Miscellaneous revenue	44,746	19,649
Demand management program revenue	171,460	30,350
Interest and dividend income	9,542	11,341
	3,311,947	2,882,116
Expenses		
Administration	316,344	291,106
Amortization	174,190	155,943
Billing and collecting	159,760	168,981
Distribution expense operation	280,794	296,121
Distribution expense maintenance	113,819	88,816
Energy cost	1,824,212	1,790,804
Interest on long-term debt	66,410	2,323
Other interest expense	9,422	10,884
Demand management program expense	171,460	30,463
	3,116,411	2,835,441
Net income before the following	195,536	46,675
Loss on disposal of assets	-	5,526
Provision for payments in lieu of corporate taxes	22,229	-
Net income for the year	173,307	41,149
Deficit, beginning of year	(439,433)	(374,673)
Change in accounting policy (Note 1)	-	(105,909)
Deficit, end of year	$ (266,126)	$ (439,433)

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

Atikokan Hydro Inc.
Statement of Cash Flows

For the year ended December 31	2009	2008
Cash provided by (used in)		
Operating activities		
Income for the year	$ 173,307	$ 41,149
Items not involving cash		
Amortization	174,190	155,943
Loss on disposal of property, plant and equipment	-	5,526
	347,497	202,618
Changes in non-cash working capital balances		
Accounts receivable	(225,753)	4,834
Unbilled revenue	8,205	(82,037)
Inventory	(8,684)	(21,013)
Prepaids	(323,423)	33,981
Accounts payable	(41,835)	133,381
Regulatory liabilities	(554,205)	(41,400)
Deferred revenue	5,121	-
Other assets	2,845	-
Payment in lieu of corporate taxes payable	22,229	-
	(768,003)	230,364
Investing activities		
Net increase in property, plant and equipment	(293,002)	(136,037)
Financing activities		
Net increase (decrease) in current portion of long-term debt	785,349	(66,529)
Increase (decrease) in customer deposits held	26,050	(1,565)
	811,399	(68,094)
Increase (decrease) in cash during the year	(249,606)	26,233
Cash position, beginning of year	296,407	270,174
Cash position, end of year	$ 46,801	$ 296,407
Supplementary cash flow information		
Total interest paid	$ 75,833	$ 13,207

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

Atikokan Hydro Inc.
Summary of Significant Accounting Policies

December 31, 2009

Nature of Business

The Corporation is incorporated under the laws of Ontario and is engaged in the distribution of retail electricity. The Corporation is currently exempt from taxes under the Income Tax Act and the Ontario Corporation Act.

Regulation

The *Energy Competition Act, 1998* was given Royal Assent on October 30, 1998, which provided for a competitive market in the generation and sale of electricity and the regulation of the monopoly electricity delivery system in the Province of Ontario (the "Province").

On May 1, 2002, the government of Ontario opened Ontario's wholesale and retail markets to competition by providing generators, retailers and consumers with open access to Ontario's transmission and distribution network ("Open Access").

Since the commencement of Open Access, electricity distributors have been purchasing their electricity requirements from the wholesale market administered by the Independent Electricity System Operator (the "IESO") and recovering the cost of electricity and certain other costs at a later date in accordance with procedures mandated by the Ontario Energy Board (the "OEB").

The OEB has regulatory oversight of electricity matters in the Province. The Ontario Energy Board Act, 1998 sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for separate businesses and filing/process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, to provide continued rate protection for rural and remote electricity customers and the responsibility for ensuring that electricity distribution companies (the "LDC") fulfill obligations to connect and service customers.

The LDC is required to charge its customers for the following amounts (all of which, other than the distribution rate, represent "a pass through" of amounts payable to third parties):

(a) Electricity Price and Related Rebates. The electricity price and related rebates represent a pass through of the commodity cost of electricity.

(b) Distribution Rate. The distribution rate is designed to recover the costs incurred by the LDC in delivering electricity to customers and the OEB-allowed rate of return. Distribution rates are regulated by the OEB and typically comprise of a fixed charge and usage-based (consumption) charge.

The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (principally sustained periods of hot or cold weather which increase the consumption of electricity and sustained periods of moderate weather which decrease the consumption of electricity).

(c) Retail Transmission Rate. The retail transmission rate represents a pass through of the wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

(d) Wholesale Market Service Charge. The wholesale market service charge represents a pass through of various wholesale market services support costs. Wholesale market service charges are regulated by the OEB.

Market participants (including distributors and retailers) are required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations.

Market-based Rate of Return

Before the introduction of rate caps in December 2002, the OEB had authorized electricity distributors to adjust their distribution rates to incorporate a market-based rate of return.

Since the rates were unbundled (May 1, 2000) for Ontario distribution companies, Atikokan Hydro Inc. has elected to take a full (9% effective May 1, 2006, 9.88% prior to May 1, 2006) rate of return on common equity for the Corporation.

Regulatory Treatments

The following regulatory treatments have resulted in accounting treatments which differ from Canadian GAAP for enterprises operating in an unregulated environment:

Regulatory Assets and Liabilities

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

Atikokan Hydro Inc.
Summary of Significant Accounting Policies

December 31, 2009

Effective January 1, 2009, the Corporation adopted amended Canadian Institute of Chartered Accountants ["CICA"] Handbook Section 1100 - "Generally Accepted Accounting Principles" ["Handbook Section 1100"], Handbook Section 3465 - "Income Taxes" ["Handbook Section 3465"], and Accounting Guideline 19 "Disclosures by Entities Subject to Rate Regulation". These amended sections and guidance established new standards and removed a temporary exemption in Handbook Section 1100 pertaining to the application of that section to the recognition and measurement of assets and liabilities arising from rate regulation. The new standards require the recognition of future income tax liabilities and assets in accordance with Handbook Section 3465 as well as a separate regulatory asset or liability balance for the amount of future income taxes expected to be included in future rates and recovered from or paid to customers, and retain existing requirements to disclose the effects of rate regulation. The revised standards are effective for interim and annual financial statements for the fiscal years beginning on or after January 1, 2009.

Following the removal of the temporary exemption for rate-regulated operations included in Handbook Section 1100, the Corporation developed accounting policies for its assets and liabilities arising from rate regulation using professional judgement and other sources issued by bodies authorized to issue accounting standards in other jurisdictions. Upon final assessment and in accordance with Handbook Section 1100, the Corporation determined that its assets and liabilities arising from rate-regulated activities qualify for recognition under Canadian GAAP and this recognition is consistent with U.S. Financial Accounting Standards Board Accounting Standards Codification 980 - "Regulated Operations". Accordingly, the removal of the temporary exemption had no effect on the Corporation's results of operations as of December 31, 2009.

Spare Transformers

Spare transformers are items that are expected to substitute for original distribution plant transformers when these original plant assets are being repaired and are held and dedicated for the specific purpose of backing up plant in service as opposed to assets available for other uses. According to the criteria set out in the AP Handbook, spare transformers are treated as property, plant and equipment (note 3, which would be recorded as inventory under Canadian GAAP for unregulated businesses).

Inventories

Inventories consist primarily of maintenance and construction materials and are stated at the lower of cost and replacement cost, with cost determined on a standard cost basis net of the provision for obsolescence.

Atikokan Hydro Inc.
Summary of Significant Accounting Policies

December 31, 2009

Basis of Accounting

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

Property, Plant and Equipment

Property, plant and equipment are recorded at cost. Amortization based on the estimated useful life of the asset is as follows:

Buildings	- 2.5% straight line basis
Transmission and distribution equipment	- 2.5% straight line basis
Other equipment	- 10% straight line basis
Computer equipment and software	- 20% straight line basis
Automotive equipment	- various straight line basis

Other Assets

Other assets are recorded at cost. Other assets were expected to be recovered through future rate charges and therefore amortization of these assets ceased when the recoveries were approved by the OEB. Management has reconsidered its' estimates of expected recoveries and has started amortizing other assets as of January 1, 2005.

Amortization is provided as follows:

Organization expense	- 10% straight line basis

Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand, bank balances and investments in money market instruments with maturities of three months or less.

Revenue Recognition

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

Customer Deposits

Customer deposits are cash collections from customers to guarantee the payment of energy bills. Deposits expected to be refunded within the next fiscal year are classified as a current liability.

Use of Estimates

The preparation of the financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions which affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses for the year. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Minister of Energy or the Minister of Finance.

Atikokan Hydro Inc.
Summary of Significant Accounting Policies

December 31, 2009

Payments in Lieu of Taxes

The Corporation is required to compute taxes under the Income Tax Act and the Ontario Corporations Tax Act and remit such amounts thereunder to the Ontario Electricity Financial Corporation. These amounts referred to as Payments in Lieu of Taxes under the Energy Competition Act, are applied to reduce certain debt obligations of the former Ontario Hydro.

Impairment of Long-lived Assets

Long-lived assets held and used by the Corporation are reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If changes in circumstances indicate that the carrying amount of an asset that an entity expects to hold and use may not be recoverable, future cash flows expected to result from the use of the asset and its disposition must be estimated. If the undiscounted value of the future cash flows is less than the carrying amount of the asset, impairment is recognized. Management believes that there has been no impairment of any of the Corporation's long-lived assets as at year end.

Future Income Taxes

Commencing January 1, 2007, the Corporation adopted the liability method of accounting for income taxes as outlined in the provisions of Section 3465 of the Handbook of the Canadian Institute of Chartered Accountants. Under this method, current income taxes are recognized for the estimated income taxes payable for the current year. Future income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities as well as for the benefit of losses available to be carried forward to future years for tax purposes that are likely to be realized.

Financial Instruments

Effective January 1, 2007, the Corporation adopted the CICA Handbook Sections 3855 - "Financial Instruments - Recognition and Measurement", 3861 - "Financial Instruments - Disclosure and Presentation" 1530 - "Comprehensive Income" and the revised CICA Handbook Section 3251 - "Equity" (the "Handbook Sections"). As provided under the standards, the comparative consolidated financial statements have not been restated. These new Handbook Sections have lead to changes in the accounting for financial instruments. All relevant changes are outlined below.

Financial Instruments - Recognition and Measurement - Section 3855

This Section establishes the standards for the recognition and measurement of financial assets and financial liabilities. At inception, all financial instruments which meet the definition of a financial asset or a financial liability are to be recorded at fair value, unless fair value cannot be reliably determined. Depending on the nature of the financial instrument, revenues, expenses, gains and losses would be reported in either net income or other comprehensive income. Subsequent measurement of each financial instrument will depend on

Atikokan Hydro Inc.
Summary of Significant Accounting Policies

December 31, 2009

the balance sheet classification elected by the Corporation. As of January 1, 2007, the Corporation has elected the following balance sheet classifications with respect to its financial assets and financial liabilities:

- Cash is classified as "Assets Held-For-Trading" and is measured at fair value.
- Accounts receivable and unbilled revenue are classified as "Loans and Receivables" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.
- Accounts payable and accrued liabilities, customer deposits and the long-term debt are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.

Comprehensive Income - Section 1530

This Section describes the recognition and disclosure requirements with respect to comprehensive income. Comprehensive income consists of net income and other comprehensive income. Other comprehensive income represents the changes in the fair value of a financial instrument which have not been included in net income.

As the Corporation had no adjustments to other comprehensive income during the year-ended December 31, 2007, the adoption of this standard does not have an impact on the December 31, 2007 consolidated financial statements.

Unless otherwise noted, it is managements opinion that the Corporation is not exposed to significant interest, currency or credit risks arising from these financial instruments. The fair value of these financial instruments approximate their carry values, unless otherwise noted.

There was no comprehensive income during the year ended December 31, 2009.

New Accounting Pronouncement

International Financial Reporting Standards ["IFRS"]

On February 13, 2008, the AcSB confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. A limited number of converged or IFRS-based standards will be incorporated into Canadian GAAP prior to 2011, with the remaining standards to be adopted at the change over date. The Corporation has an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its consolidated financial statements. At this time, the impact on the Corporation's future financial position and results of operations is not reasonably determinable or estimable.

Atikokan Hydro Inc.
Notes to Financial Statements

December 31, 2009

1. Change in Accounting Policy

Effective January 1, 2009 the Corporation adopted amended Handbook Section 3465 which refers to the recognition of future income taxes expected to be refunded to, or recovered from, customers in future electricity rates, applied on a retrospective basis without prior period restatement. The implementation of these standards did not impact the Corporation's cash flows. As a result of retrospectively applying future income tax accounting policies, opening retained earnings as at January 1, 2008 has decreased by $105,909 and regulatory liabilities increased by $105,909.

2. Accounts Receivable

	2009	2008
Trade accounts	$ 285,548	$ 95,922
Atikokan Enercom Inc.	21,677	2,407
Township of Atikokan	16,857	-
	$ 324,082	$ 98,329

3. Property, Plant and Equipment

			2009	2008
	Cost	Accumulated Amortization	Net Book Value	Net Book Value
Land	$ 15,588	$ -	$ 15,588	$ 15,588
Buildings	592,484	240,774	351,710	152,251
Transmission and distribution equipment	3,415,037	1,801,336	1,613,701	1,680,845
Other equipment	137,987	101,165	36,822	33,048
Automotive equipment	420,420	400,776	19,644	38,554
Computer equipment and software	223,378	212,042	11,336	9,704
	$ 4,804,894	$ 2,756,093	$ 2,048,801	$ 1,929,990

At December 31, 2009, net book value of stranded meters related to the deployment of smart meters amounting to $52,394 is included in property, plant and equipment. In the absence of rate regulation, property, plant and equipment would have been $53,394 lower at December 31, 2009.

4. Other Assets

	2009	2008
Transition costs	$ 31,040	$ 31,040
Accumulated amortization	(23,221)	(20,376)
	$ 7,819	$ 10,664

The transition costs are defined as follows:
Transition costs:

The OEB has allowed the Corporation to defer the cost incurred to align systems and practices and the requirements of the competitive electricity market in Ontario in accordance with the Ontario Energy Board Act, 1998. Accordingly, the Corporation has deferred these expenditures in accordance with the criteria set out in the OEB's Electricity Distribution Rate Handbook and the AP Handbook.

Under such regulation, expenditures were allowed to be deferred during the period January 1, 2000, to December 31, 2002, which would be capitalized or expensed under Canadian GAAP for unregulated businesses.

5. Long-term Debt

	2009	2008
Township of Atikokan		
Loan is unsecured, 0% and has no set terms of repayment.	$ 1,295,097	$ 1,309,297
Bank loans payable		
Prime plus 1.5%, due May 2009, monthly payments of $1,244 principal and interest, secured by certain equipment.	-	6,011
Prime plus 1.5%, due December 2009, monthly payments of $1,244 principal and interest, secured by certain equipment.	-	14,172
Prime plus 1.0%, due December 2017, monthly payments of $3,279 principal and interest, secured by certain equipment.	279,585	-
Prime plus 1.25%, due December 2024, monthly payments of $1,003 principal and interest, secured by certain equipment.	140,147	-
Atikokan Enercom		
Prime plus 0.5%, unsecured, no set terms of repayment	400,000	-
	2,114,829	1,329,480
Less current portion	49,559	36,194
	$ 2,065,270	$ 1,293,286

Principal payments due on long-term debt in the next five years and thereafter are as follows:

Year	Amount
2010	$ 49,559
2011	51,514
2012	53,362
2013	55,386
2014	56,609
Thereafter	1,848,399
	$ 2,114,829

Atikokan Hydro Inc.
Notes to Financial Statements

December 31, 2009

6. Share Capital

The authorized share capital is as follows:

Unlimited Class A Preferred shares, voting, redeemable at issue price and entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class B Preferred shares, voting, redeemable at issue price and entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class C Preferred shares, voting, redeemable at issue price and entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class D Preferred shares, non-voting, redeemable at issue price and entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class E Preferred shares, non-voting, redeemable at issue price and entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class A Common shares, voting, entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class B Common shares, voting, entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class C Common shares, non-voting, entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class D Common shares, non-voting, entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class E Common shares, non-voting, entitled to a non-cumulative dividend determined by the Board of Directors.

Issued

		2009	2008
12,779	Class A common shares	$ 1,277,900	$ 1,277,900

7. Credit Facilities

Atikokan Hydro Inc. is party to a short-term credit facility with a Canadian chartered bank pursuant to which the Corporation could borrow up to $250,000 in the form of an operating loan. The amount drawn under the credit facility as at December 31, 2009, was $nil.

Atikokan Hydro Inc.
Notes to Financial Statements

December 31, 2009

8. Financial Guarantees

Participants in the wholesale market for electricity that is administered by the Independent Electricity Market Operator are required to satisfy prescribed prudential requirements.

During the year, the Corporation became party to an irrevocable standby letter of credit with a Canadian chartered bank. The credit amounts to 2009 - $303,623 (2008 - $481,430) and expires on May 15, 2010. This letter of credit is secured by a general security agreement.

9. Regulatory Assets and Liabilities

Regulatory assets consist of the following:

	2009	2008
Other regulatory assets	118,230	81,142
Smart meters	423,729	-
Regulatory asset recovery amount	-	52,878
Net regulatory liability	$ 541,959	$ 134,020

Regulatory liabilities consist of the following:

	2009	2008
Settlement variances	$ 85,896	$ 223,622
Smart meters	-	8,540
Future income tax	83,742	96,819
Net regulatory liability	$ 169,638	$ 328,981

The regulatory assets and liabilities balances of the Corporation are defined as follows:

(a) Settlement variances:

The OEB has allowed the Corporation to defer settlement variances from May 1, 2002 to December 31, 2009. This balance represents the variances between amounts charged by the Corporation to customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred by it in the wholesale market administered by the IESO after May 1, 2002. The settlement variances related primarily to service charges, non-competitive electricity charges, imported power charges and the global adjustment. Accordingly, the Corporation has deferred these liabilities in accordance with the criteria set out in the AP Handbook.

The settlement variances net of recoveries arising after May 1, 2002 is deferred in a regulatory liability account.

Under such regulation, the variances are allowed to be deferred which would be recorded as revenue when incurred under Canadian GAAP for unregulated businesses. In the absence of rate regulation, revenues in 2009 would have been $137,726 lower. The deferred balance for unapproved settlement variances continues to be calculated and attract carrying charges in accordance with the OEB's direction. The manner and timing of disposition of the variance has not been determined by the OEB.

9. Regulatory Assets and Liabilities, continued

(b) Other Regulatory Assets:

Other regulatory assets consist of:

(i) Deferral account for OEB annual cost assessments

The OEB has allowed the Corporation to defer the OEB annual cost assessments for the fiscal years starting after January 1, 2004. Accordingly, the Corporation has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

(ii) Deferral account for cash pension contributions

The OEB has allowed the Corporation to defer the incremental OMERS pension expenditures for the fiscal years starting after January 1, 2005. Accordingly, the Corporation has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

Under such regulation, expenditures are allowed to be deferred which would be expenses under Canadian GAAP for unregulated businesses. The deferred balance continues to be calculated and attract carrying charges in accordance with the OEB's direction. In the absence of rate regulation, operating expenses in 2009 would have been $37,088 higher. The OEB has allowed the Corporation to recover the deferred amounts beginning in 2006. The Corporation was approved to recover $70,091 as part of its 2008 Rate Application.

(c) Smart meters

Effective May 1, 2006, the OEB has allowed the Corporation to defer capital expenditures, operating expenditures, depreciation expense and revenues relating to smart meters. Accordingly, the Corporation has deferred these items in accordance with the criteria set out in the AP Handbook. In the absence of rate regulation, operating revenues in 2009 would have been $7,325 lower, which relates to the amortization that would be recorded under Canadian GAAP.

The deferred balances continue to be calculated and attract carrying charges.

(d) Regulatory asset recovery account

As part of its 2008 Rate Application the Corporation was approved to recover $70,091 of deferred cash pension contributions. The approved amounts have been reclassified to a separate regulatory account in accordance with criteria set out in the AP Handbook. The balance in their accounts represents the unrecoved amounts at year end.

(e) Future income taxes

This regulatory liability account relates to the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of future tax assets.

10. Related Party Transactions

Atikokan Hydro Inc. and Atikokan Enercom Inc. are related due to common ownership.

	2009	2008
Sales to Atikokan Enercom Inc.	$ 65,992	$ 42,492

The sales were recorded at fair market value and took place in the normal course of business.

11. Future Income Tax Assets

The components of the future income tax assets as of December 31 are as follows:

	2009	2008
Transitions costs and property, plant and equipment	$ 83,742	$ 79,122
Carryforward tax losses	-	17,697
Net future income tax assets	$ 83,742	$ 96,819

12. Contingency

A class action has been brought under the *Class Proceedings Act, 1992*, seeking $500 million in restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities ("LDCs") who received late payment penalties which constitute interest at an effective rate in excess of 60% per year, contrary to Section 347 of the *Criminal Code*. This action is at a preliminary stage and pleadings have closed. The action has not yet been certified as a class action and no discoveries have been held, as the parties were awaiting the outcome of a similar class action proceeding brought against Enbridge Gas Distribution Inc. (formerly Consumers Gas.)

On April 22, 2004, the Supreme Court of Canada released a decision in the Consumers Gas case, rejecting all of the defences which had been raised by Enbridge Gas Distribution Inc., although the Court did not permit the Plaintiff class to recover damages for any period prior to the issuance of the Statement of Claim in 1994, challenging the validity of late payment penalties. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of damages. At the end of 2006, a mediation process resulted in the settlement of damages payable by Enbridge Gas Distribution Inc.

On February 4, 2008, the OEB, in response to an application filed by Enbridge, ruled that all of Enbridge's costs related to settlement of the class action lawsuit, including legal costs, settlement costs and interest, are recoverable from ratepayers. The representative plaintiff in the class action lawsuit has made a petition to the Lieutenant Governor in Council ["Cabinet"] under subsection 34(1) of the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Schedule B. for an order that the matter be submitted back to the OEB for reconsideration. A decision by Cabinet on the petition is pending.

12. Contingency (continued)

Atikokan Hydro Inc. is not a party to the Enbridge class action. It is, however, subject to the following class action described below.

Action commenced against a predecessor of Atikokan Hydro Inc. and other Ontario municipal electric utilities under the Class Proceedings Act, 1992 seeking $500,000,000 in restitution for late payment charges collected by them from their customers that were in excess of the interest limit stipulated in section 347 of the Criminal Code. This action is at a preliminary stage. Pleadings have closed but examinations for discovery have not been conducted and the classes have not been certified. After the release by the Supreme Court of Canada of its 2004 decision in the Enbridge case, the plaintiffs in this proposed class action indicated their intention to proceed with the litigation, but no formal steps have been taken.

It is aniticipated that the action will now proceed for determination in light of the reasons of the Supreme Court in the Enbridge class action.

Atikokan Hydro Inc. assumed all of the liabilities of the former utility on transfer of electrical distribution assets.

13. Pension Agreements

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

Because OMERS is a multi-employer pension plan, any pension plan surpluses or deficits are a joint responsibility of the Ontario municipal organizations and their employees. As a result, the municipality does not recognize any share of the OMERS pension surplus or deficit. The amount contributed to OMERS for 2009 was $33,526 (2008 - $34,526) for current services. The OMERS Board rate was 6.3% to 12.8% depending on the income level for 2009 (2008 - 6.5% to 10.7% depending on the income level).

14. Capital Disclosures

The Corporation's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain and improve the electricity distribution system of Atikokan Hydro Inc.;
- ensure compliance with covenants related to its credit facilities and the long-term Debt from the Township of Atikokan;

As at December 31, 2009, the Corporation's definition of capital includes shareholder's equity and long-term debt which includes the current portion of the promissory note payable to the Township. As at December 31, 2009, shareholder's equity amounts to $1,011,774 (2008 - $838,467) and long-term debt, including the current portion of the debt owing to the Township, amounts to $2,114,829 (2008 -$1,329,480). There have been no changes in the Corporation's approach to capital management during the year.

15. Risk Factors

The following is a discussion of risks and related mitigation strategies that have been identified by the Corporation for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

The Corporation's activities provide for a variety of financial risks, particularly credit risk and liquidity risk.

Credit risk
Financial instruments are exposed to credit risk as a result of the risk of the counter-party defaulting on its obligations. The Corporation monitors and limits its exposure to credit risk on a continuous basis. The Corporation provides reserves for credit risks based on the financial condition and short and long-term exposures to counterparties.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from Atikokan Hydro Inc. customers. Atikokan Hydro Inc. has approximately 1,700 customers, the majority of which are residential. Atikokan Hydro Inc. collects security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2009, Atikokan Hydro Inc. held security deposits in the amount of $108,365 (2008 - $82,315).

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the income statement. Subsequent recoveries of receivables previously provisioned are credited to the income statement.

At December 31, 2009, there were no significant concentrations of credit risk with respect to any class of financial assets or counterparties. The Corporation's maximum exposure to credit risk is equal to the carrying value of its financial assets.

Interest rate risk
The Corporation is exposed to interest rate risk in holding certain financial instruments. The Corporation's objective is to minimize net interest expense. The Corporation attempts to minimize interest rate risk by issuing long-term fixed rate debt.

Under the Corporation's Revolving Credit Facility [*Note 8*], the Corporation may obtain short-term borrowings for working capital purposes. These borrowings expose the Corporation to fluctuations in short-term interest rates [borrowings in the form of prime rate loans in Canadian dollars and bankers' acceptances and letters of credit].

Liquidity risk
The Corporation monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest expense. The Corporation has access to credit facilities and monitors cash balances daily to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due.

15. Risk Factors (continued)

Hedging and Derivatives risk
As at December 31, 2009, the Corporation has not entered into hedging and derivative financial instruments.

Foreign exchange risk
As at December 31, 2009, the Corporation has limited exposure to the changing values of foreign currencies.

16. Subsequent Events

On January 15, 2010, a conditional settlement was reached for the class action lawsuit pursuant to which the defendants would pay the amount of $17,000,000 plus costs and taxes in settlement of all claims. The amount paid by each MEU will be its proportionate share of the settlement amount based on its percentage of distribution service revenue over the period for which it has exposure for repayment of late payment penalties exceeding the interest rate limit in the Criminal Code. While the amounts have not yet been determined, it is anticipated that the Corporation's share of the settlement amount will be approximately $7,600. The settlement is conditional upon a sufficiant number of MEU's participating so as to collect the full amount of the settlement funds payable to the plaintiffs. It is also conditional upon court approval. All the MEU's involved in the settlement, including Atikokan Hydro Inc., will request an order from the OEB allowing for the future recovery from customers of all costs related to the proposed settlement. The Corporation has not accrued any liabilities in relation to this proposed settlement. There is no guarantee that the OEB will allow for total or partial recovery of such costs in the future. The outcome of the OEB decision in this regard could have an adverse impact on the results of operations and financial position of the Corporation in the future.

17. Comparative Figures

Certain prior year figures have been restated to conform to current year financial statement presentation.

Appendix F

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

Contents

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BDO Canada LLP
375 Scott Street
Fort Frances ON P9A 1H1 Canada

Auditor's Report

To the Shareholder of Atikokan Hydro Inc.

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

Management's Responsibility for the Financial Statements

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

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the presentation of the financial statements.

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

Opinion

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

Emphasis of Matter

We draw attention to Note 1 to the financial statements which describes the ability of the entity to remain a going concern. Our opinion is not qualified in respect of this matter.

BDO CANADA LLP

Chartered Accountants, Licensed Public Accountants

Fort Frances, Ontario
April 4, 2011

Atikokan Hydro Inc.
Balance Sheet

December 31	2010	2009
		Restated (Note 2)
Assets		
Current		
Cash and cash equivalents	$ 89,748	$ 46,801
Accounts receivable (Note 3)	327,124	324,082
Unbilled revenue	301,457	367,149
Inventory	108,062	102,578
Prepaids	28,358	349,297
Payments in lieu of Corporate taxes receivable	20,444	-
	875,193	1,189,907
Property, plant and equipment (Note 4)	2,232,756	1,974,173
Regulatory assets (Note 10)	720,749	541,959
Other assets (Note 5)	4,974	7,819
Future income tax assets (Note 12)	75,522	83,742
	$ 3,909,194	$ 3,797,600
Liabilities		
Current		
Accounts payable	$ 470,531	$ 440,272
Customer deposits	11,402	10,836
Payments in lieu of Corporate taxes payable	-	22,229
Current portion of long-term debt (Note 6)	48,281	49,559
Deferred revenue	-	5,121
	530,214	528,017
Regulatory liabilities (Note 10)	180,436	169,638
Customer deposits	102,618	97,529
Long-term debt (Note 6)	2,167,771	2,065,270
	2,981,039	2,860,454
Shareholder's equity		
Share capital (Note 7)	1,277,900	1,277,900
Deficit	(349,745)	(340,754)
	928,155	937,146
	$ 3,909,194	$ 3,797,600

On behalf of the Board:

_______________________ Director

_______________________ Director

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

Atikokan Hydro Inc.
Statement of Operations and Deficit

For the year ended December 31	2010	2009
		Restated (Note 2)
Revenue		
Sale of energy	$ 1,907,041	$ 1,806,595
Distribution revenue	1,146,051	1,234,365
Rent from electric property	34,911	38,196
Late payment charges	6,024	7,043
Miscellaneous revenue	133,910	44,746
Demand management program revenue	232,108	171,460
Interest and dividend income	14,799	9,542
	3,474,844	3,311,947
Expenses		
Administration	450,248	316,344
Amortization	221,088	170,576
Billing and collecting	130,786	159,760
Distribution expense operation	323,096	280,794
Distribution expense maintenance	120,699	124,785
Energy cost	1,913,140	1,824,212
Interest on long-term debt	83,048	66,410
Other interest expense	10,685	9,422
Demand management program expense	232,108	171,460
	3,484,898	3,123,763
Net income (loss) before the following	(10,054)	188,184
Provision (recovery) for payments in lieu of Corporate taxes	(1,063)	22,229
Net income (loss) for the year	(8,991)	165,955
Deficit, beginning of year	(266,126)	(439,433)
Prior period adjustment (Note 2)	(74,628)	(67,276)
Deficit, beginning of year, restated	(340,754)	(506,709)
Deficit, end of year	$ (349,745)	$ (340,754)

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

Atikokan Hydro Inc.
Statement of Cash Flows

For the year ended December 31	2010	2009
		Restated (Note 2)
Cash provided by (used in)		
Operating activities		
Income (loss) for the year	$ (8,991)	$ 165,955
Items not involving cash		
Amortization	221,088	170,576
Future income taxes	8,220	13,077
	220,317	349,608
Changes in non-cash working capital balances		
Accounts receivable	(3,042)	(225,753)
Unbilled revenue	65,691	8,205
Inventory	(5,484)	(8,684)
Prepaids	320,938	(323,423)
Accounts payable	30,257	(41,835)
Regulatory accounts	(167,992)	(567,282)
Deferred revenue	(5,121)	5,121
Other assets	2,845	2,845
Payment in lieu of Corporate taxes payable	(42,673)	22,229
	415,736	(778,969)
Investing activities		
Net increase in property, plant and equipment	(479,669)	(282,036)
Financing activities		
Net increase in long-term debt	101,224	785,349
Increase in customer deposits held	5,656	26,050
	106,880	811,399
Increase (decrease) in cash during the year	42,947	(249,606)
Cash and cash equivalents, beginning of year	46,801	296,407
Cash and cash equivalents, end of year	$ 89,748	$ 46,801

Supplementary cash flow information

	2010	2009
Total interest paid	$ 93,733	$ 75,833
Total payments in lieu of taxes	$ 43,034	$ -

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

Atikokan Hydro Inc.
Summary of Significant Accounting Policies

December 31, 2010

Nature of Business

The Corporation is incorporated under the laws of Ontario and is engaged in the distribution of retail electricity. The Corporation is currently exempt from taxes under the Income Tax Act and the Ontario Corporation Act.

Regulation

The *Energy Competition Act, 1998* was given Royal Assent on October 30, 1998, which provided for a competitive market in the generation and sale of electricity and the regulation of the monopoly electricity delivery system in the Province of Ontario (the "Province").

On May 1, 2002, the government of Ontario opened Ontario's wholesale and retail markets to competition by providing generators, retailers and consumers with open access to Ontario's transmission and distribution network ("Open Access").

Since the commencement of Open Access, electricity distributors have been purchasing their electricity requirements from the wholesale market administered by the Independent Electricity System Operator (the "IESO") and recovering the cost of electricity and certain other costs at a later date in accordance with procedures mandated by the Ontario Energy Board (the "OEB").

The OEB has regulatory oversight of electricity matters in the Province. The Ontario Energy Board Act, 1998 sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for separate businesses and filing/process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, to provide continued rate protection for rural and remote electricity customers and the responsibility for ensuring that electricity distribution companies (the "LDC") fulfill obligations to connect and service customers.

The LDC is required to charge its customers for the following amounts (all of which, other than the distribution rate, represent "a pass through" of amounts payable to third parties):

(a) Electricity Price and Related Rebates. The electricity price and related rebates represent a pass through of the commodity cost of electricity.

Atikokan Hydro Inc.
Summary of Significant Accounting Policies

December 31, 2010

Regulation (continued)

(b) Distribution Rate. The distribution rate is designed to recover the costs incurred by the LDC in delivering electricity to customers and the OEB-allowed rate of return. Distribution rates are regulated by the OEB and are typically comprised of a fixed charge and usage-based (consumption) charge.

The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (principally sustained periods of hot or cold weather which increase the consumption of electricity and sustained periods of moderate weather which decrease the consumption of electricity).

(c) Retail Transmission Rate. The retail transmission rate represents a pass through of the wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

(d) Wholesale Market Service Charge. The wholesale market service charge represents a pass through of various wholesale market service support costs. Wholesale market service charges are regulated by the OEB.

Market participants (including distributors and retailers) are required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations.

Market-based Rate of Return

Before the introduction of rate caps in December 2002, the OEB had authorized electricity distributors to adjust their distribution rates to incorporate a market-based rate of return.

Since the rates were unbundled (May 1, 2000) for Ontario distribution Companies, Atikokan Hydro Inc. has elected to take a full (9% effective May 1, 2006, 9.88% prior to May 1, 2006) rate of return on common equity for the Corporation.

Regulatory Developments

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect distribution rates and other permitted recoveries in the future.

Atikokan Hydro Inc.
Summary of Significant Accounting Policies

December 31, 2010

Regulatory Treatments The following regulatory treatments have resulted in accounting treatments which differ from Canadian GAAP for enterprises operating in an unregulated environment:

Regulatory Assets and Liabilities

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

Effective January 1, 2009, the Corporation adopted amended Canadian Institute of Chartered Accountants ("CICA") Handbook Section 1100 - "Generally Accepted Accounting Principles", Handbook Section 3465 - "Income Taxes" and Accounting Guideline 19 "Disclosures by Entities Subject to Rate Regulation". These amended sections and guidance established new standards and removed a temporary exemption in Handbook Section 1100 pertaining to the application of that section to the recognition and measurement of assets and liabilities arising from rate regulation. The new standards require the recognition of future income tax assets and liabilities in accordance with Handbook Section 3465 as well as a separate regulatory asset or liability balance for the amount of future income taxes expected to be included in future rates and recovered from or paid to customers, and retain existing requirements to disclose the effects of rate regulation. The revised standards are effective for interim and annual financial statements for the fiscal years beginning on or after January 1, 2009.

Following the removal of the temporary exemption for rate-regulated operations included in Handbook Section 1100, the Corporation developed accounting policies for its assets and liabilities arising from rate regulation using professional judgement and other sources issued by bodies authorized to issue accounting standards in other jurisdictions. Upon final assessment and in accordance with Handbook Section 1100, the Corporation determined that its assets and liabilities arising from rate-regulated activities qualify for recognition under Canadian GAAP and this recognition is consistent with U.S. Financial Accounting Standards Board Accounting Standards Codification 980 - "Regulated Operations".

Atikokan Hydro Inc.
Summary of Significant Accounting Policies

December 31, 2010

Regulatory Treatments (continued)

Spare Transformers

Spare transformers are items that are expected to substitute for original distribution plant transformers when these original plant assets are being repaired and are held and dedicated for the specific purpose of backing up plant in service as opposed to assets available for other uses. According to the criteria set out in the AP Handbook, spare transformers are treated as property, plant and equipment (note 4, which would be recorded as inventory under Canadian GAAP for unregulated businesses).

Inventories

Inventories consist primarily of maintenance and construction materials and are stated at the lower of cost and replacement cost, with cost determined on a standard cost basis net of the provision for obsolescence.

Basis of Accounting

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

Property, Plant and Equipment

Property, plant and equipment are recorded at cost. Amortization based on the estimated useful life of the asset is as follows:

Buildings	- 2.5% straight line basis
Transmission and distribution equipment	- 2.5% straight line basis
Other equipment	- 10% straight line basis
Computer equipment and software	- 20% straight line basis
Automotive equipment	- various straight line basis

Other Assets

Other assets are recorded at cost. Other assets were expected to be recovered through future rate charges and therefore amortization of these assets ceased when the recoveries were approved by the OEB. Management has reconsidered its' estimates of expected recoveries and has started amortizing other assets as of January 1, 2005.

Amortization is provided as follows:

Organization expense	- 10% straight line basis

Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand, bank balances and investments in money market instruments with maturities of three months or less.

Atikokan Hydro Inc.
Summary of Significant Accounting Policies

December 31, 2010

Revenue Recognition

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

Customer Deposits

Customer deposits are cash collections from customers to guarantee the payment of energy bills. Deposits expected to be refunded within the next fiscal year are classified as a current liability.

Use of Estimates

The preparation of the financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions which affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses for the year. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Minister of Energy or the Minister of Finance.

Payments in Lieu of Taxes

The Corporation is required to compute taxes under the Income Tax Act and the Ontario Corporations Tax Act and remit such amounts thereunder to the Ontario Electricity Financial Corporation. These amounts referred to as Payments in Lieu of Taxes under the Energy Competition Act, are applied to reduce certain debt obligations of the former Ontario Hydro.

Impairment of Long-lived Assets

Long-lived assets held and used by the Corporation are reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If changes in circumstances indicate that the carrying amount of an asset that an entity expects to hold and use may not be recoverable, future cash flows expected to result from the use of the asset and its disposition must be estimated. If the undiscounted value of the future cash flows is less than the carrying amount of the asset, impairment is recognized. Management believes that there has been no impairment of any of the Corporation's long-lived assets as at year end.

Future Income Taxes

Commencing January 1, 2007, the Corporation adopted the liability method of accounting for income taxes as outlined in the provisions of Section 3465 of the Handbook of the Canadian Institute of Chartered Accountants. Under this method, current income taxes are recognized for the estimated income taxes payable for the current year. Future income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities as well as for the benefit of losses available to be carried forward to future years for tax purposes that are likely to be realized.

Atikokan Hydro Inc.
Summary of Significant Accounting Policies

December 31, 2010

Financial Instruments

Effective January 1, 2007, the Corporation adopted the CICA Handbook Sections 3855 - "Financial Instruments - Recognition and Measurement", 3861 - "Financial Instruments - Disclosure and Presentation", 1530 - "Comprehensive Income" and the revised CICA Handbook Section 3251 - "Equity" (the "Handbook Sections"). As provided under the standards, the comparative financial statements have not been restated. These new Handbook Sections have lead to changes in the accounting for financial instruments. All relevant changes are outlined below.

Financial Instruments - Recognition and Measurement - Section 3855

This Section establishes the standards for the recognition and measurement of financial assets and financial liabilities. At inception, all financial instruments which meet the definition of a financial asset or a financial liability are to be recorded at fair value, unless fair value cannot be reliably determined. Depending on the nature of the financial instrument, revenues, expenses, gains and losses would be reported in either net income or other comprehensive income. Subsequent measurement of each financial instrument will depend on the balance sheet classification elected by the Corporation. As of January 1, 2007, the Corporation has elected the following balance sheet classifications with respect to its financial assets and financial liabilities:

- Cash and cash equivalents are classified as "Assets Held-For-Trading" and are measured at fair value.
- Accounts receivable and unbilled revenue are classified as "Loans and Receivables" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.
- Accounts payable and accrued liabilities, customer deposits and the long-term debt are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.

Comprehensive Income - Section 1530

This Section describes the recognition and disclosure requirements with respect to comprehensive income. Comprehensive income consists of net income and other comprehensive income. Other comprehensive income represents the changes in the fair value of a financial instrument which have not been included in net income.

Atikokan Hydro Inc.
Summary of Significant Accounting Policies

December 31, 2010

Financial Instruments (continued)

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

There was no comprehensive income during the year ended December 31, 2010.

New Accounting Pronouncement

International Financial Reporting Standards ("IFRS")

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

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

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

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

Atikokan Hydro Inc.
Summary of Significant Accounting Policies

December 31, 2010

New Accounting Pronouncement (continued)

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

Atikokan Hydro Inc.
Notes to Financial Statements

December 31, 2010

1. Going Concern

The accompanying financial statements have been prepared on a going concern basis, which contemplates the realization of assets and the satisfaction of liabilities and commitments in the normal course of business.

The Corporation has incurred losses to date of $349,384 which includes operating losses for the current period of $8,630. The continuation of the Corporation is dependent upon the continuing availability of operating and long-term financing and achieving a profitable level of operation through the ability to increase rates that are currently regulated by the Minister of Energy and the Ontario Energy Board.

Should the Corporation be unable to continue as a going concern it may be unable to realize the carrying value of its assets and to meet its liabilities as they become due.

Management is continuing to address the issues of increasing revenue, controlling costs, and obtaining working capital and financing. As the outcome of management's actions is dependent on future events, there is no certainty that management will be able to satisfactorily resolve these issues.

These financial statements do not reflect the adjustments and changes in presentation that would be necessary should the Corporation be unable to continue as a going concern.

2. Prior Period Adjustment

In previous years, the Corporation allocated payroll and overhead to property, plant and equipment using certain percentages. In preparation for the conversion to International Financial Reporting Standards, the Corporation has revisited their policy on capitalization of payroll. The new policy states that payroll will be allocated to property, plant and equipment when staff and machinery are used to construct or install an asset. The allocation will be based on actual hours spent on the capital item. Payroll that is not allocated to property, plant and equipment will be recognized in the statement of operations as incurred. An overhead allocation will no longer be made to property, plant and equipment.

The adjustment to 2008 and prior years resulted in a $67,276 decrease in opening property, plant and equipment and a corresponding increase to the deficit of the Corporation. The adjustment to the 2009 year resulted in a decrease in amortization of $3,614 and an increase in distribution maintenance expense of $10,966. These adjustments to 2009 and prior years have resulted in a $74,628 increase to the opening deficit in 2010.

3. Accounts Receivable

	2010	2009
Trade accounts	$ 318,021	$ 285,548
Atikokan Enercom Inc.	8,237	21,677
Township of Atikokan	866	16,857
	$ 327,124	$ 324,082

Atikokan Hydro Inc.
Notes to Financial Statements

December 31, 2010

4. Property, Plant and Equipment

	2010			2009
	Cost	Accumulated Amortization	Net Book Value	Restated (Note 2) Net Book Value
Land	$ 15,588	$ -	$ 15,588	$ 15,588
Buildings	680,682	265,939	414,743	351,710
Transmission and distribution equipment	3,336,953	1,898,729	1,438,224	1,539,073
Other equipment	147,880	110,503	37,377	36,822
Automotive equipment	762,757	442,507	320,250	19,644
Computer equipment and software	225,776	219,202	6,574	11,336
	$ 5,169,636	$ 2,936,880	$ 2,232,756	$ 1,974,173

At December 31, 2010, net book value of stranded meters related to the deployment of smart meters amounting to $37,884 (December 31, 2009 - $52,394) is included in property, plant and equipment. In the absence of rate regulation, property, plant and equipment would have been $37,884 lower at December 31, 2010 (December 31, 2009 - $52,394).

5. Other Assets

	2010	2009
Transition costs	$ 31,040	$ 31,040
Accumulated amortization	(26,066)	(23,221)
	$ 4,974	$ 7,819

The transition costs are defined as follows:

Transition costs:

The OEB has allowed the Corporation to defer the cost incurred to align systems and practices and the requirements of the competitive electricity market in Ontario in accordance with the Ontario Energy Board Act, 1998. Accordingly, the Corporation has deferred these expenditures in accordance with the criteria set out in the OEB's Electricity Distribution Rate Handbook and the AP Handbook.

Under such regulation, expenditures were allowed to be deferred during the period January 1, 2000, to December 31, 2002, which would be capitalized or expensed under Canadian GAAP for unregulated businesses.

6. Long-term Debt

	2010	2009
Township of Atikokan:		
Loan is unsecured, interest at 5%, monthly payments of $6,300 principal and interest.	**$ 1,282,096**	$ 1,295,097
Bank loans payable		
Prime plus 1.0%, due December 2017, monthly payments of $3,279 principal and interest, secured by certain equipment.	**311,376**	279,585
Prime plus 1.25%, due December 2024, monthly payments of $1,003 principal and interest, secured by certain equipment.	**222,580**	140,147
Atikokan Enercom Inc.		
Prime plus 2.75%, unsecured, no set terms of repayment.	**400,000**	400,000
	2,216,052	2,114,829
Less current portion	**48,281**	49,559
	$ 2,167,771	$ 2,065,270

Principal payments due on long-term debt in the next five years and thereafter are as follows:

Year	Amount
2011	$ 48,281
2012	50,210
2013	52,465
2014	54,822
2015	57,286
Thereafter	1,952,988
	$ 2,216,052

As of December 31, 2010, the Corporation has violated one of the financial covenants associated with the bank loans. The financial institution has indicated that they will not call the loans as a result of this violation for, at minimum, a 12 month period.

7. Share Capital

The authorized share capital is as follows:

Unlimited Class A Preferred shares, voting, redeemable at issue price and entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class B Preferred shares, voting, redeemable at issue price and entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class C Preferred shares, voting, redeemable at issue price and entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class D Preferred shares, non-voting, redeemable at issue price and entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class E Preferred shares, non-voting, redeemable at issue price and entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class A Common shares, voting, entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class B Common shares, voting, entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class C Common shares, non-voting, entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class D Common shares, non-voting, entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class E Common shares, non-voting, entitled to a non-cumulative dividend determined by the Board of Directors.

Issued

		2010	2009
12,779	Class A Common shares	$ 1,277,900	$ 1,277,900

8. Credit Facilities

Atikokan Hydro Inc. is party to a short-term credit facility with a Canadian chartered bank pursuant to which the Corporation could borrow up to $250,000 in the form of an operating loan. The amount drawn under the credit facility as at December 31, 2010, was $NIL (2009 - $NIL).

9. Financial Guarantees

Participants in the wholesale market for electricity that is administered by the Independent Electricity Market Operator are required to satisfy prescribed prudential requirements.

During the year, the Corporation became party to an irrevocable standby letter of credit with a Canadian chartered bank. The credit amounts to 2010 - $303,623 (2009 - $303,623) and has no contractual term. This letter of credit is secured by a general security agreement.

10. Regulatory Assets and Liabilities

Regulatory assets consist of the following:

	2010	2009
Settlement variances	$ 100,681	$ -
Other regulatory assets	156,510	118,230
Smart meters	463,558	423,729
Net regulatory assets	$ 720,749	$ 541,959

Regulatory liabilities consist of the following:

	2010	2009
Settlement variances	$ 21,938	$ 85,896
Future income tax	75,522	83,742
Regulatory liability repayment amount	82,976	-
Net regulatory liabilities	$ 180,436	$ 169,638

The regulatory assets and liabilities balances of the Corporation are defined as follows:

(a) Settlement variances:

This balance represents the variances between amounts charged by the Corporation to customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred by it in the wholesale market administered by the IESO after May 1, 2002. The settlement variances related primarily to service charges, non-competitive electricity charges, imported power charges and the global adjustment. Accordingly, the Corporation has deferred these liabilities in accordance with the criteria set out in the AP Handbook.

The settlement variances net of recoveries arising after May 1, 2002, are deferred in a regulatory liability account. In 2008, the OEB allowed repayment of regulatory liabilities to customers in the amount of $120,510, of which $37,534 has been repaid at year end, leaving a balance of $82,976 left to be repaid in subsequent periods.

Under such regulation, the variances are allowed to be deferred which would be recorded as revenue when incurred under Canadian GAAP for unregulated businesses. In the absence of rate regulation, revenues in 2009 would have been $137,726 lower. The deferred balance for unapproved settlement variances continues to be calculated and attract carrying charges in accordance with the OEB's direction. The manner and timing of disposition of the variance has not been determined by the OEB.

10. Regulatory Assets and Liabilities (continued)

(b) Other Regulatory Assets:

Other regulatory assets consist of:

(i) Deferral account for OEB annual cost assessments

The OEB has allowed the Corporation to defer the OEB annual cost assessments for the fiscal years starting after January 1, 2004. Accordingly, the Corporation has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

(ii) Deferral account for cash pension contributions

The OEB has allowed the Corporation to defer the incremental OMERS pension expenditures for the fiscal years starting after January 1, 2005. Accordingly, the Corporation has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

Under such regulation, expenditures are allowed to be deferred which would be expenses under Canadian GAAP for unregulated businesses. The deferred balance continues to be calculated and attract carrying charges in accordance with the OEB's direction. In the absence of rate regulation, operating expenses in 2010 would have been $38,280 higher.

(c) Smart Meters:

The smart meters regulatory asset account relates to the Province of Ontario's decision to install smart meters throughout Ontario. The LDC launched its smart meter project shortly following the Province of Ontario's announcement in 2006. In 2008, the OEB ordered the LDC to record all future expenditures and revenues related to smart meters to a regulatory asset account and allowed the LDC to keep the net book value of the stranded meters related to the deployment of smart meters in its rate base. The deferred balances continue to be calculated and attract carrying charges.

In connection with its smart meter initiatives, the Corporation has incurred capital costs for the year ended December 31, 2010. As at December 31, 2010, smart meter capital expenditures, net of accumulated depreciation, totalling $361,013 have been recorded to regulatory assets (December 31, 2009 - $358,938). These expenditures would otherwise have been recorded as property, plant and equipment under Canadian GAAP for unregulated businesses. In the absence of rate regulation, property, plant and equipment and intangible assets would have been $361,013 higher as at December 31, 2010 (December 31, 2009 - $358,938).

For the year ended December 31, 2010, smart meter operating expenses of $46,284 (2009 - $83,727), and smart meter depreciation expense of $30,383 (2009 - $7,325) were deferred which would have been expensed under Canadian GAAP for unregulated businesses. In the absence of rate regulation, for the year ended December 31, 2010, operating expenses would have been $46,284 higher (2009 - $83,727 higher), and depreciation expense would have been $46,284 higher (2009 - $83,727 higher).

Atikokan Hydro Inc.
Notes to Financial Statements

December 31, 2010

10. Regulatory Assets and Liabilities (continued)

For the year ended December 31, 2010, smart meter customer revenues of $38,970 were deferred (2009 - $17,747). In the absence of rate regulation, for the year ended December 31, 2010, revenue would have been $38,970 higher (2009 - $17,747 higher).

(d) Regulatory Asset Recovery Account:

As part of its 2008 Rate Application, the Corporation was approved to recover $70,091 of deferred cash pension contributions. The approved amounts have been reclassified to a separate regulatory account in accordance with criteria set out in the AP Handbook. The balance in their accounts represents the unrecovered amounts at year end.

(e) Future Income Taxes:

This regulatory liability account relates to the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of future tax assets.

11. Related Party Transactions

Atikokan Hydro Inc. and Atikokan Enercom Inc. are related due to common ownership.

	2010	2009
Sales to Atikokan Enercom Inc.	$ 95,324	$ 65,992

Atikokan Hydro Inc. is owned by the Corporation of the Township of Atikokan.

	2010	2009
Sales to the Corporation of the Township of Atikokan	$ 43,614	$ 20,587

The sales were recorded at fair market value and took place in the normal course of business.

12. Future Income Tax Assets

The components of the future income tax assets as of December 31 are as follows:

	2010	2009
Transition costs and property, plant and equipment	$ 75,522	$ 83,742

Atikokan Hydro Inc.
Notes to Financial Statements

13. Pension Agreements

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

Because OMERS is a multi-employer pension plan, any pension plan surpluses or deficits are a joint responsibility of the Ontario municipal organizations and their employees. As a result, the municipality does not recognize any share of the OMERS pension surplus or deficit. The amount contributed to OMERS for 2010 was $36,847 (2009 - $33,526) for current services. The OMERS Board rate was 6.4% to 13.1% depending on the income level for 2010 (2009 - 6.3% to 12.8% depending on the income level).

14. Capital Disclosures

The Corporation's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain and improve the electricity distribution system of Atikokan Hydro Inc.;
- ensure compliance with covenants related to its credit facilities and the long-term debt from the Township of Atikokan;

As at December 31, 2010, the Corporation's definition of capital includes shareholder's equity and long-term debt which includes the current portion of the promissory note payable to the Township. As at December 31, 2010, shareholder's equity amounts to $928,155 (2009 - $937,146) and long-term debt, including the current portion of the debt owing to the Township, amounts to $2,216,052 (2009 -$2,114,829). There have been no changes in the Corporation's approach to capital management during the year.

Atikokan Hydro Inc.
Notes to Financial Statements

December 31, 2010

15. Risk Factors

The following is a discussion of risks and related mitigation strategies that have been identified by the Corporation for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

The Corporation's activities provide for a variety of financial risks, particularly credit risk and liquidity risk.

Credit risk
Financial instruments are exposed to credit risk as a result of the risk of the counterparties defaulting on their obligations. The Corporation monitors and limits its exposure to credit risk on a continuous basis. The Corporation provides reserves for credit risk based on the financial condition and short and long-term exposures to counterparties.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from Atikokan Hydro Inc. customers. Atikokan Hydro Inc. has approximately 1,700 customers, the majority of which are residential. Atikokan Hydro Inc. collects security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2010, Atikokan Hydro Inc. held security deposits in the amount of $114,020 (2009 - $108,365).

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the statement of operations. Subsequent recoveries of receivables previously provisioned are credited to the statement of operations.

At December 31, 2010, there were no significant concentrations of credit risk with respect to any class of financial assets or counterparties. The Corporation's maximum exposure to credit risk is equal to the carrying value of its financial assets.

Interest rate risk
The Corporation is exposed to interest rate risk in holding certain financial instruments. The Corporation's objective is to minimize net interest expense. The Corporation attempts to minimize interest rate risk by issuing long-term fixed rate debt.

Under the Corporation's Revolving Credit Facility (*Note 8*), the Corporation may obtain short-term borrowings for working capital purposes. These borrowings expose the Corporation to fluctuations in short-term interest rates (borrowings in the form of prime rate loans in Canadian dollars and bankers' acceptances and letters of credit).

Liquidity risk
The Corporation monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest expense. The Corporation has access to credit facilities and monitors cash balances daily to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due.

Atikokan Hydro Inc.
Notes to Financial Statements

December 31, 2010

15. Risk Factors (continued)

Hedging and derivatives risk
As at December 31, 2010, the Corporation has not entered into hedging and derivative financial instruments.

Foreign exchange risk
As at December 31, 2010, the Corporation has limited exposure to the changing values of foreign currencies.

16. Comparative Figures

Certain prior year figures have been restated to conform to current year financial statement presentation.

RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND REGULATORY ACCOUNTING:

There are not items to reconciliation between the financial statements and regulatory accounting.

PRO FORMA FINANCIAL STATEMENTS - 2011 AND 2012:

The Pro Forma Statements for the 2011 Bridge Year and the 2012 Test Year accompany this Schedule as Appendix G and Appendix H respectively.

APPENDIX G

Atikokan Hydro Inc.

2011 PRO FORMA FINANCIAL STATEMENTS

ATIKOKAN HYDRO INC
2011 BALANCE SHEET

Account Description	Total
1050-Current Assets	
1005-Cash	67,000
1010-Cash Advances and Working Funds	500
1020-Interest Special Deposits	0
1030-Dividend Special Deposits	0
1040-Other Special Deposits	0
1060-Term Deposits	0
1070-Current Investments	0
1100-Customer Accounts Receivable	235,000
1102-Accounts Receivable - Services	0
1104-Accounts Receivable - Recoverable Work	52,500
1105-Accounts Receivable - Merchandise, Jobbing, etc.	0
1110-Other Accounts Receivable	0
1120-Accrued Utility Revenues	301,457
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(6,000)
1140-Interest and Dividends Receivable	0
1150-Rents Receivable	0
1170-Notes Receivable	0
1180-Prepayments	28,000
1190-Miscellaneous Current and Accrued Assets	0
1200-Accounts Receivable from Associated Companies	0
1210-Notes Receivable from Associated Companies	0
1050-Current Assets Total	**678,457**

1100-Inventory	
1305-Fuel Stock	0
1330-Plant Materials and Operating Supplies	110,000
1340-Merchandise	0
1350-Other Material and Supplies	0
1100-Inventory Total	**110,000**

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

1200-Other Assets and Deferred Charges	
1505-Unrecovered Plant and Regulatory Study Costs	0
1508-Other Regulatory Assets	255,000
1510-Preliminary Survey and Investigation Charges	0
1515-Emission Allowance Inventory	0
1516-Emission Allowance Withheld	0
1518-RCVA Retail	10,632
1521-Special Purpose Charge Assessment Variance	3,983
1525-Miscellaneous Deferred Debits	0
1530-Deferred Losses from Disposition of Utility Plant	0
1540-Deferred Losses from Disposition of Utility Plant	0
1545-Development Charge Deposits/ Receivables	0
1548-RCVA - Service Transaction Request (STR)	22,681
1550-LV Charges - Variance	0
1555-Smart Meters Recovery	405,442
1556-Smart Meters OM & A	134,878
1562-Deferred PILs	0
1563-Deferred PILs - Contra	0
1565-C & DM Costs	0
1566-C & DM Costs Contra	0
1570-Qualifying Transition Costs	0
1571-Pre Market CofP Variance	0
1572-Extraordinary Event Losses	0
1574-Deferred Rate Impact Amounts	0
1580-RSVA - Wholesale Market Services	(21,520)
1582-RSVA - One-Time	0
1584-RSVA - Network Charges	4,102
1586-RSVA - Connection Charges	25,334
1588-RSVA - Commodity (Power)	25,207
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	0
1592-PILs and Tax Variance for 2006 & Subsequent Years	0
1595-Disposition and Recovery of Regulatory Balances	(112,000)
1606-Intangible plant	2,129
1200-Other Assets and Deferred Charges Total	**755,868**

1450-Distribution Plant	
1805-Land	0
1806-Land Rights	0
1808-Buildings and Fixtures	0
1810-Leasehold Improvements	0
1815-Transformer Station Equipment - Normally Primary above 50 kV	0
1820-Distribution Station Equipment - Normally Primary below 50 kV	503,618
1825-Storage Battery Equipment	0
1830-Poles, Towers and Fixtures	2,086,585
1835-Overhead Conductors and Devices	0
1840-Underground Conduit	0
1845-Underground Conductors and Devices	0
1850-Line Transformers	498,776
1855-Services	0
1860-Meters	307,776
1865-Other Installations on Customer's Premises	0
1450-Distribution Plant Total	**3,396,755**

1500-General Plant	
1905-Land	15,588
1906-Land Rights	0
1908-Buildings and Fixtures	685,382
1910-Leasehold Improvements	0
1915-Office Furniture and Equipment	61,120
1920-Computer Equipment - Hardware	49,090
1925-Computer Software	178,186
1930-Transportation Equipment	762,757
1935-Stores Equipment	0
1940-Tools, Shop and Garage Equipment	90,260
1945-Measurement and Testing Equipment	0
1950-Power Operated Equipment	0
1955-Communication Equipment	0
1960-Miscellaneous Equipment	0
1970-Load Management Controls - Customer Premises	0
1975-Load Management Controls - Utility Premises	0
1980-System Supervisory Equipment	0
1985-Sentinel Lighting Rentals	0
1990-Other Tangible Property	0
1995-Contributions and Grants	0
1500-General Plant Total	**1,842,383**

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

1600-Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(3,117,804)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	0
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	0
2160-Accumulated Amortization of Other Utility Plant	0
2180-Accumulated Amortization of Non-Utility Property	0
1600-Accumulated Amortization Total	**(3,117,804)**

Total Assets	**3,665,659**

1650-Current Liabilities	
2205-Accounts Payable	646,507
2208-Customer Credit Balances	0
2210-Current Portion of Customer Deposits	11,500
2215-Dividends Declared	0
2220-Miscellaneous Current and Accrued Liabilities	0
2225-Notes and Loans Payable	0
2240-Accounts Payable to Associated Companies	0
2242-Notes Payable to Associated Companies	0
2250-Debt Retirement Charges (DRC) Payable	0
2252-Transmission Charges Payable	0
2254-Electric Safety Authority Fees Payable	0
2256-Independent Market Operator Fees and Penalties Payable	0
2260-Current Portion of Long Term Debt	12,000
2262-Ontario Hydro Debt - Current Portion	0
2264-Pensions and Employee Benefits - Current Portion	0
2268-Accrued Interest on Long Term Debt	0
2270-Matured Long Term Debt	0
2272-Matured Interest on Long Term Debt	0
2285-Obligations Under Capital Leases--Current	0
2290-Commodity Taxes	(25,900)
2292-Payroll Deductions / Expenses Payable	0
2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	(20,444)
2296-Future Income Taxes - Current	0
1650-Current Liabilities Total	**623,663**

1700-Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	0
2306-Employee Future Benefits	0
2308-Other Pensions - Past Service Liability	0
2310-Vested Sick Leave Liability	0
2315-Accumulated Provision for Rate Refunds	0
2320-Other Miscellaneous Non-Current Liabilities	0
2325-Obligations Under Capital Lease--Non-Current	0
2330-Devolpment Charge Fund	0
2335-Long Term Customer Deposits	108,000
2340-Collateral Funds Liability	0
2345-Unamortized Premium on Long Term Debt	0
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	0
2350-Future Income Tax - Non-Current	(75,522)
2405-Other Regulatory Liabilities	0
2410-Deferred Gains From Disposition of Utility Plant	0
2415-Unamortized Gain on Reacquired Debt	0
2425-Other Deferred Credits	0
2435-Accrued Rate-Payer Benefit	0
1700-Non-Current Liabilities Total	**32,478**

1800-Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	0
2510-Debenture Advances	0
2515-Required Bonds	0
2520-Other Long Term Debt	1,270,334
2525-Term Bank Loans - Long Term Portion	476,233
2530-Ontario Hydro Debt Outstanding - Long Term Portion	0
2550-Advances from Associated Companies	400,000
1800-Long-Term Debt Total	**2,146,567**

1850-Shareholders' Equity	
3005-Common Shares Issued	1,277,900
3008-Preference Shares Issued	0
3010-Contributed Surplus	0
3020-Donations Received	0
3022-Devolpment Charges Transferred to Equity	0
3026-Capital Stock Held in Treasury	0
3030-Miscellaneous Paid-In Capital	0
3035-Installments Received on Capital Stock	0
3040-Appropriated Retained Earnings	0
3045-Unappropriated Retained Earnings	(407,379)
3046-Balance Transferred From Income	(7,571)
3047-Appropriations of Retained Earnings - Current Period	0
3048-Dividends Payable-Preference Shares	0
3049-Dividends Payable-Common Shares	0
3055-Adjustment to Retained Earnings	0
3065-Unappropriated Undistributed Subsidiary Earnings	0
1850-Shareholders' Equity Total	**862,950**

Total Liabilities & Shareholder's Equity	**3,665,658**

Balance Sheet Total	1

ATIKOKAN HYDRO INC
2011 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	(657,982)
4010-Commercial Energy Sales	0
4015-Industrial Energy Sales	0
4020-Energy Sales to Large Users	0
4025-Street Lighting Energy Sales	(32,784)
4030-Sentinel Energy Sales	0
4035-General Energy Sales	(822,000)
4040-Other Energy Sales to Public Authorities	0
4045-Energy Sales to Railroads and Railways	0
4050-Revenue Adjustment	(91,789)
4055-Energy Sales for Resale	(129,000)
4060-Interdepartmental Energy Sales	0
4062-WMS	(186,416)
4064-Billed WMS-One Time	0
4066-NS	(138,964)
4068-CS	(60,817)
4075-LV Charges	0
3000-Sales of Electricity Total	**(2,119,752)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(1,150,000)
4082-RS Rev	(4,000)
4084-Serv Tx Requests	(1,000)
4090-Electric Services Incidental to Energy Sales	0
3050-Revenues From Services - Distirbution Total	**(1,155,000)**

3100-Other Operating Revenues	
4205-Interdepartmental Rents	0
4210-Rent from Electric Property	(34,911)
4215-Other Utility Operating Income	0
4220-Other Electric Revenues	0
4225-Late Payment Charges	(6,024)
4230-Sales of Water and Water Power	0
4235-Miscellaneous Service Revenues	(7,100)
4240-Provision for Rate Refunds	0
4245-Government Assistance Directly Credited to Income	0
3100-Other Operating Revenues Total	**(48,035)**

3150-Other Income & Deductions	
4305-Regulatory Debits	0
4310-Regulatory Credits	0
4315-Revenues from Electric Plant Leased to Others	0
4320-Expenses of Electric Plant Leased to Others	0
4325-Revenues from Merchandise, Jobbing, Etc.	(75,000)
4330-Costs and Expenses of Merchandising, Jobbing, Etc	20,000
4335-Profits and Losses from Financial Instrument Hedges	0
4340-Profits and Losses from Financial Instrument Investments	0
4345-Gains from Disposition of Future Use Utility Plant	0
4350-Losses from Disposition of Future Use Utility Plant	0
4355-Gain on Disposition of Utility and Other Property	0
4360-Loss on Disposition of Utility and Other Property	2,942
4365-Gains from Disposition of Allowances for Emission	0
4370-Losses from Disposition of Allowances for Emission	0
4375-Revenues from Non-Utility Operations	(232,000)
4380-Expenses of Non-Utility Operations	232,000
4385-Expenses of Non-Utility Operations	0
4390-Miscellaneous Non-Operating Income	(4,000)
4395-Rate-Payer Benefit Including Interest	0
4398-Foreign Exchange Gains and Losses, Including Amortization	0
3150-Other Income & Deductions Total	**(56,058)**

3200-Investment Income	
4405-Interest and Dividend Income	(9,000)
4415-Equity in Earnings of Subsidiary Companies	0
3200-Investment Income Total	**(9,000)**

3350-Power Supply Expenses	
4705-Power Purchased	1,804,516
4708-WMS	164,896
4710-Cost of Power Adjustments	0
4712-0	0
4714-NW	143,066
4715-System Control and Load Dispatching	0
4716-NCN	86,151
4720-Other Expenses	0
4725-Competition Transition Expense	0
4730-Rural Rate Assistance Expense	0
4750-LV Charges	0
3350-Power Supply Expenses Total	**2,198,629**

3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	0
5010-Load Dispatching	0
5012-Station Buildings and Fixtures Expense	0
5014-Transformer Station Equipment - Operation Labour	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0
5016-Distribution Station Equipment - Operation Labour	1,060
5017-Distribution Station Equipment - Operation Supplies and Expenses	200
5020-Overhead Distribution Lines and Feeders - Operation Labour	229,359
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	41,868
5030-Overhead Subtransmission Feeders - Operation	1,440
5035-Overhead Distribution Transformers - Operation	0
5040-Underground Distribution Lines and Feeders - Operation Labour	0
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	0
5050-Underground Subtransmission Feeders - Operation	0
5055-Underground Distribution Transformers - Operation	0
5060-Street Lighting and Signal System Expense	0
5065-Meter Expense	0
5070-Customer Premises - Operation Labour	0
5075-Customer Premises - Materials and Expenses	0
5085-Miscellaneous Distribution Expense	0
5090-Underground Distribution Lines and Feeders - Rental Paid	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	0
5096-Other Rent	0
3500-Distribution Expenses - Operation Total	**273,927**

3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	0
5110-Maintenance of Structures	0
5112-Maintenance of Transformer Station Equipment	0
5114-Mtaint Dist Stn Equip	585
5120-Maintenance of Poles, Towers and Fixtures	0
5125-Maintenance of Overhead Conductors and Devices	5,763
5130-Maintenance of Overhead Services	187
5135-Overhead Distribution Lines and Feeders - Right of Way	41,628
5145-Maintenance of Underground Conduit	0
5150-Maintenance of Underground Conductors and Devices	0
5155-Maintenance of Underground Services	0
5160-Maintenance of Line Transformers	12,361
5165-Maintenance of Street Lighting and Signal Systems	0
5170-Sentinel Lights - Labour	0
5172-Sentinel Lights - Materials and Expenses	0
5175-Maintenance of Meters	1,947
5178-Customer Installations Expenses - Leased Property	0
5195-Maintenance of Other Installations on Customer Premises	0
3550-Distribution Expenses - Maintenance Total	**62,471**

3650-Billing and Collecting	
5305-Supervision	2,660
5310-Meter Reading Expense	44,819
5315-Customer Billing	94,693
5320-Collecting	0
5325-Collecting - Cash Over and Short	0
5330-Collection Charges	0
5335-Bad Debt Expense	5,311
5340-Miscellaneous Customer Accounts Expenses	2,000
3650-Billing and Collecting Total	**149,483**

3700-Community Relations	
5405-Supervision	0
5410-Community Relations - Sundry	0
5415-Energy Conservation	0
5420-Community Safety Program	0
5425-Miscellaneous Customer Service and Informational Expenses	0
3700-Community Relations Total	**0**

3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	6,000
5610-Management Salaries and Expenses	119,084
5615-General Administrative Salaries and Expenses	127,518
5620-Office Supplies and Expenses	7,954
5625-Administrative Expense Transferred-Credit	0
5630-Outside Services Employed	124,766
5635-Property Insurance	8,894
5640-Injuries and Damages	0
5645-Employee Pensions and Benefits	0
5650-Franchise Requirements	0
5655-Regulatory Expenses	10,307
5660-General Advertising Expenses	1,200
5665-Miscellaneous Expenses	40,376
5670-Rent	0
5675-Maintenance of General Plant	40,264
5680-Electrical Safety Authority Fees	2,031
5685-Independent Market Operator Fees and Penalties	0
5695-OM&A Contra Account	0
3800-Administrative and General Expenses Total	**488,395**

3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	190,722
5710-Amortization of Limited Term Electric Plant	0
5715-Amortization of Intangibles and Other Electric Plant	0
5720-Amortization of Electric Plant Acquisition Adjustments	0
5725-Miscellaneous Amortization	0
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	0
5735-Amortization of Deferred Development Costs	0
5740-Amortization of Deferred Charges	0
3850-Amortization Expense Total	**190,722**

3900-Interest Expense	
6005-Interest on Long Term Debt	85,000
6010-Amortization of Debt Discount and Expense	0
6015-Amortization of Premium on Debt-Credit	0
6020-Amortization of Loss on Reacquired Debt	0
6025-Amortization of Gain on Reacquired Debt-Credit	0
6030-Interest on Debt to Associated Companies	12,310
6035-Other Interest Expense	10,000
6040-Allowance for Borrowed Funds Used During Construction-Credit	0
6042-Allowance for Other Funds Used During Construction	0
6045-Interest Expense on Capital Lease Obligations	0
3900-Interest Expense Total	**107,310**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	0
3950-Taxes Other Than Income Taxes Total	**0**
4000-Income Taxes	
6110-Income Taxes	0
6115-Provision for Future Income Taxes	(75,522)
4000-Income Taxes Total	**(75,522)**
4100-Extraordinary & Other Items	
6205-Donations	0
6210-Life Insurance	0
6215-Penalties	0
6225-Other Deductions	0
4100-Extraordinary & Other Items Total	**0**
Net Income - (Gain)/Loss	**7,571**

APPENDIX H

COPY OF Atikokan Hydro Inc.

2012 PRO FORMA STATEMENTS

ATIKOKAN HYDRO INC
2012 BALANCE SHEET

Account Description	Total
1050-Current Assets	
1005-Cash	69,000
1010-Cash Advances and Working Funds	500
1020-Interest Special Deposits	0
1030-Dividend Special Deposits	0
1040-Other Special Deposits	0
1060-Term Deposits	0
1070-Current Investments	0
1100-Customer Accounts Receivable	235,000
1102-Accounts Receivable - Services	0
1104-Accounts Receivable - Recoverable Work	52,500
1105-Accounts Receivable - Merchandise, Jobbing, etc.	0
1110-Other Accounts Receivable	0
1120-Accrued Utility Revenues	301,457
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(6,000)
1140-Interest and Dividends Receivable	0
1150-Rents Receivable	0
1170-Notes Receivable	0
1180-Prepayments	28,000
1190-Miscellaneous Current and Accrued Assets	0
1200-Accounts Receivable from Associated Companies	0
1210-Notes Receivable from Associated Companies	0
1050-Current Assets Total	**680,457**

1100-Inventory	
1305-Fuel Stock	0
1330-Plant Materials and Operating Supplies	111,110
1340-Merchandise	0
1350-Other Material and Supplies	0
1100-Inventory Total	**111,110**

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

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1200-Other Assets and Deferred Charges	
1505-Unrecovered Plant and Regulatory Study Costs	0
1508-Other Regulatory Assets	295,000
1510-Preliminary Survey and Investigation Charges	0
1515-Emission Allowance Inventory	0
1516-Emission Allowance Withheld	0
1518-RCVA Retail	14,417
1525-Miscellaneous Deferred Debits	0
1530-Deferred Losses from Disposition of Utility Plant	0
1540-Deferred Losses from Disposition of Utility Plant	0
1545-Development Charge Deposits/ Receivables	0
1548-RCVA - Service Transaction Request (STR)	24,508
1550-LV Charges - Variance	0
1555-Smart Meters Recovery	(84,818)
1556-Smart Meters OM & A	206,411
1562-Deferred PILs	0
1563-Deferred PILs - Contra	0
1565-C & DM Costs	0
1566-C & DM Costs Contra	0
1570-Qualifying Transition Costs	0
1571-Pre Market CofP Variance	0
1572-Extraordinary Event Losses	0
1574-Deferred Rate Impact Amounts	0
1580-RSVA - Wholesale Market Services	(43,000)
1582-RSVA - One-Time	0
1584-RSVA - Network Charges	8,200
1586-RSVA - Connection Charges	50,700
1588-RSVA - Commodity (Power)	50,500
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	0
1592-PILs and Tax Variance for 2006 & Subsequent Years	0
1595-Disposition and Recovery of Regulatory Balances	(11,000)
1606-Intangible plant	0
1200-Other Assets and Deferred Charges Total	**510,918**

1450-Distribution Plant	
1805-Land	0
1806-Land Rights	0
1808-Buildings and Fixtures	0
1810-Leasehold Improvements	0
1815-Transformer Station Equipment - Normally Primary above 50 kV	0
1820-Distribution Station Equipment - Normally Primary below 50 kV	511,618
1825-Storage Battery Equipment	0
1830-Poles, Towers and Fixtures	2,140,385
1835-Overhead Conductors and Devices	0
1840-Underground Conduit	0
1845-Underground Conductors and Devices	0
1850-Line Transformers	504,776
1855-Services	0
1860-Meters	601,784
1865-Other Installations on Customer's Premises	0
1450-Distribution Plant Total	**3,758,563**

1500-General Plant	
1905-Land	15,588
1906-Land Rights	0
1908-Buildings and Fixtures	693,882
1910-Leasehold Improvements	0
1915-Office Furniture and Equipment	61,120
1920-Computer Equipment - Hardware	132,895
1925-Computer Software	185,186
1930-Transportation Equipment	762,757
1935-Stores Equipment	0
1940-Tools, Shop and Garage Equipment	106,760
1945-Measurement and Testing Equipment	0
1950-Power Operated Equipment	0
1955-Communication Equipment	0
1960-Miscellaneous Equipment	0
1970-Load Management Controls - Customer Premises	0
1975-Load Management Controls - Utility Premises	0
1980-System Supervisory Equipment	0
1985-Sentinel Lighting Rentals	0
1990-Other Tangible Property	0
1995-Contributions and Grants	0
1500-General Plant Total	**1,958,188**

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

1600-Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(3,347,854)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	0
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	0
2160-Accumulated Amortization of Other Utility Plant	0
2180-Accumulated Amortization of Non-Utility Property	0
1600-Accumulated Amortization Total	**(3,347,854)**

Total Assets	**3,671,382**

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1650-Current Liabilities	
2205-Accounts Payable	646,507
2208-Customer Credit Balances	0
2210-Current Portion of Customer Deposits	11,500
2215-Dividends Declared	0
2220-Miscellaneous Current and Accrued Liabilities	0
2225-Notes and Loans Payable	0
2240-Accounts Payable to Associated Companies	0
2242-Notes Payable to Associated Companies	0
2250-Debt Retirement Charges (DRC) Payable	0
2252-Transmission Charges Payable	0
2254-Electric Safety Authority Fees Payable	0
2256-Independent Market Operator Fees and Penalties Payable	0
2260-Current Portion of Long Term Debt	12,000
2262-Ontario Hydro Debt - Current Portion	0
2264-Pensions and Employee Benefits - Current Portion	0
2268-Accrued Interest on Long Term Debt	0
2270-Matured Long Term Debt	0
2272-Matured Interest on Long Term Debt	0
2285-Obligations Under Capital Leases--Current	0
2290-Commodity Taxes	(25,900)
2292-Payroll Deductions / Expenses Payable	0
2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	(20,444)
2296-Future Income Taxes - Current	0
1650-Current Liabilities Total	**623,663**

1700-Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	0
2306-Employee Future Benefits	0
2308-Other Pensions - Past Service Liability	0
2310-Vested Sick Leave Liability	0
2315-Accumulated Provision for Rate Refunds	0
2320-Other Miscellaneous Non-Current Liabilities	0
2325-Obligations Under Capital Lease--Non-Current	0
2330-Devolpment Charge Fund	0
2335-Long Term Customer Deposits	108,000
2340-Collateral Funds Liability	0
2345-Unamortized Premium on Long Term Debt	0
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	0
2350-Future Income Tax - Non-Current	(75,522)
2405-Other Regulatory Liabilities	0
2410-Deferred Gains From Disposition of Utility Plant	0
2415-Unamortized Gain on Reacquired Debt	0
2425-Other Deferred Credits	0
2435-Accrued Rate-Payer Benefit	0
1700-Non-Current Liabilities Total	**32,478**

1800-Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	0
2510-Debenture Advances	0
2515-Required Bonds	0
2520-Other Long Term Debt	1,257,970
2525-Term Bank Loans - Long Term Portion	418,510
2530-Ontario Hydro Debt Outstanding - Long Term Portion	0
2550-Advances from Associated Companies	376,000
1800-Long-Term Debt Total	**2,052,480**

1850-Shareholders' Equity	
3005-Common Shares Issued	1,277,900
3008-Preference Shares Issued	0
3010-Contributed Surplus	0
3020-Donations Received	0
3022-Devolpment Charges Transferred to Equity	0
3026-Capital Stock Held in Treasury	0
3030-Miscellaneous Paid-In Capital	0
3035-Installments Received on Capital Stock	0
3040-Appropriated Retained Earnings	0
3045-Unappropriated Retained Earnings	(567,752)
3046-Balance Transferred From Income	252,613
3047-Appropriations of Retained Earnings - Current Period	0
3048-Dividends Payable-Preference Shares	0
3049-Dividends Payable-Common Shares	0
3055-Adjustment to Retained Earnings	0
3065-Unappropriated Undistributed Subsidiary Earnings	0
1850-Shareholders' Equity Total	**962,761**

Total Liabilities & Shareholder's Equity	**3,671,382**

Balance Sheet Total	(0)

ATIKOKAN HYDRO INC
2012 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	(723,780)
4010-Commercial Energy Sales	0
4015-Industrial Energy Sales	0
4020-Energy Sales to Large Users	0
4025-Street Lighting Energy Sales	(39,341)
4030-Sentinel Energy Sales	0
4035-General Energy Sales	(822,000)
4040-Other Energy Sales to Public Authorities	0
4045-Energy Sales to Railroads and Railways	0
4050-Revenue Adjustment	(171,084)
4055-Energy Sales for Resale	(129,000)
4060-Interdepartmental Energy Sales	0
4062-WMS	(207,734)
4064-Billed WMS-One Time	0
4066-NS	(126,556)
4068-CS	(31,162)
4075-LV Charges	0
3000-Sales of Electricity Total	**(2,250,657)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(1,476,998)
4082-RS Rev	(4,000)
4084-Serv Tx Requests	(1,000)
4090-Electric Services Incidental to Energy Sales	0
3050-Revenues From Services - Distirbution Total	**(1,481,998)**
3100-Other Operating Revenues	
4205-Interdepartmental Rents	0
4210-Rent from Electric Property	(34,911)
4215-Other Utility Operating Income	0
4220-Other Electric Revenues	0
4225-Late Payment Charges	(6,024)
4230-Sales of Water and Water Power	0
4235-Miscellaneous Service Revenues	(7,100)
4240-Provision for Rate Refunds	0
4245-Government Assistance Directly Credited to Income	0

3100-Other Operating Revenues Total	**(48,035)**
3150-Other Income & Deductions	
4305-Regulatory Debits	0
4310-Regulatory Credits	0
4315-Revenues from Electric Plant Leased to Others	0
4320-Expenses of Electric Plant Leased to Others	0
4325-Revenues from Merchandise, Jobbing, Etc.	(75,000)
4330-Costs and Expenses of Merchandising, Jobbing, Etc	20,000
4335-Profits and Losses from Financial Instrument Hedges	0
4340-Profits and Losses from Financial Instrument Investments	0
4345-Gains from Disposition of Future Use Utility Plant	0
4350-Losses from Disposition of Future Use Utility Plant	0
4355-Gain on Disposition of Utility and Other Property	0
4360-Loss on Disposition of Utility and Other Property	0
4365-Gains from Disposition of Allowances for Emission	0
4370-Losses from Disposition of Allowances for Emission	0
4375-Revenues from Non-Utility Operations	(232,000)
4380-Expenses of Non-Utility Operations	232,000
4385-Expenses of Non-Utility Operations	0
4390-Miscellaneous Non-Operating Income	(4,000)
4395-Rate-Payer Benefit Including Interest	0
4398-Foreign Exchange Gains and Losses, Including Amortization	0
3150-Other Income & Deductions Total	**(59,000)**
3200-Investment Income	
4405-Interest and Dividend Income	(9,000)
4415-Equity in Earnings of Subsidiary Companies	0
3200-Investment Income Total	**(9,000)**

3350-Power Supply Expenses	
4705-Power Purchased	1,813,905
4708-WMS	164,734
4710-Cost of Power Adjustments	0
4712-0	0
4714-NW	134,756
4715-System Control and Load Dispatching	0
4716-NCN	81,862
4720-Other Expenses	0
4725-Competition Transition Expense	0
4730-Rural Rate Assistance Expense	0
4750-LV Charges	0
3350-Power Supply Expenses Total	**2,195,257**
3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	0
5010-Load Dispatching	0
5012-Station Buildings and Fixtures Expense	0
5014-Transformer Station Equipment - Operation Labour	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0
5016-Distribution Station Equipment - Operation Labour	1,087
5017-Distribution Station Equipment - Operation Supplies and Expenses	205
5020-Overhead Distribution Lines and Feeders - Operation Labour	265,093
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	42,915
5030-Overhead Subtransmission Feeders - Operation	1,476
5035-Overhead Distribution Transformers - Operation	0
5040-Underground Distribution Lines and Feeders - Operation Labour	0
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	0
5050-Underground Subtransmission Feeders - Operation	0
5055-Underground Distribution Transformers - Operation	0
5060-Street Lighting and Signal System Expense	0
5065-Meter Expense	107,573
5070-Customer Premises - Operation Labour	0
5075-Customer Premises - Materials and Expenses	0
5085-Miscellaneous Distribution Expense	0
5090-Underground Distribution Lines and Feeders - Rental Paid	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	0
5096-Other Rent	0
3500-Distribution Expenses - Operation Total	**418,349**

3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	0
5110-Maintenance of Structures	0
5112-Maintenance of Transformer Station Equipment	0
5114-Mtaint Dist Stn Equip	599
5120-Maintenance of Poles, Towers and Fixtures	0
5125-Maintenance of Overhead Conductors and Devices	5,907
5130-Maintenance of Overhead Services	191
5135-Overhead Distribution Lines and Feeders - Right of Way	42,669
5145-Maintenance of Underground Conduit	0
5150-Maintenance of Underground Conductors and Devices	0
5155-Maintenance of Underground Services	0
5160-Maintenance of Line Transformers	1,814
5165-Maintenance of Street Lighting and Signal Systems	0
5170-Sentinel Lights - Labour	0
5172-Sentinel Lights - Materials and Expenses	0
5175-Maintenance of Meters	1,996
5178-Customer Installations Expenses - Leased Property	0
5195-Maintenance of Other Installations on Customer Premises	0
3550-Distribution Expenses - Maintenance Total	**53,177**

3650-Billing and Collecting	
5305-Supervision	2,727
5310-Meter Reading Expense	45,939
5315-Customer Billing	97,060
5320-Collecting	0
5325-Collecting - Cash Over and Short	0
5330-Collection Charges	0
5335-Bad Debt Expense	5,444
5340-Miscellaneous Customer Accounts Expenses	2,000
3650-Billing and Collecting Total	**153,170**

3700-Community Relations	
5405-Supervision	0
5410-Community Relations - Sundry	0
5415-Energy Conservation	0
5420-Community Safety Program	0
5425-Miscellaneous Customer Service and Informational Expenses	0
3700-Community Relations Total	**0**

3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	6,000
5610-Management Salaries and Expenses	122,061
5615-General Administrative Salaries and Expenses	130,706
5620-Office Supplies and Expenses	8,153
5625-Administrative Expense Transferred-Credit	0
5630-Outside Services Employed	127,886
5635-Property Insurance	9,116
5640-Injuries and Damages	0
5645-Employee Pensions and Benefits	0
5650-Franchise Requirements	0
5655-Regulatory Expenses	60,564
5660-General Advertising Expenses	1,230
5665-Miscellaneous Expenses	41,386
5670-Rent	0
5675-Maintenance of General Plant	41,271
5680-Electrical Safety Authority Fees	2,082
5685-Independent Market Operator Fees and Penalties	0
5695-OM&A Contra Account	0
3800-Administrative and General Expenses Total	**550,455**

3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	197,456
5710-Amortization of Limited Term Electric Plant	0
5715-Amortization of Intangibles and Other Electric Plant	0
5720-Amortization of Electric Plant Acquisition Adjustments	0
5725-Miscellaneous Amortization	0
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	0
5735-Amortization of Deferred Development Costs	0
5740-Amortization of Deferred Charges	0
3850-Amortization Expense Total	**197,456**

3900-Interest Expense	
6005-Interest on Long Term Debt	82,300
6010-Amortization of Debt Discount and Expense	0
6015-Amortization of Premium on Debt-Credit	0
6020-Amortization of Loss on Reacquired Debt	0
6025-Amortization of Gain on Reacquired Debt-Credit	0
6030-Interest on Debt to Associated Companies	11,435
6035-Other Interest Expense	10,000
6040-Allowance for Borrowed Funds Used During Construction-Credit	0
6042-Allowance for Other Funds Used During Construction	0
6045-Interest Expense on Capital Lease Obligations	0
3900-Interest Expense Total	**103,735**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	0
3950-Taxes Other Than Income Taxes Total	**0**
4000-Income Taxes	
6110-Income Taxes	0
6115-Provision for Future Income Taxes	(75,522)
4000-Income Taxes Total	**(75,522)**
4100-Extraordinary & Other Items	
6205-Donations	0
6210-Life Insurance	0
6215-Penalties	0
6225-Other Deductions	0
4100-Extraordinary & Other Items Total	**0**
Net Income - (Gain)/Loss	**(252,613)**

INFORMATION ON AFFILIATES:

As noted earlier in this exhibit, the Town of Atikokan created Atikokan Hydro Inc. and Atikokan Enercom Inc .as an affiliate company. The company's are operated as two distinct companies, each paying their own way.

Atikokan Hydro and Atikokan Enercom do have some common Board Members, but have always maintained the appropriate differential ratios of 1/3 relating to common Board Members.

All cash, banking and all assets are recorded separately for each company on secure computer systems with appropriate controls in place to ensure all records, and transactions are totally separate.

Atikokan Enercom's main business is to act as the only cell phone dealer for the community. Atikokan Enercom holds an electrical contractors license and does some line construction for various entities in the surrounding area.

MATERIALITY THRESHOLDS:

Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, issued by the Board June 28, 2011 states the relevant materiality threshold would be $50,000 for a distributor with a distribution revenue requirement less than or equal to $10 million. In this application Atikokan Hydro has used a materiality threshold of $50,000 since its distribution revenue requirement is less than $10 million.

Rate Base Overview

The rate base used for the purpose of calculating the revenue requirement used in this Application is the average of the balances at the beginning and the end of the 2012 Test Year, plus a working capital allowance, which is 15% of the sum of the cost of power and controllable expenses.

The net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. Atikokan Hydro does not have any non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses. Atikokan Hydro has calculated its 2012 Test Year Rate Base as $ 2,913,786.

Atikokan Hydro has provided a summary of its rate base calculations for the years 2008 Board Approved, 2008 Actual, 2009 to 2010 Actual, 2011 Bridge Year and 2012 Test Year in Table 2-1 below.

Table 2-1

Summary of Rate Base

Description	2008 OEB Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 Test Year
Gross Fixed Assets	5,032,491	4,621,076	4,804,897	5,169,638	5,239,138	5,716,751
Accumulated Depreciation	2,483,926	2,691,084	2,830,723	2,936,882	3,117,804	3,347,854
Net Book Value	2,548,565	1,929,992	1,974,174	2,232,756	2,121,334	2,368,897
Average Net Book Value	2,363,115	1,941,283	1,952,083	2,103,465	2,177,045	2,408,225
Working Capital	2,512,539	2,635,828	2,705,895	2,913,853	3,172,906	3,370,408
Working Capital Allowance	376,881	395,374	405,884	437,078	475,936	505,561
Rate Base	2,739,996	2,336,658	2,357,967	2,540,543	2,652,981	2,913,786

Atikokan Hydro's capital investment in its distribution plant and equipment has averaged $332,652 per year for 2008, 2009, and 2010. This contributes to the year over year variance in actual Gross Fixed Assets. As discussed in Atikokan Hydro's Asset Management Plan, filed as Appendix A to this Exhibit, the Town of Atikokan is similar to many communities in Northwestern Ontario and has been experiencing a declining population. Atikokan Hydro had 1,795 metered customers in 2003 which has decreased to 1,682 metered customers by the end of 2010 and forecasted to slip to 1,673 by the end of the 2012 Test Year. Given the decrease in growth over the past decades, Atikokan Hydro finds itself in the unique position of having a distribution system with assets that are aging but are being under utilized. Atikokan Hydro's capital spending will be concentrated on the replacement of aging assets that are at the end of their useful life.

Atikokan Hydro has provided a summary of its cost of power and controllable expenses used in calculating working capital for the period 2008 Actual to 2010 Actual, including the 2008 Board Approved, 2011 Bridge Year and 2012 Test Year in Table 2-2, below. Details of Atikokan Hydro's calculation of working capital allowance are provided further along in this Exhibit.

Table 2-2

Summary of Working Capital Calculation

Description	2008 OEB Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 Test Year
Cost of Power	1,703,494	1,790,804	1,824,212	1,913,140	2,198,629	2,195,257
Operations	311,895	296,121	322,006	332,111	273,927	418,349
Maintenance	38,800	88,816	41,928	51,665	62,471	53,177
Billing & Collecting	170,950	168,981	159,760	130,786	149,483	153,170
Administration & General Exp.	287,400	291,106	357,989	486,151	488,395	550,455
Working Capital	**2,512,539**	**2,635,828**	**2,705,895**	**2,913,853**	**3,172,906**	**3,370,408**
Working Capital Allowance 15%	**376,881**	**395,374**	**405,884**	**437,078**	**475,936**	**505,561**

The changes in working capital are primarily attributed to the annual changes in Cost of Power resulting from weather and changes in the market price of electricity and increases in OM&A expenditures. In 2010, Atikokan Hydro changed its capitalization policy to no longer capitalize expenses that were not directly related to the installation of capital. This caused an increase in 2010 administration and general expense. However, the revised capitalization policy is aligned with the IFRS standard. As a result, with Atikokan Hydro's movement to IFRS in 2012 there is no impact on 2012 capital additions or OM&A expenses. With regards to working capital allowance, Atikokan Hydro's has taken "the 15% allowance approach" in accordance with the Filing Requirement. Atikokan Hydro's working capital allowance is based on 15% of cost of power and controllable expenses.

In support of its rate base calculation, Atikokan Hydro has included details of its Gross Assets, Accumulated Depreciation, Working Capital and Fixed Asset Continuity Schedules for 2008 Actual to 2012 Test Year as required in the Filing Requirements.

Budget Process:

In managing its distribution system assets, Atikokan Hydro's main objective is to optimize performance of the assets at a reasonable cost with due regard for system reliability, safety, and customer service expectations. Atikokan Hydro is committed to providing our customers with an economical, safe, reliable supply of electricity. Atikokan Hydro's Asset Management Plan, which sets out Atikokan Hydro's processes for determining the necessary distribution system investments to ensure safe, reliable delivery of electricity to its customers, accompanies this Exhibit as Appendix A.

The Capital Budget process at Atikokan Hydro is an integral planning tool and ensures that appropriate resources are available to maintain its capital infrastructure. It is the responsibility of Senior Management to coordinate the capital budget and forecast process and present a Capital budget and long range forecast to the Board of Directors for approval.

Once the Board of Directors approve the annual budget the budget amounts do not change but rather provide a plan against which actual results may be evaluated.

Capital Budget:

Atikokan Hydro's capital budget is segregated into the following categories:

- Asset Management Capital Expenditures
- Other Capital Expenditures

Asset management capital expenditures are capital projects relating to Atikokan Hydro's existing and new capital infrastructure or projects identified through regulatory and legislative requirements. Other Capital Expenditures are general assets relating to Office Furniture and Equipment, Communications Equipment, Computer Hardware and Software, Vehicles and Miscellaneous Tools and Equipment.

This Application incorporates Atikokan Hydro's 2011 Bridge Year & 2012 Test Year Capital and Operating, Maintenance & Administration Budgets used in determining the revenue requirement to bring these plans to fruition.

Atikokan Hydro includes its 6 year capital budget in table 2-3. The concentration of capital will be on replacing and rebuilding much of Atikokan Hydro's distribution system. In 2015 and 2016, Atikokan Hydro will need to concentrate on its fleet with replacing a service vehicle in 2015 and a double bucket truck in 2016. As noted under Substations, reclamation of oil and substation work will be completed over a two year period ending in 2015.

Table 2-3
Six Year Capital Budget

Asset Category	USofA	Budget 2012	Budget 2013	Budget 2014	Budget 2015	Budget 2016	Budget 2017
Transformer Station Equip >50 kV	1820	$8,000	$8,000	$35,000	$35,000	$1,000	$1,000
Poles, Towers & Fixtures	1830	$58,800	$55,000	$45,000	$30,000	$45,000	$85,000
O/H Conductors & Devices	1835	$0	$9,880	$6,000	$0	$6,000	$6,000
Line Transformers	1850	$7,000	$3,000	$3,000	$0	$0	$3,000
Services	1855	$0	$14,000	$0	$0	$0	$0
Meters	1860	$0	$2,500	$3,000	$0	$0	$2,500
Buildings and Fixtures	1908	$8,500	$4,000	$4,000	$1,000	$1,000	$1,000
Office Furniture and Equipment	1915	$0	$3,200	$1,000	$1,000	$1,000	$1,000
Computer Equipment - Hardware	1920	$12,000	$2,000	$2,000	$2,000	$2,000	$2,000
Computer Equipment – Software	1925	$8,000	$0	$1,000	$0	$0	$0
Fleet	1930	0	$0	$-	$50,000	$325,000	$0
Tools, Shop & Garage Eq	1940	$16,500	$5,000	$1,000	$1,000	$1,000	$1,000
Measure & Test Equip	1945	$0	$2,000	$2,000	$2,000	$2,000	$2,000
Miscellaneous Equipment	1960	$0	$2,000	$2,000	$2,000	$2,000	$2,000
Total		**$118,800**	**$110,580**	**$105,000**	**$124,000**	**$386,000**	**$106,500**

Atikokan Hydro's Capital Budget process is based on:

- **Customer Demand:**

These are projects that Atikokan Hydro undertakes to meet customer obligations in accordance with the OEB's Distribution System Code (the "DSC") and Atikokan Hydro's Conditions of Service. Activities include connecting new residential and general service customers; Atikokan

Hydro would contribute to the cost of these projects using the economic evaluation methodology in accordance with the DSC and the provisions of its Conditions of Service for system expansions to determine the level of capital contribution.

- **Replacement:**

Replacement projects are completed when it has been determined through proper condition assessment that assets have reached their end of useful life. Atikokan Hydro completes visual inspections of its plant and performs predictive testing on certain assets where such testing is available, and replaces assets based on inspection and testing results as warranted. In some cases the projects involve spot replacement of assets; in other cases, the projects involve complete asset replacement within a geographic area. When replacing assets by doing a rebuild, Atikokan Hydro strives to use the most efficient assets available. New assets require less maintenance, deliver better reliability and reduce safety risks to the general public.

- **Capacity:**

As noted previously, Atikokan Hydro has experienced load decline over several decades. This has left Atikokan Hydro with a system that has ample capacity that will require on going rebuilding and refurbishing of infrastructure.

- **Regulatory Requirements:**

These projects are capital investments which are being driven by regulatory requirements. These requirements may include, among others, directions from the OEB, the IESO, the Ministry of Energy or the Ministry of Environment. In 2006, The Government of Ontario established targets for the installation of 800,000 smart electricity meters by December 31, 2008 and installation of smart meters for all Ontario customers by December 31, 2011. On May 30, 2008, Atikokan Hydro was advised by the fairness commissioner that:

> *"It* is *the judgment of PRP International, Inc.,* as *the Fairness Commissioner, that the determinations of the two* (2) *highest ranked Proponents for the ((Group of the Northern Five LDCs" (Atikokan Hydro Inc., Fort Francis Hydro Power Corporation, Kenora Hydro Electric Corporation Ltd, Sioux Lookout Hydro Inc., and Thunder Bay Hydro Electricity Distribution) requirements are:*

• *Elster Metering,* as *the recommended Preferred Proponent, based on* its *highest ranking, and*

• *KTI/Sensus Limited being the* second *ranked Proponent.*

These determinations were made in a fair (objective and competent) manner and consistent with the evaluation and selection processes set *out in the RFP,* issued *August* 14, *2007."*

Atikokan Hydro completed the installation of smart meters by the end of 2010. As outlined in detail in Exhibit 9, Atikokan Hydro is proposing to include smart meter assets in the 2012 rate base

For 2008, Atikokan Hydro also included the elimination of long-term load transfers as a regulatory requirement pursuant to the DSC.

- **Substations:**

Substation investments are undertaken to improve or maintain reliability to large numbers of customers and to maintain security and safety at the substations. Atikokan Hydro is being vigilant in monitoring the oil conditions in its substations and has an item in the budget to have the oil refurbished over a 2 year period in years 3 and 4 of the 6 year capital budget. Further tests and monitoring will occur and then the oil will be treated to remove any moisture and appropriate inhibitors added. With ongoing monitoring, this investment could add an additional 15 to 20 years to the life of the assets.

Customer Connections and Metering:

Capital expenditures include meter installations, meter upgrades, and the capital components of wholesale and retail meter verification activities. As of December 31, 2010 Atikokan Hydro Inc has completed 100% of the deployment of Smart Meters as approved by Ontario Regulation 427/06. Smart Meter capital is currently recorded in the smart meter variance account 1555. Atikokan Hydro is proposing the disposition on its smart meter variance accounts in this Application.

General Plant Capital Projects:

General plant capital projects are also been categorized into project pools. Each pool generally by OEB USoA category has identified within it the specific focus of the capital requirement and includes:

- Land, Buildings and Leasehold Improvements (USoA 1905, 1908, 1910)
- Office Furniture & Equipment (USoA 1915)
- Computer Hardware & Software(USoA 1920, 1925)
- Transportation/Vehicles Equipment (USoA 1930)
- Stores Equipment, Tools and Measuring Equipment (USoA 1935, 1940, 1945)
- Other Tangible Property (USoA 1990)

Capitalization Policy:

Atikokan Hydro does not have a formal written capitalization policy. Atikokan Hydro follows Generally Accepted Accounting Principles, in particular the CICA Handbook Section 3060, Capital Assets as well as the guidelines as set out in the OEB Accounting Procedure Handbook. As previously mentioned, Atikokan Hydro changed its capitalization practices in 2010 which in turn allowed the capitalization policy to be aligned with IFRS standards for 2012. As components are replaced, they will be capitalized if they meet the following criteria.

A capital asset is broadly defined as being one that will provide future economic benefits to the organization. The definition in the OEB Handbook includes items which:

1. are held for use in the production or supply of goods and services, for rental to others, for administrative purposes or for the development, construction, maintenance or repair of other capital assets
2. have been acquired, constructed or developed with the intention of being used on a continuing basis, and
3. are not intended for sale in the ordinary course of business.

From this definition, it follows that these assets have lasting value to a company (greater than one year). These broad definitions should be applied to determine the classification of a purchase as capital. Any directly attributable expenditures to acquire, construct or better that asset should therefore be capitalized. All other expenditures should be expensed as a period expense in the year they occur.

Once an expenditure has been determined to be capital in nature, it must also pass a minimum threshold for capitalization. Atikokan Hydro has set this minimum threshold at $200. Professional judgment must be applied as in certain instances, if the expenditure does not meet the $200 threshold, but it is a small vital component in a larger capital asset construction (i.e. ties at the base of a pole), then the item should still be capitalized.

Atikokan Hydro does not capitalize interest on funds used during construction as capital projects are budgeted for and completed in the fiscal year. In addition, Atikokan Hydro no longer capitalizes, through internal cost allocations, any indirect administrative support costs such as Finance or Facilities. Atikokan Hydro does not have a Human Resource or Corporate Services Department.

Atikokan Hydro's Distribution System:

Atikokan Hydro owns and operates the electricity distribution system in the Town of Atikokan Hydro Inc serving more than 1,600 residential and business customers. Atikokan Hydro is supplied power from one Hydro One Transformer Station [Moose Lake TS] at 44 KV. Atikokan Hydro owns and operates 23 KM of 44 KV sub-transmission line to feed Atikokan Hydro's four substations. The 44 kV feeders are strategically arranged so they can be paralleled, and each substation can be fed from either feeder. This allows Atikokan to have a very reliable source of power. The 44 kV lines both start at Moose Lake TS, and meet in the centre of the Town. The system is the shape of a football, starting at Moose Lake, and ending at the 3M3-3M3 tie switch. This physical separation gives Atikokan security in the event of a disaster such as a forest fire. Atikokan Hydro Inc distributes electricity to the Town of Atikokan at the primary voltage of 8.32 KV [8320/4800] and one area at 4.16 KV. The main customer area has 3 of the four substations, and they can be paralleled for restoration of power, or to move customers from one station to another to allow maintenance without any customer inconvenience.

Atikokan Hydro licensed service area is 370 square kilometres with most of Atikokan Hydro's customers concentrated in a 25 square kilometre area. Atikokan Hydro's distribution system is made up of 92 kilometres of overhead lines, 1289 poles, and 352 distribution transformers [89 in stock] and 1708 meters all of which are Smart Meters installed on Residential and General Service Customers.

Asset Management Plan:

Atikokan Hydro has developed an Asset Management Plan which outlines the capital and operating expenditures necessary to ensure that Atikokan Hydro continues to provide highest standards for the safe, reliable supply of electricity at the lowest cost. A copy of the Asset Management Plan is attached to this Exhibit as Appendix A.

The Asset Management Plan provides for:

- Replacement of greater than 40 year old plant.
- Construction of new plant required to service the Town of Atikokan.
- Inspection and testing of existing plant
- Maintenance of the highest standard of service to the Town of Atikokan residents and businesses

Atikokan Hydro 's Asset Management Plan has been developed with due regard to the different Acts, Regulations, Codes and Guidelines and the continual updating of good utility practice to ensure the needs of the Town of Atikokan and Atikokan Hydro customers are met.

Service Quality and Reliability

Atikokan Hydro monitors and relies on its service quality and reliability indices (SQIs) monthly as a means of measuring system performance. Atikokan Hydro's commitment to stakeholders is to ensure "highest standards of performance and business excellence for the safe, reliable provision of service".

Atikokan Hydro also tracks the cause of outages, as provided in the following table [Table 2-4 - Service Interruptions by Code], from which Atikokan Hydro is able to determine whether corrective action is required to prevent or reduce similar occurrences.

Table 2-4
Service Interruptions by Code

Code	Cause	
0	**Unknown/other**	Customer Interruptions with no apparent cause that contributed to the outage
1	**Scheduled Outage**	Customer Interruptions due to the disconnection at a selected time for the purpose of construction or preventative maintenance
2	**Loss Of Supply**	Customer Interruptions due to problems in the bulk electricity supply system
3	**Tree Contacts**	Customer interruptions caused by faults resulting from tree contact with energized circuits
4	**Lightning**	Customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flash-overs
5	**Defective Equipment**	Customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance
6	**Adverse Weather**	Customer interruptions resulting from rain. Ice storms, snow, winds, extreme temperatures, freezing rain, frost or other extreme weather conditions (exclusive of code 3 and code 4 events)
7	**Human Element**	Customer Interruptions due to the interface of utility staff with the system
8	**Foreign Interference**	Customer Interruptions beyond the control of the utility such as animals, vehicles, dig-ins vandalism, sabotage, and foreign objects

Service Reliability Indices

The chart below provides Atikokan Hydro's reliability performance for each of the measures over the period 2007-2010. Year over year fluctuations may result from variations in weather such as extreme lightning, excessive snowfalls, foreign interference such as animal contacts and motor vehicle accidents. Atikokan Hydro's system performance indices are trending positively. This being said the "duration" and "restoration time" continued to improve. The service reliability statistics SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index) including and excluding Hydro One related incidents are provided in the following chart.

1 **Chart 2-1**

2 **Historical System Quality Indices**

SQI	2007		2008		2009		2010	
	Excluding Supply Loss	Total System	Excluding Supply Loss	Total System	Excluding Supply Loss	Total System	Excluding Supply Loss	Total System
SAIDI	0.900	4.900	0.503	1.113	0.198	1.451	0.026	0.074
SAIFI	1.000	2.220	1.466	1.475	0.388	1.992	0.028	2.016
CAIDI	0.900	2.210	0.343	0.754	0.511	0.729	0.936	0.037

Rate Base Variance Analysis

The following Table 2-5 sets out Atikokan Hydro 's year over year rate base variances for the 2008 Actual, 2008 OEB Approved,2009 Actual, 2010 Actual, 2011 Bridge Year and 2012 Test Year. The variances between the 2008 Actual and the 2008 Board Approved amounts in the Gross Fixed Assets results from capital projects included in the 2008 Board Approved amounts that were not completed until 2009 and 2010. These projects were the building of a new garage and the purchase of the new double bucket truck. These projects were not completed in 2008 since Atikokan Hydro did not receive approved 2008 rates early enough to allow financing to be arranged for the projects.

Table 2-5

Rate Base Variances

Description	2008 OEB Approved	2008 Actual Variance from 2008 Board Approved	2009 Actual Variance from 2008 Actual	2010 Actual Variance from 2009 Actual	2011 Bridge Year Variance from 2010 Actual	2012 Test Year Variance from 2011 Bridge
Gross Fixed Assets	5,032,491	-411,415	183,821	364,742	69,500	477,613
Accumulated Depreciation	2,483,926	207,158	139,638	106,159	180,922	230,050
Net Book Value	2,548,565	-618,573	44,183	258,582	-111,422	247,563
Average Net Book Value	2,363,115	-421,832	10,800	151,382	73,580	231,180
Working Capital	2,512,539	123,290	70,067	207,958	259,053	197,502
Working Capital Allowance	376,881	18,493	10,510	31,194	38,858	29,625
Rate Base	2,739,996	-403,338	21,310	182,576	112,438	260,805

Gross Fixed Asset Variance Analysis

The Town of Atikokan has experienced significant decline in population as noted in table 2-6 below. This has translated into a reduction in load as well as fewer customers as noted in other parts of this exhibit.

Table 2-6

Atikokan Population Comparison table[1]

	Atikokan	Ontario
Population in 2006	3,293	12,160,282
Population in 2001	3,632	11,410,046
2001 to 2006 population change	-9.3 %	6.6 %
Total private dwellings	1,535	4,972,869
Private houses/condos occupied by usual residents	1,418	4,554,251
Population density per square kilometre	10.4	13.4
Land area	316.74 km^2	907,573.82 km^2

MPAC has published the Town of Atikokan's population to be 2845 in 2010. As a result, Atikokan Hydro capital expenditure objective is to maintain and provide a reliable distribution system to those customers who continue to live and work in Atikokan.

For the purposes of this Application Atikokan Hydro has provided information for the period 2008 and forward. Atikokan Hydro's investment in capital has increased in each year from 2008 to 2010 as set out in Table 2-7 below – Percentage Change in Gross Fixed Assets.

Table 2.7

Percentage Change in Gross Fixed Assets

Description	2008 Actual Variance from 2008 Board Approved	2009 Actual Variance from 2008 Actual	2010 Actual Variance from 2009 Actual	2011 Bridge Year Variance from 2010 Actual	2012 Test Year Variance from 2011 Bridge
Gross Fixed Assets	-8.90%	3.83%	7.06%	1.33%	8.35%

As noted above, and reflected in the Rate Base Analysis, Atikokan Hydro was not able to proceed with the building of the new garage and the purchase of the new truck in 2008. These

[1] http://www.city-data.com/canada/Atikokan-Township.html

items were in the board approved capital forecast. The garage was built in 2009 and the truck was ordered in 2009 and was delivered in 2010. Atikokan Hydro's capital additions by USoA for the years 2008 to the 2012 Test Year, is provided in Table 2-8 and discussed in further detail in this Exhibit.

Table 2-8

Capital Additions 2008 Actual to 2012 Test Year

Capital Additions 2008 Actual to 2012 Test Year

USoA	Description	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 Test Year
1820	Distribution Station Equipment	881	7,049	800	17,000	8,000
1830	Poles, Towers and Fixtures	65,465	55,918	133	43,800	58,800
1850	Line Transformers	65,579	1,937	0	5,000	7,000
1860	Meters	515	13,953	33,068	0	0
Total Additions to Plant		**132,440**	**78,857**	**34,001**	**65,800**	**73,800**
1908	Buildings and Fixtures	43,211	221,611	88,197	8,500	8,500
1915	Office Furniture and Equipment	12,243	9,012	1,228	0	0
1920	Computer Equipment - Hardware	3,364	4,919	0	1,500	12,000
1925	Computer Software	882	4,724	2,398	0	8,000
1930	Transportation Equipment			342,337		
1940	Tools, Shop and Garage Equipment	5,972	3,897	8,665	3,500	16,500
Total Additions to Other Assets		**65,673**	**244,162**	**442,825**	**13,500**	**45,000**
Capital Additions		**198,112**	**323,019**	**476,826**	**79,300**	**118,800**

For 2009 to 2011, once the capital additions are adjusted for disposition outlined in the continuity statement in the pages that follow the resulting amounts equal the changes to gross fixed assets shown in Table 2-5. For 2012, the change in gross fixed assets shown in Table 2-5 reflects the capital additions outlined above minus adjustments for forecasted dispositions plus adjustments for smart meter capital and stranded meters which is explained below.

Atikokan Hydro's capital investment is driven as discussed below

The first driver of Atikokan Hydro 's capital investment is its obligation to connect a customer in accordance with Section 28 of the *Electricity Act, 1998*, Section 7 of Atikokan Hydro 's Electricity Distribution License and the Distribution System Code.

The final driver is Atikokan Hydro's own capital investment required to meet its commitment to provide a safe and reliable supply of electricity to its customers. Details are provided in Atikokan Hydro 's Asset Management Plan attached as Appendix A to this Exhibit but in summary includes the rebuilding and conversion of deteriorating 8.32kV and 4.16 kV distribution plant, pole replacement and other capital works required as a result of inspection and testing of existing distribution plant. Other Asset investments include building/facilities, computer hardware, software, vehicles and communication equipment.

Accumulated Depreciation

Atikokan Hydro uses the straight line method of amortization to determine the depreciation expense for all distribution assets on a pooled basis and identifiable assets individually. A full year's amortization is calculated on a straight line basis over estimated useful life of the asset. Up to 2011, Atikokan Hydro follows the amortization schedule provided at Schedule B of the OEB's 2006 Electricity Distribution Rate Handbook. For 2012, the depreciation amount reflects modified IFRS as discussed under the Capital Project section of this Exhibit.

For the purposes of this rate application, Atikokan Hydro used the half year rule for calculating depreciation expense for the 2012 Test Year. Details of Atikokan Hydro's depreciation by year, by account number are provided in the Fixed Asset Continuity Schedules set out in the Capital Project section of this Exhibit.

Further information on Atikokan Hydro's depreciation expenses is provided in Exhibit 4.

Capital Projects

The following section sets out the year over year variances in Atikokan Hydro's capital expenditures by the OEB's USoA classification. Also provided are the annual fixed asset continuity schedules, capital projects by USoA and explanations for the capital projects exceeding the materiality threshold of $50,000. This information has been presented for the years 2008 to 2010 Actuals, the 2011 Bridge Year and the 2012 Test Year.

2008 Actual Capital Additions:

The 2008 Fixed Asset Continuity Schedule, Table 2-9 provides a summary of the additions and disposals based on the OEB USoA classification.

Table 2-9
2008 Fixed Asset Continuity Schedule

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2008

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	0	0	0	0	0	0	0	0	0
CEC	1806	Land Rights	0	0	0	0	0	0	0	0	0
1	1808	Buildings and Fixtures	0	0	0	0	0	0	0	0	0
	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
	1815	Transformer Station Equipment - Normally Prima	0	0	0	0	0	0	0	0	0
1	1820	Distribution Station Equipment - Normally Primar	477,888	881	0	478,769	283,898	6,396	0	290,294	188,475
	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
1	1830	Poles, Towers and Fixtures	2,052,199	65,465	19,423	2,098,241	881,961	90,134	3,667	968,428	1,129,813
1	1835	Overhead Conductors and Devices	0	0	0	0	0	0	0	0	0
1	1840	Underground Conduit	0	0	0	0	0	0	0	0	0
1	1845	Underground Conductors and Devices	0	0	0	0	0	0	0	0	0
1	1850	Line Transformers	464,836	65,579	31,025	499,390	334,718	14,000	7,625	341,092	158,297
1	1855	Services	0	0	0	0	0	0	0	0	0
1	1860	Meters	398,765	515	300	398,980	180,479	14,509	300	194,688	204,292
	1865	Other Installations on Customer's Premises	0	0	0	0	0	0	0	0	0
N/A	1905	Land	15,588	0	0	15,588	0	0	0	0	15,588
CEC	1906	Land Rights	0	0	0	0	0	0	0	0	0
1	1908	Buildings and Fixtures	328,271	43,211	609	370,874	205,852	13,287	0	219,139	151,734
	1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture and Equipment	53,801	12,243	15,164	50,880	41,118	4,073	10,627	34,564	16,317
45	1920	Computer Equipment - Hardware	55,981	3,364	16,675	42,670	44,196	4,351	15,676	32,871	9,800
12	1925	Computer Software	170,183	882	0	171,065	169,430	1,194	0	170,624	441
10	1930	Transportation Equipment	445,006	0	24,586	420,420	384,806	19,304	22,242	381,867	38,553
10	1935	Stores Equipment	0	0	0	0	0	0	0	0	0
8	1940	Tools, Shop and Garage Equipment	74,342	5,972	6,115	74,199	57,828	5,155	5,466	57,517	16,682
	1945	Measurement and Testing Equipment	0	0	0	0	0	0	0	0	0
	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
10	1955	Communication Equipment	0	0	0	0	0	0	0	0	0
	1960	Miscellaneous Equipment	0	0	0	0	0	0	0	0	0
	1970	Load Management Controls - Customer Premise	0	0	0	0	0	0	0	0	0
	1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
	1980	System Supervisory Equipment	0	0	0	0	0	0	0	0	0
	1985	Sentinel Lighting Rentals	0	0	0	0	0	0	0	0	0
	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
1	1995	Contributions and Grants	0	0	0	0	0	0	0	0	0
	2005	Property under Capital Lease	0	0	0	0	0	0	0	0	0
		Total before Work in Process	**4,536,860**	**198,112**	**113,896**	**4,621,076**	**2,584,286**	**172,402**	**65,604**	**2,691,084**	**1,929,992**
WIP		Work in Process	0	0	0	0	0	0	0	0	0
		Total after Work in Process	**4,536,860**	**198,112**	**113,896**	**4,621,076**	**2,584,286**	**172,402**	**65,604**	**2,691,084**	**1,929,992**

10	1935	Transportation	84,216
10	1955	Communication Equipment	

Less: Fully Allocated Depreciation	
Transportation	19,304
Communication	
Net Depreciation	153,098

2008 Actual Capital Projects

The following Table 2-10 provides Atikokan Hydro's 2008 capital additions, by project, project type and USoA. There were no projects that exceeded the materiality threshold of $50,000,

Table 2 -10

2008 Actual Capital Projects

Year: 2008

USoA #	Description	CCA Class	Various Pole Changes	New Town Hall ext	Crossarm Changes	Upgrades along Hwy 11B	Delta - wye conversion lift stn	Prep for new garage furnace AC office	Signage Substations and ML TS	Printers, Folder, etc	Tools Shop	Computer Hardware	Computer Software	Total
1820	Distribution Station Equipment -		$ -						$ 881					$ 881
1830	Poles, Towers and Fixtures	1	$ 29,267	$ 12,543	$ 12,586	$ 11,069								$ 65,465
1850	Line Transformers	1		$ 22,195			$ 43,384							$ 65,579
1860	Meters	1							$ 515					$ 515
1908	Buildings and Fixtures	1						$ 43,211						$ 43,211
1915	Office Furniture and Equipment	8								$ 12,243				$ 12,243
1920	Computer Equipment -	45										$ 3,364		$ 3,364
1925	Computer Software	12											$ 882	$ 882
1940	Tools, Shop etc.	8									$ 5,972			$ 5,972
	Total		$ 29,267	$ 34,738	$ 12,586	$ 11,069	$ 43,384	$ 43,211	$ 1,396	$ 12,243	$ 5,972	$ 3,364	$ 882	$ 198,112

2009 Actual Capital Additions:

The 2009 Fixed Asset Continuity Schedule, Table 2-11 provides a summary of the additions and disposals based on the OEB USoA classification.

Table 2-11
2009 Fixed Asset Continuity Schedule

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2009

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	0	0	0	0	0	0	0	0	0
CEC	1806	Land Rights	0	0	0	0	0	0	0	0	0
47	1808	Buildings and Fixtures	0	0	0	0	0	0	0	0	0
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment - Normally Primai	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment - Normally Primary	478,769	7,049	0	485,818	290,294	14,626	0	**304,920**	180,898
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers and Fixtures	2,098,241	55,918	4,798	2,149,361	**968,428**	88,944	4,798	**1,052,574**	1,096,787
47	1835	Overhead Conductors and Devices	0	0	0	0	0	0	0	0	0
47	1840	Underground Conduit	0	0	0	0	0	0	0	0	0
47	1845	Underground Conductors and Devices	0	0	0	0	0	0	0	0	0
47	1850	Line Transformers	499,390	1,937	450	500,876	341,092	14,077	450	**354,719**	146,157
47	1855	Services	0	0	0	0	0	0	0	0	0
47	1860	Meters	398,980	13,953	133,950	278,983	194,688	16,508	47,444	**163,752**	115,231
N/A	1865	Other Installations on Customer's Premises	0	0	0	0	0	0	0	0	0
N/A	1905	Land	15,588	0	0	15,588	0	0	0	0	15,588
CEC	1906	Land Rights	0	0	0	0	0	0	0	0	0
47	1908	Buildings and Fixtures	370,874	221,611	0	592,484	219,139	21,635	0	**240,774**	351,710
13	1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture and Equipment	50,880	9,012	0	59,892	34,564	4,960	0	**39,524**	20,368
10	1920	Computer Equipment - Hardware	42,670	4,919	0	47,590	32,871	5,744	0	**38,615**	8,975
12	1925	Computer Software	171,065	4,724	0	175,788	170,624	2,803	0	**173,427**	2,361
10	1930	Transportation Equipment	420,420	0	0	420,420	381,867	18,909	0	**400,776**	19,644
8	1935	Stores Equipment	0	0	0	0	0	0	0	0	0
8	1940	Tools, Shop and Garage Equipment	74,199	3,897	0	78,095	57,517	4,124	0	61,641	16,454
8	1945	Measurement and Testing Equipment	0	0	0	0	0	0	0	0	0
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communication Equipment	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	0	0	0	0	0	0	0	0	0
47	1970	Load Management Controls - Customer Premises	0	0	0	0	0	0	0	0	0
47	1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equipment	0	0	0	0	0	0	0	0	0
47	1985	Sentinel Lighting Rentals	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
47	1995	Contributions and Grants	0	0	0	0	0	0	0	0	0
0	2005	Property under Capital Lease	0	0	0	0	0	0	0	0	0
		Total before Work in Process	**4,621,076**	**323,019**	**139,198**	**4,804,897**	**2,691,084**	**192,330**	**52,692**	**2,830,723**	**1,974,174**
WIP		Work in Process	0	0	0	0	0	0	0	0	0
		Total after Work in Process	**4,621,076**	**323,019**	**139,198**	**4,804,897**	**2,691,084**	**192,330**	**52,692**	**2,830,723**	**1,974,174**

183,821

	1925	Transportation
	1930	Stores Equipment

Less: Fully Allocated Depreciation		
Transportation	18,909	
Communication	2,845	organization expense
Net Depreciation	170,576	

2009 Actual Capital Projects

The following Table 2-12 provides Atikokan Hydro's 2009 capital additions, by project, project type and USoA as well as the total projects, by USoA that fall under the materiality threshold. Those projects that exceed the materiality threshold of $50,000 have been highlighted

Table 2-12
2009 Actual Capital Projects

Year: 2009

USoA #	Description	CCA Class	Various Pole Changes	Hemlock Rebuild	Dorothy Rebuild	Transformer Changes	Caland MS	New Town Hall	Wholesale / Interval Meters	Garage 2009 Component	Bill Folder etc	Substations	Shop Tools	Software Updates	Total
1820	Distribution Station Equipment -	47						-				$ 7,049			$ 7,049
1830	Poles, Towers and Fixtures	47	$ 31,853	$ 9,695	$ 8,541		$ 3,750	$ 2,079							$ 55,918
1850	Line Transformers	47				$ 1,937									$ 1,937
1860	Meters	47							$ 13,953						$ 13,953
1908	Buildings and Fixtures	47								$ 221,611					$ 221,611
1915	Office Furniture and Equipment	CEC									9,012				$ 9,012
1920	Computer Equipment - Hardware	47									$ 4,919				$ 4,919
1925	Computer Software	13												$ 4,724	$ 4,724
1940	Tools, Shop and Garage	8											$ 3,897		$ 3,897
	Total		$ 31,853	$ 9,695	$ 8,541	$ 1,937	$ 3,750	$ 2,079	$ 13,953	$ 221,611	$ 13,931	$ 7,049	$ 3,897	$ 4,724	$ 323,019

Project 2009: New Garage for new truck: Total Cost $221,611

In its application EB-2008-0014, Atikokan Hydro had identified the need to replace an aging bucket truck as well as construct a new garage for the storage of its line equipment. In late 2008 and early 2009, specifications were finalized, engineered plans obtained and the garage was tendered in early fall of 2008, to be completed in 2009.

The 2400 square foot three bay garage is heated with in floor hot water heating fueled by natural gas.

2010 Actual Capital Additions:

The 2010 Fixed Asset Continuity Schedule, Table 2-13 provides a summary of the additions and disposals based on the OEB USoA classification.

Table 2-13
2010 Fixed Asset Continuity Schedule

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2010

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	0	0	0	0	0	0	0	0	0
CEC	1806	Land Rights	0	0	0	0	0	0	0	0	0
47	1808	Buildings and Fixtures	0	0	0	0	0	0	0	0	0
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment - Normally Primary	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment - Normally Primary	485,818	800	0	486,618	304,920	14,048	0	318,968	167,650
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers and Fixtures	2,149,361	133	101,709	2,047,785	1,052,574	86,823	30,694	1,108,703	939,081
47	1835	Overhead Conductors and Devices	0	0	0	0	0	0	0	0	0
47	1840	Underground Conduit	0	0	0	0	0	0	0	0	0
47	1845	Underground Conductors and Devices	0	0	0	0	0	0	0	0	0
47	1850	Line Transformers	500,876	0	6,100	494,776	354,719	14,077	6,100	362,696	132,080
47	1855	Services	0	0	0	0	0	0	0	0	0
47	1860	Meters	278,983	33,068	4,275	307,776	163,752	23,513	78,903	108,362	199,413
N/A	1865	Other Installations on Customer's Premises	0	0	0	0	0	0	0	0	0
N/A	1905	Land	15,588	0	0	15,588	0	0	0	0	15,588
CEC	1906	Land Rights	0	0	0	0	0	0	0	0	0
47	1908	Buildings and Fixtures	592,484	88,197	0	680,682	240,774	25,165	0	265,940	414,742
13	1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture and Equipment	59,892	1,228	0	61,120	39,524	4,810	0	44,333	16,787
10	1920	Computer Equipment - Hardware	47,590	0	0	47,590	38,615	3,599	0	42,214	5,376
12	1925	Computer Software	175,788	2,398	0	178,186	173,427	3,561	0	176,988	1,198
10	1930	Transportation Equipment	420,420	342,337	0	762,757	400,776	41,731	0	442,507	320,250
8	1935	Stores Equipment	0	0	0	0	0	0	0	0	0
8	1940	Tools, Shop and Garage Equipment	78,095	8,665	0	86,760	61,641	4,528	0	66,169	20,591
8	1945	Measurement and Testing Equipment	0	0	0	0	0	0	0	0	0
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communication Equipment	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	0	0	0	0	0	0	0	0	0
47	1970	Load Management Controls - Customer Premises	0	0	0	0	0	0	0	0	0
47	1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equipment	0	0	0	0	0	0	0	0	0
47	1985	Sentinel Lighting Rentals	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
47	1995	Contributions and Grants	0	0	0	0	0	0	0	0	0
	2005	Property under Capital Lease	0	0	0	0	0	0	0	0	0
		Total before Work in Process	**4,804,897**	**476,826**	**112,084**	**5,169,638**	**2,830,723**	**221,856**	**115,697**	**2,936,882**	**2,232,756**
WIP		Work in Process	0	0	0	0	0	0	0	0	0
		Total after Work in Process	**4,804,897**	**476,826**	**112,084**	**5,169,638**	**2,830,723**	**221,856**	**115,697**	**2,936,882**	**2,232,756**

364,742

	1925	Transportation
	1930	Stores Equipment

Less: Fully Allocated Depreciation
Transportation 768
Communication
Net Depreciation 221,088

2010 Actual Capital Projects

The following Table 2-14 provides Atikokan Hydro's capital additions, by project, project type and USoA as well as the total projects, by USoA that fall under the materiality threshold. Those projects that exceed the materiality threshold of $50,000 have been highlighted

Table 2-14

2010 Actual Capital Projects

Year: 2010

USoA #	Description	CCA Class	Pole Change Prep	Old Garage Siding & Insulation	Old Garage Inside & Lighting	Drainage, Outdoor Lighting	Sbustation Fence upgraed	Delta - wye conversion Preperation	Software Updates	UPS units for workstaions	Shop Tools	9095 55' Double Bucket Truck	Total
1820	Distribution Station Eq <50kV	47					$ 800						$ 800
1830	Poles, Towers and Fixtures	47	$ 133										$ 133
1860	Meters	47						33,068					$ 33,068
1908	Buildings and Fixtures	47	$ -	$ 31,180	$ 42,118	$ 14,899							$ 88,197
1915	Office Furniture and Equipment	CEC	$ -							$ 1,228			$ 1,228
1925	Computer Software	13							$ 2,398				$ 2,398
1930	Transportation Equipment	10										$ 342,337	$ 342,337
1940	Tools, Shop and Garage Equipm	8									$ 8,665		$ 8,665
	Total		$ 133	$ 31,180	$ 42,118	$ 14,899	$ 800	$ 33,068	$ 2,398	$ 1,228	$ 8,665	$ 342,337	$ 476,826

Project 2010: New 55 foot Double Bucket Truck Total Cost: $342,337

As identified and discussed in Board approved EB-2008-0014, Atikokan Hydro had plans to enhance its service vehicle fleet. Given the need to create a new building in order to store the vehicle, the 2009 garage had to be completed. In early 2009 specifications for the new double bucket truck were finalized, and the tender awarded on May 2, 2009. The truck was not delivered and charged as an asset until April of 2010.

2011 Bridge Year Forecast Capital Additions

The 2011 Fixed Asset Continuity Schedule, Table 2-15 provides a summary of the additions and disposals based on the OEB USoA classification.

Table 2-15
2011 Fixed Asset Continuity Schedule

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2011

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
N/A	1805	Land	0	0	0	0	0	0	0	0	0
CEC	1806	Land Rights	0	0	0	0	0	0	0	0	0
47	1808	Buildings and Fixtures	0	0	0	0	0	0	0	0	0
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment - Normally Primar	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment - Normally Primary	486,618	17,000	0	503,618	318,968	14,728	0	333,696	169,922
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers and Fixtures	2,047,785	43,800	5,000	2,086,585	1,108,703	86,709	5,000	1,190,412	896,172
47	1835	Overhead Conductors and Devices	0	0	0	0	0	0	0	0	0
47	1840	Underground Conduit	0	0	0	0	0	0	0	0	0
47	1845	Underground Conductors and Devices	0	0	0	0	0	0	0	0	0
47	1850	Line Transformers	494,776	5,000	1,000	498,776	362,696	13,003	1,000	374,699	124,077
47	1855	Services	0	0	0	0	0	0	0	0	0
47	1860	Meters	307,776	0	0	307,776	108,362	16,390	0	124,752	183,023
N/A	1865	Other Installations on Customer's Premises	0	0	0	0	0	0	0	0	0
N/A	1905	Land	15,588	0	0	15,588	0	0	0	0	15,588
CEC	1906	Land Rights	0	0	0	0	0	0	0	0	0
47	1908	Buildings and Fixtures	680,682	8,500	3,800	685,382	265,940	24,559	3,800	286,699	398,683
13	1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture and Equipment	61,120	0	0	61,120	44,333	3,775	0	48,109	13,011
10	1920	Computer Equipment - Hardware	47,590	1,500	0	49,090	42,214	2,909	0	45,123	3,967
12	1925	Computer Software	178,186	0	0	178,186	176,988	1,199	0	178,187	(1)
10	1930	Transportation Equipment	762,757	0	0	762,757	442,507	22,996	0	465,502	297,255
8	1935	Stores Equipment	0	0	0	0	0	0	0	0	0
8	1940	Tools, Shop and Garage Equipment	86,760	3,500	0	90,260	66,169	4,454	0	70,624	19,636
8	1945	Measurement and Testing Equipment	0	0	0	0	0	0	0	0	0
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communication Equipment	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	0		0	0	0	0	0	0	0
47	1970	Load Management Controls - Customer Premises	0	0	0	0	0	0	0	0	0
47	1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equipment	0	0	0	0	0	0	0	0	0
47	1985	Sentinel Lighting Rentals	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
47	1995	Contributions and Grants	0	0	0	0	0	0	0	0	0
	2005	Property under Capital Lease	0	0	0	0	0	0	0	0	0
		Total before Work in Process	**5,169,638**	**79,300**	**9,800**	**5,239,138**	**2,936,882**	**190,722**	**9,800**	**3,117,804**	**2,121,334**
WIP		Work in Process	0	0	0	0	0	0	0	0	0
		Total after Work in Process	**5,169,638**	**79,300**	**9,800**	**5,239,138**	**2,936,882**	**190,722**	**9,800**	**3,117,804**	**2,121,334**

	1925	Transportation
	1930	Stores Equipment

Less: Fully Allocated Depreciation	
Transportation	
Communication	
Net Depreciation	190,722

2011 Forecast Bridge Year Capital Projects

The following Table 2-16 provides Atikokan Hydro's forecast capital additions, by project, project type and USoA for 2011. There are no forecasted projects that exceeded the materiality threshold of $50,000. With regards to HST for 2011 capital projects, all capital expenditures for 2011 are exclusive of PST.

Table 2-16

Year: 2011

USoA #	Description	CCA Class	Feeder 1 pole changes	Refurbishing tanks and painting	Transformer Changes	Office Roof	Printer	Shop Tools	Total
1820	Distribution Station Equipment -	47		$ 17,000					$ 17,000
1830	Poles, Towers and Fixtures	47	$ 48,000						$ 43,800
1850	Line Transformers	47			$ 5,000				$ 5,000
1908	Buildings and Fixtures	47				$ 8,500			$ 8,500
1920	Computer Equipment - Hardware	10					$ 1,500		$ 1,500
1940	Tools, Shop and Garage	8						$ 3,500	$ 3,500
	Total		**$ 48,000**	**$ 17,000**	**$ 5,000**	**$ 8,500**	**$ 1,500**	**$ 3,500**	**$ 79,300**

2011 Forecast Capital Projects

2012 Test Year Forecast Capital Additions:

The 2012 Fixed Asset Continuity Schedule, Table 2-17 provides a summary of the additions and disposals based on the OEB USoA classification. .

Table 2-17

2012 Fixed Asset Continuity Schedule

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2012

Adjusted for IFRS
Adjusted for Smart Meters

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	0	0	0	0	0	0	0	0	0
CEC	1806	Land Rights	0	0	0	0	0	0	0	0	0
47	1808	Buildings and Fixtures	0	0	0	0	0	0	0	0	0
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment - Normally Primai	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment - Normally Primary	503,618	8,000	0	511,618	333,696	15,500	0	349,196	162,422
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers and Fixtures	2,086,585	58,800	5,000	2,140,385	1,190,412	63,547	5,000	1,248,959	891,426
47	1835	Overhead Conductors and Devices	0	0	0	0	0	0	0	0	0
47	1840	Underground Conduit	0	0	0	0	0	0	0	0	0
47	1845	Underground Conductors and Devices	0	0	0	0	0	0	0	0	0
47	1850	Line Transformers	498,776	7,000	1,000	504,776	374,699	4,037	1,000	377,736	127,041
47	1855	Services	0	0	0	0	0	0	0	0	0
47	1860	Meters	601,784	0	0	601,784	108,417	29,006	0	137,423	464,361
N/A	1865	Other Installations on Customer's Premises	0	0	0	0	0	0	0	0	0
N/A	1905	Land	15,588	0	0	15,588	0	0	0	0	15,588
CEC	1906	Land Rights	0	0	0	0	0	0	0	0	0
47	1908	Buildings and Fixtures	685,382	8,500	0	693,882	286,699	24,729	0	311,428	382,454
13	1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture and Equipment	61,120	0	0	61,120	48,109	3,132	0	51,241	9,879
10	1920	Computer Equipment - Hardware	122,895	12,000	2,000	132,895	103,053	27,404	2,000	128,457	4,438
12	1925	Computer Software	178,186	8,000	1,000	185,186	178,187	2,000	1,000	179,187	5,999
10	1930	Transportation Equipment	762,757	0	0	762,757	465,502	22,822	0	488,324	274,433
8	1935	Stores Equipment	0	0	0	0	0	0	0	0	0
8	1940	Tools, Shop and Garage Equipment	90,260	16,500	0	106,760	70,624	5,279	0	75,903	30,857
8	1945	Measurement and Testing Equipment	0	0	0	0	0	0	0	0	0
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communication Equipment	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	0	0	0	0	0	0	0	0	0
47	1970	Load Management Controls - Customer Premises	0	0	0	0	0	0	0	0	0
47	1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equipment	0	0	0	0	0	0	0	0	0
47	1985	Sentinel Lighting Rentals	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
47	1995	Contributions and Grants	0	0	0	0	0	0	0	0	0
	2005	Property under Capital Lease	0	0	0	0	0	0	0	0	0
		Total before Work in Process	**5,606,951**	**118,800**	**9,000**	**5,716,751**	**3,159,398**	**197,456**	**9,000**	**3,347,854**	**2,368,897**
WIP		Work in Process	0			0	0			0	0
		Total after Work in Process	**5,606,951**	**118,800**	**9,000**	**5,716,751**	**3,159,398**	**197,456**	**9,000**	**3,347,854**	**2,368,897**

	1925	Transportation
	1930	Stores Equipment

Less: Fully Allocated Depreciation	
Transportation	
Communication	
Net Depreciation	197,456

The values highlighted in blue and green in Table 2-17 reflect adjustments to the 2012 continuity statements to account for modified IFRS (i.e. highlighted blue) and smart meters (i.e. highlighted green)

Table 2-18 provides the adjustments made to CGAAP depreciation to reflect modified IFRS under a useful life assumption of 45 years. Since Atikokan Hydro's capitalization policy was already aligned with modified IFRS the following adjustments to depreciation are the only changes Atikokan Hydro has made to reflect modified IFRS in this application.

Table 2-18

Adjustment in Depreciation from CGAAP to MIFRS

USoA	Description	CGAAP Value	Modified IFRS Adjustment for 45 Year Useful Life	MIFRS Value
1820	Distribution Station Equipment	$14,888	$612	$15,500
1830	Poles, Towers and Fixtures	$87,885	($24,338)	$63,547
1850	Line Transformers	$13,143	($9,106)	$4,037

Table 2-19 provides the adjustments made to the 2012 continuity statement to account for smart meters and stranded meters

Table 2-19

Adjustment for Smart Meters and Stranded Meters

USoA	Description	Value Before Adjustments	Smart Meter Adjustment	Stranded Meter Adjustment	Value in Continuity Statement
1860	Meters – Gross Assets	$307,776	$398,721	($104,713)	$601,784
1860	Meters – Accum. Deprec.	$124,752	$65,003	($81,338)	$108,417
1860	Meters – Depreciation	$16,220	$27,295	($14,509)	$29,006
1920	Computer Hardware – Gross Assets	$49,090	$73,805		$122,895
1920	Computer Hardware – Accum. Deprec.	$45,123	$57,930		$103,053
1920	Computer Hardware – Depreciation	$1,457	$25,947		$27,404

Additional information on the adjustments associated with smart meters and stranded meters are provided in Exhibit 9.

2012 Forecast Test Year Capital Projects

The following Table 2-20 provides Atikokan Hydro's forecast capital additions, by project, project type and USoA for 2012. There are no projects forecasted that will exceeded the materiality threshold of $50,000. With regards to HST for 2012 capital projects, all capital expenditures for 2012 are exclusive of PST.

Table 2-20

2012 Test Year Forecast Capital Projects

Year: 2012

USoA #	Description	CCA Class	Refurbishing tanks and painting	Feeder 5 Upgrade	Feeder 1 Continued	Transformer Changes	Drainage at Yard	Office Computers	Software updates	Shop Tools	Total
1820	Distribution Station Equipment -	47	$ 8,000								$ 8,000
1830	Poles, Towers and Fixtures	47		$ 38,000	$ 20,800						$ 58,800
1850	Line Transformers	47				$ 7,000					$ 7,000
1906	Buildings and Fixtures	47					$ 8,500				$ 8,500
1908	Computer Equipment - Hardware	47						$ 12,000			$ 12,000
1920	Computer Software	10							$ 8,000		$ 8,000
1940	Measurement and Testing	8								$ 16,500	$ 16,500
	Total		$ 8,000	$ 38,000	$ 20,800	$ 7,000	$ 8,500	$ 12,000	$ 8,000	$ 16,500	$ 118,800

Summary

Atikokan Hydro submits that its historical capital investment in its distribution system has primarily been in response to the needs of the Town of Atikokan and the investment in its existing distribution system has been required to improve the efficiency and reliability of its distribution system to ensure the safe and reliable supply of electricity that Atikokan Hydro's customer have come to expect.

Atikokan Hydro further submits that its forecasted capital investments for the 2011 Bridge Year and 2012 Test Year are consistent with the required investments of prior years and are prudent and just in supporting the Town of Atikokan and the continued safety and reliability of its distribution system.

Asset Management Plan Summary

Atikokan Hydro 's Asset Management Plan has been developed with due regard to the different Acts, Regulations, Codes and Guidelines and the continual updating of good utility practice to ensure the needs of the Town of Atikokan and Atikokan Hydro customers are met.

The Asset Management Plan will allow Atikokan Hydro to proceed in an orderly and efficient manner to ensure that older assets are either replaced or refurbished in a timely fashion. Due regard will be given to the results of annual inspections and analysis as well as such tools as the reliability indices.

Atikokan Hydro's six year capital budget maps out the capital expenditure plans for the next six years. A summary of the six year capital budget is outlined in Table 2-3 and is repeated here in Table 2-21 for convenience. The priority of plans has been arrived at by careful consideration to reports from annual inspections, third part testing [for oil in transformers] and available revenue for the larger fleet assets.

Table 2-21

Six Year Capital Budget

Asset Category	USofA	Budget 2012	Budget 2013	Budget 2014	Budget 2015	Budget 2016	Budget 2017
Transformer Station Equip >50 kV	1820	$8,000	$8,000	$35,000	$35,000	$1,000	$1,000
Poles, Towers & Fixtures	1830	$58,800	$55,000	$45,000	$30,000	$45,000	$85,000
O/H Conductors & Devices	1835	$0	$9,880	$6,000	$0	$6,000	$6,000
Line Transformers	1850	$7,000	$3,000	$3,000	$0	$0	$3,000
Services	1855	$0	$14,000	$0	$0	$0	$0
Meters	1860	$0	$2,500	$3,000	$0	$0	$2,500
Buildings and Fixtures	1908	$8,500	$4,000	$4,000	$1,000	$1,000	$1,000
Office Furniture and Equipment	1915	$0	$3,200	$1,000	$1,000	$1,000	$1,000
Computer Equipment - Hardware	1920	$12,000	$2,000	$2,000	$2,000	$2,000	$2,000
Computer Equipment - Software	1925	$8,000	$0	$1,000	$0	$0	$0
Fleet	1930	0	$0	$-	$50,000	$325,000	$0
Tools, Shop & Garage Eq	1940	$16,500	$5,000	$1,000	$1,000	$1,000	$1,000
Measure & Test Equip	1945	$0	$2,000	$2,000	$2,000	$2,000	$2,000
Miscellaneous Equipment	1960	$0	$2,000	$2,000	$2,000	$2,000	$2,000
Total		**$118,800**	**$110,580**	**$105,000**	**$124,000**	**$386,000**	**$106,500**

Green Energy Basic Plan Summary

Atikokan Hydro has created and submitted a “Basic Green Energy Act plan” [the plan] to the OPA in accordance with Board Decision 2009-0397. A copy of the plan is included as “Appendix B” as well as the letter from the OPA confirming OPA acceptance of the Basic Green Energy Act plan and both are attached at the end of this exhibit.

Atikokan Hydro remains committed to actively assisting the province in developing Green Energy in accordance with the Green Energy and Green Economy Act. Transmission restraints in the Northwest Region in general and the specific nuances of Moose Lake TS will prevent any immediate FIT programs from proceeding. LDC restrictions outlined in the plan will limit installations within Atikokan Hydro’s service area to micro fit installations.

Given the above conditions, Atikokan Hydro will not be seeking and cost recovery related to the plan.

.Working Capital Calculations

Atikokan Hydro's working capital allowance is forecast to be $ 505,561 for the 2012 Test Year. Atikokan Hydro has not undertaken a Working Capital lead-lag study and as such has calculated its working capital allowance using the 15% Allowance Approach in accordance with page 19 of the OEB's Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, dated June 22, 2011. Atikokan Hydro submits that its working capital calculations are not only consistent with the Filing Guidelines but are also consistent with OEB Decisions in distributors' cost of service applications approved in 2009, 2010 and 2011, where a utility specific lead-lag study had not been undertaken. The working capital allowance is based on Atikokan Hydro's proposed 2012 Test Year controllable expenses and cost of power. Atikokan Hydro has provided the calculations by the OEB's USoA classification for each of 2008 Actual to 2010 Actual, the 2011 Bridge Year and the 2012 Test Year in Table 2.22 below. The 2012 Test Year Cost of Power calculations are provided in Table 2-23 below.

The following Table 2-22 sets out Atikokan Hydro's year over year working capital variances for the 2008 OEB Approved, 2008 to 2010 Actuals, 2011 Bridge Year and 2012 Test Year. The detailed the variances in the OM&A accounts are discussed in further detail in Exhibit 4.

Table 2-22
Detailed Working Capital Calculations

Detailed, Account by Account, OM&A Expense Table

Account	Description	2008 Actual	Allowance for Working Capital	2009 Actual	Allowance for Working Capital	2010 Actual	Allowance for Working Capital	2011Bridge Year	Allowance for Working Capital	2012 Test Year	Allowance for Working Capital
	Rate used for Working Capital Allowance		15%		15%		15%		15%		15%
	Operations										
5005	Operation Supervision and Engineering										
5010	Load Dispatching										
5012	Station Buildings and Fixtures Expense										
5014	Transformer Station Equipment - Operation Labour										
5015	Transformer Station Equipment - Operation Supplies and Expenses										
5016	Distribution Station Equipment - Operation Labour	15,455.35	2,318.30	3,989.16	598.37	0	-	$ 1,060	159.00	$ 1,087	162.98
5017	Distribution Station Equipment - Operation Supplie	$ 1,873	280.99	$ 470	70.54	$ -	-	$ 200	30.00	$ 205	30.75
5020	Overhead Distribution Lines and Feeders - Operati	$ 221,989	33,298.29	$ 229,359	34,403.88	$ 261,114	39,167.08	$ 229,359	34,403.88	$ 265,093	39,763.98
5025	Overhead Distribution Lines and Feeders - Operati	$ 42,189	6,328.38	$ 57,381	8,607.15	$ 27,341	4,101.12	$ 41,868	6,280.22	$ 42,915	6,437.22
5030	Overhead Sub-transmission Feeders - Operation	$ 9,898	1,484.68	$ 30,272	4,540.87	$ 42,657	6,398.53	$ 1,440	216.00	$ 1,476	221.40
5035	Overhead Distribution Transformers - Operation	$ 3,941	591.22	$ 65	9.76	$ -	-	$ -	-	$ -	-
5040	Underground Distribution Lines and Feeders - Ope	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-
5045	Underground Distribution Lines and Feeders - Ope	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-
5050	Underground Sub-transmission Feeders - Operatio	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-
5055	Underground Distribution Transformers - Operation	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-
5060	Street Lighting and Signal System Expense	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-
5065	Meter Expense	$ 159	23.81	$ 21	3.10	$ 1,000	149.94	$ -	-	$ 107,573	16,136.02
5070	Customer Premises - Operation Labour	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-
5075	Customer Premises - Operation Materials and Exp	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-
5085	Miscellaneous Distribution Expenses	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-
5090	Underground Distribution Lines and Feeders - Ren	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-
5095	Overhead Distribution Lines and Feeders - Rental	$ 617	92.51	$ 448	67.20	$ -	-	$ -	-	$ -	-
5096	Other Rent		-		-		-	$ -	-	$ -	-
	Operations - Sub Total	$ 296,121	$ 44,418	$ 322,006	$ 48,301	$ 332,111	$ 49,817	$ 273,927	$ 41,089	$ 418,349	$ 62,752
	Maintenance				-		-		-		
5105	Maintenance Supervision and Engineering	$ -	-		-		-	$ -	-	$ -	-
5110	Maintenance of Buildings and Fixtures - Distributio	$ -	-		-		-	$ -	-	$ -	-
5112	Maintenance of Transformer Station Equipment	$ -	-		-		-	$ -	-	$ -	-
5114	Maintenance of Distribution Station Equipment	$ 3,804	570.61	$ 1,072	160.77	$ 585	87.73	$ 585	87.73	$ 599	89.92
5120	Maintenance of Poles, Towers and Fixtures	$ -	-		-		-	$ -	-	$ -	-
5125	Maintenance of Overhead Conductors and Devices	$ 748	112.13	$ 1,416	212.34	$ 20,406	3,060.90	$ 5,763	864.47	$ 5,907	886.08
5130	Maintenance of Overhead Services	$ 9,784	1,467.58		-	$ 222	33.29	$ 187	27.98	$ 191	28.68
5135	Overhead Distribution Lines and Feeders - Right of	$ 51,058	7,658.68	$ 27,718	4,157.64	$ 29,522	4,428.30	$ 41,628	6,244.22	$ 42,669	6,400.32
5145	Maintenance of Underground Conduit	$ -	-		-		-	$ -	-	$ -	-
5150	Maintenance of Underground Conductors and Devi	$ -	-		-		-	$ -	-	$ -	-
5155	Maintenance of Underground Services	$ -	-		-		-	$ -	-	$ -	-
5160	Maintenance of Line Transformers	$ 19,523	2,928.50	$ 27	4.02	$ 250	37.50	$ 12,361	1,854.15	$ 1,814	272.10
5165	Maintenance of Street Lighting and Signal Systems	$ -	-		-		-	$ -	-	$ -	-
5170	Sentinel Lights - Labour	$ -	-		-		-	$ -	-	$ -	-
5172	Sentinel Lights - Materials and Expenses	$ -	-		-		-	$ -	-	$ -	-
5175	Maintenance of Meters	$ 3,899	584.89	$ 730	109.48	$ 680	102.02	$ 1,947	292.10	$ 1,996	299.40
5178	Customer Installations Expenses - Leased Property	$ -	-		-		-	$ -	-	$ -	-
5195	Maintenance of Other Installations on Customer Pr	$ -	-	$ 10,966	1,644.90		-	$ -		$ -	-
	Maintenance - Sub Total	$ 88,816	$ 13,322	$ 41,928	$ 6,289	$ 51,665	$ 7,750	$ 62,471	$ 9,371	$ 53,177	$ 7,977

Detailed Working Capital Calculations (continued)

Account	Description	2008 Actual	Allowance for Working Capital	2009 Actual	Allowance for Working Capital	2010 Actual	Allowance for Working Capital	2011 Bridge Year	Allowance for Working Capital	2012 Test Year	Allowance for Working Capital
	Rate used for Working Capital Allowance		15%		15%		15%		15%		15%
	Billing and Collecting										
5305	Supervision	$ 4,043	606.38	$ 3,139	470.81	$ 7,700	1,155.06	$ 2,660	399.00	$ 2,727	408.98
5310	Meter Reading Expense	$ 45,772	6,865.79	$ 51,303	7,695.52	$ 32,118	4,817.64	$ 44,819	6,722.83	$ 45,939	6,890.90
5315	Customer Billing	$ 110,711	16,606.66	$ 97,640	14,646.02	$ 87,381	13,107.16	$ 94,693	14,203.90	$ 97,060	14,559.00
5320	Collecting	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-
5325	Collecting - Cash Over and Short	$ 50	7.50	$ 311	46.65	-$ 338	- 50.64	$ -	-	$ -	-
5330	Collection Charges	-$ 5,200	- 780.00	-$ 1,300	- 195.00	$ -	-	$ -	-	$ -	-
5335	Bad Debt Expense	$ 6,355	953.32	$ 5,655	848.19	$ 3,924	588.64	$ 5,311	796.72	$ 5,444	816.63
5340	Miscellaneous Customer Accounts Expenses	$ 7,250	1,087.50	$ 3,013	451.88	$ -	-	$ 2,000	300.00	$ 2,000	300.00
	Billing and Collecting -Sub Total	$ 168,981	$ 25,347	$ 159,760	$ 23,964	$ 130,786	$ 19,618	$ 149,483	$ 22,422	$ 153,170	$ 22,976
Community Relations											
5405	Supervision	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-
5410	Community Relations - Sundry	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-
5415	Energy Conservation	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-
5420	Community Safety Program	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-
5425	Miscellaneous Customer Service and Informationa	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-
5505	Supervision	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-
5510	Demonstrating and Selling Expense	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-
5515	Advertising Expenses	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-
5520	Miscellaneous Sales Expense	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-
	Community Relations -Sub Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Administrative and General Expenses										
5605	Executive Salaries and Expenses	$ 6,000	900.00	$ 6,000	900.00	$ 6,000	900.00	$ 6,000	900.00	$ 6,000	900.00
5610	Management Salaries and Expenses	$ 11,639	1,745.88	$ 105,204	15,780.60	$ 116,180	17,426.98	$ 119,084	17,862.66	$ 122,061	18,309.22
5615	General Administrative Salaries and Expenses	$ 17,205	2,580.82	$ 48,937	7,340.49	$ 124,407	18,661.11	$ 127,518	19,127.64	$ 130,706	19,605.83
5620	Office Supplies and Expenses	$ 6,244	936.57	$ 8,450	1,267.50	$ 7,416	1,112.39	$ 7,954	1,193.14	$ 8,153	1,222.97
5625	Administrative Expense Transferred - Credit	$ -	-		-	$ -	-	$ -	-	$ -	-
5630	Outside Services Employed	$ 153,350	23,002.43	$ 85,873	12,881.02	$ 135,076	20,261.43	$ 124,766	18,714.96	$ 127,886	19,182.84
5635	Property Insurance	$ 7,271	1,090.63	$ 8,379	1,256.88	$ 8,604	1,290.53	$ 8,894	1,334.10	$ 9,116	1,367.45
5640	Injuries and Damages	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-
5645	Employee Pensions and Benefits	$ -	-	$ 1,460	219.00	$ -	-	$ -	-	$ -	-
5650	Franchise Requirements	$ -	-		-	$ -	-	$ -	-	$ -	-
5655	Regulatory Expenses	$ 11,522	1,728.33	$ 5,142	771.25	$ 13,149	1,972.34	$ 10,307	1,545.99	$ 60,564	9,084.64
5660	General Advertising Expenses	$ 617	92.51	$ 977	146.50	$ 1,649	247.39	$ 1,200	180.00	$ 1,230	184.50
5665	Miscellaneous General Expenses	$ 41,225	6,183.68	$ 44,060	6,608.94	$ 35,845	5,376.72	$ 40,376	6,056.44	$ 41,386	6,207.86
5670	Rent	$ -	-		-		-	$ -	-	$ -	-
5675	Maintenance of General Plant	$ 36,034	5,405.09	$ 41,646	6,246.84	$ 35,905	5,385.72	$ 40,264	6,039.65	$ 41,271	6,190.64
5680	Electrical Safety Authority Fees	$ -	-	$ 1,862	279.35	$ 1,920	288.05	$ 2,031	304.72	$ 2,082	312.34
5685	Independent Electricity System Operator Fees and	$ -	-		-		-	$ -	-	$ -	-
5695	OM&A Contra Account	$ -	-		-		-	$ -	-	$ -	-
6205	Donations (Charitable Contributions)		-		-		-		-		-
	Administrative and General Expenses - Sub To	$ 291,106	$ 43,666	$ 357,989	$ 53,698	$ 486,151	$ 72,923	$ 488,395	$ 73,259	$ 550,455	$ 82,568
Total OM&A		$ 845,024	$ 126,754	$ 881,683	$ 132,252	$ 1,000,713	$ 150,107	$ 974,277	$ 146,141	$ 1,175,151	$ 176,273

Description		2008 Actual	Allowance for Working Capital	2009 Actual	Allowance for Working Capital	2010 Actual	Allowance for Working Capital	2011 Bridge Year	Allowance for Working Capital	2012 Test Year	Allowance for Working Capital
	Rate Used for Working Capital Allowance		**15%**		**15%**		**15%**		**15%**		**15%**
	Cost of Power										
4705	Power Purchased	1,460,469	219,070	1,478,562	221,784	1,562,937	234,441	1,804,516	270,677	1,813,905	272,086
4708	WMS	150,160	22,524	156,758	23,514	144,832	21,725	164,896	24,734	164,734	24,710
4710	Cost of Power Adjustments	-		-	-	-	-	-	-	-	-
4712	Charges One Time	-		-	-	-	-	-	-	-	-
4714	NW	101,545	15,232	113,805	17,071	126,466	18,970	143,066	21,460	134,756	20,213
4715	System Control and Load Dispatching	-	-	-	-	-	-	-	-	-	-
4716	NCN	78,630	11,794	75,087	11,263	78,905	11,836	86,151	12,923	81,862	12,279
4720	Other Expenses	-	-	-	-	-	-	-	-	-	-
4725	Competition Transition Expense	-	-	-	-	-	-	-	-	-	-
4730	Rural Rate Assistance Expense	-	-	-	-	-	-	-	-	-	-
4750	LV Charges	-	-	-	-	-	-		-	-	-
	Total Cost of Power	**1,790,804**	**268,621**	**1,824,212**	**273,632**	**1,913,140**	**286,971**	**2,198,629**	**329,794**	**2,195,257**	**329,289**
	Working Capital Allowance Total	**2,635,828**	**395,374**	**2,705,895**	**405,884**	**2,913,853**	**437,078**	**3,172,906**	**475,936**	**3,370,408**	**505,561**

Cost of Power

Atikokan Hydro has calculated cost of power for the 2011 Bridge year and 2012 Test Year based on the results of the load forecast which is discussed in detail in Exhibit 3 below. The electricity prices used in the calculation were the published prices in the OEB's Regulated Price Plan Price Report – May 1, 2011 to April 30, 2012, issued April 19, 2011. Atikokan Hydro will update the electricity prices should the OEB publish a revised Regulated Price Plan Report prior to a Decision.

The cost of power calculations for the 2011 Bridge Year and a cost of power summary are provided in the following Table 2-23 and Table 2-24 respectively. The cost of power calculations for the 2012 Test Year and a cost of power summary are provided in the following Table 2-25 and Table 2-26 respectively.

Table 2-23

2011 Bridge Year Cost of Power Forecast Calculation

2011 Load Foreacst	kWh	kW	2010 %RPP
Residential	10,274,885		90%
General Service < 50 kW	5,089,171		96%
General Service 50 to 4,999 kW	7,131,769	18,958	0%
General Service 50 to 4,999 kW Interval	620,154	1,648	0%
Street Lighting	476,215	1,344	0%
TOTAL	**23,592,195**	**21,950**	

Electricity - Commodity RPP	2011	2011 Loss			
Class per Load Forecast RPP	**Forecasted**	**Factor**		**2011**	
Residential	9,247,397	1.0753	9,943,726	$0.07298	$725,693
General Service < 50 kW	4,885,604	1.0753	5,253,490	$0.07298	$383,400
General Service 50 to 4,999 kW	0	1.0753	0	$0.07298	$0
General Service 50 to 4,999 kW Interval	0	1.0753	0	$0.07298	$0
Street Lighting	0	1.0753	0	$0.07298	$0
TOTAL	**14,133,001**		**15,197,216**		**$1,109,093**

Electricity - Commodity Non-RPP	2011	2011 Loss			
Class per Load Forecast	**Forecasted**	**Factor**		**2011**	
Residential	1,027,489	1.0753	1,104,858	$0.06837	$75,539
General Service < 50 kW	203,567	1.0753	218,895	$0.06837	$14,966
General Service 50 to 4,999 kW	7,131,769	1.0753	7,668,792	$0.06837	$524,315
General Service 50 to 4,999 kW Interval	620,154	1.0753	666,851	$0.06837	$45,593
Street Lighting	476,215	1.0753	512,075	$0.06837	$35,011
TOTAL	**9,459,194**		**10,171,471**		**$695,424**

Transmission - Network		Volume			
Class per Load Forecast		**Metric**		**2011**	
Residential		kWh	11,048,584	$0.0060	$66,292
General Service < 50 kW		kWh	5,472,386	$0.0054	$29,551
General Service 50 to 4,999 kW		kW	18,958	$2.1742	$41,218
General Service 50 to 4,999 kW Interval		kW	1,648	$2.3066	$3,802
Street Lighting		kW	1,344	$1.6399	$2,203
TOTAL					**$143,066**

Transmission - Connection		Volume			
Class per Load Forecast		**Metric**		**2011**	
Residential		kWh	11,048,584	$0.0037	$40,880
General Service < 50 kW		kWh	5,472,386	$0.0032	$17,512
General Service 50 to 4,999 kW		kW	18,958	$1.2723	$24,120
General Service 50 to 4,999 kW Interval		kW	1,648	$1.4062	$2,318
Street Lighting		kW	1,344	$0.9834	$1,321
TOTAL					**$86,151**

Wholesale Market Service					
Class per Load Forecast				**2011**	
Residential			11,048,584	$0.0052	$57,453
General Service < 50 kW			5,472,386	$0.0052	$28,456
General Service 50 to 4,999 kW			7,668,792	$0.0052	$39,878
General Service 50 to 4,999 kW Interval			666,851	$0.0052	$3,468
Street Lighting			512,075	$0.0052	$2,663
TOTAL			**25,368,687**		**$131,917**

Rural Rate Assistance					
Class per Load Forecast				**2011**	
Residential			11,048,584	$0.0013	$14,363
General Service < 50 kW			5,472,386	$0.0013	$7,114
General Service 50 to 4,999 kW			7,668,792	$0.0013	$9,969
General Service 50 to 4,999 kW Interval			666,851	$0.0013	$867
Street Lighting			512,075	$0.0013	$666
TOTAL			**25,368,687**		**$32,979**

Table 2-24

2011 Bridge Year Cost of Power Summary

Cost of Power Account	2011
4705-Power Purchased	$1,804,516
4708-Charges-WMS	$131,917
4714-Charges-NW	$143,066
4716-Charges-CN	$86,151
4730-Rural Rate Assistance	$32,979
4750-Low Voltage	
TOTAL	**2,198,629**

Table 2-25

2012 Test Year Cost of Power Forecast Calculation

2012 Load Foreacst	kWh	kW	2010 %RPP
Residential	11,395,913		90%
General Service < 50 kW	6,387,021		96%
General Service 50 to 4,999 kW	4,916,203	13,068	0%
General Service 50 to 4,999 kW Interval	427,496	1,136	0%
Street Lighting	466,493	1,316	0%
TOTAL	**23,593,125**	**15,521**	

Electricity - Commodity RPP	2012	2012 Loss			
Class per Load Forecast RPP	**Forecasted**	**Factor**		**2012**	
Residential	10,256,322	1.0742	11,017,341	$0.07298	$804,046
General Service < 50 kW	6,131,540	1.0742	6,586,500	$0.07298	$480,683
General Service 50 to 4,999 kW	0	1.0742	0	$0.07298	$0
General Service 50 to 4,999 kW Interval	0	1.0742	0	$0.07298	$0
Street Lighting	0	1.0742	0	$0.07298	$0
TOTAL	**16,387,862**		**17,603,841**		**$1,284,728**

Electricity - Commodity Non-RPP	2012	2012 Loss			
Class per Load Forecast	**Forecasted**	**Factor**		**2012**	
Residential	1,139,591	1.0742	1,224,149	$0.06837	$83,695
General Service < 50 kW	255,481	1.0742	274,438	$0.06837	$18,763
General Service 50 to 4,999 kW	4,916,203	1.0742	5,280,985	$0.06837	$361,061
General Service 50 to 4,999 kW Interval	427,496	1.0742	459,216	$0.06837	$31,397
Street Lighting	466,493	1.0742	501,107	$0.06837	$34,261
TOTAL	**7,205,263**		**7,739,894**		**$529,177**

Transmission - Network		Volume			
Class per Load Forecast		**Metric**		**2012**	
Residential		kWh	12,241,490	$0.0056	$68,552
General Service < 50 kW		kWh	6,860,938	$0.0051	$34,991
General Service 50 to 4,999 kW		kW	13,068	$2.0445	$26,718
General Service 50 to 4,999 kW Interval		kW	1,136	$2.1690	$2,465
Street Lighting		kW	1,316	$1.5421	$2,030
TOTAL					**$134,756**

Transmission - Connection		Volume			
Class per Load Forecast		**Metric**		**2012**	
Residential		kWh	12,241,490	$0.0035	$42,845
General Service < 50 kW		kWh	6,860,938	$0.0030	$20,583
General Service 50 to 4,999 kW		kW	13,068	$1.2016	$15,703
General Service 50 to 4,999 kW Interval		kW	1,136	$1.3281	$1,509
Street Lighting		kW	1,316	$0.9288	$1,222
TOTAL					**$81,862**

Wholesale Market Service					
Class per Load Forecast				**2012**	
Residential			12,241,490	$0.0052	$63,656
General Service < 50 kW			6,860,938	$0.0052	$35,677
General Service 50 to 4,999 kW			5,280,985	$0.0052	$27,461
General Service 50 to 4,999 kW Interval			459,216	$0.0052	$2,388
Street Lighting			501,107	$0.0052	$2,606
TOTAL			**25,343,735**		**$131,787**

Rural Rate Assistance					
Class per Load Forecast				**2012**	
Residential			12,241,490	$0.0013	$15,914
General Service < 50 kW			6,860,938	$0.0013	$8,919
General Service 50 to 4,999 kW			5,280,985	$0.0013	$6,865
General Service 50 to 4,999 kW Interval			459,216	$0.0013	$597
Street Lighting			501,107	$0.0013	$651
TOTAL			**25,343,735**		**$32,947**

Table 2-26

2012 Test Year Cost of Power Summary

Cost of Power Account	2012
4705-Power Purchased	$1,813,905
4708-Charges-WMS	$131,787
4714-Charges-NW	$134,756
4716-Charges-CN	$81,862
4730-Rural Rate Assistance	$32,947
4750-Low Voltage	
TOTAL	**2,195,257**

ATIKOKAN HYDRO INC.

ASSET MANAGEMENT PLAN

2012 to 2017

Atikokan Hydro Electric Corporation Ltd. Asset Management Plan

Atikokan Hydro Overview

Atikokan Hydro Inc. [Atikokan Hydro] was originally established in 1956 as the Hydro Electric Commission of the Township of Atikokan. Atikokan Hydro Inc was incorporated in 2000 under the Ontario Business Corporations Act, as mandated by The Electricity Act, 1998. The Town of Atikokan owns 100% of the shares of Atikokan Hydro. All assets and liabilities associated with the former Hydro Electric Commission of the Township of Atikokan were transferred to Atikokan Hydro. Atikokan Hydro operates under the direction of a three member Board of Directors that are appointed by Atikokan Town Council. Atikokan Hydro is regulated by the Ontario Energy Board (OEB) in accordance to codes and regulations and operates under the Distribution Licence ED-2003-0001.

Atikokan Hydro serves over 1690 residential and business customers in the Town of Atikokan. Electricity is transmitted from Hydro One's Moose Lake TS to Atikokan Hydro's substations via Atikokan Hydro's two 44 KV circuits . Atikokan Hydro has three substations in the most densely populated customer area that distributes the electricity at 8320/4800 volts. Atikokan Hydro has one substation in a sparsely populated area that delivers electricity at 4160 volts. Atikokan Hydro's distribution system then delivers electricity at the appropriate voltage to residential and commercial customers. Atikokan Hydro has converted most of its Delta services to Wye, and only offers Wye connections to new three phase installations.

Similar to all communities in Northwestern Ontario, the Assessment Corporation shows a decline in population for Atikokan from 3,632 in 2001 to 3,293 in 2006. The demise of the Forestry Industry in Ontario was amplified by the closure of the Atikokan Forest Products sawmill and Firbratech, a particle board plant.

Atikokan Population Comparison table[1]

	Atikokan	Ontario
Population in 2006	3,293	12,160,282
Population in 2001	3,632	11,410,046
2001 to 2006 population change	-9.3 %	6.6 %
Total private dwellings	1,535	4,972,869
Private houses/condos occupied by usual residents	1,418	4,554,251
Population density per square kilometre	10.4	13.4
Land area	316.74 km^2	907,573.82 km^2

[1] http://www.city-data.com/canada/Atikokan-Township.html

MPAC has published the Town of Atikokan's population to be 2845 in 2010. The table above shows a 15% growth disparity when compared to the province.

Corporate Mission and Values

Mission Statement

Atikokan Hydro is committed to:

- efficiently deliver a reliable supply of electrical energy to our customers at competitive distribution rates in the Town of Atikokan
- provide a safe and rewarding work environment for our employees
- assure that future supply is available to meet Atikokan's changing needs
- be a good corporate citizen within the Town of Atikokan

Corporate Values

In pursuit of our goals, Atikokan Hydro holds certain core values in the operation of the utility and as it relates to its customer, staff and shareholder.

Atikokan Hydro values its employees, customers, partners, and our community. We provide our employees with a safe, healthy environment with fair remuneration and opportunities for learning.

We value our customers and work hard to win their trust and support. We strive for excellence and continuous improvement in all aspects of our business. At all times we will act with integrity and respect. We value the long term health and sustainability of Atikokan Hydro and work to create value for our shareholder by focusing on core business strengths and pursuing appropriate business opportunities.

Asset Management Overview

Atikokan Hydro has not had a formal asset management plan but has been working towards completing a plan. Our accounting system for our major assets will be moving from Canadian Generally Accepted Accounting Practices [CGAAP] to the International Financial Reporting System [IFRS] as of January 1, 2012. Atikokan Hydro has taken the opportunity to do a detailed analysis of its major assets including value, age and amortization policy as part of the conversion from CGAAP to IFRS. The firm of LLP BDO was hired to assist with the conversion process. Atikokan Hydro staff members did a complete inspection and tabulation of all poles, conductors, substations and associated equipment. The resultant information will assist in the execution of an Asset Management Plan.

This information, combined with infrastructure inspections that exceed the Distribution System Code [DSC], and expected asset life will allow long term plans and budgets to be prepared to ensure that the Town of Atikokan is provided with safe, reliable and affordable electricity.

Atikokan Hydro has established a comprehensive system of inspection and performance reporting procedures to provide for continuous assessments of its distribution business and to achieve consistency with its corporate mission and value statements. These procedures present information to satisfy the reporting requirements of the Ontario Energy Board's (OEB) Distribution System Code (DSC). Atikokan Hydro is also developing reporting mechanisms that go beyond these regulatory obligations and are focused on continuous performance improvements to ensure the availability of long term capacity to meet the needs of the community, all of which contribute to effective and successful management of the distribution system assets.

Atikokan Hydro regards asset management as the foundation for the performance of its distribution system. Senior management is committed to the process and ensures that sufficient resources are allocated to implement the plan. This requires an upfront investment in personnel, internal and outsourced, to set up the plan and the long term resources to complete the annual planning, inspecting, reporting and implementation activities. The quality and consistency of the reporting data is paramount to a successful plan. Because of the small size of Atikokan Hydro, the responsibility for the continuous management of the plan is assigned to senior management to act in the role of Asset Manager. The duties of the group are parsed out based on individual skill sets. Senior Management's responsibilities primarily involve risk management (Section 5 below), i.e. ensuring that:

- The inspection process is organized with assets identified in reasonable zones and segments.
- Inspections and follow up maintenance is continuously being effectively organized and performed
- Records are accurate and current
- Condition analysis is completed correctly
- Risk ratings are developed and recommendations from the Annual System Performance Report are captured
- The condition of the system is reviewed for the short, medium and long term periods to ensure that maintaining and enhancing the reliability of the system are achieved in the safest and most cost effective manner.

The inspection process is organized with assets identified in reasonable areas and classes. Atikokan Hydro has two 44 KV feeders and 6 Distribution voltage feeders. Inspections and follow up maintenance is continuously being effectively organized and performed. While the DSC requires inspections of distribution assets once every 3 years, Atikokan Hydro actually inspects its feeders annually. Items of concern are divided into three categories, 1 [immediate Action] 2 [within the next budget year] and 3 [to be considered with major rebuilds]. The condition of the asset drives the budget process to a certain extent. Major rebuilds may also capture future category 2 items.

Asset Management Consideration and Priorities

To provide consistency with its corporate mission and values Atikokan Hydro has to manage its assets while recognizing realistic performance goals. Customer expectations for the delivery of safe, reliable electricity at a reasonable price have to be respected. The following considerations are critical to the plan:

- The plan should create opportunities for improved efficiencies
- The activities should demonstrate good stewardship in the long term up-keep of the distribution system
- Service delivery should be safe, fair and consistent within all customer groups
- The performance measures should demonstrate progress towards or achievement of the goals within reasonable budget considerations
- Maintenance plans should be consistent with good utility practice but capture specific items from the annual assessments and performance report
- Capital investment plans should justify proposed expenditures and be flexible to respond to new priorities and extended life expectancies
- Annual reviews of the plan and asset management processes
- The asset management plan should compliment all those activities consistent with the Green Energy Act.

Risk Management

Risk management is a fundamental activity in any business and in the electrical distribution industry it requires a systematic approach to assess the following attributes of each asset:

- Condition
- Risk exposure
- Age and life expectancy
- Location
- Operational data, and
- Maintenance

Atikokan Hydro is developing a detailed process to consistently record and track the attributes of its major system assets. The baseline for the condition of these assets was addressed in a comprehensive 2011 assessment of all components in the summary categories of Overhead Lines [Poles and Conductors], Underground Lines [minimal] and Substations. The data from these assessments will be used to complete condition analyses, and to take into account the performance considerations and age. This forms the basis for maintenance and capital investment recommendations. The continuous collection and upkeep of this data capitalizes on the inspection activities required by the DSC plus the maintenance activities of field crews and specialized contractors. This upkeep, plus the results of any capital improvements, is critical to maintaining accurate and current records of the assets. The framework for the assessments and the performance of the distribution system are contained within.

Condition Assessment and Analysis

The DSC clearly reinforces the principles of good utility practice and identifies a systematic approach to distribution system inspection and maintenance. Atikokan Hydro has enhanced these requirements to generate complete Condition Assessments for all of its key facilities. This Condition Assessment process provides for regular monitoring of these facilities and a balance to the performance measures of the distribution system.

For ease of administration Atikokan Hydro has divided the assets into 6 feeders within the Town based on the feeders that distribute power and two feeders for the 44 KV circuits. Five of the feeders are identified by the map in **Appendix A**, and the two 44 KV feeders are identified in **Appendix B.**

We continue to construct a solid assessment of the distribution system conditions from the baseline data and the upkeep of this data becomes critical as concern reports are addressed either by maintenance activities or capital investments.

The annual overhead and Distribution Inspection forms (**Appendix C)** are prepared for each feeder. The results of each feeder are identified with the appropriate response as required. If action is taken, the Daily Work Form and any related forms are utilized **[Appendix D]** Once the project is competed, it is issued a certificate of Inspection **[Appendix E]**

.Any items of concern are defined and documented ***and*** categorized as follows:

1. Immediate Action
2. Within the next budget year and
3. To be considered with major rebuilds

All feeders are inspected annually. Since Atikokan Hydro has few underground assets, these assets are grouped within the assigned feeder inspection periods.

The completed Inspection Forms are the foundation for the following years work requirements and represent the current year's baseline data. For example, the recently completed inspection forms this year set the work requirements for next year, 2012 if it immediate action is not needed.

Atikokan Hydro owns and maintains four substations. Three substations are in the most densely populated area of the Town of Atikokan, and one is in a more remote sparsely populated area of the Town of Atikokan. Even though the feeders can be paralleled to supply load should one of the substations need to be out of service, it is of utmost importance that the stations are inspected monthly (**Appendix F)**

This data is collected and maintained using existing hard copy forms. Senior Management reviews the assessments to identify any issues requiring immediate attention or consideration within the budget recommendations.

The Minimum Inspection Requirements of the DSC are addressed and reported annually. Senior Management will ensure that these inspection cycles are coordinated with the condition assessments to minimize duplication of effort and maximize the efficiency of the process. They will also ensure that any changes to the condition of the components, due to inspection, maintenance or capital investments are updated within the database to ensure the records are kept current. Periodic audits of condition assessments will be made to ensure that consistent, accurate records are maintained.

Performance Considerations and Initiatives

Atikokan Hydro does not have a Supervisory Control And Data Acquisition [SCADA] system or breakers. Atikokan Hydro developed high level overviews of all the significant attributes of Atikokan Hydro's distribution system and the practices that contribute to its performance and reliability. We continually review system performance with standard indices, compare the performance with trouble reports and inspection reports, and use the information for recommendations on future expenditures.

The standard reliability indices (SAIDA, CAIDI, and SAIFI) and the recommendations on maintenance and capital expenditures are based on the performance of the individual feeders. These performance considerations have to be rationalized with the results of the condition assessment and the potential for Smart Grid/New Technology applications to arrive at maintenance and capital budget recommendations that represent the best value to Atikokan Hydro and its customers. The recommendations also have to reflect the potential timeframes resulting from the condition assessment and require experienced judgment. Senior Management will consult with the appropriate personnel to arrive at consensus for these recommendations. The evaluation and data base created in preparation for the conversion to IFRS, especially the componentization results, is also a valuable tool in assessing future capital expenditures. Results from the monthly inspections are used to ensure this valuable tool is kept up to date.

- **System Performance Review**

Atikokan Hydro is implementing an annual System Performance Review. This review will provide an annual critique of the previous year's performance and provides constructive direction on the up-coming priorities for maintenance and capital investments with a strong emphasis on reliability performance improvements. The following specific attributes will be reviewed and addressed within the Annual System Performance Report:

1. Substation and feeder performance at 8320/4800V primary voltage levels
2. System maintenance activities and priorities
3. Reliability statistics and observations
4. Future maintenance recommendations
5. Future capital budget recommendations

Atikokan Hydro operates a distribution system comprising high voltage networks at 8320/4800V. Outage data is collected and reviewed in a very basic format through trouble reports and time sheets. This data will be reviewed continuously and analyzed with attention given to the causes of feeder failures and loadings. Any patterns of system failures will continue to be analyzed e.g. tree or animal contacts, underground cable failures. This performance analysis contributes to the prioritization of the maintenance activities and capital budgets projects.

Atikokan Hydro's annual System Performance Report will provide detailed information on the performance of its substation and distribution feeders at all primary voltage levels. It will analyze the worst performing feeders and provides commentary and recommendations for improvements.

Substation capacities and loadings will be reviewed to identify any weaknesses in the system capabilities for station and feeder back-ups. Maintenance activities and priorities are also to be reviewed, in detail, to confirm consistency with the budgetary plans and identify issues requiring renewed or accelerated attention. Reliability statistics (SAIDI, SAIFI, and CAIDI,) will be tracked and provide a perspective on the longer term trends for the performance of the distribution system.

Innovation and New Technology

Frequency and duration of outages has been inconsistent in the past for various reasons generally attributed to storms. The SAIDI indicator has shown improvement. This is due to the nature of the mainly urban design of the distribution system with inherent back-up feeders in place. Any long duration outages are likely to result from circumstances beyond the control of Atikokan Hydro, for example loss of supply from Hydro One, extreme weather, or natural disaster.

Atikokan Hydro places a high priority on continuous improvements and the application of new technology within its distribution system. We hope to use the smart meter data, once fully functional, in conjunction with our Operational Data Store and CIS system to consider aspects of transformer and feeder loading. This information will provide much better data for use in protection schemes which will reduce the frequency and duration of outages. It is expected to also contribute to recommendations for additional loop feeds and new remote switching capabilities if demonstrated value for cost is appropriate.

Maintenance Plans

Atikokan Hydro performs annual and biannual maintenance that is consistent with good utility practices and is prepared annually to deliver safe, reliable service, in the most cost effective manner. Routine activities occurring annually are forecasted with the help of historical data and expected internal labour costs. Non routine items provided by 3rd party vendors are estimated based on proposals or quotations. Non routine items undergo a rigorous review for determining value for cost, including items that are of a code or compliance nature.

The following items are included within this plan:

- **Wood Pole Replacement**

  The condition assessment provides the basis for testing of wood poles. The condition of poles continues to be completed on a yearly rotation as required in the DSC. Maintenance of anchors and other hazards are identified and assessed for repair or replacement at this time.

- **Substation Oil Quality Monitoring**

  Oil Samples for substations are analyzed every 3 years. This will assist Atikokan Hydro in having oil treated or replaced to extend the lives of our substations.

- **Tree Trimming**

  The annual DSC inspections identify areas of concern for the tree trim program. The program generally consists of three seasons. Urban areas are maintained spring and fall and the inaccessible areas such as the rugged terrain of Atikokan Hydro's 44 KV circuits are maintained during winter road conditions, generally January and February. Customer concerns are dealt with in a timely manner and either scheduled for the seasonal maintenance or immediate action if required. Chemical control is utilized where necessary.

Capital Investment Plan

The Capital Investment Plan serves as a primary input for the future year's capital budget and also as the placeholder for the longer term projects recommended from the Condition Assessment. It is reviewed and updated annually to reflect the latest performance priorities of the distribution system.

Historically Atikokan Hydro has spent between $ 75,000 and $ 125,000 annually on capital expenditures. Aging infrastructure prompted a review of assets that are deemed "critical" in 2008. Atikokan Hydro's bucket trucks were identified as critical and the process to procure a new truck and associated storage space resulted in significant capital expenditures in 2009 and 2010.

We will be able to focus on long-term feeder planning with an importance placed on smart grid and the inclusion of distributed generation from solar, wind, and bio-mass. A Smart Grid Plan has not yet been developed, but a Basic Green Energy Act Plan has been developed.

- **Short Term**

  Any capital investment recommendations resulting from the performance of particular assets, the Condition Assessment and any applicable new technology solutions, that are required within a one year period, are considered annually within this plan. Those assets identified as immediate priority are scheduled accordingly. These are prepared by Senior Management and are documented

- **Long Term**

  The longer term recommendations resulting from the system performance, the Condition Assessment and any applicable new technology solutions are captured and summarized in a 5 year forecast. Potential timeframes and budgetary estimates for individual projects are documented and subjected to annual review and prioritization.

  This plan is updated and refined annually to capture the progress in maintaining and upgrading the distribution system and any significant changes in the performance of the distribution system.

Given the data received from the CGAAP to IFRS conversion exercise, Atikokan Hydro has chosen a useful life of 45 years for distribution equipment and has deemed10 years remaining on older assets. While many of the assets are in the older category, it is important to note that age is only one factor to consider when developing and deploying an Asset Management Plan. The actual performance of the asset needs to be weighted heavily in budget decisions. Simply put, a newer asset may have a poorer system reliability rating, and would be replaced sooner to ensure safe and reliable power for Atikokan Hydro's customers and shareholder.

While all assets are important to the successful operation of an LDC, Atikokan Hydro will concentrate on upgrades to its distribution system, substation life enhancement and major equipment to ensure we are able to fulfil our goals and mission statement in providing safe, reliable and affordable power to our customers.

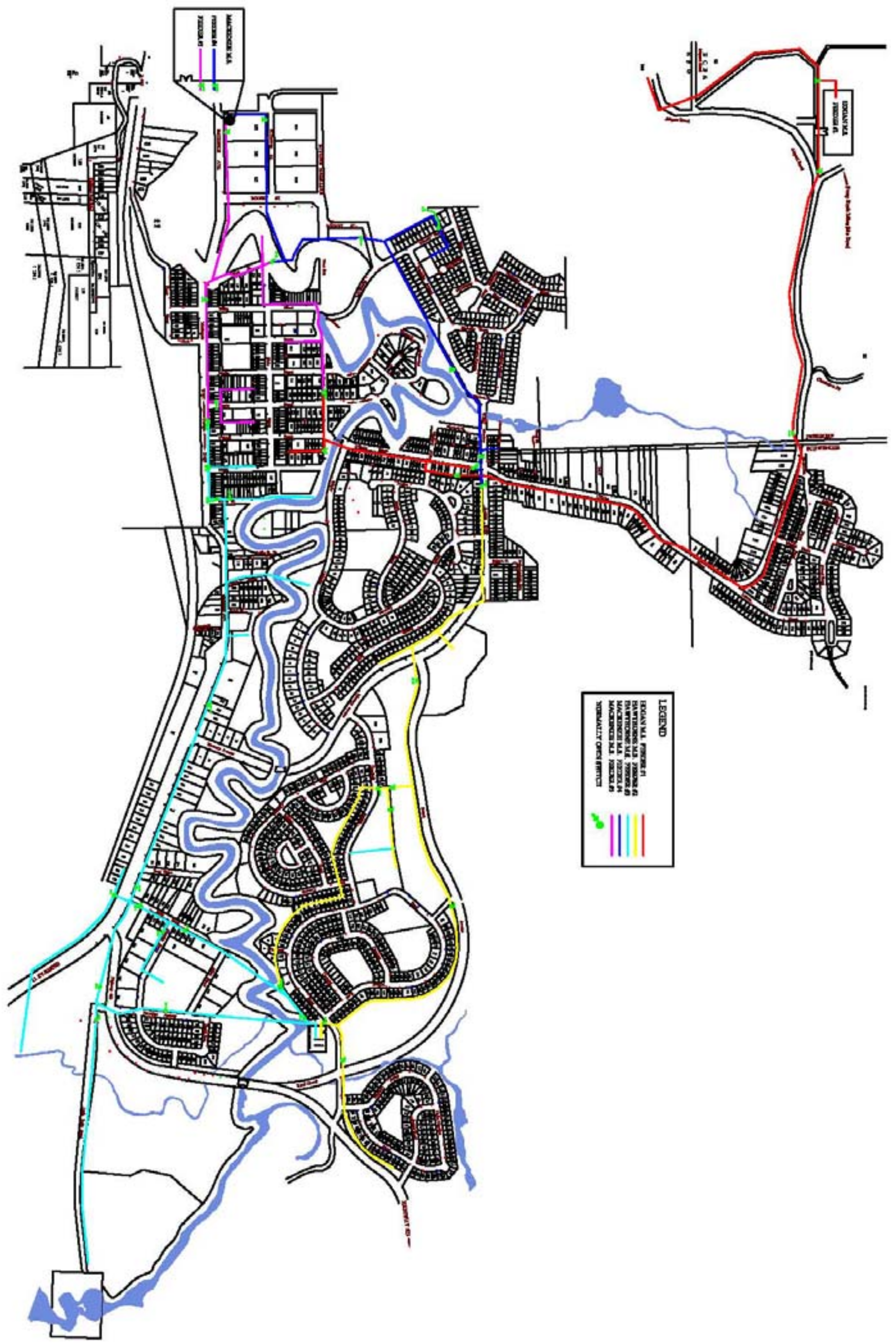
Atikokan Hydro has enclosed a capital budget for the years 2012 to 2017 **[Appendix G].** This budget concentrates effort on USofA 1820, 1830, 1835 and 1930.

In the first two years of the proposed capital budget, Atikokan Hydro will concentrate on the 1830 and 1835 group of assets (poles and conductors). Years three and four will see a concentration on refurbishing the oil in our substations while continuing to upgrade our distribution feeders. We will need to replace a service vehicle at that time also; Year Five will focus on replacing our aging double bucket truck, and continuing with upgrading our distribution assets. In year six Atikokan Hydro will again concentrate on refurbishing poles and conductors.

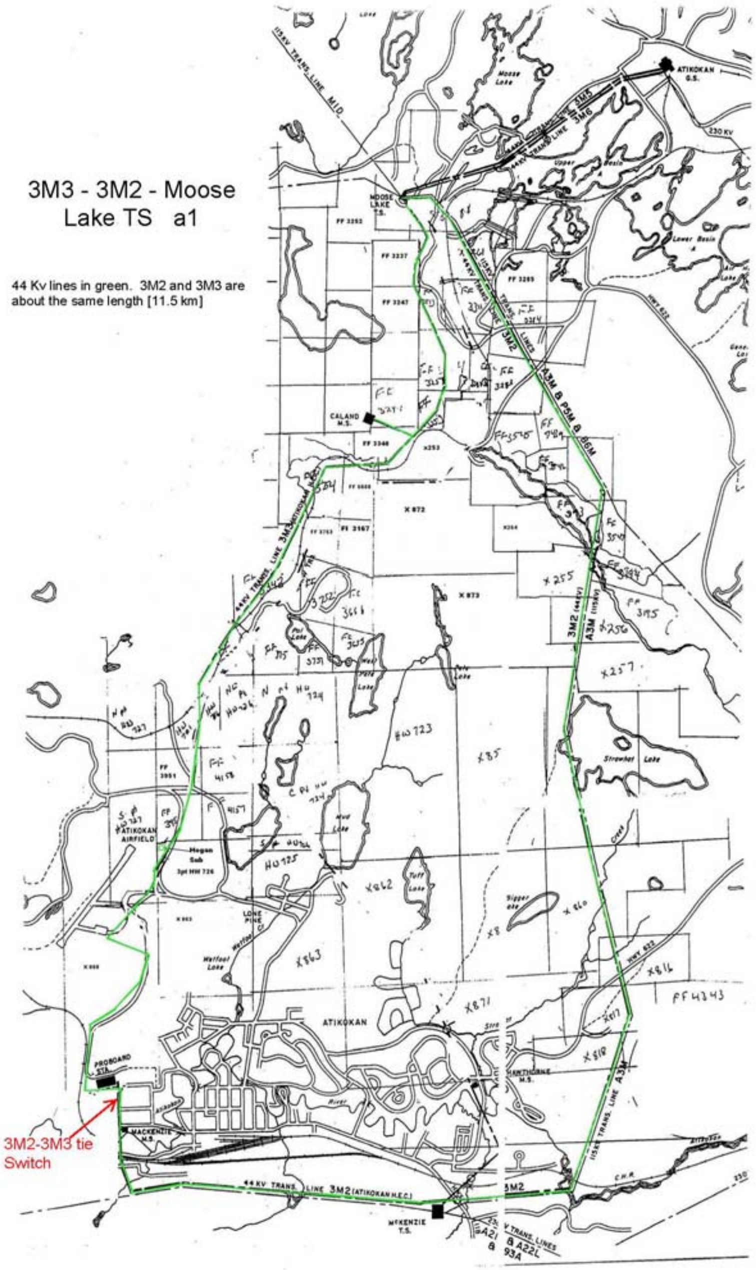
Appendix H is an excerpt from our IFRS conversion data and includes data on the age and quantity of poles as well as the lengths of various types of conductor by feeder. As noted earlier, age will not be the only driver for the replacement and upgrading of assets. Risk mitigation will play an important role as well as economies of scale and scope. An example would be to upgrade the feeders where the copper conductor is located may receive priority over an older section. This weighting would be determined by senior management utilizing the yearly feeder inspection reports in conjunction with the IFRS conversion data and the various reliability indices. An example of scale of scope would be to do a complete section of a back yard segment of a feeder to gain any synergy from utilizing specialized equipment that could be rented for a specific period of time [e.g. vacuuming holes instead of digging].

As with any successful plan, targets and results must be clear and focussed while at the same time having some flexibility inherent to the plan to allow for asset condition changes as will as be open enough to take advantage of technological improvements in both method and material. A successful Asset management plan will in fact become a living document updated at least yearly.

Appendix A



Appendix B


3M3 - 3M2 - Moose Lake TS a1
44 Kv lines in green. 3M2 and 3M3 are about the same length [11.5 km]
3M2-3M3 tie Switch
ATIKOKAN G.S.
MOOSE LAKE T.S.
CALAND M.S.
ATIKOKAN AIRFIELD
ATIKOKAN
MACKENZIE M.S.
MCKENZIE T.S.
HAWTHORNE M.S.
44 KV TRANS. LINE 3M2 (ATIKOKAN H.E.C.)
Strawhat Lake
Wetfoot Lake

Appendix C

Power line Inspection Report 09

Feeder Inspected F1 **Inspected by:** Name of Inspector **Signature:**

Item of Concern

Location / Address	Pole	Xarm	Insulators	Primary	Secondary	Service	Transformer	Trees	Comments	Correction Date

Priority: 1- Public Safety Concern
2- Possible Equipment / Power Failure
3- Regular Maintenance Issue

Appendix D

Daily Work Sheet

Date:

Location/Job Site:

Drawing #s:

Description of work:

Power Outage Sheets (if required):

Work/Plans approved by:

Employees on site:

Qualified Personnel on Site:

Signature of Qualified Personnel:

Job completion date:

Appendix E

Certificate of Approval

This is to certify that the construction as recorded in this document for Atikokan Hydro Inc. is consistent with the approved Plan, Standard Designs, Work Instructions, Legacy Construction and that approved equipment has been used.

Name: ______________________ Date: ____________________

Signature: ___________________ Position: ___________________

Appendix F

Atikokan Hydro Inc. - Monthly Substation Inspections

	Acceptable	Problem/ Condition Description	Date of Correction
Yard:			
Condition of Driveway & Yard			
Condition of Station Fence & Gates			
Condition Of Signage			
Condition Of Locks			
Condition of Fence Grounds			
Vegetation Growth			
Tower Structure:			
Cement Foundation			
Corrosion/Rust			
Loose Bolts			
Phase Markers			
Structure Condition			
Condition of Insulators/Arrestors			
Transformer;			
Phase/ Feeder -			
Leaking Oil			
Paint Condition			
Rust / Corrosion			
Damage			
Condition of Brushings			
Transformer;			
Phase/ Feeder -			
Leaking Oil			
Paint Condition			
Rust / Corrosion			
Damage			
Condition of Brushings			

Appendix F (Atikokan Hydro Inc – Monthly Substation Inspections) Continued

Transformer;

Phase/ Feeder -
Leaking Oil
Paint Condition
Rust / Corrosion
Damage
Condition of Brushings

Transformer;

Phase/ Feeder -
Leaking Oil
Paint Condition
Rust / Corrosion
Damage
Condition of Brushings

Notes/ Comments:

Inspection Date: ______________________________

Inspected By: ______________________________

Signature: ______________________________

Appendix G

Capital Budget

Asset Category	USofA	Budget 2012	Budget 2013	Budget 2014	Budget 2015	Budget 2016	Budget 2017
Transformer Station Equip >50 kV	**1820**	$8,000	$8,000	$35,000	$35,000	$1,000	$1,000
Poles, Towers & Fixtures	**1830**	$58,800	$55,000	$45,000	$30,000	$45,000	$85,000
O/H Conductors & Devices	**1835**	$0	$9,880	$6,000	$0	$6,000	$6,000
Line Transformers	**1850**	$7,000	$3,000	$3,000	$0	$0	$3,000
Services	**1855**	$0	$14,000	$0	$0	$0	$0
Meters	**1860**	$0	$2,500	$3,000	$0	$0	$2,500
Buildings and Fixtures	**1908**	$8,500	$4,000	$4,000	$1,000	$1,000	$1,000
Office Furniture and Equipment	**1915**	$0	$3,200	$1,000	$1,000	$1,000	$1,000
Computer Equipment - Hardware	**1920**	$12,000	$2,000	$2,000	$2,000	$2,000	$2,000
Computer Equipment - Software	**1925**	$8,000	$0	$1,000	$0	$0	$0
Fleet	**1930**	$0	$0	$0	$50,000	$325,000	$0
Tools, Shop & Garage Etc.	**1940**	$16,500	$5,000	$1,000	$1,000	$1,000	$1,000
Measure & Test Equip	**1945**	$0	$2,000	$2,000	$2,000	$2,000	$2,000
Miscellaneous Equipment	**1960**	$0	$2,000	$2,000	$2,000	$2,000	$2,000
Total		$118,800	$110,580	$105,000	$124,000	$386,000	$106,500

Appendix H

POLES [per feeder]

Year Installed	1950	1960	1970	1980	1990	2000	Total
Feeder 1	96	47	16	11	13	21	204
Feeder 2	139	93	25	13	7	4	281
Feeder 3	101	35	22	17	16	17	208
Feeder 4	49	36	18	15	7	6	131
Feeder 5	60	13	16	6	13	11	119
Feeder 6	0	55	9	2	1	4	71
Feeder 3M2	0	84	52	9	4	0	149
Feeder 3M3	0	50		27	49	0	126
Total	445	413	158	100	110	63	1289

Conductor [km per feeder]

3/0 ACSR	1/0 ACSR	#2ACSR	#4 Cu	366 MCM	2/0 UG	Total
11.52	1.28					12.80
11.73	4.18	2.82	-	-	-	18.73
11.61	1.30	3.31	0.28	-	1.16	17.66
6.72		7.93	-	-	0.52	15.17
7.86		0.92	1.10		0.12	8.90
14.30		1.59		9.30	0.20	26.49
8.97		0.45	-	29.90	-	39.32
13.30		-	-	16.90	-	30.20
86.00	6.76	17.02	1.38	56.10	2.00	169.26

Legend	
ACSR	Aluminum covered steel reinforced
Cu	Copper [hard drawn]
MCM	Thousand circular mils[2]
UG	Under ground

[2] A **circular mil** is a unit of area, equal to the area of a circle with a diameter of one mil (one thousandth of an inch). It is a convenient unit for referring to the area of the cross section of a wire or cable as it can be calculated without reference to pi (π).

Appendix B

ATIKOKAN HYDRO INC

BASIC

GREEN ENERGY ACT PLAN

Table of Contents

Introduction

In accordance with Board Decision 2009-0397, Atikokan Hydro, is submitting a Basic GEA plan, for OPA consideration.

Atikokan Hydro Inc ("Atikokan Hydro") is a licensed electricity distributor (ED-2003-0001) that owns and operates electricity distribution systems that provide service to the Town of Atikokan [formerly the Township of Atikokan]. The area of the Town of Atikokan is approximately 380 km square. For reference purposes for data presented later in this plan, it should be noted that Atikokan Hydro in located in the area described as Northwest. For clarity and focus of Atikokan Hydro's Green Energy Act Plan, it is relevant to point out that the Northwest area distribution system operates at 115 kV. It should also be stated that most of the distribution consists of long single circuit radial feeds. There are very few locations that are fed with 115 kV circuits that are in close proximity to a 230 kV source that have multiple sources of 115 kV supply similar to Moose Lake. Atikokan Hydro's source of supply is from Moose Lake via two 44 KV lines, and is discussed in detail later . The 230KV circuits are part of the bulk distribution system that spans the province. Each area's capacity was assigned to the portion of the of the bulk system in the area with consideration for the capacity of the specific asset. The Northwest Region was assigned 100 MW which was allocated to the 230 KV circuits. There is an area of constraint between Thunder Bay and Wawa [this section is known as the east-west tie line]. The 115 KV and less than 50 KV circuits could then act as collectors for the Bulk Transmission assets. Moose Lake TS can be supplied by the 115 KV A3M circuit which is a direct link to the 230 KV MacKenzie TS tertiary windings. The 230 KV lines in Northwestern Ontario are connected to the rest of the province by a section of the line known as the east-west tie line.[1] It is hoped to have capacity increased after 2017.

Current Assessment of Distribution System

Atikokan Hydro's point of supply is Moose Lake TS, and Atikokan Hydro owns the 3M2 and 3M3 sub transmission feeders fed from the T2 and T3 bus respectively. These operate at 44 kV and are connected directly to Moose Lake TS. The 3M2 and 3M3 lines are shown on the attached map [Appendix "A"].

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[1] **Pages 27 to 32 from**
http://www.powerauthority.on.ca/sites/default/files/page/Transmission%20Presentation.pdf

The Atikokan Hydro service area is supported with substantial transmission assets within Northwest Ontario. As noted, Atikokan Hydro is connected to the Moose Lake TS.

Moose Lake TS is a standard 1940s vintage TS with a dual bus arrangement that can be tied together. The primary side is 115 kV with a complex closed transition switching arrangement amongst four circuits. The four circuits are the A3M [Mackenzie TS to Moose Lake TS], the M2D [Moose Lake TS to Dryden TS], the B6M [Moose Lake TS to Lakehead TS] and the M1S which serves as a collector for privately owned hydro electric generators including Valery Falls, Calm Lake and Crilly.

There is an anomaly with Moose Lake TS in that the bus capacities at the 44 kV level are significantly different. The T2 transformer is 8 MVA while the T3 transformer is 15 MVA. This will be an important distinction when Atikokan Hydro's circuits are discussed later. The purpose of this preamble is to provide data to understand the direction and output of that Atikokan Hydro Green Energy Plan.

The Northwest allocation of 100 MW of FIT capacity is associated with the bulk transmission assets which are 230 KV circuits, One of the four 115 KV circuits from Moose Lake TS is the A3M which is a direct link to the tertiary windings on MacKenzie TS. MacKenzie TS [PL20] is a 230kV station that connects

to the Atikokan Thermal Generating Station via the N93A;

to the Lakehead TS [P12] via the A21L and A22L double circuit on one tower [eventually to Wawa];

to the D26A [MacKenzie TS to Dryden TS {FP25}] and

to the F25A[MacKenzie TS to Fort Frances TS {FR22}.

The D26A and F25A eventually converge in Kenora at the Kenora TS {FP34} and continue on to Manitoba. Thus the 230 kV circuits provide a conduit from Manitoba to Southern and Eastern Ontario.

The 230 kV line is considered the highway for transmission capacity as it exists in Northwest region. The following table is an excerpt from the OPA's document "TAT_Circuit_Table.pdf"

Table 1[2]

Connection Availability Table – Circuit

Circuit	Circuit Availability (MW)	Area	Area Availability (MW)	Name of Transmitter
A3M	100	Northwest	100	Hydro One Networks Inc.
B6M	0	Northwest	100	Hydro One Networks Inc.
M1S	30	Northwest	100	Hydro One Networks Inc.
M2D	0	Northwest	100	Hydro One Networks Inc.

The table shows the entire Area Availability [northwest region] for FIT capacity as 100 MW, and indicates that the A3M [hence Moose Lake TS] could access the entire 100 MW.

Table 2[3]

Connection Availability Table – Station

Station Name	Bus Name	Available Station Capacity	Supply Circuit 1	Availability (MW)	Supply Circuit 2	Availability (MW)	Area	Area Limit (MW)
MOOSE LAKE TS	Total	0	Not expected to be limited by a supply circuit				Northwest	100
MOOSE LAKE TS	T2	5	Not expected to be limited by a supply circuit				Northwest	100
MOOSE LAKE TS	T3	0	Not expected to be limited by a supply circuit				Northwest	100

Table 2 follows table 1, but distinguishes the 115 kV circuit capacity from the actual Moose Lake TS bus capacity which will relate to the description of Atikokan Hydro's feeders.

It is important to note here that the T3 bus or the bus connected to the larger transformer has been allocated a capacity of 0, and even though the T2 bus has been allocated a capacity of 5 MW, the station capacity remains at 0.[discussion with OPA staff revealed that this rating is given to the OPA by Hydro One, and since there are no applications on file for projects connecting to Moose Lake, the OPA has not investigated why Moose Lake TS is rated at 0 even though their data shows one transformer with 5 MW capacity].

Table 3 below indicates that by April 8, 2010, that 98.95 MW of the 100 MW limit for the Northwest region have been allocated with contract offers. Further investigation into the Long Term

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[2] **Excerpt from http://fitapp.powerauthority.on.ca/Resources.aspx?pt=conntables Document TAT_Circuit_Table**

[3] **Excerpt from http://fitapp.powerauthority.on.ca/Resources.aspx?pt=conntables Document TAT_TS_Table**

Energy Plan indicates that enhancements to the east-west tie line will not occur until 2017. There will not be any more capacity available until the east-west tie line's capacity is increased.[4]

Reference to OPA document: "11220_Priority_Ranking_FINAL_by_Region1" on page 7 indicates that there is presently 921.9 MW of applications [5]awaiting access to the Northwest 230 KV circuits.

[4] **See reference note 1**

[5] **http://fit.powerauthority.on.ca/Storage/11220_Priority_Ranking_FINAL_by_Region1.pdf**

Table 3[6]

FIT Contracts April 8, 2010 - Project City Order

Applicant Legal Name	Project Name	Project City	Project Source	Nameplate Capacity (kW)	Region	Current State
Namewaminikan Hydro Inc.	Namewaminikan Waterpower Project	Beardmore	Water	10,000.00	Northwest	CONTRACT OFFERED
Pic Mobert Hydro Power Joint Venture	Gitchi Animki Niizh Generating Station	Brothers Township	Water	10,000.00	Northwest	CONTRACT OFFERED
Pic Mobert Hydro Power Joint Venture	Gitchi Animki Bezhig Generating Station	Brothers Township	Water	8,900.00	Northwest	CONTRACT OFFERED
High Falls Development Partnership	High Falls Hydropower Development	District of Rainy River	Water	6,400.00	Northwest	CONTRACT OFFERED
Cyntech Corporation	Black Bay Solar Project Phase 2	Dorion Township	Solar PV Groundmount	750.00	Northwest	CONTRACT OFFERED
Horizon Hydro LP	Trout Lake River Hydroelectric Project	Ear Falls	Water	4,000.00	Northwest	CONTRACT OFFERED
Big Thunder Wind Park LP	Big Thunder Beta Windpark	Municipality of Neebing	Wind On - Shore	16,500.00	Northwest	CONTRACT OFFERED
Ontario Solar PV Fields 1 Limited Partnership	Wainwright Solar Park	Oxdrift	Solar PV Groundmount	10,000.00	Northwest	CONTRACT OFFERED
Ontario Solar PV Fields 2 Limited Partnership	Morley Solar Park	Stratton, in the Township of Morley	Solar PV Groundmount	10,000.00	Northwest	CONTRACT OFFERED
Xeneca Limited Partnership	McGraw Falls 2089284	Thunder Bay District	Water	2,400.00	Northwest	CONTRACT OFFERED
Ontario Solar PV Fields 3 Limited Partnership	Vanzwolf Solar Park	Township of Dawson	Solar PV Groundmount	10,000.00	Northwest	CONTRACT OFFERED
Ontario Solar PV Fields 4 Limited Partnership	Dave Rampel Solar Park	Township of Dawson	Solar PV Groundmount	10,000.00	Northwest	CONTRACT OFFERED
				98,950.00		

[6] **Excerpts from 10981_FIT_Contracts_April_8_10_-_Project_City_Order_rev**

Description of Atikokan Hydro's feeders

As noted above, Atikokan Hydro's 3M3 feeder is connected to the T3 bus at Moose Lake TS. The T3 bus has the greatest physical capacity, but in table 2 has been rated at 0 MW capacity. The 3M2 feeder is connected to the T2 bus and has been allocated a 5 MW capacity. The total station has been allocated 0 MW capacity to accept renewable energy generation. [Discussion with OPA staff revealed that this rating is given to OPA by Hydro One, and since there are no applications on file for projects connecting to Moose Lake, the OPA has not investigated why Moose Lake TS is rated at 0 even though their data shows one bus with 5 MW capacity]. Table 3 indicates that by April 8, 2010 nearly all of the northwest region capacity had been allocated. Since capacity for renewable generation under the guidelines of the Green Energy Act was allocated to the provincial bulk system operating at 230 kV and above, there will not be opportunity to introduce any more 10 MW and above projects until the 230 kV constraint is adjusted.

The "Long Term Energy Plan" [IPSP II][7] contemplates an upgrade to the east-west tie line asset in the 2017 to 2018 time frame, there will not be any more FIT contracts awarded until capacity is increased on the 230 kV system.

Applications from renewable generators over 10kW

Atikokan Hydro does not have any applications from renewable generators over 10kW for connection, and the OPA has never received any applications for renewable generators over 10 kW for the FIT program.

Overall potential for developing renewable generation in the distributor's service area

In the past, prior to the FIT program there has been some interest in private generation in Atikokan Hydro's service area. Since the inception of the FIT program there has been no serious interest by customers or generators in developing renewable generation in Atikokan Hydro's service area. It is not likely that any generator would be interested in Atikokan Hydro's service area for the next 5 years or longer [until there is capacity in the northwest region]. The non standard configuration of Moose Lake TS would make Atikokan Hydro's service area very

[7] **See reference 1**

unattractive. A generator would not want to be in the position of being constrained off if there would be a failure on either the T3 bus or on Atikokan Hydro's 3M3 line. It could be argued that until the northwest region's backlog was reduced by an increased capacity on the 230 kV circuits or load in Atikokan Hydro's service area increased to warrant an upgrade of Moose Lake TS, that it would be very challenging to make a financial argument to support the investment in generation in Atikokan Hydro's service area.

Constraints within the distributor's system related to the connection of renewable generation

Atikokan Hydro has four substations fed from the two 44 kV feeders. Three of the substations are located within the more densely populated area of Atikokan Hydro's service area. These substations supply five feeders. These feeders are configured to allow load to be transferred from one feeder to the other without interrupting customers. This has an advantage of being able to match load to sub station capacity as well as restoring power should a sub station be interrupted. This is often termed a ring bus configuration that can accommodate closed transition switching.

The sub stations are protected by fuses and load break switches. If generation were to be added, regardless of the location, it would need to be sized to accommodate reverse flow in the smallest sub station. Industry standards [Hydro One] would suggest this would be less than 5% or less than 100kW. Upgrading a substation would have a significant negative impact on rates for Atikokan Hydro customers considering load is not expected to grow significantly in the next 5 years.

Upstream constraints of a host distributor or transmitter that may affect the ability to accommodate renewable generation connection in the distributor's service area

Tables 1, 2 and 3 above show the constraints at Moose Lake TS that will prevent any renewable generation connection for greater than five years or the foreseeable future. Table 3 shows that by April 8, 2010 most of the northwest region allocation had been awarded to applicants. Page 7 of 11220_Priority_Ranking_FINAL_by_Region1.pdf [attached] indicates that the Northwest region is oversubscribed by 921.9 MW of applications. The LTEP [Long Term Energy Plan] [8]documentation on the OEB web site would indicate a modest relief after 2017.

Any information received from the OPA regarding integrated planning for regions of the province or the province as a whole

Correspondence with OPA staff directed Atikokan Hydro to the following link http://fit.powerauthority.on.ca/Storage/11220_Priority_Ranking_FINAL_by_Region1.pdf as well as the links noted in tables 1, 2 and 3.

Atikokan Hydro feeders that are connected to Moose Lake TS have some physical capacity to accommodate FIT generators. Moose Lake TS has a rating of 0 MW capacities [table 2]. Moose Lake TS feeder A3M could access the capacity allocated to the 230 kV assets, but the allocated capacity is significantly over subscribed.

Atikokan Hydro and OPG are the only connections to Moose Lake TS. Atikokan Hydro is not aware of any integrated planning for the northwest region in the next 5 years.

Conclusion

Atikokan Hydro is submitting a basic plan to the OPA for comment and acceptance. Atikokan Hydro has been able to accept micro fit generators [less than 10 kW] renewable generation.

[8] See reference 1

Atikokan Hydro has provided detail on the circuits attached to the Transformer station. Atikokan Hydro's system that encompasses five feeders is better suited to micro fit generation with the following concerns.

Atikokan Hydro's system was designed with a basic calculation of 3 kW per residential customer. The 3 kW design does have the potential to limit micro fit generation. It would appear that although potential generators were encouraged to apply for 10 kW contracts, it is physically impossible to install more than 5 or 6 kW on most residential establishments, with the average being about 3 kW.

By being pro-active with customers and micro fit service providers, it is anticipated that Atikokan Hydro will be able to handle most if not all proponents. While there has been a flurry of interest with 20 or so applicants, only 4 have actually installed systems. The four installations total about 20 kW of solar roof top generation. There were no costs to Atikokan Hydro to complete these installations. The installations are via dual socket meter base provided by the customer, and the customer pays for the cost of the meter.

Since the inception of micro fit incentives and the price adjusting for ground mounted solar, coupled with a suggested review of pricing in November, Atikokan Hydro does not expect a significant increase in projects for 2011. If the conditions stay status quo, Atikokan Hydro is aware of an additional 20 or 30 kW for late 2011 or 2012.

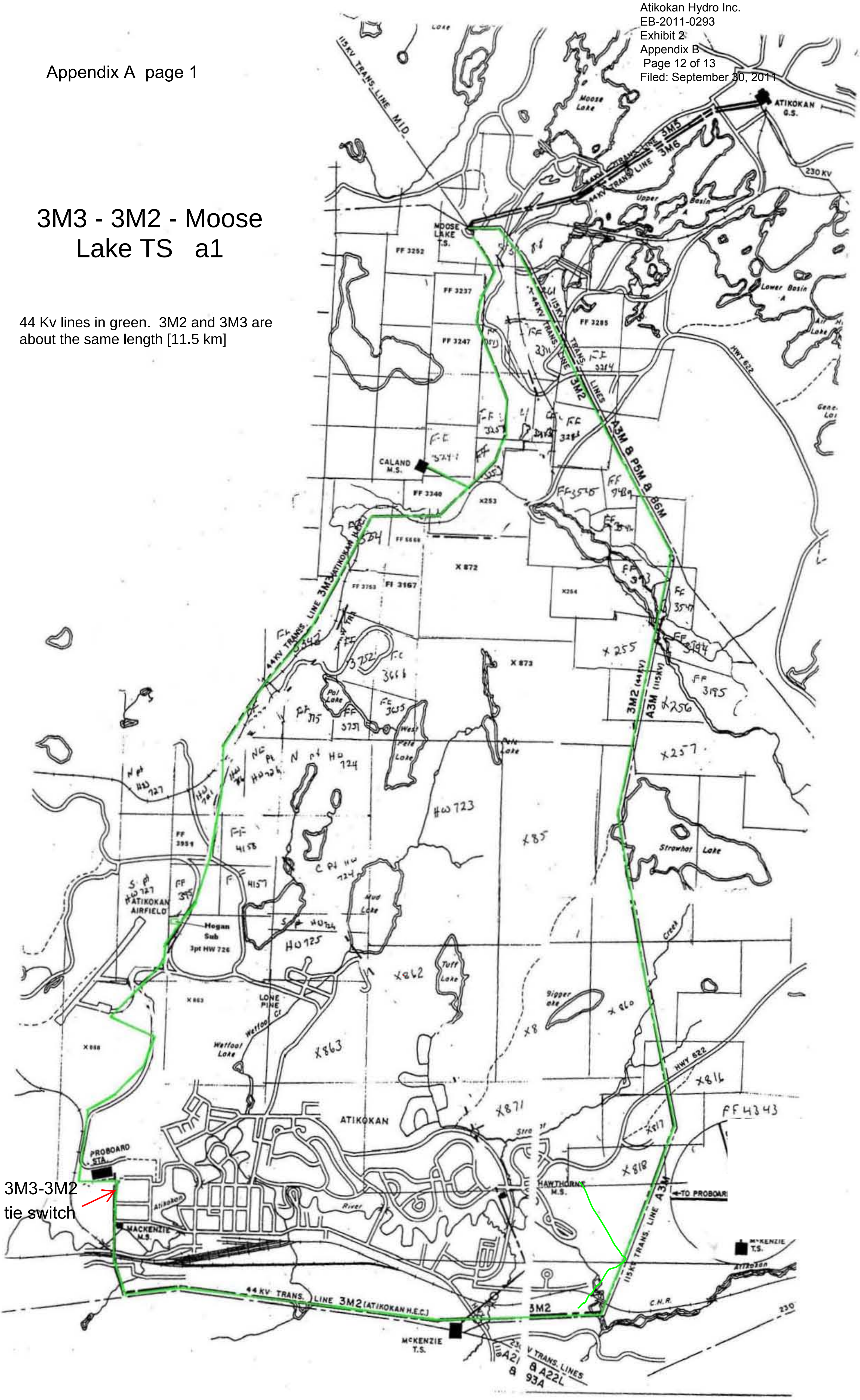
It should be noted that Atikokan Hydro has only had interest in solar generation. The installations last winter proved to be difficult to produce any generation because of the snow fall. Atikokan Hydro has made potential investors aware of this condition.

Atikokan Hydro will continue to monitor the capacity for the Northwest region, but given present time line indications, it would not be prudent for Atikokan Hydro to make investments or apply for rates to support investments to support renewable FIT installations for at least another 5 years. Atikokan Hydro will continue to assist and work with microfit proponents to ensure connections are timely.

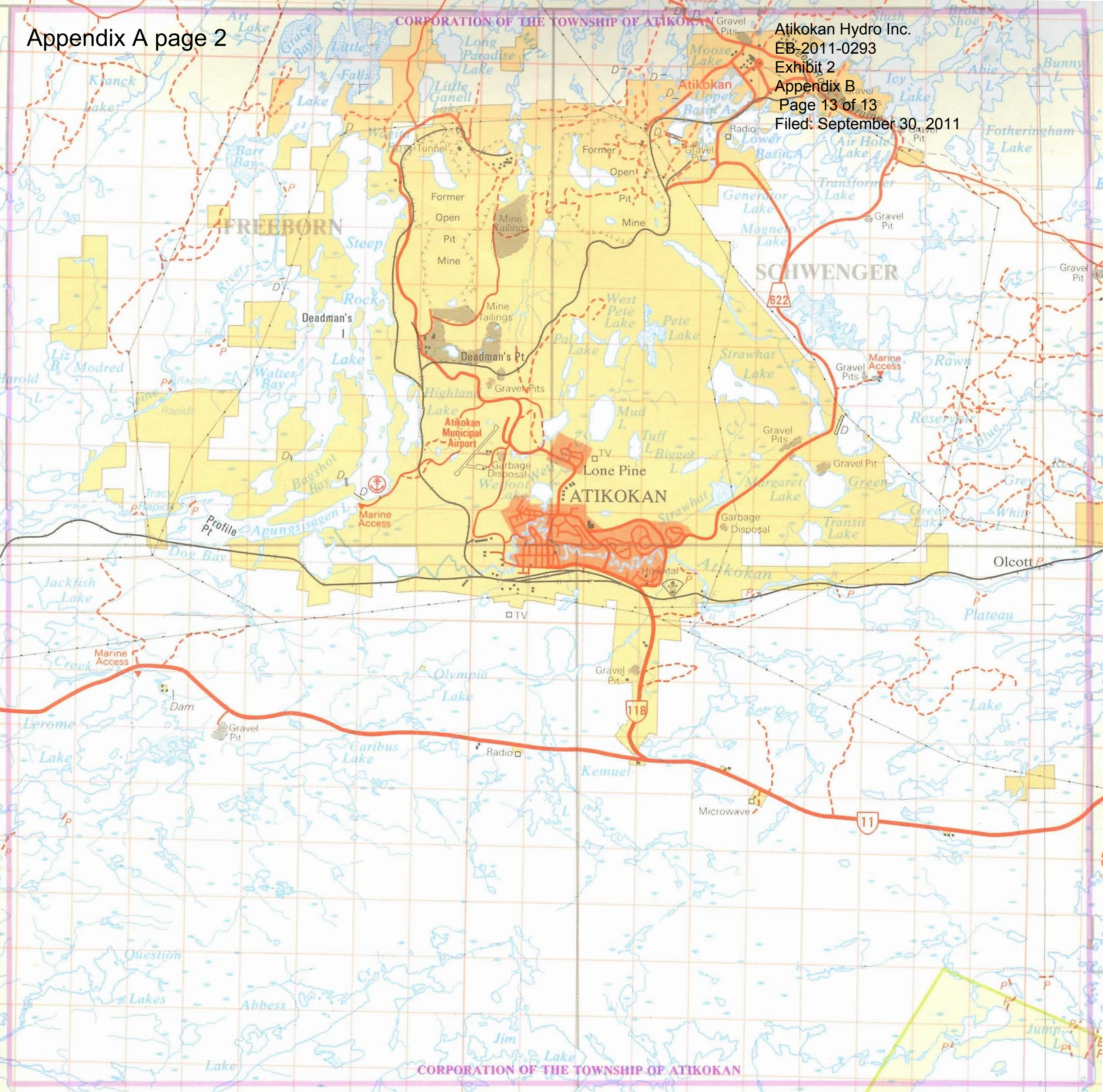
Appendix A page 1

3M3 - 3M2 - Moose Lake TS a1

44 Kv lines in green. 3M2 and 3M3 are about the same length [11.5 km]



Appendix A page 2



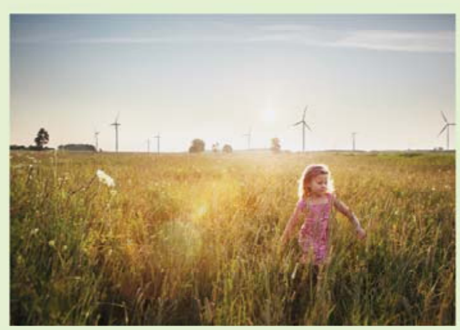
Appendix C

OPA Letter of Comment:

Atikokan Hydro Inc.

Basic Green Energy Act Plan

August 25, 2011



ONTARIO POWER AUTHORITY

Appendix C

Introduction

On March 25, 2010, The Ontario Energy Board ("the OEB") issued its Filing Requirements for Distribution System Plans. As a condition of Licence, Ontario Distributors are required to file a Green Energy Act Plan as part of their cost of service application.

The Filing Requirements distinguish between Basic and Detailed Green Energy Act Plans ("Plan" or "GEA Plan") and outline the specific information and level of detail which must be provided for each type of Plan. Recognizing the importance of coordinated planning in achieving the goals of the *Green Energy and Green Economy Act, 2009* (the "GEA"), distributors must consult with embedded and host distributors, upstream transmitters and the OPA in preparing their Plans. For both Basic and Detailed Plans, distributors are required to submit as part of the Plan, a letter of comment from the OPA.

The OPA will review distributors' Basic Plans to ensure consistency with regard to FIT and microFIT applications received, as well as with integrated Plans for the region or the system as a whole.

Atikokan Hydro Inc. Basic Green Energy Act Plan

On July 29, 2011, the OPA received a Basic GEA Plan from Atikokan Hydro Inc. ("Atikokan Hydro"). The OPA has reviewed Atikokan Hydro's Plan and has provided its comments below.

OPA FIT/microFIT Applications Received

Atikokan Hydro's Plan identifies 0 FIT applications and indicates that in regards to microFIT "while there has been a flurry of interest with 20 or so applicants, only 4 have actually installed systems. The four installations total about 20 kW of solar roof top generation".

To date, the OPA has received 0 capacity allocation exempt FIT applications, 0 capacity allocation required FIT applications and 28 microFIT applications to Atikokan Hydro's system for a total of 0 MW of FIT applications and 0.26 MW of microFIT applications. At this time, 4 microFIT applications have been connected and 1 microFIT application has been terminated (leaving a total of 0.22 MW of microFIT applications to be connected).

Upstream Transmission Constraints

Atikokan Hydro's GEA Plan indentified that based on the station availability published by OPA in October 2009, that there are 0 MW of available capacity on Moose Lake TS. The Plan also notes that the Northwest region has been fully subscribed and notes there are more than 900 MW of FIT applications in the Northwest awaiting the Economic Connection Test (ECT). Atikokan Hydro also notes that the LTEP indicates the enhancements to the East-West Tie line will not occur until 2017. The information noted in Atikokan Hydro's Plan is consistent with information provided by the OPA.

Economic Connection Test Results

There has been no ECT performed to date.

Opportunities for Integrated Solutions

There are no known corresponding expansions among neighbouring LDCs that could be addressed through integrated transmission solutions at this time.

Conclusion

Given the insignificant discrepancy on the tracking of microFIT activities, the OPA finds that Atikokan Hydro's GEA Plan is reasonably consistent with the OPA's information regarding known renewable energy generation connections.

The OPA appreciates the opportunity to comment on Atikokan Hydro's Basic GEA Plan.

Exhibit	Tab	Schedule	Appendix	Contents
3 – Operating Revenue				
	1	1		Overview of Operating Revenue
	2	1		Weather Normalized Load and Customer/ Connection Forecast
	2		A	Monthly Data Used for Regression Analysis
	3	1		Operating Revenue Variance Analysis.
	3	2		Transformer Allowance
	3	3		Variance Analysis on Other Distribution Revenue

OVERVIEW OF OPERATING REVENUE:

This Exhibit provides the details of Atikokan Hydro's operating revenue for 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, the 2011 Bridge Year and the 2012 Test Year. This Exhibit also provides a detailed variance analysis by rate class of the operating revenue components. Distribution revenue excludes revenue from commodity sales.

Atikokan Hydro is proposing a total Service Revenue Requirement of $1,579,603 for the 2012 Test Year. This amount includes a Base Revenue Requirement of $ 1,454,368 plus revenue offsets of $125,235 to be recovered through Other Distribution Revenue.

A summary of all operating revenue is presented below in Table 3-1 and provides a comparison of total revenues from the 2008 OEB approved year to the 2012 Test Year.

Throughput Revenue:

Information related to Atikokan Hydro's throughput revenue includes details on the weather normalized load forecasting methodology reflecting expected CDM results and a forecast of customers by rate class based on the historical number of customers billed throughout the year.

A detailed variance analysis on the historical throughput revenue is also provided in this Exhibit.

Other Revenue:

Other revenues include Standard Service Supply (SSS) Administration Charges, Late Payment Charges, Miscellaneous Service Revenues and Merchandise and Jobbing Revenues.

A detailed variance analysis on other revenue is set out later on this Exhibit.

Table 3-1: Summary of Operating Revenue

	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test at Current Rates	2012 Test at Proposed Rates
Distribution Throughput Revenue							
Residential	$779,960	$610,650	$751,844	$684,040	$616,293	$660,258	$885,536
GS<50	$252,667	$217,849	$304,417	$256,070	$295,304	$254,263	$299,438
GS>50	$30,193	$34,738	$101,815	$127,054	$144,384	$101,818	$135,810
Intermediate	$0	$25,537	$0	$0	$0	$0	$0
Sentinel Lights	$295	$543	$2,486	$2,899	$3,284		
Street Lighting	$24,821	$28,330	$66,613	$71,199	$86,081	$74,018	$133,584
Unmetered Scattered Load	$5,765	$0	$0	$0	$0	$0	$0
Total	**1,093,701**	**917,646**	**1,227,176**	**1,141,263**	**1,145,346**	**1,090,357**	**1,454,368**
Other Distribution Revenue							
SSS Administration Revenue		$4,816	$7,189	$4,788	$4,654	$4,200	$4,200
Rent from Electric Property	31536	$35,045	$38,196	$34,911	$34,911	$34,911	$34,911
Late Payment Charges	6233	$5,624	$7,043	$6,024	$6,024	$6,024	$6,024
Specific Service Charges	5886	$5,322	$32,896	$6,745	$7,100	$7,100	$7,100
Merchandise & Jobbing	0	$0	$0	$86,125	$55,000	$55,000	$55,000
Other Distribution Rev.	0	$8,688	$11,849	$16,927	$6,058	$9,000	$9,000
Other Income & Exp.	17301	$11,341	$9,542	$14,799	$9,000	$9,000	$9,000
Total	**$60,956**	**$70,836**	**$106,716**	**$170,318**	**$122,747**	**$125,235**	**$125,235**
Grand Total	**$1,154,657**	**$988,482**	**$1,333,892**	**$1,311,581**	**$1,268,093**	**$1,215,592**	**$1,579,603**

WEATHER NORMALIZED LOAD AND CUSTOMER/CONNECTION FORECAST

The purpose of this evidence is to present the process used by Atikokan Hydro to prepare the weather normalized load and customer/connection forecast used to design the proposed 2012 electricity distribution rates.

In summary, Atikokan Hydro has used the same regression analysis methodology used by a number of distributors in previous Cost of Service rate applications to determine a prediction model. With regard to the overall process of load forecasting, Atikokan Hydro submits that conducting a regression analysis on historical electricity purchases to produce an equation that will predict purchases is appropriate. Atikokan Hydro has the data for the amount of electricity (in kWh) purchased from the IESO for use by Atikokan Hydro's customers. With a regression analysis, these purchases can be related to other monthly explanatory variables such as heating degree days and cooling degree days which occur in the same month. The results of the regression analysis produce an equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total level of weather normalized purchases for the Bridge Year and the Test Year which is converted to bill kWh by rate class. A detailed explanation of the process is provided later in this evidence.

During proceedings related to the 2009 and 2010 Cost of Service applications for a number of other distributors, intervenors expressed concerns with the load forecasting process that was proposed at the time by those distributors. For the 2009 Cost of Service applications, intervenors suggested the regression analysis should be conducted on an individual rate class basis and the regression analysis would be based on monthly billed kWh by rate class. Atikokan Hydro submits that conducting a regression analysis which relates the monthly billed kWh of a class to other monthly variables is problematic. The monthly billed amount does not reflect the amount consumed in the month. Rather, it reflects the amount billed. The amount billed is based on billing cycle meter reading schedules whose reading dates vary and typically are not at month end. The amount billed could include consumption from the prior month or even earlier. Using a regression analysis to relate rate class billing data to a variable such as heating degree days does not appear to be reasonable, since the resulting regression model would attempt to relate heating degree days in a month to the amount billed in the month, not the amount consumed. In Atikokan Hydro’s view, variables such as heating degree days impact the amount consumed and not the amount billed. It is possible to estimate the amount consumed in a month based on the amount billed, but until smart meters are fully deployed this would only be an estimate. This would reduce the accuracy of a regression model that is based on monthly billing data.

In addition, Atikokan Hydro understands that a number of 2010 costs of service applicants attempted to conduct the regression analysis on a rate class basis but were unsuccessful in achieving reasonable results that could be used in the load forecasting process. Conducting the regression analysis on purchases provides better results since a higher level of historical data increases the accuracy of the regression analysis.

Atikokan Hydro understands that to a certain degree the process of developing a load forecast for a Cost of Service rate application is an evolving science for electricity distributors in the province. During the review of 2010 Cost of Service applications, Board staff and intervenors expressed concern that the regression analysis assigned coefficients to some variable that were counter intuitive. For example, the customer variable would have a negative coefficient assigned to it which meant as the number of customers increased the energy forecast decreased. 2010 applicants explained that this was related to the recent Conservation and Demand Management (“CDM”) savings in the utility but in the view of Board staff and intervenors this was not a sufficient explanation. Further, the regression analysis indicated that some of the variables used in the load forecasting formula were not statistically significant and should not have been included in the equation. Atikokan Hydro has attempted to address these concerns in the load forecast used in this Application. However, Atikokan Hydro expects to include additional improvements to the load forecasting methodology in future Cost of Service rate applications by: i) taking into consideration data provided by smart meters; and ii) evaluating how others will conduct load forecasts in future Cost of Service rate applications. Based on the OEB’s approval of this methodology in a number of previous Cost of Service applications, and based on the discussion that follows, Atikokan Hydro submits that its load forecasting methodology is reasonable at this time for the purposes of this Application.

The following provides the material to support the weather normalized load forecast used by Atikokan Hydro in this Application.

Table 3-2: Summary of Load and Customer/Connection Forecast						
Year	**Billed (GWh)**	**Growth (GWh)**	**Percent Change**	**Customer/ Connection Count**	**Growth**	**Percent Change (%)**
Billed Energy (GWh) and Customer Count / Connections						
2008 Board Approved	23.8			2,300		
2003 Actual	41.5			2,416		
2004 Actual	36.2	(5.3)	(12.7%)	2,376	(40.5)	(1.7%)
2005 Actual	43.3	7.1	19.7%	2,355	(20.5)	(0.9%)
2006 Actual	43.3	0.0	0.0%	2,344	(11.0)	(0.5%)
2007 Actual	38.5	(4.8)	(11.2%)	2,329	(15.0)	(0.6%)
2008 Actual	24.6	(13.9)	(36.2%)	2,312	(17.5)	(0.8%)
2009 Actual	23.3	(1.3)	(5.1%)	2,315	3.0	0.1%
2010 Actual	22.9	(0.4)	(1.7%)	2,305	(9.5)	(0.4%)
2011 Normalized Bridge	**23.6**	**0.3**	**1.3%**	**2,301**	**(13.7)**	**(0.6%)**
2012 Normalized Test	**23.6**	**0.0**	**0.0%**	**2,297**	**(4.1)**	**(0.2%)**

The information in the table above provides weather actual data from 2003 to 2010, while 2011 and 2012 are weather normalized. Atikokan Hydro does not have a process to properly adjust weather actual data to a weather normal basis. However, based on the process outlined in this Exhibit, a process to forecast energy on a weather normalized basis has been developed and used in this Application.

Total Customers and Connections are on a mid-year basis and streetlight, sentinel lights and unmetered loads are measured as connections.

Actual and forecasted billed amounts and numbers of customers are shown in Table 3-3 and customer usage is shown in Table 3-4, on a rate class basis.

Table 3-3: Billed Energy and Number of Customers / Connections by Rate Class						
Year	**Residential**	**GS<50 kW**	**GS>50 kW**	**Street Lighting**	**Intermediate**	**Total**
Billed Energy (GWh)						
2008 Board Approved	10.9	5.4	7.0	0.5	0.0	23.8
2003 Actual	11.2	6.2	7.5	0.5	16.1	41.5
2004 Actual	10.8	5.6	7.2	0.5	12.0	36.2
2005 Actual	11.1	5.7	7.2	0.5	18.8	43.3
2006 Actual	10.8	5.5	6.9	0.5	19.6	43.3
2007 Actual	11.0	5.7	7.2	0.5	14.1	38.5
2008 Actual	10.3	5.4	7.2	0.5	1.1	24.6
2009 Actual	9.8	5.0	8.1	0.5	0.0	23.3
2010 Actual	9.9	5.0	7.5	0.5	0.0	22.9
2011 Normalized Bridge	**10.3**	**5.1**	**7.8**	**0.5**	**0.0**	**23.6**
2012 Normalized Test	**11.4**	**6.4**	**5.3**	**0.5**	**0.0**	**23.6**
Number of Customers/Connections						
2008 Board Approved	1,421	240	20	619		2,300
2003 Actual	1,502	270	22	622	1	2,416
2004 Actual	1,482	255	21	618	1	2,376
2005 Actual	1,468	247	21	620	1	2,355
2006 Actual	1,456	246	20	621	1	2,344
2007 Actual	1,444	244	20	621	1	2,329
2008 Actual	1,433	238	21	620	1	2,312
2009 Actual	1,435	239	21	621		2,315
2010 Actual	1,424	238	21	623		2,305
2011 Normalized Bridge	**1,424**	**233**	**21**	**623**		2,301
2012 Normalized Test	**1,424**	**235**	**15**	**623**		2,297

Table 3-4: Annual Usage per Customer/Connection by Rate Class						
Year	**Residential**	**GS<50 kW**	**GS>50 kW**	**Street Lighting**	**Intermediate**	**Total**
Energy Usage per Customer/Connection (kWh per customer/connection)						
2008 Board Approved	7,683	22,398	350,993	861	0	10,368
2003 Actual	7,449	22,838	348,713	864	16,081,346	17,165
2004 Actual	7,323	22,133	340,763	842	12,033,248	15,235
2005 Actual	7,586	23,026	352,275	816	18,768,448	18,388
2006 Actual	7,392	22,344	346,738	785	19,638,898	18,481
2007 Actual	7,592	23,258	361,076	819	14,122,517	16,522
2008 Actual	7,216	22,680	351,523	789	1,140,822	10,626
2009 Actual	6,798	20,749	394,872	800	0	10,066
2010 Actual	6,973	21,121	357,813	779	0	9,943
2011 Normalized Bridge	**7,218**	**21,824**	**370,382**	**764**	**0**	**10,254**
2012 Normalized Test	**8,006**	**27,184**	**359,620**	**748**	**0**	**10,273**
Annual Growth Rate in Usage per Customer/Connection						
2008 Board Approved v 2008 Actual	6.5%	(1.2%)	(0.2%)	9.1%		(2.4%)
2003 Actual						
2004 Actual	(1.7%)	(3.1%)	(2.3%)	(2.5%)	(25.2%)	(11.2%)
2005 Actual	3.6%	4.0%	3.4%	(3.1%)	56.0%	20.7%
2006 Actual	(2.6%)	(3.0%)	(1.6%)	(3.9%)	4.6%	0.5%
2007 Actual	2.7%	4.1%	4.1%	4.4%	(28.1%)	(10.6%)
2008 Actual	(5.0%)	(2.5%)	(2.6%)	(3.6%)	(91.9%)	(35.7%)
2009 Actual	(5.8%)	(8.5%)	12.3%	1.4%		(5.3%)
2011 Normalized Bridge	**6.2%**	**5.2%**	**(6.2%)**	**(4.5%)**		**1.9%**
2012 Normalized Test	**10.9%**	**24.6%**	**(2.9%)**	**(2.1%)**		**0.2%**

LOAD FORECAST AND METHODOLOGY

Atikokan Hydro's weather normalized load forecast is developed in a three-step process. First, a total system weather normalized purchased energy forecast is developed based on a multifactor regression model that incorporates historical load, weather, days in the month and customer data. Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Next, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load, their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast that has been determined from the regression model. The forecast of customers by rate class is determined using a geometric mean analysis. For those rate classes that use kW for the distribution volumetric billing determinant, an adjustment factor is applied to class energy forecast based on the historical relationship between kW and kWh. In addition, the billed energy by rate class is adjusted in 2011 and 2012 to reflect 10% and 20%, respectively of the four year licensed CDM targets (i.e. 2011 to 2014) assigned to Atikokan Hydro.

A detailed explanation of the load forecasting process follows.

Purchased KWh Load Forecast

An equation to predict total system purchased energy is developed using a multifactor regression model with the following independent variables: weather (heating and cooling degree days); days in month, number of customers and Intermediate class flag indicating whether or not the one Intermediate customer was in production. The regression model uses monthly kWh and monthly values of independent variables from May 2002 to April 2011 to determine the monthly regression coefficients. This provides 108 monthly data points which represents a reasonable data set for use in a regression analysis. Based on the recent global activity surrounding climate change, historical weather data is showing that there is a warming of the global climate system. In this regard, Atikokan Hydro submits that it is appropriate to review the impact of weather since May 2002 on the energy usage and then determine the average weather conditions from May 2002 to April 2011 which would be applied in the forecasting process to determine a weather normalized forecast. However, in accordance with the OEB's

Filing Requirements, Atikokan Hydro has also provided a sensitivity analysis showing the impact on the 2012 forecast of purchases assuming weather normal conditions are based on a 10-year average and a 20-year trend of weather data.

The multifactor regression model has determined drivers of year-over-year changes in Atikokan Hydro's load growth; these include weather, number of days in the month, number of customers and an Intermediate class flag. These factors are captured within the multifactor regression model.

Weather impacts on load are apparent in both the winter heating season, and in the summer cooling season. For that reason, both Heating Degree Days (i.e. a measure of coldness in winter) and Cooling Degree Days (i.e. a measure of summer heat) are modeled.

The following outlines the prediction model used by Atikokan Hydro to predict weather normal purchases for 2011 and 2012:

Atikokan Hydro's Monthly Predicted kWh Purchases

= Heating Degree Days * 873
+ Cooling Degree Days * 4,402
+ Number of Days in the Month * 99,754
+ Intermediate Class Flag * 1,514,871
+ Number of Customers * 4,259
+ Intercept of (11,136,388)

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix A.

The sources of data for the various data points are:

a) Environment Canada website for monthly heating degree day and cooling degree information. Weather data from the Atikokan (AUT) Station was used.

b) The calendar provided information related to number of days in the month.

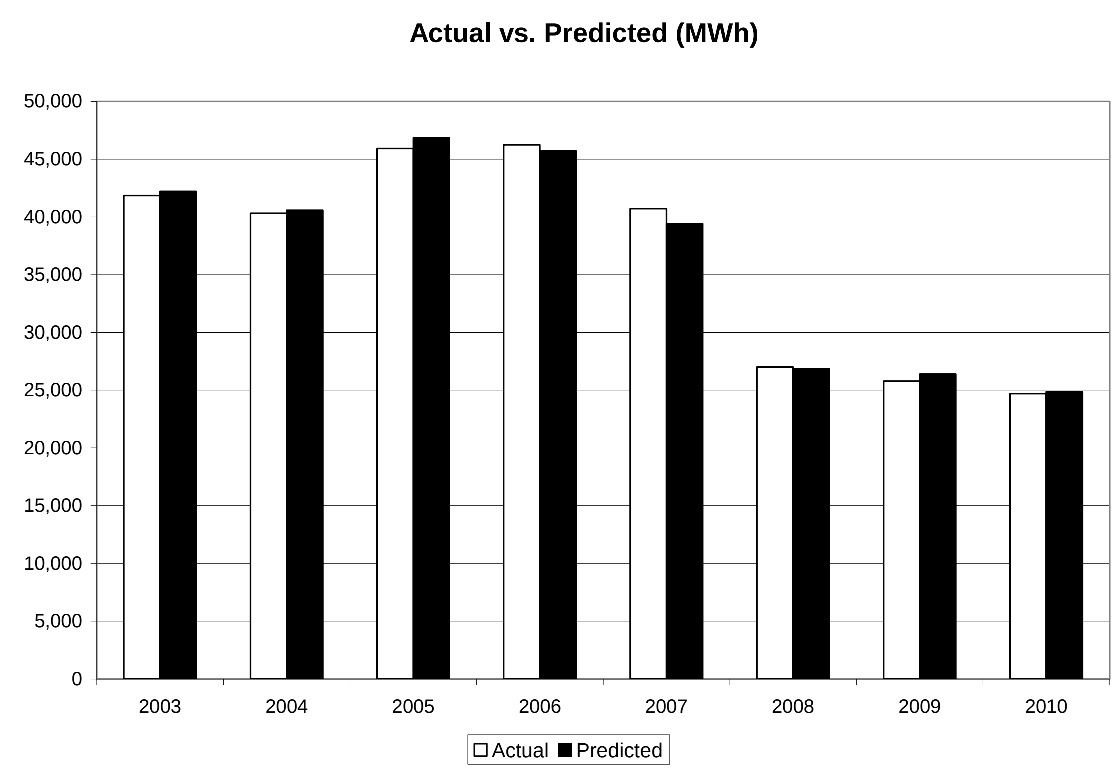
c) The Intermediate class flag was determined based on the review of monthly usage over the 108 months of data

d) The number of customers was based on historical information from the Atikokan Hydro billing system

The prediction formula has the following statistical results:

Table 3-5: Statistcial Results	
Statistic	**Value**
R Square	95.2%
Adjusted R Square	94.9%
F Test	403.0
T-stats by Coefficient	
Intercept	(7.7)
Heating Degree Days	12.3
Cooling Degree Days	3.0
Number of Days in Month	4.0
Intermediate Class Flag	31.3
Number of Customers/Connections	7.9

The annual results of the above prediction formula compared to the actual annual purchases from 2003 to 2010 are shown in the chart below. The chart indicates the resulting prediction equation appears to be reasonable.



The following table outlines the data that supports the above chart. In addition, the predicted total system purchases for Atikokan Hydro are provided for 2011 and 2012. For 2011 and 2012 the system purchases reflect a weather normalized forecast for the full year. In addition, values for 2012 are provided with a 10 year average and a 20 year trend assumption for weather normalization.

Table 3-6: Total System Purchases Excluding Large Use			
Year	**Actual**	**Predicted**	**% Difference**
Purchased Energy (GWh)			
2003	41.9	42.2	0.8%
2004	40.3	40.6	0.6%
2005	45.9	46.9	2.1%
2006	46.2	45.7	(1.1%)
2007	40.7	39.4	(3.2%)
2008	27.0	26.9	(0.5%)
2009	25.8	26.4	2.4%
2010	24.7	24.9	0.6%
2011 Normalized Bridge		**25.5**	
2012 Normalized Test		**25.6**	
2011 Weather Normal - 10 year average		**25.6**	
2011 Weather Normal - 20 year trend		**25.7**	

The weather normalized amount for 2012 is determined by using 2012 dependent variables in the prediction formula on a monthly basis together with the average monthly heating degree days and cooling degree days that occurred from May 2002 to April 2011 (i.e. nine years). The 2012 weather normalized 10 year average value represents the average heating degree days and cooling degree days that occurred from January 2001 to December 2010. The 2012 weather normalized 20 year trend value reflects the trend in monthly heating degree days and cooling degree days that occurred from January 1991 to December 2010.

The weather normal nine year average has been used as the purchased forecast in this Application for the purposes of determining a billed kWh load forecast which is used to design rates. The nine year average has been used as this is consistent with the period of time over which the regression analysis was conducted.

Billed KWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by a historical loss factor. This adjustment has been made by Atikokan Hydro using the average loss factor from 2003 to 2010 of 1.0742. With this average loss factor the total weather normalized billed energy will be 23.7 GWh for 2011 (i.e. 25.5/1.0742) and 23.8 GWh for 2012 (i.e. 25.6/1.0742) before adjustment for CDM discussed below.

Billed KWh Load Forecast and Customer/Connection Forecast by Rate Class

Since the total weather normalized billed energy amount is known, this amount needs to be distributed by rate class for rate design purposes taking into consideration the customer/connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available as shown in the following table.

Table 3-7: Historical Customer/Connection Data

Year	Residential	GS<50 kW	GS>50 kW	Street Lighting	Intermediate	Total
Number of Customers/Connections						
2003	1,502	270	22	622	1	2,416
2004	1,482	255	21	618	1	2,376
2005	1,468	247	21	620	1	2,355
2006	1,456	246	20	621	1	2,344
2007	1,444	244	20	621	1	2,329
2008	1,433	238	21	620	1	2,312
2009	1,435	239	21	621		2,315
2010	1,424	238	21	623		2,305

From the historical customer/connection data the growth rates in customers/ connections can be evaluated. The growth rates are provided in the following table. The geometric mean growth rate in number of customers is also provided. The geometric mean approach provides the average compounding growth rate from 2003 to 2010.

Table 3-8: Growth Rate in Customer/Connections				
Year	**Residential**	**GS<50 kW**	**GS>50 kW**	**Street Lighting**
Growth Rate in Customers/Connections				
2003				
2004	(1.4%)	(5.7%)	(2.3%)	(0.6%)
2005	(0.9%)	(3.1%)	(2.4%)	0.3%
2006	(0.8%)	(0.2%)	(2.4%)	0.2%
2007	(0.8%)	(1.0%)	0.0%	(0.1%)
2008	(0.8%)	(2.5%)	2.5%	(0.2%)
2009	0.1%	0.6%	0.0%	0.2%
2010	(0.8%)	(0.6%)	2.4%	0.3%
Geometric Mean	**(0.8%)**	**(1.8%)**	**(0.3%)**	**0.0%**

For the GS < 50 kW, GS > 50 kW and Street Lighting classes the resulting geometric mean was first applied to the 2010 customer/connection numbers to determine the forecast of customer/connections in 2011 and 2012. However, for the GS < 50 kW and GS > 50 kW classes a manual adjustment to move six customers from the GS > 50 kW class to the GS < 50 kW class to reflect reclassification of these customers.

For the Residential class it has been assumed the 2011 and 2012 number of customers will remain at the 2010 level since Atikokan Hydro does not expect the number of customers in this class to decline below the 2010 level. The following table outlines the forecast of customers and connections by rate class.

Table 3-9: Customer/Connection Forecast					
Year	**Residential**	**GS<50 kW**	**GS>50 kW**	**Street Lighting**	**Total**
Forecast Number of Customers/Connections					
2011	**1,424**	**233**	**21**	**623**	**2,301**
2012	**1,424**	**235**	**15**	**623**	**2,297**

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. The following table provides the average annual usage per customer by rate class from 2003 to 2010.

Table 3-10: Historical Annual Usage per Customer				
Year	**Residential**	**GS<50 kW**	**GS>50 kW**	**Street Lighting**
Annual kWh Usage Per Customer/Connection				
2003	7,449	22,838	348,713	864
2004	7,323	22,133	340,763	842
2005	7,586	23,026	352,275	816
2006	7,392	22,344	346,738	785
2007	7,592	23,258	361,076	819
2008	7,216	22,680	351,523	789
2009	6,798	20,749	394,872	800
2010	6,973	21,121	356,612	779

From the historical usage per customer/connection data the growth rate in usage per customer/connection can be reviewed. That information is provided in the following table. The geometric mean growth rate has also been shown.

Table 3-11: Growth Rate in Usage Per Customer/Connection				
Year	**Residential**	**GS<50 kW**	**GS>50 kW**	**Street Lighting**
Growth Rate in Customer/Connection				
2003				
2004	(1.7%)	(3.1%)	(2.3%)	(2.5%)
2005	3.6%	4.0%	3.4%	(3.1%)
2006	(2.6%)	(3.0%)	(1.6%)	(3.9%)
2007	2.7%	4.1%	4.1%	4.4%
2008	(5.0%)	(2.5%)	(2.6%)	(3.6%)
2009	(5.8%)	(8.5%)	12.3%	1.4%
2010	2.6%	1.8%	(9.7%)	(2.6%)
Geometric Mean	**(0.9%)**	**(1.1%)**	**0.3%**	**(1.5%)**

For the forecast of usage per customer/connection the historical geometric mean was applied to the 2010 usage and the resulting usage forecast is as follows:

Table 3-12: Forecast Annual kWh Usage per Customer/Connection				
Year	**Residential**	**GS<50 kW**	**GS>50 kW**	**Street Lighting**
Forecast Annual kWh Usage per Customers/Connection				
2011	**6,908**	**20,887**	**357,755**	**768**
2012	**6,843**	**20,655**	**358,902**	**757**

With the preceding information the non-normalized weather billed energy forecast can be determined by applying the forecast numbers of customers/connections from Table 3-9 by the forecast of annual usage per customer/connection from Table 3-12. The resulting non-normalized weather billed energy forecast is shown in the following table.

Table 3-13: Non-normalized Weather Billed Energy Forecast					
Year	**Residential**	**GS<50 kW**	**GS>50 kW**	**Street Lighting**	**Total**
NON-normalized Weather Billed Energy Forecast (GWh)					
2011 (Not Normalized)	**9.8**	**4.9**	**7.5**	**0.5**	**22.7**
2012 (Not Normalized)	**9.7**	**4.9**	**5.3**	**0.5**	**20.4**

The non-normalized weather billed energy forecast has been determined but this needs to be adjusted in order to be aligned with the total weather normalized billed energy forecast. As previously determined, the total weather normalized billed energy forecast is 23.7 GWh for 2011 and 23.8 GWh for 2012.

The difference between the non-normalized and normalized forecast adjustments is 1.0 GWh in 2011 (i.e. 23.7 -22.7) and 3.4 GWh in 2012 (i.e. 23.8 – 20.4). The difference is assumed to be associated with moving the forecast from a non-normalized to a weather normal basis and this amount will be assigned to those rate classes that are weather sensitive. Based on the weather normalization work completed by Hydro One for Atikokan Hydro for the cost allocation study, which has been used to support this Application, it was determined that the weather sensitivity by rate classes is as follows:

Table 3-14: Weather Sensitivity by Rate Class			
Residential	**GS<50 kW**	**GS>50 kW**	**Street Lighting**
Weather Sensitivity			
84%	84%	68%	0%

For the GS > 50 kW class the weather sensitivity amount of 68% was provided in the weather normalization work completed by Hydro One. For the Residential and General Service < 50 kW classes, it is has been assumed in previous Cost of Service applications that these two classes are 100% weather sensitive. Intervenors expressed concern with this assumption and have suggested that 100% weather sensitivity is not appropriate. Atikokan Hydro agrees with this position but also submits that the weather sensitivity for the Residential and GS < 50 kW classes should be higher than the GS > 50 kW class. As a result, Atikokan Hydro has assumed the weather sensitivity for the Residential and General Service < 50 kW classes to be mid-way between 100% and 68%, or 84%.

The difference between the non-normalized and normalized forecast of 1.0 GWh in 2011 and 3.4 GWh in 2012 has been assigned on a *pro rata* basis to each rate class based on the above level of weather sensitivity.

With regards to CDM, the four year licensed target for Atikokan Hydro is 1,160,000 kWh. It has been assumed that 10% of this target (i.e. 116,000 kWh) will be achieved in 2011 and that 20% of the target (i.e. 232,000 kWh) will be achieved in 2012. These reductions in billed energy have been assigned to each rate by year in proportion to the information in table 3-13.

In addition, a manual adjustment has made to the GS < 50 kW and GS> 50 kW class to reflect the impact of kWh usage from the reclassification of six customers.

The following table outlines how the classes have been adjusted to align the non-normalized forecast with the normalized forecast and reflect the adjustments discussed above.

Table 3-15: Alignment of Non-normal to Weather Normal Forecast

Year	Residential	GS<50 kW	GS>50 kW	Street Lighting	Total
Non-normalized Weather Billed Energy Forecast (GWh)					
2011 Non-Normalized Bridge	9.8	4.9	7.5	0.5	22.7
2012 Non-Normalized Test	9.7	4.9	5.3	0.5	20.4
Weather Adjustment (GWh)					
2011	0.5	0.2	0.3	0.0	1.0
2012	1.8	0.9	0.8	0.0	3.4
CDM Adjustment (GWh)					
2011	(0.1)	(0.0)	(0.0)	(0.0)	(0.1)
2012	(0.1)	(0.1)	(0.1)	(0.0)	(0.2)
Reclassification Adjustment (GWh)					
2011					
2012		0.7	(0.7)		0.0
Weather Normalized Billed Energy Forecast (GWh)					
2011 Normalized Bridge	10.3	5.1	7.8	0.5	23.6
2012 Normalized Test	11.4	6.4	5.3	0.5	23.6

Billed KW Load Forecast

There are two rate classes that charge volumetric distribution on per kW basis. These include GS > 50 kW and Street lighting. As a result, the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. The forecast of kW for these classes is based on a review of the historical ratio of kW to kWhs and applying the average ratio to the forecasted kWh to produce the required kW.

The following table outlines the annual demand units by applicable rate class.

Table 3-16: Historical Annual kW per Applicable Rate Class

Year	GS>50 kW	Street Lighting	Total
Billed Annual kW			
2003	20,708	1,601	22,309
2004	16,244	1,563	17,806
2005	20,153	1,512	21,664
2006	18,817	1,462	20,279
2007	18,838	1,333	20,171
2008	18,111	1,296	19,407
2009	21,388	1,160	22,549
2010	22,208	1,449	23,657

The following table illustrates the historical ratio of kW/kWh as well as the average ratio for 2003 to 2010.

Table 3-17: Historical kW/KWh Ratio per Applicable Rate Class

Year	GS>50 kW	Street Lighting
Ratio of kW to kWh		
2003	0.2762%	0.2983%
2004	0.2270%	0.3005%
2005	0.2791%	0.2988%
2006	0.2713%	0.3001%
2007	0.2609%	0.2623%
2008	0.2513%	0.2651%
2009	0.2642%	0.2335%
2010	0.2965%	0.2985%
Average 2003 to 2010	**0.2658%**	**0.2821%**

The average ratio was applied to the weather normalized billed energy forecast in Table 3-15 to provide the forecast of kW by rate class as shown below. The following table outlines the forecast of kW for the applicable rate classes.

Table 3-18: kW Forecast by Applicable Rate Class			
Year	**GS>50 kW**	**Street Lighting**	**Total**
Predicted Billed kW			
2009 Normalized Bridge	**20,606**	**1,344**	**21,950**
2010 Normalized Test	**14,205**	**1,316**	**15,521**

Table 3-19 provides a summary of the billing determinants by rate class that are used to develop the proposed rates.

Table 3-19: Summary of Forecast						
	2008 Board Approved	**2008**	**2009**	**2010**	**2011 Weather Normalized Bridge**	**2012 Weather Normalized Test**
ACTUAL AND PREDICTED KWH PURCHASES						
Actual kWh Purchases		27,014,076	25,781,622	24,708,723		
Predicted kWh Purchases		26,872,443	26,388,500	24,858,071	25,467,177	25,592,783
% Difference of actual and predicted purchases		(0.5%)	2.4%			
BILLING DETERMINANTS BY CLASS						
Residential						
Customers	1,421	1,433	1,435	1,424	1,424	1,424
kWh	10,918,134	10,340,422	9,751,774	9,926,568	10,274,885	11,395,913
GS<50 kW						
Customers	240	238	239	238	233	235
kWh	5,375,424	5,386,486	4,958,913	5,016,254	5,089,171	6,387,021
GS>50 kW						
Customers	20	21	21	21	21	15
kWh	7,019,868	7,206,213	8,094,881	7,488,858	7,751,923	5,343,698
kW	18,599	18,111	21,388	22,208	20,606	14,205
Intermediate	0	1	0	0	0	0
Customers	0	1,140,822	0	0	0	0
kWh						
Street Lighting						
Customers	619	620	621	623	623	623
kWh	532,895	488,938	496,845	485,568	476,215	466,493
kW	1,693	1,296	1,160	1,449	1,344	1,316
Total						
Customer/Connections	2,300	2,312	2,315	2,305	2,301	2,297
kWh	23,846,321	24,562,881	23,302,413	22,917,248	23,592,195	23,593,125
kW from applicable classes	20,292	19,407	22,549	23,657	21,950	15,521

Appendix A

	Purchased	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Intermediate Class Flag	Number of Customers/Connections	Predicted Purchases
May-02	4,573,577	338.7	2.9	31	1	2,460	4,256,510
Jun-02	4,260,627	79.7	35.3	30	1	2,457	4,058,859
Jul-02	4,562,117	12.1	84.5	31	1	2,453	4,301,772
Aug-02	4,203,237	33.7	28.2	31	1	2,450	4,058,450
Sep-02	3,873,917	143.8	23.3	30	1	2,446	4,018,881
Oct-02	4,274,057	540.7	0	31	1	2,443	4,348,236
Nov-02	4,161,567	706.8	0	30	1	2,440	4,379,128
Dec-02	4,409,707	850.9	0	31	1	2,436	4,590,321
Jan-03	5,097,790	989.2	0	31	1	2,433	4,696,695
Feb-03	4,717,710	994.6	0	28	1	2,430	4,387,773
Mar-03	4,446,570	769.1	0	31	1	2,426	4,475,777
Apr-03	3,975,240	433.3	0	30	1	2,423	4,068,462
May-03	3,844,650	212.6	0	31	1	2,419	3,961,149
Jun-03	3,428,880	86	16	30	1	2,416	3,806,911
Jul-03	3,846,460	28.4	35.3	31	1	2,413	3,926,949
Aug-03	2,891,760	29.7	56.8	31	0	2,409	2,493,472
Sep-03	1,967,640	173.2	9	30	0	2,406	2,294,239
Oct-03	2,417,070	412.9	1.4	31	0	2,403	2,555,447
Nov-03	2,458,490	667.8	0	30	0	2,399	2,657,708
Dec-03	2,768,410	832.8	0	31	0	2,396	2,887,148
Jan-04	3,085,313	1187.2	0	31	0	2,392	3,182,199
Feb-04	2,532,523	811.7	0	29	0	2,389	2,640,468
Mar-04	2,474,943	708.5	0	31	0	2,386	2,735,498
Apr-04	2,400,573	457	0	30	0	2,382	2,401,785
May-04	2,303,903	347.3	0	31	0	2,379	2,391,386
Jun-04	3,164,823	137.2	16	30	1	2,376	3,679,115
Jul-04	4,224,053	31.4	35.3	31	1	2,374	3,764,169
Aug-04	3,844,613	140.5	56.8	31	1	2,372	3,946,780
Sep-04	3,855,953	123.6	9	30	1	2,370	3,614,601
Oct-04	4,054,133	369.7	1.4	31	1	2,369	3,888,496
Nov-04	3,939,313	562.4	0	30	1	2,367	3,943,550
Dec-04	4,440,873	972.9	0	31	1	2,365	4,394,433
Jan-05	4,722,183	1124.7	0	31	1	2,364	4,519,693
Feb-05	3,915,913	812.6	0	28	1	2,362	3,940,661
Mar-05	4,024,213	824.2	0	31	1	2,360	4,242,775
Apr-05	3,705,613	368	0	30	1	2,358	3,737,439
May-05	3,726,493	264.6	0	31	1	2,357	3,739,639
Jun-05	3,486,993	56.4	26.6	30	1	2,355	3,567,911
Jul-05	3,654,493	34.2	71	31	1	2,354	3,839,806
Aug-05	3,331,013	69.5	28	31	1	2,353	3,677,456
Sep-05	3,350,603	149.9	18.2	30	1	2,352	3,600,859
Oct-05	3,965,603	372.3	1	31	1	2,351	3,815,179
Nov-05	3,975,733	640.1	0	30	1	2,350	3,940,934
Dec-05	4,052,273	872.2	0	31	1	2,350	4,239,430
Jan-06	3,921,263	809.2	0	31	1	2,349	4,180,520
Feb-06	3,835,713	934.6	0	28	1	2,348	3,986,840
Mar-06	4,038,473	678.9	0	31	1	2,347	4,058,947
Apr-06	3,709,953	324.7	0	30	1	2,346	3,646,038
May-06	3,886,953	200	15.1	31	1	2,345	3,699,476
Jun-06	3,562,953	56.3	14.3	30	1	2,344	3,466,833
Jul-06	3,884,013	10.3	75.2	31	1	2,343	3,789,154
Aug-06	3,680,103	38.3	18.5	31	1	2,342	3,558,710
Sep-06	3,526,943	205.7	4.2	30	1	2,340	3,536,846
Oct-06	3,974,403	462.4	0	31	1	2,339	3,836,913
Nov-06	3,963,533	568.6	0	30	1	2,338	3,824,558
Dec-06	4,247,253	809.9	0	31	1	2,337	4,129,666

	Purchased	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Intermediate Class Flag	Number of Customers/Connections	Predicted Purchases
Jan-07	4,446,737	997.6	0	31	1	2,335	4,288,222
Feb-07	4,162,837	999.6	0	28	1	2,334	3,985,382
Mar-07	4,047,317	674.4	0	31	1	2,333	3,995,389
Apr-07	3,649,477	478.8	0	30	1	2,332	3,719,534
May-07	3,822,617	186.5	8.1	31	1	2,330	3,594,410
Jun-07	3,322,417	57.9	39.1	30	1	2,329	3,513,499
Jul-07	3,434,017	41.2	57.4	31	1	2,328	3,673,010
Aug-07	3,216,537	65.5	21.9	31	1	2,326	3,531,760
Sep-07	2,797,977	175.6	6.6	30	0	2,325	1,939,708
Oct-07	2,739,437	333	0	31	0	2,323	2,141,626
Nov-07	2,340,337	663.5	0	30	0	2,322	2,324,219
Dec-07	2,742,337	989.2	0	31	0	2,320	2,702,129
Jan-08	2,748,532	1024	0	31	0	2,319	2,726,650
Feb-08	2,586,142	986	0	29	0	2,317	2,487,491
Mar-08	2,452,042	829	0	31	0	2,316	2,543,363
Apr-08	2,152,630	497	0	30	0	2,314	2,147,704
May-08	2,293,140	340	0	31	0	2,313	2,104,258
Jun-08	1,988,380	119	3	30	0	2,312	1,816,870
Jul-08	1,874,560	43	23	31	0	2,312	1,940,160
Aug-08	1,864,830	47	32	31	0	2,312	1,987,058
Sep-08	1,761,190	193	8	30	0	2,312	1,907,570
Oct-08	2,282,500	390	0	31	0	2,313	2,146,758
Nov-08	2,212,490	645	0	30	0	2,313	2,270,624
Dec-08	2,797,640	1129	0	31	0	2,313	2,793,936
Jan-09	2,785,280	1184	0	31	0	2,314	2,843,810
Feb-09	2,237,810	881	0	28	0	2,314	2,280,718
Mar-09	2,270,800	748	0	31	0	2,314	2,465,538
Apr-09	2,176,770	451	0	30	0	2,314	2,107,716
May-09	2,177,131	319	0	31	0	2,315	2,092,940
Jun-09	2,055,085	125	17	30	0	2,315	1,899,339
Jul-09	1,699,677	91	1	31	0	2,314	1,894,117
Aug-09	1,764,408	88	22	31	0	2,313	1,984,604
Sep-09	1,670,262	81	6	30	0	2,313	1,803,710
Oct-09	2,217,469	468	0	31	0	2,312	2,210,775
Nov-09	2,015,515	507	0	30	0	2,311	2,141,435
Dec-09	2,711,415	995	0	31	0	2,310	2,663,798
Jan-10	2,584,646	989	0	31	0	2,309	2,654,398
Feb-10	2,225,892	856	0	28	0	2,308	2,235,902
Mar-10	2,093,200	528	0	31	0	2,308	2,244,977
Apr-10	1,997,885	332	0	30	0	2,307	1,970,285
May-10	1,773,769	195	0	31	0	2,306	1,947,050
Jun-10	1,674,623	99	0	30	0	2,305	1,759,930
Jul-10	2,021,846	6	0	31	0	2,305	1,776,832
Aug-10	1,928,285	46	0	31	0	2,304	1,810,800
Sep-10	1,824,415	256	0	30	0	2,304	1,893,092
Oct-10	1,849,823	334	0	31	0	2,304	2,059,555
Nov-10	2,235,662	585	0	30	0	2,303	2,177,294
Dec-10	2,498,677	645	0	31	0	2,303	2,327,955
Jan-11	2,610,200	756	0	31	0	2,303	2,423,302
Feb-11	2,246,462	827	0	28	0	2,302	2,184,812
Mar-11	2,236,546	760	0	31	0	2,302	2,424,098
Apr-11	2,047,023	438	0	30	0	2,302	2,041,553

	Purchased	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Intermediate Class Flag	Number of Customers/Connections	Predicted Purchases
May-11		267	3	31	0	2,301	2,003,108
Jun-11		91	19	30	0	2,301	1,816,710
Jul-11		33	42	31	0	2,300	1,969,920
Aug-11		62	29	31	0	2,300	1,936,607
Sep-11		167	9	30	0	2,300	1,838,548
Oct-11		409	0	31	0	2,299	2,109,178
Nov-11		616	0	30	0	2,299	2,186,807
Dec-11		900	0	31	0	2,299	2,532,535
Jan-12		1007	0	31	0	2,298	2,624,631
Feb-12		900	0	29	0	2,298	2,330,745
Mar-12		724	0	31	0	2,298	2,375,214
Apr-12		420	0	30	0	2,297	2,008,142
May-12		267	3	31	0	2,297	1,985,664
Jun-12		91	19	30	0	2,297	1,799,293
Jul-12		33	42	31	0	2,296	1,952,503
Aug-12		62	29	31	0	2,296	1,919,190
Sep-12		167	9	30	0	2,296	1,821,132
Oct-12		409	0	31	0	2,295	2,091,762
Nov-12		616	0	30	0	2,295	2,169,390
Dec-12		900	0	31	0	2,295	2,515,118

OPERATING REVENUE VARIANCE ANALYSIS

THROUGHPUT REVENUE and OTHER OPERATING REVENUE

VARIANCE ANALYSIS ON THROUGHPUT REVENUE:

A summary of historical and forecast operating revenues is presented in Table 3-1. A variance analysis for the other net operating revenue will be provided further in Tab 3 Schedule 2 of this Exhibit.

2008 Board Approved:

Atikokan Hydro's operating revenue in fiscal 2008 was $1,154,657. Throughput revenue was $1,093,701 or 94.7% of total revenues. Other net operating revenue accounts for the remaining $60,956.

2008 Actual:

Atikokan Hydro's operating revenue in fiscal 2008 was $988,482. Throughput revenue was $917,646 or 92.8% of total revenues. Other net operating revenue accounts for the remaining $70,836.

Table 3-20: Comparison 2008 Actual to 2008 Board Approved

Throughput Revenue	2008 Board Approved	2008 Actual	Difference $	Difference %
Residential	$779,960	$610,650	-$169,311	-21.7%
GS<50	$252,667	$217,849	-$34,817	-13.8%
GS>50	$30,193	$34,738	$4,545	15.1%
Intermediate		$25,537	$25,537	100.0%
Sentinel Lights	$295	$543	$248	83.9%
Street Lighting	$24,821	$28,330	$3,508	14.1%
Unmetered Scattered Load	$5,765	$0	-$5,765	-100.0%
Total	$1,093,701	$917,646	-$176,055	-16.1%

Throughput revenue for 2008 was 18.4% or $201,592 lower than the amounts approved in the 2008 EDR primarily due to lower kWh usage in the Residential and GS <50 kW.

The timing difference between the 2008 Actual amounts which are based on the fiscal year of January 1 to December 31, 2008, and the 2008 EDR amounts, which are based on the rate year of June 1, 2008 to April 30, 2009 also contribute to the variance, since the 2008 rates did not come into effect until June 2008.

Table 3-21 below compares the 2008 EDR Approved billing quantities to the 2008 Actual quantities.

Table 3-21: Comparison 2008 Actual to 2008 Board Approved

	Customer/Connections			kWh		kW		
Billing Quantiites	2008 Board Approved	2008 Actual	Difference	2008 Board Approved	2008 Actual	2008 Board Approved	2008 Actual	Volumeteric Difference
Residential	1,421	1,433	12	10,918,134	10,340,422			(577,712)
GS<50	240	238	(3)	5,375,424	5,386,486			11,062
GS>50	20	21	1			18,599	18,111	(488)
Intermediate	0	1						
Sentinel Lights	1	0	(1)			1	0	(1)
Street Lighting	619	620	1			1,693	1,296	(397)
Unmetered Scattered Load	7	0	(7)	5,942	0			(5,942)
Total	2,308	2,312	3	16,299,500	15,726,908	20,293	19,407	

2009 Actual:

Atikokan Hydro's operating revenue in fiscal 2009 was $1,333,892, as shown in Exhibit 3, Tab 1, Table 3-1. Throughput revenue totaled $1,227,176 or 92% of total revenues. Other net operating revenue accounts for the remaining revenue of $106,716.

Comparison 2009 Actual to 2008 Actual – Throughput Revenue*:*

Table 3-22: Comparison 2009 Actual to 2008 Actual

Throughput Revenue	2008 Actual	2009 Actual	Difference $	Difference %
Residential	$610,650	$751,844	$141,195	23.1%
GS<50	$217,849	$304,417	$86,568	39.7%
GS>50	$34,738	$101,815	$67,078	193.1%
Intermediate	$25,537	$0	-$25,537	-100.0%
Sentinel Lights	$543	$2,486	$1,943	358.1%
Street Lighting	$28,330	$66,613	$38,283	135.1%
Unmetered Scattered Load	$0	$0	$0	0.0%
Total	$917,646	$1,227,176	$309,530	33.7%

The 2009 throughput revenue was $309,530 or 33.7% higher than the 2008 actual revenue. The increased usage from residential customers was offset by reductions in the general service rate classes. Despite load reductions for the general service classes, revenue increased for all rate classes due to timing differences between the fiscal and rate year periods, as January 1, 2009 to April 30, 2009 reflected the full impact of the 2008 EDR rate increase, and IRM adjustments between May 1, 2009 and December 31, 2009.

Table 3-23 below compares the 2008 Actual billing quantities to the 2009 Actual quantities.

Table 3-23: Comparison 2009 Actual to 2008 Actual

	Customer/Connections			**kWh**		**kW**		
Billing Quantiites	2008 Actual	2009 Actual	Difference	2008 Actual	2009 Actual	2008 Actual	2009 Actual	Volumeteric Difference
Residential	1,433	1,435	2	10,340,422	9,751,774			(588,648)
GS<50	238	239	2	5,386,486	4,958,913			(427,573)
GS>50	21	21	0			18,111	21,388	3,277
Intermediate	1	0	(1)					
Sentinel Lights								
Street Lighting	620	621	2			1,296	1,160	(136)
Unmetered Scattered Load								0
Total	2,312	2,315	4	15,726,908	14,710,687	19,407	22,549	

2010 Actual:

Atikokan Hydro's operating revenue in fiscal 2010 was $1,311,581, as shown in Exhibit 3, Tab 1, Table 3-1. Throughput revenue totaled $1,141,263 or 87% of total revenues. Other net operating revenue accounts for the remaining revenue of $170,318.

Comparison 2010 Actual to 2009 Actual Throughput Revenue:

Table 3-24: Comparison 2010 Actual to 2009 Actual

Throughput Revenue	2009 Actual	2010 Actual	Difference $	Difference %
Residential	$751,844	$684,040	-$67,805	-9.0%
GS<50	$304,417	$256,070	-$48,347	-15.9%
GS>50	$101,815	$127,054	$25,239	24.8%
Intermediate	$0	$0	$0	0.0%
Sentinel Lights	$2,486	$2,899	$413	16.6%
Street Lighting	$66,613	$71,199	$4,586	6.9%
Unmetered Scattered Load	$0	$0	$0	0.0%
Total	$1,227,176	$1,141,263	-$85,913	-7.0%

Throughput revenue in 2010 was 7% or $85,913 lower than in 2009 due to a combination of overall customer count/connection decline (see Table 3-25) and the 2010 IRM rate changes effective May 1, 2010. In addition, the decline resulted from economic conditions and the reclassification of some General Service < 50 customers to the General Service >50 class contributes to the negative variance. Further to this, for the period starting on June 1, 2008 until September 30, 2008, Atikokan charged customers according to its currently approved rates (2007) rather than the Board approved 2008 rates from its CoS. The Board indicated Atikokan could recover the foregone revenue during that period through a foregone revenue rate riders to be in effect until April 30, 2009. As a result, in 2009 Atikokan Hydro showed greater revenues than 2010 as a result of the foregone revenue rider. Therefore, although the total Kwh and KW in Table 3-25; 2010’s consumption was greater than the prior year 2009 the 2010 throughput revenues were lower.

Table 3-25 below compares the 2009 Actual billing quantities to the 2010 Actual quantities.

Table 3-25: Comparison 2010 Actual to 2009 Actual

	Customer/Connections			kWh		kW		
Billing Quantiites	2009 Actual	2010 Actual	Difference	2009 Actual	2010 Actual	2009 Actual	2010 Actual	Volumeteric Difference
Residential	1,435	1,424	(11)	9,751,774	9,926,568			174,794
GS<50	239	238	(2)	4,958,913	5,016,254			57,341
GS>50	21	21	1			21,388	22,208	820
Intermediate								
Sentinel Lights								
Street Lighting	621	623	2			1,160	1,449	289
Unmetered Scattered Load								0
Total	2,315	2,305	(10)	14,710,687	14,942,822	22,549	23,657	

2011 Bridge Year:

Atikokan Hydro's operating revenue is forecasted to be $1,268,093 in 2011 as shown in Exhibit 3, Tab 1, Table 3-1. Throughput revenue totals $1,145,346 or 90% of total revenues. Other net operating revenue accounts for the remaining revenue of $122,747.

Comparison 2011 Bridge to 2010 Actual Throughput Revenue:

Table 3-26: Comparison 2011 Bridge to 2010 Actual

Throughput Revenue	2010 Actual	2011 Bridge	Difference $	Difference %
Residential	$684,040	$616,293	-$67,747	-9.9%
GS<50	$256,070	$295,304	$39,234	15.3%
GS>50	$127,054	$144,384	$17,330	13.6%
Intermediate	$0	$0	$0	0.0%
Sentinel Lights	$2,899	$3,284	$385	13.3%
Street Lighting	$71,199	$86,081	$14,882	20.9%
Unmetered Scattered Load	$0	$0	$0	0.0%
Total	$1,141,263	$1,145,346	$4,084	0.4%

Total throughput operating revenue is forecast to be 0.4% or $ 4,084 higher than the 2010 amounts. In 2010, the mild winter and cool summer produced comparatively lower kWh as indicated in Table 3-27 below.

Table 3-27: Comparison 2011 Actual to 2010 Actual

	Customer/Connections			kWh		kW		
Billing Quantiites	2010 Actual	2011 Bridge	Difference	2010 Actual	2011 Bridge	2010 Actual	2011 Bridge	Volumeteric Difference
Residential	1,424	1,424	0	9,926,568	10,274,885			348,317
GS<50	238	233	(4)	5,016,254	5,089,171			72,917
GS>50	21	21	(0)			22,208	20,606	(1,602)
Intermediate								
Sentinel Lights								
Street Lighting	623	623	0			1,449	1,344	(106)
Unmetered Scattered Load								0
Total	2,305	2,301	(4)	14,942,822	15,364,056	23,657	21,950	

2012 Test Year:

Atikokan Hydro's 2012 Test Year operating revenue is forecasted to be $1,579,603 as shown in Exhibit 3, Tab 1, Table 3-1. Throughput revenue totals $1,454,368 or 92.07% of total revenues. Other net operating revenue accounts for the remaining revenue of $125,235.

Comparison of 2012 Test Year to 2011 Bridge Year Throughput Revenue:

Table 3-28: Comparison 2012 Test to 2011 Bridge

Throughput Revenue	2011 Bridge	2012 Test	Difference $	Difference %
Residential	$616,293	$885,536	$269,243	43.7%
GS<50	$295,304	$299,438	$4,134	1.4%
GS>50	$144,384	$135,810	-$8,574	-5.9%
Intermediate	$0	$0	$0	0.0%
Sentinel Lights	$3,284	$0	-$3,284	-100.0%
Street Lighting	$86,081	$133,584	$47,503	55.2%
Unmetered Scattered Load	$0	$0	$0	0.0%
Total	$1,145,346	$1,454,368	$309,022	27.0%

Total throughput revenue is forecasted to be $309,022 or 27.0% higher than the 2011 Bridge year. This variance is due to increased revenue resulting from this rate application.

Table 3-29 below compares the 2011 Bridge Year billing quantities to the 2012 Test Year billing quantities.

Table 3-29: Comparison 2012 Test to 2011 Bridge

	Customer/Connections			**kWh**		**kW**		
Billing Quantiites	2011 Bridge	2012 Test	Difference	2011 Bridge	2012 Test	2011 Bridge	2012 Test	Volumeteric Difference
Residential	1,424	1,424	0	10,274,885	11,395,913			1,121,028
GS<50	233	235	2	5,089,171	6,387,021			1,297,850
GS>50	21	15	(6)			20,606	14,205	(6,402)
Intermediate								
Sentinel Lights								
Street Lighting	623	623	0			1,344	1,316	(27)
Unmetered Scattered Load								0
Total	2,301	2,297	(4)	15,364,056	17,782,934	21,950	15,521	

TRANSFORMER ALLOWANCE

Atikokan Hydro currently provides a Transformer Ownership Allowance Credit of 10% of the GS > 50 kW class kW volumetric distribution rate to those customers that own their own transformer facilities. Atikokan Hydro is proposing to maintain this rate for the 2012 Test Year for eligible customers.

VARIANCE ANALYSIS ON OTHER DISTRIBUTION REVENUE

2008 Board Approved Comparison to 2008 Actual – Other Operating Revenue:

Table 3-30 below summarizes the variance by account description.

Table 3-30: Comparison 2008 Actual to 2008 Board Approved

Other Distribution Revenue	2008 Board Approved	2008 Actual	Difference $	Difference %
SSS Administration Revenue	$0	$4,816	$4,816	100.0%
Rent from Electric Property	$31,536	$35,045	$3,509	11.1%
Late Payment Charges	$6,233	$5,624	-$609	-9.8%
Specific Service Charges	$5,886	$5,322	-$564	-9.6%
Merchandise & Jobbing	$0	$0	$0	0.0%
Other Distribution Rev.	$0	$8,688	$8,688	100.0%
Other Income & Exp.	$17,301	$11,341	-$5,960	-34.4%
Total	$60,956	$70,836	$9,880	16.2%

2009 Actual Comparison to 2008 Actual – Other Operating Revenue

Table 3-31 below summarizes the variance by account description.

Table 3-31: Comparison 2009 Actual to 2008 Actual

Other Distribution Revenue	2008 Actual	2009 Actual	Difference $	Difference %
SSS Administration Revenue	$4,816	$7,189	$2,372	49.3%
Rent from Electric Property	$35,045	$38,196	$3,151	9.0%
Late Payment Charges	$5,624	$7,043	$1,419	25.2%
Specific Service Charges	$5,322	$32,896	$27,574	518.1%
Merchandise & Jobbing	$0	$0	$0	0.0%
Other Distribution Rev.	$8,688	$11,849	$3,162	36.4%
Other Income & Exp.	$11,341	$9,542	-$1,799	-15.9%
Total	$70,836	$106,716	$35,880	50.7%

2010 Actual Comparison to 2009 Actual – Other Operating Revenue:

Table 3-32 below summarizes the variance by account description followed by a discussion on those variances over $50,000.

Table 3-32: Comparison 2010 Actual to 2009 Actual				
Other Distribution Revenue	2009 Actual	2010 Actual	Difference $	Difference %
SSS Administration Revenue	$7,189	$4,788	-$2,401	-33.4%
Rent from Electric Property	$38,196	$34,911	-$3,285	-8.6%
Late Payment Charges	$7,043	$6,024	-$1,020	-14.5%
Specific Service Charges	$32,896	$6,745	-$26,151	-79.5%
Merchandise & Jobbing	$0	$86,125	$86,125	100.0%
Other Distribution Rev.	$11,849	$16,927	$5,077	42.8%
Other Income & Exp.	$9,542	$14,799	$5,257	55.1%
Total	$106,716	$170,318	$63,602	59.6%

In 2010 the Merchandise and Jobbing has a variance of $86,125. This difference results from Atikokan Hydro recording these revenues as revenues in 2010 instead of an offset to expenses.

2011 Bridge Year Comparison to 2010 Actual – Other Operating Revenue:

Table 3-33 below summarizes the variance by account description.

Table 3-33: Comparison 2011 Bridge to 2010 Actual				
Other Distribution Revenue	2010 Actual	2011 Bridge	Difference $	Difference %
SSS Administration Revenue	$4,788	$4,654	-$134	-2.8%
Rent from Electric Property	$34,911	$34,911	$0	0.0%
Late Payment Charges	$6,024	$6,024	$0	0.0%
Specific Service Charges	$6,745	$7,100	$355	5.3%
Merchandise & Jobbing	$86,125	$55,000	-$31,125	-36.1%
Other Distribution Rev.	$16,927	$6,058	-$10,869	-64.2%
Other Income & Exp.	$14,799	$9,000	-$5,799	-39.2%
Total	$170,318	$122,747	-$47,571	-27.9%

2012 Test Year Comparison to 2011 Bridge Year– Other Operating Revenue:

Table 3-34 below summarizes the variance by account description.

Table 3-34: Comparison 2012 Test to 2011 Bridge				
Other Distribution Revenue	2011 Bridge	2012 Test	Difference $	Difference %
SSS Administration Revenue	$4,654	$4,200	-$454	-9.8%
Rent from Electric Property	$34,911	$34,911	$0	0.0%
Late Payment Charges	$6,024	$6,024	$0	0.0%
Specific Service Charges	$7,100	$7,100	$0	0.0%
Merchandise & Jobbing	$55,000	$55,000	$0	0.0%
Other Distribution Rev.	$6,058	$9,000	$2,942	48.6%
Other Income & Exp.	$9,000	$9,000	$0	0.0%
Total	$122,747	$125,235	$2,488	2.0%

MANAGERS SUMMARY

OVERVIEW OF OPERATING COSTS:

Operating Costs:

The operating costs presented in this Exhibit represent the annual expenditures required to sustain Atikokan Hydro's distribution operations. Atikokan Hydro follows the OEB's Accounting Procedures Handbook (the "APH") in distinguishing work performed between operations and maintenance. A summary of Atikokan Hydro's operating costs for 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year and the 2012 Test Year in accordance with the Filing Requirements, is provided in Table 4.1 below. A summary of the variances as required by the Filing Requirements is provided in Tables 4.2 through 4.6.

Table 4.1

Summary of OM&A Expenses

Description	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Test Year	2012 Bridge Year
Operations	311,895	296,121	322,006	332,111	273,927	418,349
Maintenance	38,800	88,816	41,928	51,665	62,471	53,177
Billing & Collecting	170,950	168,981	159,760	130,786	149,483	153,170
Community Relations	-	-	-	-	-	-
Administrative & General Expenses	287,400	291,106	357,989	486,151	488,395	550,455
Total OM&A Expense	809,045	845,024	881,683	1,000,713	974,277	1,175,151
Year over Year Increase		4.45%	4.34%	13.50%	-2.64%	20.62%
CAGR from 2008 Board Approved						9.78%
CAGR from 2008 Actual						8.59%
Inflation Rate (Canada CPI)		2.37%	0.30%	1.78%	2.98%	2.98%

Table 4.2 Summary OM&A Expense Variances 2008 Approved vs. 2008 Actual

OM&A: 2008 Approved Vs. 2008 Actual				
Description	2008 Board Approved	2008 Actual	Variance ($)	Variance (%)
Operations	311,895	296,121	-15,774	-5.06%
Maintenance	38,800	88,816	50,016	128.91%
Billing & Collecting	170,950	168,981	-1,969	-1.15%
Community Relations	-	-	-	
Administrative & General Expense	287,400	291,106	3,706	1.29%
Total OM&A Expense (Controllable)	809,045	845,024	35,979	4.45%

Table 4.3 Summary OM&A Expense Variances 2008 Actual vs. 2009 Actual

OM&A: 2008 Actual Vs. 2009 Actual				
Description	2008 Actual	2009 Actual	Variance ($)	Variance (%)
Operations	296,121	322,006	25,885	8.74%
Maintenance	88,816	41,928	-46,888	-52.79%
Billing & Collecting	168,981	159,760	-9,221	-5.46%
Community Relations	-	-	-	
Administrative & General Expense	291,106	357,989	66,883	22.98%
Total OM&A Expense (Controllable)	845,024	881,683	36,659	4.34%

Table 4.4 Summary OM&A Expense Variances 2009 Actual vs. 2010 Actual

OM&A: 2009 Approved Vs. 2010 Actual				
Description	2009 Actual	2010 Actual	Variance ($)	Variance (%)
Operations	322,006	332,111	10,105	3.14%
Maintenance	41,928	51,665	9,737	23.22%
Billing & Collecting	159,760	130,786	-28,974	-18.14%
Community Relations	-	-	-	
Administrative & General Expense	357,989	486,151	128,162	35.80%
Total OM&A Expense (Controllable)	881,683	1,000,713	119,030	13.50%

Table 4.5 Summary OM&A Expense Variances 2010 Actual vs. 2011 Bridge

OM&A: 2010 Approved Vs. 2011 Bridge				
Description	2010 Actual	2011 Bridge Year	Variance ($)	Variance (%)
Operations	332,111	273,927	-58,184	-17.52%
Maintenance	51,665	62,471	10,806	20.92%
Billing & Collecting	130,786	149,483	18,697	14.30%
Community Relations	-	-	-	
Administrative & General Expense	486,151	488,395	2,244	0.46%
Total OM&A Expense (Controllable)	1,000,713	974,276	-26,437	-2.64%

Table 4.6 Summary OM&A Expense Variances 2011 Bridge vs. 2012 Test

OM&A: 2011 Bridge Vs. 2012 Test				
Description	2011 Bridge Year	2012 Test Year	Variance ($)	Variance (%)
Operations	273,927	418,349	144,422	52.72%
Maintenance	62,471	53,177	-9,294	-14.88%
Billing & Collecting	149,483	153,170	3,687	2.47%
Community Relations	-	-	-	
Administrative & General Expense	488,395	550,445	62,050	12.70%
Total OM&A Expense (Controllable)	974,276	1,175,141	200,865	20.62%

Detailed information with respect to OM&A costs and variances, arranged by USoA account, is provided later on this Exhibit under section OM&A Detailed Costs.

The variance used to determine the OM&A accounts requiring analysis has been prescribed by the Filing Requirements as $50,000 for a distributor with a distribution revenue requirement less than or equal to $10 million

OM&A Costs:

OM&A costs in this Exhibit represent Atikokan Hydro's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and government direction; and to maintain distribution business service quality and reliability at targeted performance levels; ensuring the Town of Atikokan is provided with safe, reliable and affordable electricity. OM&A costs also include providing services to customers connected to Atikokan Hydro's distribution system, and meeting the requirements of the OEB's Standard Supply Service Code and Retail Settlement Code.

The proposed OM&A cost expenditures for the 2012 Test Year are the result of business planning and work prioritization process that ensures that the most appropriate, cost effective solutions are put in place.

Atikokan Hydro is proposing recovery of 2012 Test Year OM&A costs, excluding Amortization, PILs and Interest totaling $1,175,151.

OM&A Budgeting Process Used by Atikokan Hydro:

The operating budget is prepared annually and coordinated by senior management. Senior management further presents the OM&A budget to be and reviewed and approved by the Board of Directors. Once the Board of Directors approves the annual budget the budget amounts do not change but rather provide a plan against which actual results may be evaluated. The operating budget process at Atikokan Hydro is an integral planning tool and ensures that appropriate resources are available to maintain its distribution system assets. In preparation of the OM&A budget; managing Atikokan's distribution system assets, Atikokan Hydro's main objective is to optimize performance of the assets at a reasonable cost with due regard for system reliability, safety, and customer service expectations.

Operating Work plans:

The line foreman and administration provides input for the preparation of the departmental budget. The following directives are provided to senior management:

- Outside expenses for all department budgets are built using previous year actual, current year forecast and current year budget as the base;
- Outstanding work projects;
- Review the headcount of the department and outline any changes for upcoming retirees and or further job safety training requirements

Income Tax, Large Corporation Tax and Ontario Capital Taxes:

Atikokan Hydro is subject to the payment of PILs under Section 93 of the *Electricity Act, 1998*, as amended. The Applicant does not pay Section 89 proxy taxes, and is exempt from the payment of income and capital taxes under the *Income Tax Act (Canada)* and the Ontario *Corporations Tax Act*. The PILs assumed in the application for 2012 is $17,926. In order to support the PILs amount Atikokan Hydro has completed the Board's 2012 Test year Income Tax PILs Workform and has filed a working copy of this work form as part of this application. Along with the 2010 Federal and Ontario Tax Returns provided in Appendix A this should provide the evidence to support the PILs assumed in the 2012 revenue requirement.

DEPARTMENTAL AND CORPORATE OM&A ACTIVITIES:

OPERATIONS & MAINTENANCE

The expenses for this department include all costs relating to the operation (5000-5096) and maintenance (5105-5195) of Atikokan Hydro's electrical system. This includes both direct labor costs and non-capital material spending to support both scheduled and reactive maintenance events. In addition, costs are allocated from support departments to cover the costs of Labour, and Stores. Atikokan Hydro's maintenance strategy is, to the extent possible, to minimize reactive and emergency-type work through an effective planned maintenance program (including predictive and preventative actions).

Atikokan Hydro's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with Atikokan Hydro's capital project work, so that where maintenance programs have identified matters the correction of which require capital investments, Atikokan Hydro may adjust its capital spending priorities to address those matters.

Predictive Maintenance:

Predictive maintenance activities involve the testing of elements of the Atikokan Hydro distribution system. These activities include transformer oil analysis, planned visual inspections and pole testing completed on a scheduled basis. Any identified deficiencies found are prioritized and addressed within a suitable time frame dependent on the assessment condition:

1. Immediate Action
2. Within the next budget year and
3. To be considered with major rebuilds

Preventative Maintenance:

Preventative maintenance activities include inspection, servicing and repair of network components. This includes overhead. Also included are regular inspections and repair of substation components and ancillary equipment. The work is performed using a combination of time and condition based methodologies.

Emergency Maintenance:

This item includes unexpected system repairs to the electrical system that must be addressed immediately. The costs include those related to repairs caused by storm damage, emergency tree trimming and on-call premiums. Atikokan Hydro constantly evaluates its maintenance data to adjust predictive and preventative actions. The ultimate objective is to reduce emergency maintenance. An emergency call line is directed to the "on call" linesman in the event of service problems outside of normal business hours. The "on call" personnel assesses and calls for any assistance as required from other line crew personnel in the event of an emergency callout.

Service Work:

The majority of costs related to service work pertain to service upgrades requested by customers, and requests to provide safety coverage for work (overhead line cover ups). This includes service disconnections and reconnections by Atikokan Hydro for all service classes; assisting pre-approved contractors; the making of final connections after Electrical Safety Authority ("ESA") inspection for service upgrades; and changes of service locations.

Metering:

The Atikokan Hydro's Line crew is responsible for the installation, testing, and commissioning of new and existing simple and complex metering installations. Testing of complex metering installations ensures the accuracy of the installation and verifies meter multipliers for billing purposes. When necessary, for the safety of Atikokan employees, hired trainers are brought in for advice on complex meter installations.

The line crew further read meters for move in/out commonly known as cut-out and cut-in reads. Meters are also checked where billing notices consumption exceptions. Both activities performed by operations allow for line patrols; proactively monitoring theft of power, meter or line malfunctions.

Substation Services:

Substation services activities address the maintenance of all equipment at Atikokan Hydro's 4 substations. This includes both labor costs and non-capital material spending to support both scheduled and emergency maintenance events. As with the maintenance activities, Atikokan Hydro's substation maintenance strategy focuses on minimizing, to the extent possible, emergency-type work by improving the effectiveness of Atikokan Hydro's planned maintenance program (including predictive and preventative actions) for its substations.

ENGINEERING DEPARTMENT

Atikokan Hydro does not have an Engineering Department. The line crew is responsible for keeping asset related data up to date and Supervisory Control and data Acquisition (SCADA). Atikokan Hydro's asset records are used for asset management activities. Engineering required beyond Atikokan Hydro's internal abilities is outsourced to vendors.

STORES/WAREHOUSE

Stores activities are shared by Atikokan Hydro's line crew and administrative employees. Together, duties include being accountable for managing the procurement, control, and movement of materials. This would include monitoring inventory levels, issuing material receipts, material issues, and material returns as required. The cost of the stores department is allocated to all departmental, capital and Third Party receivable accounts as an overhead cost based on direct material costs.

GARAGE/TRANSPORTATION FLEET

The maintenance and control of Atikokan Hydro's 6 vehicles and 4 off-road vehicles is shared by the line crew. The objectives include keeping maintenance schedules to ensure vehicle reliability and safety, and the minimization of vehicle (on/off road) down time. Vehicle costs are allocated to operations, maintenance, capital and Third Party receivable accounts based on number of hours used. A standard hourly cost/hr is set for all vehicles within the fleet.

LABOUR BURDEN /SAFETY AND HEALTH

The office staff collects the cost of all employee benefits and payroll taxes such as EI, CPP, EHT, WSIB, and group insurances. Costs are allocated to all departments, capital and Third Party receivable amounts based on direct labour.

Health and Safety Costs expensed include Health & Safety program supplies as well labour costs associated with safety meetings. Atikokan Hydro is committed to maximizing productivity and reducing risk of injury by initiating safety and health measures that focus on preventative actions. The commitment to safety and health is significant, and involves documenting unsafe behaviors, monitoring conformance to established standards and policies, determining the effectiveness of safety training and monitoring the resolution of safety recommendations/audits; commitment to continuous improvement in training; and identifying and correcting root causes for system deficiencies. Atikokan Hydro in 2007 received achieved the milestone Bronze Award for 30 years without a loss-time incident and continue to apply safety measures daily.

CUSTOMER SERVICE

The Office Staff is also responsible for the customer service activities for approximately 1700 customers in Atikokan Hydro's service area. These activities include meter reading, billing, call centre, collections, and other back office functions. Atikokan Hydro aspires to achieve customer service excellence in its processes and customer programs. The costs associated with the Customer Service department are collected in accounts 5305 to 5340.

Meter Reading:

Meter reading is completed using Savage Data for smart meters with the exception of a few customers who have smart meters with demand that have to be read and reset by line crew. The time spent meter reading has significantly been reduced. There is no cost savings to Atikokan Hydro as the meter reading has always been completed by in-house staff; line crew. This however does allot more available to complete other OM&A activities.

Billing:

Atikokan Hydro bills all customers monthly and issues approximately a total of 20,500 electricity invoices annually to customers. This total count includes on average 175 final bills for customers moving within or outside of Atikokan Hydro's service territory. The billing functions include the VEE (validating, editing and estimating) processes; EBT and retailer settlement functions for 120 retailer accounts; account adjustments; processing meter changes; and other various account related field service orders and mailing services. All bills are printed and mailed from the Atikokan Hydro office. Atikokan Hydro offers customers a number of billing and payment options including walk-in counter service, a night deposit box, an equal payment plan, and a preauthorized payment plan, Debit Card, Cheque and Cash are accepted, Credit Card payment is available through a 3rd party and payments can also be paid at banking institutions. Atikokan Hydro's regular office hours are Monday to Friday 8:30 to 4:30 excluding stat holidays.

Collections:

Collections involve a combination of activities, including the collection of overdue active accounts, security deposits and final bills for service termination. In an effort to minimize credit losses, Atikokan Hydro enforces a prudent credit policy in accordance with the Distribution System Code. Active overdue accounts are collected by in-house staff through notices, letters and direct telephone contact. Final bill collections are turned over to a collection agency after collection methods are exhausted.

Community Relations:

Atikokan Hydro is committed to providing consumer information and responses in a timely and proactive manner, on electricity distribution and related issues. Atikokan Hydro maintains a presence in the communities it serves, where Atikokan Hydro staff is available to answer customer questions in a friendly environment.

Atikokan Hydro has an important role to play in educating the public about electricity safety and energy conservation. Atikokan Hydro continues to participate with the OPA in administering programs directed at Energy Conservation and mailing all OEB literature when required.

ADMINISTRATIVE AND GENERAL EXPENSES

Administrative and general expenses include expenses incurred in connection with the general administration of the utility's operations. Within Atikokan Hydro, the following functional areas (5605, 5610 and 5615) are considered to be part of general administration and, as such, all expenses incurred within these functional areas are accounted for as administrative and general expenses:

Executive Salaries and Expenses: 5605

This account includes only remuneration for Atikokan Hydro’s Board of Directors and President.

Management Salaries and Expenses: 5610

This account includes the salary for Atikokan Hydro’s CEO, Secretary/Treasurer.

Administrative Services: 5615

Administrative Services includes: Accounting/Finance, Corporate Administration and Personnel Administration. Accounting/Finance responsibilities include the preparation of statutory, management and Board of Directors financial reporting in accordance with GAAP; all daily accounting functions, including accounts payable, accounts receivable, and general accounting; accounting systems; and supporting tax compliance. Regulatory reporting and compliance with applicable codes and legislation governing Atikokan Hydro including development and preparation of rate filings, performance reporting, and compliance are also Finance responsibilities. Corporate Administration and Personnel Administration responsibilities include providing support services required to operate an effective corporation as well as human resource-related support services.

Outside Service Employed: 5630

Outside Services Employed by Atikokan Hydro include, but are not limited to, consulting and professional fees of accountants and auditors, actuaries, legal services, public relations counsel and tax consultants.

Regulatory Expenses: 5655

Regulatory Expenses include those expenses incurred in connection with Decisions and Orders on Cost Awards for hearings, proceedings, technical sessions, and other matters before the OEB or other regulatory bodies, including annual assessment fees paid to a regulatory body. Annual fees assessed by the OEB are included in this expenditure category. Also included in this expense category is annual ESA audit Regulation 22/04 Electrical District Safety expenses.

Miscellaneous General Expense: 5665

Membership dues, other miscellaneous costs are included in this account. Atikokan Hydro is a member of the Electrical Distributor Association and the local Chamber of Commerce.

Maintenance of General Plant: 5675

Expenses under Maintenance of General Plant include all costs of operating the service centre and office building. These include items such as: building utility costs, maintenance & repairs to the office building, lawn care & snow removal and janitorial contract.

Electrical Safety Authority (“ESA”): 5680

Expenses under Electrical Safety Authority (“ESA”) fees include all annual charges from the ESA; excluding audit charges (see 5665).

OM&A DETAILED COSTS

Table 4-7
Detailed Account by Account Operation Expenses

Operation Expenses							
USoA	Distribution Expenses - Operation	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test Year
5016	Distribution Station Equipment - Labour	0	15,455	3,989	0	1,060	1,087
5017	Distribution Station Equipment - Operation Supplies/Expenses	0	1,873	470	0	200	205
5020	Overhead Distribution Lines/Feeder Labour	264,945	221,989	229,359	261,114	229,359	265,093
5025	Overhead Distribution Lines/Feeder Supplies/Expenses	35,300	42,189	57,381	27,341	41,868	42,915
5030	Overhead Subtransmission Feeders	5,000	9,898	30,272	42,657	1,440	1,476
5035	Overhead Distribution Transformer Operation	0	3,941	65	0	0	0
5065	Meter Expense	6,200	159	21	1,000	0	107,573
5095	Overhead Distribution Line/Feeders Rental PD	450	617	448	0	0	0
	TOTAL OPERATIONS	311,895	296,121	322,005	332,112	273,927	418,349

Table 4-8
Detailed Account by Account Maintenance Expenses

Maintenance Expenses							
USoA	Distribution Expenses - Maintenance	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test Year
5114	Maintenance of Distribution Stn Equipment	2,000	3,804	1,072	585	585	599
5125	Maintenance Of O/head Conductors & Devices	0	748	1,416	20,406	5,763	5,907
5130	Maintenance Of Overhead Services	4,500	9,784	0	222	187	191
5135	Overhead Distribution Lines/Feeders-Right of Way	25,000	51,058	27,718	29,522	41,628	42,669
5160	Maintenance of Line Transformers	800	19,523	27	250	12,361	1,814
5175	Maintenance of Meters	6,500	3,899	730	680	1,947	1,996
5195	Maintenance of Other Installations on Customer Premises	0	0	10,966	0	0	0
	TOTAL MAINTENANCE	38,800	88,816	41,929	51,665	62,471	53,176

Table 4-9
Detailed Account by Account Billing & Collecting Expenses

Billing & Collecting Expenses							
USoA	Billing & Collecting Expenses	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test Year
5305	Supervision	4,900	4,043	3,139	7,700	2,660	2,727
5310	Meter Reading Expense	52,050	45,772	51,303	32,118	44,819	45,939
5315	Customer Billing	110,000	110,711	97,640	87,381	94,693	97,060
5325	Collecting - Cash Over and Shortage	0	50	311	(338)	0	0
5330	Collection Charges	(6000)	(5200)	(1300)	0	0	0
5335	Bad Debt Expense	3,000	6,355	5,655	3,924	5,311	5,444
5340	Miscellaneous Customer Accounts Expenses	6,800	7,250	3,013	0	2,000	2,000
	TOTAL MAINTENANCE	170,750	168,981	159,761	130,785	149,483	153,170

Table 4-10
Detailed Account by Account General & Administrative Expenses

General & Administrative Expenses							
USoA	General & Administrative Expenses	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test Year
5605	Executive Salaries and Expenses	6,000	6,000	6,000	6,000	6,000	6,000
5610	Management Salaries and Expenses	12,500	11,639	105,204	116,180	119,084	122,061
5615	General Admin Salaries and Expenses	62,000	17,205	48,937	124,407	127,518	130,706
5620	Office Supplies amd Expenses	7,200	6,244	8,450	7,416	7,954	8,153
5630	Outside Service Employed	65,000	153,350	85,873	135,076	124,766	127,886
5635	Property Insurance	8,000	7,271	8,379	8,604	8,894	9,116
5645	Employee Pensions and Benefits			1,460			
5655	Reglatory Expenses	14,000	11,522	5,142	13,149	10,307	60,564
5660	General Advertising Expenses	2,400	617	977	1,649	1,200	1,230
5665	Miscellaneous Expense	60,200	41,225	44,060	35,845	40,376	41,386
5675	Maintenance and General Plant	43,600	36,034	41,646	35,905	40,264	41,271
5680	Electrical Safety Authority Fees	6,500	0	1,862	1,920	2,031	2,082
	TOTAL GENERAL & ADMINISTRATIVE EXPENSES	287,400	291,107	357,990	486,151	488,394	550,455

VARIANCE ANALYSIS ON OM&A COSTS:

Atikokan Hydro has provided a detailed OM&A cost table covering the periods from 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year and 2012 Test Year. Before moving to a variance analysis for each account that exceeds the materiality threshold ($50,000), a summary of total OM&A expenses is presented below along with an analysis of the high level cost drivers from 2008 Board Approved to 2012 Test Year.

Table 4-11
OM&A Cost Drivers

OM&A	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test Year
Opening Balance		$ 809,045	$ 845,025	$ 881,683	$ 1,000,713	$ 974,277
Outside Services			-$ 67,477	$ 49,203		
Operations		-$ 15,774				
Maintenance		$ 50,016			$ 10,806	
General & Administrative		$ 3,707				
Billing & Collecting		-$ 1,969			$ 16,697	
Staffing Changes						$ 30,000
Operation Changes					-$ 58,184	
Regulatory Costs			-$ 6,380			$ 50,000
LEAP Funding					$ 2,000	
Management Salaries & Expenses (5610)			$ 93,565	$ 10,976	$ 2,904	$ 2,977
General & Administrative Salaries (5615)			$ 31,732	$ 75,470	$ 3,111	$ 3,188
Smart Meters (5065)						$ 107,573
Miscellaneous Adjustment			-$ 14,782	-$ 16,619	-$ 3,770	$ 7,136
Closing Balance	$ 809,045	$ 845,025	$ 881,683	$ 1,000,713	$ 974,277	$ 1,175,151

2008 Cost Driver

- Operations (-$15,774) were some what less than Board approved due to fewer weather related issues.
- Maintenance ($50,016) was higher in 2008 due to the failure of a cross arm on the 3M2 line that required the use of additional personnel and equipment. More maintenance of right of way also occurred

- General and Administrative expenses ($3,707) were up slightly because in 2008 these expenses were capitalized and with maintenance being higher, less administrative time was capitalized
- Billing and collection (-$1,969) was lower than the board approved amount because of efficiencies realized the billing department as well as an improved economy so that time on collections was reduced.

2009 Cost driver

- Outside Services (-$67,477) declined since the 2008 cost of service application had been completed resulting in a much reduced overall expenditure in outside services in 2009.
- Regulatory Costs (-$6,380) also declined since there were more costs in 2008 because of the Cost of Service Application
- Management Salaries & Expenses ($93,565) increased resulting from Atikokan Hydro's change in capitalization policy to not capitalize indirect costs not related to the installation of capital.
- General & Administrative Salaries ($31,732) - additional costs resulted from staffing changes: Staffing changes occurred in 2009 with one staff member retiring in early Q3. The position was filled and a summer student had been hired, and significant overtime was required to adapt to the new billing and accounting system.
- Miscellaneous Adjustments (-$14,782) which are various minor adjustments occurred over the year to act as a driver for this amount.

2010 Cost Driver

- Outside Services ($49,203) costs increased as a result of Atikokan Hydro's 2011 IRM application that was prepared in 2010. Atikokan Hydro used the support of a rate consultant and reported these costs in its outside services account. Atikokan Hydro has limited resources due to its size and limited number of employees. For this reason, employees require assistance as time is limited and it is for the best interest of Atikokan Hydro's employees to be provided the additional resources in the preparation of rate applications.

- Management Salaries & Expenses ($10,976) increased resulting from a Management salary review initiated by the Board of Directors which in turn the Board of Directors approved a salary increase to account for 40 hour working weeks and inflationary increases.
- General & Administrative Salaries ($75,470) increased resulting from Atikokan Hydro's change in capitalization policy to not capitalize indirect costs not related to the installation of capital.
- Miscellaneous Adjustments (-$16,619)

2011 Cost Driver

- Maintenance ($10,806) - more time is being allocated to Maintenance compared to the prior year 2010. More brushing is required to be completed. In addition, the Town of Atikokan experienced several storms early in the year and has continuing to have bad weather where further brushing and tree removal is required to eliminate future hazards.
- Billing & Collecting ($16,697) which includes an increase in bad debt expense and the costs attributable to the billing requirements from smart meters. Other expenses include the costs associated with retailers.
- Operations Changes (-$58,184) - Atikokan Hydro did not allocate the same time to Operations has it has in prior years. A few factors contribute to this. One being Atikokan linemen crew spent several months working on the IFRS conversion. Further asset details were required for asset count and valuation purposes. Atikokan Hydro has further been working on capital projects; line rebuilds due to the aging infrastructure.
- LEAP Funding ($2,000) - As per the OEB's report on Low-income Energy Assistance Programs dated July 22, 2011, Atikokan Hydro paid out $2,000 for the 2011 Bridge Year. As set out in the LEAP Report, the Board has determined that the greater of 0.12% of a distributor's Board-approved distribution revenue requirement, or $2,000, is a reasonable commitment by all distributors to emergency financial assistance. The $2,000 minimum is intended to ensure that, for smaller distributors, more funding is available than otherwise would be if based solely on a percentage of distribution revenues. The LEAP amount should

be calculated based on total distribution revenues, and is to be recovered from all rate classes based on the respective distribution revenue of each of those rate classes.

- General & Administrative Salaries and Management Salaries & Expenses ($6,015 = $2,904 + $3,111) - this increases are attributable to wage increases as per the collective agreement.
- Miscellaneous Adjustments (-$3,770)

2012 Cost Driver

- Staffing changes ($30,000) - Atikokan Hydro is anticipating a lineman to retire mid year of the test year 2012 and will be required to hire a new lineman apprentice. Atikokan Hydro maintains a crew of 4 lineman in order to meet its commitment to the Town of Atikokan in providing safe and reliable supply of electricity. For this reason, it is utmost important to replace the retiree but additional training costs will be incurred.
- Regulatory Costs ($50,000) represents a fourth of its anticipated costs for Atikokan's 2012 Cost of Service Application. Atikokan Hydro has taken into consideration its costs associated with the Board, Intervenors, and outsourced assistance from Borden Ladner Gervais LLP.
- General & Administrative Salaries and Management Salaries & Expenses ($6,165 = $2,977 + $3,188) – these increases are attributable to wage increases as per the collective agreement.
- Smart Meter Expenses ($107,573)
  - Atikokan Hydro anticipates that all Smart Meter costs of $69,453 be brought into the regular OM&A costing. Atikokan Hydro has requested the board allow the Smart Meter costs to be brought into OM&A. For purposes of the CoS, Atikokan has assumed it is brought in for rate purposes.
  - Web presentation for customers to read their consumption via the world wide web is estimated at this time to be $8,120.
  - If the demands of smart meters continue, Atikokan Hydro will require another employee on a full time basis. This is anticipated to cost an additional $30,000.
- Miscellaneous Adjustments ($7,136)

Variance Analysis:

Consistent with the Ontario Energy Board Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 28, 2011, Atikokan Hydro has provided variance analyses for the 2012 Test Year vs. 2008 - Last Board-Approved Rebasing Application (Actual) and between the 2012 Test Year and 2010 Actual (Most Current Audited Actual). Atikokan Hydro has reviewed the variance of each USoA account and provided explanations for variances exceeding a materiality threshold of $50,000. The variances are indicated in the following tables and an explanation of each variance is presented in the following section.

2008 ACTUAL VERSUS 2012 TEST YEAR

Table 4-12

2008 Actual to 2012 Test Year – Operation Expenses - Account Variances

Operations Expenses 2008 Actual vs. 2012 Test Year					
USoA	Operations Expenses	2008 Actual	2012 Test Year	Variance ($)	Variance (%)
5005	Operation Supervision and Engineering	0	0	0	0.00%
5010	Load Dispatching	0	0	0	0.00%
5012	Station Buildings and Fixtures Expense	0	0	0	0.00%
5014	Transformer Station Equipment - Operation Labour	0	0	0	0.00%
5015	Transformer Station Equipment - Operation Supplies and Expenses	0	0	0	0.00%
5016	Distribution Station Equipment - Operation Labour	15,455	1,087	-14,369	-92.97%
5017	Distribution Station Equipment - Operation Supplies and Expenses	1,873	205	-1,668	-89.06%
5020	Overhead Distribution Lines and Feeders - Operation Labour	221,989	265,093	43,105	19.42%
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	42,189	42,915	726	1.72%
5030	Overhead Sub-transmission Feeders - Operation	9,898	1,476	-8,422	-85.09%
5035	Overhead Distribution Transformers - Operation	3,941	0	-3,941	-100.00%
5040	Underground Distribution Lines and Feeders - Operation Labour	0	0	0	0.00%
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	0	0	0	0.00%
5050	Underground Sub-transmission Feeders - Operation	0	0	0	0.00%
5055	Underground Distribution Transformers - Operation	0	0	0	0.00%
5060	Street Lighting and Signal System Expense	0	0	0	0.00%
5065	Meter Expense	159	107,573	107,415	67658.53%
5070	Customer Premises - Operation Labour	0	0	0	0.00%
5075	Customer Premises - Operation Materials and Expenses	0	0	0	0.00%
5085	Miscellaneous Distribution Expenses	0	0	0	0.00%
5090	Underground Distribution Lines and Feeders - Rental Paid	0	0	0	0.00%
5095	Overhead Distribution Lines and Feeders - Rental Paid	617	0	-617	-100.00%
5096	Other Rent	0	0	0	0.00%
	TOTAL OPERATION EXPENSES	296,121	418,349	122,228	41.28%

Table 4-13

2008 Actual to 2012 Test Year – Maintenance Expenses - Account by Account Variances

Distribution Expenses - Maintenance 2008 Actual vs. 2012 Test Year					
USoA	Distribution Expenses - Maintenance	2008 Actual	2012 Test Year	Variance ($)	Variance (%)
5105	Maintenance Supervision and Engineering	0	0	0	0.00%
5110	Maintenance of Buildings and Fixtures - Distribution Stations	0	0	0	0.00%
5112	Maintenance of Transformer Station Equipment	0	0	0	0.00%
5114	Maintenance of Distribution Station Equipment	3,804	599	-3,205	-84.24%
5120	Maintenance of Poles, Towers and Fixtures	0	0	0	0.00%
5125	Maintenance of Overhead Conductors and Devices	748	5,907	5,160	690.26%
5130	Maintenance of Overhead Services	9,784	191	-9,593	-98.05%
5135	Overhead Distribution Lines and Feeders - Right of Way	51,058	42,669	-8,389	-16.43%
5145	Maintenance of Underground Conduit	0	0	0	0.00%
5150	Maintenance of Underground Conductors and Devices	0	0	0	0.00%
5155	Maintenance of Underground Services	0	0	0	0.00%
5160	Maintenance of Line Transformers	19,523	1,814	-17,709	-90.71%
5165	Maintenance of Street Lighting and Signal Systems	0	0	0	0.00%
5170	Sentinel Lights - Labour	0	0	0	0.00%
5172	Sentinel Lights - Materials and Expenses	0	0	0	0.00%
5175	Maintenance of Meters	3,899	1,996	-1,903	-48.81%
5178	Customer Installations Expenses - Leased Property	0	0	0	0.00%
5195	Maintenance of Other Installations on Customer Premises	0	0	0	0.00%
	TOTAL MAINTENANCE EXPENSES	88,816	53,177	-35,639	-40.13%

Table 4-14

2008 Actual to 2012 Test Year – General & Administrative Expenses - Account Variances

Administrative & General Expenses 2008 Actual vs. 2012 Bridge Year					
USoA	Adminstrative & General Expenses	2008 Actual	2012 Bridge Year	Variance ($)	Variance (%)
5605	Executive Salaries and Expenses	6,000	6,000	0	0.00%
5610	Management Salaries and Expenses	11,639	122,061	110,422	90.46%
5615	General Administrative Salaries and Expenses	17,205	130,706	113,500	86.84%
5620	Office Supplies and Expenses	6,244	8,153	1,909	23.42%
5625	Administrative Expense Transferred - Credit	0	0	0	0.00%
5630	Outside Services Employed	153,350	127,886	-25,464	-19.91%
5635	Property Insurance	7,271	9,116	1,846	20.24%
5640	Injuries and Damages	0	0	0	0.00%
5645	Employee Pensions and Benefits	0	0	0	0.00%
5650	Franchise Requirements	0	0	0	0.00%
5655	Regulatory Expenses	11,522	60,564	49,042	80.98%
5660	General Advertising Expenses	617	1,230	613	49.86%
5665	Miscellaneous General Expenses	41,225	41,386	161	0.39%
5670	Rent	0	0	0	0.00%
5675	Maintenance of General Plant	36,034	41,271	5,237	12.69%
5680	Electrical Safety Authority Fees	0	2,082	2,082	100.00%
5685	Independent Electricity System Operator Fees and Penalties	0	0	0	0.00%
5695	OM&A Contra Account	0	0	0	0.00%
6205	Donations (Charitable Contributions)	0	0	0	0.00%
	TOTAL ADMINISTRATIVE & GENERAL EXPENSES	291,106	550,455	259,349	89.09%

Table 4-15

2008 Actual to 2012 Test Year – Billing & Collecting Expenses - Account Variances

Billing & Collecting Expenses 2008 Actual vs. 2012 Bridge Year					
USoA	Billing & Collecting Expenses	2008 Actual	2012 Bridge Year	Variance ($)	Variance (%)
5305	Supervision	4,043	2727	-1316	-32.55%
5310	Meter Reading Expense	45,772	45939	167	0.36%
5315	Customer Billing	110,711	97060	-13651	-14.06%
5320	Collecting	0	0	0	0.00%
5325	Collecting - Cash Over and Short	50	0	-50	-100.00%
5330	Collection Charges	-5,200	0	5200	0.00%
5335	Bad Debt Expense	6,355	5444	-911	-16.74%
5340	Miscellaneous Customer Accounts Expenses	7,250	2000	-5250	-262.50%
	TOTAL BILLING & COLLECTING EXPENSES	168,981	153,170	-15,811	-9.36%

5065 Meter Expenses $107,573

Within the USoA account 5605, Atikokan Hydro has reported for 2012 the costs for OM&A of smart meters in the amount of $69,453. Atikokan is requesting in this application to record the smart meters in its rate base, see Exhibit 9 for further explanation. Further, Atikokan Hydro has reported $30,000 to this account; if the demands of the smart meters continue, another employee will be required on a full time basis. Another $8,120 is reported here for web presentment for customers reading their consumption via the web.

5610 – Management Salaries & Expenses $110,422

Within the USoA account 5610, Atikokan Hydro has reported as the account entails; management salaries and expenses. The increase is attributable to wage increases but mainly a change in capitalization policy. In 2010 Atikokan Hydro's capitalization policy was revised to no longer capitalize OM&A expenses that were not directly associated with the installation of the capital. As outlined in Exhibit 2, this change allow Atikokan Hydro to be aligned with IFRS account standards which Atikokan Hydro must follow for 2012 This has increased payroll expenses as there is no longer indirect overhead allocated to capital.

5615 – General & Administrative Services $113,500

The reason for this increase is the same as account 5610.

2010 ACTUAL VERSUS 2012 TEST YEAR:

Table 4-16
2010 Actual vs. 2012 Test Year – Operating Expenses – Account Variances

Operations Expenses 2010 Actual vs. 2012 Bridge Year					
USoA	Operations Expenses	2010 Actual	2012 Bridge Year	Variance ($)	Variance (%)
5005	Operation Supervision and Engineering	0	0	0	0.00%
5010	Load Dispatching	0	0	0	0.00%
5012	Station Buildings and Fixtures Expense	0	0	0	0.00%
5014	Transformer Station Equipment - Operation Labour	0	0	0	0.00%
5015	Transformer Station Equipment - Operation Supplies and Expenses	0	0	0	0.00%
5016	Distribution Station Equipment - Operation Labour	0	1,087	1,087	100.00%
5017	Distribution Station Equipment - Operation Supplies and Expenses	0	205	205	100.00%
5020	Overhead Distribution Lines and Feeders - Operation Labour	261,114	265,093	3,979	1.52%
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	27,341	42,915	15,574	56.96%
5030	Overhead Sub-transmission Feeders - Operation	42,657	1,476	-41,181	-96.54%
5035	Overhead Distribution Transformers - Operation	0	0	0	0.00%
5040	Underground Distribution Lines and Feeders - Operation Labour	0	0	0	0.00%
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	0	0	0	0.00%
5050	Underground Sub-transmission Feeders - Operation	0	0	0	0.00%
5055	Underground Distribution Transformers - Operation	0	0	0	0.00%
5060	Street Lighting and Signal System Expense	0	0	0	0.00%
5065	Meter Expense	1,000	107,573	106,574	10661.76%
5070	Customer Premises - Operation Labour	0	0	0	0.00%
5075	Customer Premises - Operation Materials and Expenses	0	0	0	0.00%
5085	Miscellaneous Distribution Expenses	0	0	0	0.00%
5090	Underground Distribution Lines and Feeders - Rental Paid	0	0	0	0.00%
5095	Overhead Distribution Lines and Feeders - Rental Paid	0	0	0	0.00%
5096	Other Rent	0	0	0	0.00%
	TOTAL BILLING & COLLECTING EXPENSES	332,111	418,349	86,238	25.97%

Table 4-17

2010 Actual vs. 2012 Test Year – Maintenance Expenses – Account Variances

Distribution Expenses - Maintenance 2010 Actual vs. 2012 Test Year					
USoA	Distribution Expenses - Maintenance	2010 Actual	2012 Test Year	Variance ($)	Variance (%)
5105	Maintenance Supervision and Engineering	0	0	0	0.00%
5110	Maintenance of Buildings and Fixtures - Distribution Stations	0	0	0	0.00%
5112	Maintenance of Transformer Station Equipment	0	0	0	0.00%
5114	Maintenance of Distribution Station Equipment	585	599	15	2.50%
5120	Maintenance of Poles, Towers and Fixtures	0	0	0	0.00%
5125	Maintenance of Overhead Conductors and Devices	20,406	5,907	-14,499	-71.05%
5130	Maintenance of Overhead Services	222	191	-31	-13.82%
5135	Overhead Distribution Lines and Feeders - Right of Way	29,522	42,669	13,147	44.53%
5145	Maintenance of Underground Conduit	0	0	0	0.00%
5150	Maintenance of Underground Conductors and Devices	0	0	0	0.00%
5155	Maintenance of Underground Services	0	0	0	0.00%
5160	Maintenance of Line Transformers	250	1,814	1,564	625.59%
5165	Maintenance of Street Lighting and Signal Systems	0	0	0	0.00%
5170	Sentinel Lights - Labour	0	0	0	0.00%
5172	Sentinel Lights - Materials and Expenses	0	0	0	0.00%
5175	Maintenance of Meters	680	1,996	1,316	193.49%
5178	Customer Installations Expenses - Leased Property	0	0	0	0.00%
5195	Maintenance of Other Installations on Customer Premises	0	0	0	0.00%
	TOTAL MAINTENANCE EXPENSES	51,665	53,177	1,512	2.93%

Table 4-18

2010 Actual to 2012 Test Year – General & Administrative Expenses - Account Variances

Administrative & General Expenses 2010 Actual vs. 2012 Bridge Year					
USoA	Adminstrative & General Expenses	2010 Actual	2012 Bridge Year	Variance ($)	Variance (%)
5605	Executive Salaries and Expenses	6,000	6,000	0	0.00%
5610	Management Salaries and Expenses	116,180	122,061	5,882	4.82%
5615	General Administrative Salaries and Expenses	124,407	130,706	6,298	4.82%
5620	Office Supplies and Expenses	7,416	8,153	737	9.04%
5625	Administrative Expense Transferred - Credit	0	0	0	0.00%
5630	Outside Services Employed	135,076	127,886	-7,191	-5.62%
5635	Property Insurance	8,604	9,116	513	5.62%
5640	Injuries and Damages	0	0	0	0.00%
5645	Employee Pensions and Benefits	0	0	0	0.00%
5650	Franchise Requirements	0	0	0	0.00%
5655	Regulatory Expenses	13,149	60,564	47,415	78.29%
5660	General Advertising Expenses	1,649	1,230	-419	-34.09%
5665	Miscellaneous General Expenses	35,845	41,386	5,541	13.39%
5670	Rent	0	0	0	0.00%
5675	Maintenance of General Plant	35,905	41,271	5,366	13.00%
5680	Electrical Safety Authority Fees	1,920	2,082	162	7.78%
5685	Independent Electricity System Operator Fees and Penalties	0	0	0	0.00%
5695	OM&A Contra Account	0	0	0	0.00%
6205	Donations (Charitable Contributions)	0	0	0	0.00%
	TOTAL ADMINISTRATIVE & GENERAL EXPENSES	486,151	550,455	64,304	13.23%

Table 4-19

2010 Actual vs. 2012 Test Year – Billing & Collecting Expenses – Account Variances

Billing & Collecting Expenses 2010 Actual vs. 2012 Bridge Year					
USoA	Billing & Collecting Expenses	2010 Actual	2012 Bridge Year	Variance ($)	Variance (%)
5305	Supervision	7,700	2,727	-4,974	-64.59%
5310	Meter Reading Expense	32,118	45,939	13,822	30.09%
5315	Customer Billing	87,381	97,060	9,679	9.97%
5320	Collecting	0	0	0	0.00%
5325	Collecting - Cash Over and Short	-338	0	338	-100.00%
5330	Collection Charges	0	0	0	0.00%
5335	Bad Debt Expense	3,924	5,444	1,520	27.92%
5340	Miscellaneous Customer Accounts Expenses	0	2,000	2,000	100.00%
	TOTAL BILLING & COLLECTING EXPENSES	130,786	153,170	22,384	17.12%

2010 ACTUAL to 2012 TEST YEAR:

5065 Meter Expenses $106,573

The reason for this variance is consistent with the rationale provided for this account for the 2008 actual to 2012 test year comparison.

The table below sets out the OM&A cost per customer and Full Time equivalent employee.

Table 4-20

OM&A Cost per Customer and per FTEE						
	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 Test Year
Number of Customers/Connections	2,300	2,312	2,315	2,305	2,301	2,297
Total OM&A	$ 809,045	$ 845,025	$ 881,685	$ 1,000,716	$ 974,275	$ 1,175,150
OM&A cost per customer	$351.76	$365.57	$380.94	$434.15	$423.44	$511.66
Number of FTEEs	7	7	9	8	8	9
Customers/FTEEs	328.57	330.21	257.17	288.13	287.60	255.19
OM&A Cost per FTEE	$ 115,578	$ 120,718	$ 97,965	$ 125,090	$ 121,784	$ 130,572

Regulatory costs as indicated in the variance analysis are presented in Table 4-21. Regulatory costs for the 2012 rate application amounting to $60,564, including consulting costs as well as anticipated Board and Intervenor expenses have been considered over a four year period in the 2012 OM&A budget. The costs that have been included are indicated below:

Table 4-21

Regulatory Costs

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	2008 - Last Rebasing Year	2010 - Last Year of Actuals	2011 Bridge Year	Annual % Change	2012 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655	$ 7,761	On-Going	$ 2,936	$ 6,775	$ 7,761	14.55%	$ 7,761	0.00%
2	OEB Hearing Assessments (applicant-originated)	5655		On-Going						
3	OEB Section 30 Costs (OEB-initiated)	5655	$ 400	On-Going	$ 401	$ 238	$ 226	-4.99%	$ 400	76.88%
4	Expert Witness costs for regulatory matters	5655			$ -					
5	Legal costs for regulatory matters									
6	Consultants' costs for regulatory matters	5655	$ 50,000	On-Time	$ 4,620				$ 50,000	
7	Operating expenses associated with staff resources allocated to regulatory matters	5615								
8	Operating expenses associated with other resources allocated to regulatory matters [1]	5605	$ 551	On-Going	$ 888	$ 2,393	$ 468	-80.43%	$ 551	17.64%
9	Other regulatory agency fees or	5655	$ 1,852	On-Going	$ 2,677	$ 2,380	$ 1,852	-22.19%	$ 1,852	0.00%
10	Any other costs for regulatory matters (please define)	5655								
11	Intervenor costs	5655		On-Time	$ -	$ 1,363		-100.00%		
12	Sub-total - Ongoing Costs [3]		$ 10,564		$ 6,902	$ 11,786	$ 10,307	-12.55%	$ 10,564	2.49%
13	Sub-total - One-time Costs [4]		$ 50,000		$ 46,200	$ 1,363	$ -	-100.00%	$ 50,000	
14	Total		$ 60,564		$ 53,102	$ 13,149	$ 10,307	-21.61%	$ 60,564	487.60%

CHARGES TO AFFILIATES FOR SERVICES PROVIDED

Introduction:

Atikokan Hydro provides and receives services from its affiliate Atikokan Enercom. Atikokan Hydro also performs services for its shareholder, The Town of Atikokan. All financial arrangements are based on cost recovery or commercially acquired amounts. The rent for space is the same per square foot at the mall in the parking lot.

There is no opportunity to use knowledge from one company to give advantage to the other. Credit checks for communication sales are done by an independent non affiliated entity.

Atikokan Hydro does not have Board of Director related costs for affiliates.

A summary of charges to affiliates for services provided in 2008 Actual, 2009 Actual, 2010 Actual together with the projections for the 2011 Bridge Year and 2012 Test Year, are shown in the following Table 4-22

The agreement between Atikokan Hydro and Atikokan Enercom is provided in Appendix B of this Exhibit.

SERVICES PROVIDED by Atikokan Hydro to Atikokan Enercom

Atikokan Hydro and its affiliate Atikokan Enercom share some equipment and office space. Atikokan Enercom hires Atikokan Hydro Employees for various contracting and cell phone sales that Atikokan Enercom is involved in.

Atikokan Enercom maintains separate financial records from Atikokan Hydro and separate books of account. While the actual data entry for Atikokan Enercom bookkeeping is provided by employees of Atikokan Hydro, confidentiality is maintained because the customers of Atikokan Enercom and the customers of Atikokan Hydro are unrelated and the services required are so different that the communication of any information as between the two affiliates is of no benefit whatsoever to the other. Customer lists of Atikokan Hydro and Atikokan Enercom are not shared and there is no distribution of these lists to any other person or group within the Town or any other person or organization. Staff of the Town of Atikokan is not permitted access to the customer list or any other information relating to Atikokan Enercom and Atikokan Hydro.

Atikokan Enercom pays Atikokan Hydro for the work provided by secretarial and other staff of Atikokan Hydro the sum of $800.00 per pay. Atikokan Enercom is also billed for related services after hours or recoverable contracted jobs. Atikokan Enercom is billed monthly for these services. Atikokan Enercom is billed its proportionate share of operating costs at a rate of 5% of yearly costs.

Office Rental

Atikokan Hydro rents office space to Atikokan Enercom. Rental revenue is recorded in account 4210-3 Rental Revenue. Enercom occupies 150 square feet of space in the building owned by Hydro and pays to Hydro the sum of $96.00 per month. Rental revenue is recorded in 5642; Operating Expenses.

Street Light Services

Atikokan Hydro employees are contracted by Atikokan Enercom to perform streetlight maintenance for the Town of Atikokan; Atikokan Hydro's shareholder. This service is billed to the town and includes charges for labour based on employee time as well as trucks and material expenses. These costs are summarized in Table 4-22 below. These services are billed monthly and recorded to 4235, revenues from jobbing. While Atikokan Hydro used to bill the town direct for the streetlight maintenance. Legislative changes occurred where Atikokan Hydro was no longer be able to hold a provisional contractors licence to maintain street lighting for its shareholder, the Town of Atikokan. This change was to occurred at the end of 2009.. Knowing the changes were coming, Atikokan Hydro made changes for 2010 whereby Enercom hires Atikokan Hydro employees and equipment for maintenance of the streetlights. The Electrical Safety Authority would not issue an LDC a license to do street lighting and the provisional licence was rescinded by the Electrical Safety Authority. Maintenance rates were designed for street lighting work so the Town would not see an increase in maintenance rates. Hydro takes all overhead as income.

Table 4-22
Shared Service/Corporate Cost Allocation

Year: 2008

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
Atikokan Hydro Inc.	Atikokan Enercom	Labour	Cost Recovery	20,800	20,800	100%
Atikokan Hydro Inc.	Atikokan Enercom	Shared Operating Costs	Cost Recovery	1,472	29,443	5%
Atikokan Hydro Inc.	Atikokan Enercom	Office Space	$0.64/sq. ft	1,152	0	100%
Atikokan Hydro Inc.	Atikokan Enercom	Interac Use	Cost Recovery	120	384	31%
Atikokan Hydro Inc.	Town of Atikokan	Streetlight Maintenance	Cost + markup	32,458	25,428	128%

Year: 2009

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
Atikokan Hydro Inc.	Atikokan Enercom	Labour	Cost Recovery	20,800	20,800	100%
Atikokan Hydro Inc.	Atikokan Enercom	Shared Operating Costs	Cost Recovery	1,857	37,148	5%
Atikokan Hydro Inc.	Atikokan Enercom	Office Space	$0.64/sq. ft	1,152	0	100%
Atikokan Hydro Inc.	Atikokan Enercom	Interac Use	Cost Recovery	120	384	31%
Atikokan Hydro Inc.	Town of Atikokan	Streetlight Maintenance	Cost + markup	52,628	40,483	130%

Year: 2010

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
Atikokan Hydro Inc.	Atikokan Enercom	Labour	Cost Recovery	22,844	22,844	100
Atikokan Hydro Inc.	Atikokan Enercom	Shared Operating Costs	Cost Recovery	1,734	34,685	5%
Atikokan Hydro Inc.	Atikokan Enercom	Office Space	$0.64/sq. ft	1,152	0	100%
Atikokan Hydro Inc.	Atikokan Enercom	Interac Use	Cost Recovery	120	384	31%
Atikokan Hydro Inc.	Atikokan Enercom	Strretlight Maintenance	Cost + markup	34,401	19,515	176%

Year: 2011

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
Atikokan Hydro Inc.	Atikokan Enercom	Labour	Cost Recovery	23,800	23,800	100%
Atikokan Hydro Inc.	Atikokan Enercom	Shared Operating Costs	Cost Recovery	1,800	36,000	5%
Atikokan Hydro Inc.	Atikokan Enercom	Office Space	$0.64/sq. ft	1,152	0	100%
Atikokan Hydro Inc.	Atikokan Enercom	Streetlight Maintenance	Cost + markup	26,740	16,009	167%

Year: 2012

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
Atikokan Hydro Inc.	Atikokan Enercom	Labour	Cost Recovery	23,800	23,800	100%
Atikokan Hydro Inc.	Atikokan Enercom	Shared Operating Costs	Cost Recovery	1,800	36,000	5%
Atikokan Hydro Inc.	Atikokan Enercom	Office Space	$0.64/sq. ft	1,152	0	100%
Atikokan Hydro Inc.	Atikokan Enercom	Streetlight Maintenance	Cost + markup	26,740	16,244	165%

PURCHASE OF PRODUCTS AND SERVICE FROM NON-AFFILIATES

Atikokan Hydro purchases many services and products from third parties. Table 4-23 outlines the expenditures by vendor where the annual amount exceeded $50,000 per year, for the years 2008, 2009 and 2010, respectively. Table 4-23 also contains the vendor information for the bridge year 2011 where the year to date amount has exceeded $50,000 as of June 30, 2011. Commitments to suppliers have not been made for the Test Year (2012). Purchases for 2012 operating and capital works will continue to be based on the methodology contained within Atikokan Hydro's Procurement Policy, which has been attached as Appendix C to this Exhibit.

Table 4-23

2008 Non-Affiliate Suppliers			
Vendor	**Amount $**	**Product/Services**	**Procurement Method**
The MEARIE Group	54,741	Employee Insurance Benefits	Sole Source

2009 Non-Affiliate Suppliers			
Vendor	**Amount $**	**Product/Services**	**Procurement Method**
Elster Canadian Metering	278,608	Smart Meters	RFP
Posi-Plus Ontario Inc.	333,626	Bucket Truck	Tender
The MEARIE Group	61,094	Employee Insurance Benefits	Sole Source
Thunder Bay Hydro Utilities Services Inc.	162,834	Billing/Metering/OPA Support	Northwest Group Sole Source

2010 Non-Affiliate Suppliers			
Vendor	**Amount $**	**Product/Services**	**Procurement Method**
The MEARIE Group	61,099	Employee Insurance Benefits	Sole Source
Thunder Bay Hydro Utilities Services Inc.	120,876	Billing/Metering/OPA Support	Northwest Group Sole Source

2011 Non-Affiliate Suppliers (As of June 30th, 2011)			
Vendor	**Amount $**	**Product/Services**	**Procurement Method**
Thunder Bay Hydro Utilities Services Inc.	52,772	Billing/Metering/OPA Support	Northwest Group Sole Source

EMPLOYEE COMPENSATION, INCENTIVE PLAN EXPENSES, PENSION EXPENSE AND POST RETIREMENT BENEFITS:

Compensation/Performance System

Union

Atikokan Hydro's unionized staff is represented by the Canadian Union of Public Employees Local 752. The current collective agreement expires March 31, 2014; formal negotiations will begin prior to. The current agreement, which was entered into in April 1, 2010 includes annual wage increases of 3% April 1, 2010 and annual wage increases of 2.5% effective April 1, 2011, 2012 and 2013.

Executive/Management

Executive and Management compensation plan consists of salaries and benefits. Each position within the company has been placed on a pay scale which is reviewed annually by senior management and the Board of Directors'. The review is based on performance and an inflationary adjustment. Changes to senior management compensation, if any, are approved by the Board of Directors. Atikokan Hydro does not offer any incentive or bonus compensation.

Benefits

Atikokan Hydro offers its employees a comprehensive and competitive benefits package that includes medical insurance, life insurance, vacation and retirement plan. The plans are designed to address the health and welfare needs of the employees; the plans are both the same for management and union employees.

All full time staff participates in the OMERS pension plan.

All full time staff participates in Post-Retirement Benefits, the accrued expense is based on an actuarial valuation.

Employee Compensation and Benefits:

Atikokan Hydro has set out employee compensation and benefits information in Table 4-24 below in accordance with the filing requirements which outlines that where there are three or fewer employees in any category, the applicant should aggregate this category with the category to which it is most closely related. This higher level of aggregation should be continued, if required, to ensure that no category contains three or fewer employees. In this regard, Atikokan Hydro has aggregated the executive and management together in the union category and has aggregated its part time employee into the full-time.

Employee complement, compensation and benefits are set out in Table 4-24 below.

Table 4-24

	LRY - Board Approved 2008	LRY - Actual 2008	Historical Year 2 2009	Historical Year 1 2010	Bridge Year 2011	Test Year 2012
Number of Employees (FTEs including Part-Time)[1]						
Executive						
Management						
Non-Union						
Union	7	7	9	8	8	9
Total	7	7	9	8	8	9
Number of Part-Time Employees						
Executive						
Management						
Non-Union						
Union	-	-	1	1	1	1
Total	-	-	1	1	1	1
Total Salary and Wages						
Executive						
Management						
Non-Union						
Union	$ 475,417	$ 484,474	$ 546,811	$ 549,829	$ 555,073	$ 628,949
Total	$ 475,417	$ 484,474	$ 546,811	$ 549,829	$ 555,073	$ 628,949
Current Benefits						
Executive						
Management						
Non-Union						
Union	$ 82,263	$ 86,194	$ 91,396	$ 91,540	$ 101,805	$ 104,485
Total	$ 82,263	$ 86,194	$ 91,396	$ 91,540	$ 101,805	$ 104,485
Accrued Pension and Post-Retirement Benefits						
Executive						
Management						
Non-Union						
Union		$ 2,549	$ 3,224	$ 4,314	$ 4,280	$ 7,097
Total	$ -	$ 2,549	$ 3,224	$ 4,314	$ 4,280	$ 7,097
Total Benefits (Current + Accrued)						
Executive	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ -	$ -	$ -	$ -	$ -	$ -
Non-Union	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ 82,263	$ 88,743	$ 94,620	$ 95,854	$ 106,086	$ 111,581
Total	$ 82,263	$ 88,743	$ 94,620	$ 95,854	$ 106,086	$ 111,581
Total Compensation (Salary, Wages, & Benefits)						
Executive	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ -	$ -	$ -	$ -	$ -	$ -
Non-Union	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ 557,681	$ 573,217	$ 641,432	$ 645,683	$ 661,158	$ 740,531
Total	$ 557,681	$ 573,217	$ 641,432	$ 645,683	$ 661,158	$ 740,531
Compensation - Average Yearly Base Wages						
Executive						
Management						
Non-Union						
Union		$ 64,596	$ 53,852	$ 63,411	$ 66,197	$ 66,979
Total	$ -	$ 64,596	$ 53,852	$ 63,411	$ 66,197	$ 66,979
Compensation - Average Yearly Overtime						
Executive						
Management						
Non-Union						
Union		$ 5,384	$ 7,768	$ 6,077	$ 3,642	$ 3,734
Total	$ -	$ 5,384	$ 7,768	$ 6,077	$ 3,642	$ 3,734
Compensation - Average Yearly Incentive Pay						
Executive						
Management						
Non-Union						
Union	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -	$ -
Compensation - Average Yearly Benefits						
Executive						
Management						
Non-Union						
Union		$ 9,860	$ 9,462	$ 9,585	$ 10,609	$ 10,144
Total	$ -	$ 9,860	$ 9,462	$ 9,585	$ 10,609	$ 10,144
Total Compensation	$ 557,681	$ 573,217	$ 641,432	$ 645,683	$ 661,158	$ 740,531
Total Compensation Charged to OM&A		$ 547,933	$ 610,484	$ 620,790	$ 646,549	$ 708,113
Total Compensation Capitalized	$ 557,681	$ 25,284	$ 30,948	$ 24,893	$ 14,610	$ 32,418

Change in Employee Compensation & Benefits

2008 Actual vs. 2009 Actual

Union:
Change in FTE: +2.0
Management:
Change in FTE: 0
Change in Wages: +$62,337

The increase 2.0 FTEs in union positions is the result of a few employee changes that occurred during 2009. The changes included both in August, 1 (one) retiree and 1 (one) new hire to replace the retiree. A summer student was also hired, and a part-time employee hired late December. The summer student and the part-time employee hired late December were considered to be one for this comparison table.

2009 had wage increases as per the collective agreement for union employees. Management wages were also reviewed this year. Further, 2009 was a busy fiscal year because of the staffing changes and the conversion between the old and the new billing system required for the smart meters. For these reasons, in comparing the total compensation and average overtime between 2008 and 2009; considerable increases are noted. The summer student was additional payroll expenses for Atikokan Hydro that was not existent in 2008.

2009 Actual vs. 2010 Actual

Union:
Change in FTE: -1
Management:
Change in FTE: 0
Change in Wages: +$3,018

Management positions was reviewed and adjusted accordingly June of 2010 to reflect 40 working hours a week and inflationary increases. The change impacts salary of $12,497.38 a year.

In 2010, Atikokan Hydro renegotiated a collective agreement with a four year term effective April 1, 2010. This resulted in a 3 % wage increase and change of working hours for the inside employees. Inside staff now work 40 hours a week instead of 35 hours. Atikokan Hydro negotiated this as a means to control the overtime inside employees were working on a regular basis as a result of the new billing system for smart meters. Further to this, yearly base wage increases occurred as progressive increases for both the new full time and part time hires (from 2009) as per the collective agreements probationary and wage increase periods. Along with this, it must be noted that Atikokan Hydro's retiree in 2009 would have been at the top of the wage progression scale, whereas, the new hirer needed to earn the probation phases as per the collective agreement. For this reason, overall, despite the wage increases for union and management, and the change in working hours; payroll for 2010 only increased $3,018 from the previous year 2009.

Yearly costs of benefits has been impacted from 2009 to 2010 as a result of the 2010 collective agreement changes: increased working week for inside staff that occurred midyear of 2010 and wage increases; long-term disability has been increased.

2010 Actual vs. 2011 Bridge

Union:
Change in FTE: 0
Management:
Change in FTE: 0
Change in Wages: +$5,244

The 2011 Bridge year payroll is forecasted to be slightly hirer than 2010. This is based on wage increases for union as per the collective agreement. It is noticed that the change in working hours for inside staff has reduced the overtime costs for Atikokan Hydro.

2011 Bridge vs. 2012 Test

Union:
Change in FTE: +1.0
Management:
Change in FTE: 0
Change in Wages: +$73,876

Atikokan Hydro's increase in full time employees is dependent on a few factors. Atikokan Hydro may have another retires in 2012 and will require to hire an apprentice if the employees chooses to retiree. Atikokan Hydro estimates this to cost an additional $30,000. Furthermore, if the demands of the smart meters continue, another employee will be required on a full time basis. This is expected to be another $30,000 to Atikokan Hydro. (Currently, Atikokan Hydro has one part-time employee; less than three, who is considered to be Full-Time for purposes of this application) These factors have been taken into consideration when forecasting the total 2012 test year employee costs. Further, the April 1, 2012 wage increases were also taken into consideration by taking 2011 wages adding 2.5% as per the collective agreement.

OMERS Pension Expense:

Atikokan Hydro's employees are members of the Ontario Municipal Employees Retirement System ("OMERS"). Accordingly, Atikokan Hydro has provided the OMERS pension premium information for 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year, and the 2012 Test Year in the table below.

Table 4-25
Pension Premium Information

Pension Premiums Information					
	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test Year
OMERS Premium Paid	33,316	28,978	25,157	44,143	47,138

Post-Retirement Benefits - Premiums:

Atikokan Hydro pays life insurance benefits on behalf of its retired employees. Actual premiums paid for 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year, and 2012 Test Year, are shown in Table 4-26.

Table 4-26
Post-Retirement Benefit Information

Post-Retirement Premiums Information					
	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test Year
Post-Retirement Premium Paid	2,549	3,224	4,314	4,280	7,070

DEPRECIATION, AMORTIZATION AND DEPLETION:

Amortization on capital assets is calculated as follows:

Atikokan Hydro assets each have its own pool/category ie. Buildings, Office Equipment, Tools, Poles, Line Transformers, etc. Amortization is calculated on a straight line basis over the estimated remaining useful life of the assets at the end of the previous year; plus:

Atikokan Hydro's amortization policy has been to take a full year's amortization on capital additions during the current year. Based on this policy and the audited Financial Statements, for years 2008 through 2011 in this Cost of Service Application, the full year of amortization was used for additions. As per OEB guidelines, for this rate application, Atikokan Hydro has applied the half year rule for calculating depreciation expense for the test year 2012 for applicable additions. Atikokan Hydro recognizes that it should have changed its accounting policy to the half year rule following the 2008 cost of service application. Atikokan Hydro will change its accounting policy for amortization to reflect the half year rule for 2011 and going forward.

From evaluation of Atikokan Hydro's asset base, value and service in service along with consideration of the IFRS, Atikokan has made changes to the estimated useful life of some of its assets: Distribution Station Equipment, Poles, Towers, Fixtures, and Line Transformers. These assets will now be amortized over 45 years as opposed to 25. It is assumed these assets currently have ten years remaining before they are fully amortized. Straight line depreciation will still apply but the half-year will be applied to yearly capital additions. Atikokan Hydro Inc. recognizes this will adhere to the board's general policy for electricity distribution rate setting.

Atikokan Hydro does not have any Asset Retirement Obligations at this time.

Atikokan Hydro's depreciation details are listed in the Fixed Asset Continuity Schedule; this includes by asset and its corresponding OEB account number. Prior to 2010, Atikokan expensed its depreciation of vehicles. Atikokan Hydro changed this for 2010 and is now consistent with amortization of all its assets. The change was a result of consultation between management and Atikokan auditors.

The following tables outlined the depreciation expense in accordance with the filing requirements.

Table 4-27

Depreciation Expense - 2008

Year: 2008

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense	Did Depreciation Rate in "g" Change (Yes/No)? [3]
1805	Land			0		0				
1808	Buildings			0		0				
1810	Leasehold Improvements			0		0				
1815	Transformer Station Equipment >50 kV			0		0				
1820	Distribution Station Equipment <50 kV	193,990	0	193,990	881	194,871	25	4%	6,396	No
1825	Storage Battery Equipment			0		0				
1830	Poles, Towers & Fixtures	1,170,238	19,423	1,150,815	65,465	1,216,280	25	4%	90,134	No
1835	Overhead Conductors & Devices			0		0				
1840	Underground Conduit			0		0				
1845	Underground Conductors & Devices			0		0				
1850	Line Transformers	130,118	31,025	99,093	65,579	164,672	25	4%	14,000	No
1855	Services (Overhead and Underground)			0		0				
1860	Meters	218,286	300	217,986	515	218,501	25	4%	14,509	No
1860	Meters (Smart Meters)			0		0				
1905	Land			0		0				
1906	Land Rights			0		0				
1908	Buildings & Fixtures	122,419	609	121,810	43,211	165,021	25	4%	13,287	No
1910	Leasehold Improvements			0		0				
1915	Office Furniture & Equipment (10 Years)	12,683	15,164	-2,481	12,243	9,762	10	10%	4,073	No
1915	Office Furniture & Equipment (5 Years)			0		0				
1920	Computer Equipment - Hardware			0		0				
1920	Computer Equip. - Hardware (Post Mar. 22/04)	11,785	16,675	-4,890	3,364	-1,525	5	20%	4,351	No
1920	Computer Equip. - Hardware (Post Mar. 19/07)			0		0				
1925	Computer Software	753	0	753	882	1,635	2	50%	1,194	No
1930	Transportation Equipment	60,200	24,586	35,615	0	35,615	5	20%	19,304	No
1935	Stores Equipment			0		0				
1940	Tools, Shop & Garage Equipment	16,514	6,115	10,399	5,972	16,371	10	10%	5,155	No
1945	Measurement & Testing Equipment			0		0				
1950	Power Operated Equipment			0		0				
1955	Communications Equipment			0		0				
1955	Communication Equipment (Smart Meters)			0		0				
1960	Miscellaneous Equipment			0		0				
1975	Load Management Controls Utility Premises			0		0				
1980	System Supervisor Equipment			0		0				
1985	Miscellaneous Fixed Assets			0		0				
1995	Contributions & Grants			0		0				
etc.				0		0				
				0		0				
	Total	1,936,986	113,896	1,823,089	198,112	2,021,201			172,402	

Less Fully Allocated Depreciation	
Transportation	19,304
Net Depreciation	153,098

Table 4-28

Depreciation Expense - 2009

Year: 2009

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + (d)[2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense	Did Depreciation Rate in "g" Change (Yes/No)?[3]
1805	Land			0		0				
1808	Buildings			0		0				
1810	Leasehold Improvements			0		0				
1815	Transformer Station Equipment >50 kV			0		0				
1820	Distribution Station Equipment <50 kV	478,769	0	478,769	7,049	485,818	25	$ 0.04	14,626	No
1825	Storage Battery Equipment			0		0				
1830	Poles, Towers & Fixtures	1,129,813	4,798	1,125,015	55,918	1,180,933	25	$ 0.04	88,944	No
1835	Overhead Conductors & Devices			0		0				
1840	Underground Conduit			0		0				
1845	Underground Conductors & Devices			0		0				
1850	Line Transformers	158,297	450	157,847	1,937	159,784	25	$ 0.04	14,077	No
1855	Services (Overhead and Underground)			0		0				
1860	Meters	204,292	133,950	70,342	13,953	84,295	25	$ 0.04	16,508	No
1860	Meters (Smart Meters)			0		0				
1905	Land			0		0				
1906	Land Rights			0		0				
1908	Buildings & Fixtures	151,734	0	151,734	221,611	373,345	25	$ 0.04	21,635	No
1910	Leasehold Improvements			0		0				
1915	Office Furniture & Equipment (10 Years)	16,317	0	16,317	9,012	25,328	10	$ 0.10	4,960	No
1915	Office Furniture & Equipment (5 Years)			0		0				
1920	Computer Equipment - Hardware			0		0				
1920	Computer Equip. - Hardware (Post Mar. 22/04)	9,800	0	9,800	4,919	14,719	5	$ 0.20	5,744	No
1920	Computer Equip. - Hardware (Post Mar. 19/07)			0		0				
1925	Computer Software	441	0	441	4,724	5,164	2	$ 0.50	2,803	No
1930	Transportation Equipment	38,553	0	38,553	0	38,553	5	$ 0.20	18,909	No
1935	Stores Equipment			0		0				
1940	Tools, Shop & Garage Equipment	16,682	0	16,682	3,897	20,578	10	$ 0.10	4,124	No
1945	Measurement & Testing Equipment			0		0				
1950	Power Operated Equipment			0		0				
1955	Communications Equipment			0		0				
1955	Communication Equipment (Smart Meters)			0		0				
1960	Miscellaneous Equipment			0		0				
1975	Load Management Controls Utility Premises			0		0				
1980	System Supervisor Equipment			0		0				
1985	Miscellaneous Fixed Assets			0		0				
1995	Contributions & Grants			0		0				
etc.				0		0				
				0		0				
	Total	2,204,697	139,198	2,065,499	323,018	2,388,518			192,330	

Table 4-29

Depreciation Expense - 2010

Year: 2010

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense	Did Depreciation Rate in "g" Change (Yes/No)? [3]
1805	Land			0		0				
1808	Buildings			0		0				
1810	Leasehold Improvements			0		0				
1815	Transformer Station Equipment >50 kV			0		0				
1820	Distribution Station Equipment <50 kV	180,898	0	180,898	800	181,698	25	4%	14,048	No
1825	Storage Battery Equipment			0		0				
1830	Poles, Towers & Fixtures	1,096,787	101,709	995,078	133	995,211	25	4%	86,823	No
1835	Overhead Conductors & Devices			0		0				
1840	Underground Conduit			0		0				
1845	Underground Conductors & Devices			0		0				
1850	Line Transformers	146,157	6,100	140,057	0	140,057	25	4%	14,077	No
1855	Services (Overhead and Underground)			0		0				
1860	Meters	115,230	4,275	110,955	33,068	144,023	25	4%	23,513	No
1860	Meters (Smart Meters)			0		0				
1905	Land			0		0		0%		
1906	Land Rights			0		0				
1908	Buildings & Fixtures	351,710	0	351,710	88,197	439,907	25	4%	25,165	No
1910	Leasehold Improvements			0		0				
1915	Office Furniture & Equipment (10 Years)	20,368	0	20,368	1,228	21,596	10	10%	4,810	No
1915	Office Furniture & Equipment (5 Years)			0		0				
1920	Computer Equipment - Hardware			0		0				
1920	Computer Equip. - Hardware (Post Mar. 22/04)	8,975	0	8,975	0	8,975	5	20%	3,599	No
1920	Computer Equip. - Hardware (Post Mar. 19/07)			0		0				
1925	Computer Software	2,361	0	2,361	2,398	4,759	2	50%	3,561	No
1930	Transportation Equipment	19,644	0	19,644	342,337	361,981	5	20%	41,731	No
1935	Stores Equipment			0		0				
1940	Tools, Shop & Garage Equipment	16,454	0	16,454	8,665	25,119	10	10%	4,528	No
1945	Measurement & Testing Equipment			0		0				
1950	Power Operated Equipment			0		0				
1955	Communications Equipment			0		0				
1955	Communication Equipment (Smart Meters)			0		0				
1960	Miscellaneous Equipment			0		0				
1975	Load Management Controls Utility Premises			0		0				
1980	System Supervisor Equipment			0		0				
1985	Miscellaneous Fixed Assets			0		0				
1995	Contributions & Grants			0		0				
etc.				0		0				
				0		0				
	Total	1,958,585	112,084	1,846,501	476,826	2,323,326			221,856	

Table 4-30

Depreciation Expense - 2011

Year: 2011

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense	Did Depreciation Rate in "g" Change (Yes/No)? [3]
1805	Land			0		0				
1808	Buildings			0		0				
1810	Leasehold Improvements			0		0				
1815	Transformer Station Equipment >50 kV			0		0				
1820	Distribution Station Equipment <50 kV	167,650	0	167,650	17,000	184,650	25	4%	14,728	No
1825	Storage Battery Equipment			0		0				
1830	Poles, Towers & Fixtures	939,081	5,000	934,081	43,800	977,881	25	4%	86,709	No
1835	Overhead Conductors & Devices			0		0				
1840	Underground Conduit			0		0				
1845	Underground Conductors & Devices			0		0				
1850	Line Transformers	132,080	1,000	131,080	5,000	136,080	25	4%	13,003	No
1855	Services (Overhead and Underground)			0		0				
1860	Meters	199,413	0	199,413	0	199,413	25	4%	16,390	No
1860	Meters (Smart Meters)			0		0				
1905	Land			0		0				
1906	Land Rights			0		0				
1908	Buildings & Fixtures	414,742	3,800	410,942	8,500	419,442	25	4%	24,559	No
1910	Leasehold Improvements			0		0				
1915	Office Furniture & Equipment (10 Years)	16,787	0	16,787	0	16,787	10	10%	3,775	No
1915	Office Furniture & Equipment (5 Years)			0		0				
1920	Computer Equipment - Hardware			0		0				
1920	Computer Equip. - Hardware (Post Mar. 22/04)	5,376	0	5,376	0	5,376	5	20%	2,909	No
1920	Computer Equip. - Hardware (Post Mar. 19/07)			0		0				
1925	Computer Software	1,198	0	1,198	1,500	2,698	2	50%	1,199	No
1930	Transportation Equipment	320,250	0	320,250	0	320,250	5	20%	22,996	No
1935	Stores Equipment			0		0				
1940	Tools, Shop & Garage Equipment	20,591	0	20,591	3,500	24,091	10	10%	4,454	No
1945	Measurement & Testing Equipment			0		0				
1950	Power Operated Equipment			0		0				
1955	Communications Equipment			0		0				
1955	Communication Equipment (Smart Meters)			0		0				
1960	Miscellaneous Equipment			0		0				
1975	Load Management Controls Utility Premises			0		0				
1980	System Supervisor Equipment			0		0				
1985	Miscellaneous Fixed Assets			0		0				
1995	Contributions & Grants			0		0				
etc.				0		0				
				0		0				
	Total	2,217,168	9,800	2,207,368	79,300	2,286,668			190,722	

Less Fully Allocated Depreciation
Transportation
Net Depreciation 190,722

Table 4-31

Depreciation Expense - 2012

-

Year: 2012

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Did Depreciation Rate in "g" Change (Yes/No)? [3]
1805	Land			0		0				
1808	Buildings			0		0				
1810	Leasehold Improvements			0		0				
1815	Transformer Station Equipment >50 kV			0		0				
1820	Distribution Station Equipment <50 kV	169,922	0	169,922	8,000	177,922	45	2%	15,500	Yes
1825	Storage Battery Equipment			0		0				
1830	Poles, Towers & Fixtures	896,172	5,000	891,172	58,800	949,972	45	2%	63,547	Yes
1835	Overhead Conductors & Devices			0		0				
1840	Underground Conduit			0		0				
1845	Underground Conductors & Devices			0		0				
1850	Line Transformers	124,077	1,000	123,077	7,000	130,077	45	2%	4,037	Yes
1855	Services (Overhead and Underground)			0		0				
1860	Meters	94,736	0	94,736	0	94,736	25	4%	1,711	No
1860	Meters (Smart Meters)	398,721	0	398,721	0	398,721	25	4%	27,295	No
1905	Land			0		0				
1906	Land Rights			0		0				
1908	Buildings & Fixtures	398,683	0	398,683	8,500	407,183	25	4%	24,729	No
1910	Leasehold Improvements			0		0				
1915	Office Furniture & Equipment (10 Years)	13,011	0	13,011	0	13,011	10	10%	3,132	No
1915	Office Furniture & Equipment (5 Years)			0		0				
1920	Computer Equipment - Hardware			0		0				
1920	Computer Equip. - Hardware (Post Mar. 22/04)	19,842	2,000	17,842	12,000	29,842	5	20%	27,404	No
1920	Computer Equip. - Hardware (Post Mar. 19/07)			0		0				
1925	Computer Software	0	1,000	-1,000	8,000	7,000	2	50%	2,000	No
1930	Transportation Equipment	297,255	0	297,255	0	297,255	5	20%	22,822	No
1935	Stores Equipment			0		0				
1940	Tools, Shop & Garage Equipment	19,636	0	19,636	16,500	36,136	10	10%	5,279	No
1945	Measurement & Testing Equipment			0		0				
1950	Power Operated Equipment			0		0				
1955	Communications Equipment			0		0				
1955	Communication Equipment (Smart Meters)			0		0				
1960	Miscellaneous Equipment			0		0				
1975	Load Management Controls Utility Premises			0		0				
1980	System Supervisor Equipment			0		0				
1985	Miscellaneous Fixed Assets			0		0				
1995	Contributions & Grants			0		0				
etc.				0		0				
				0		0				
	Total	2,432,056	9,000	2,423,056	118,800	2,541,856			197,456	

Less Fully Allocated Depreciation	
Transportation	
Net Depreciation	197,456

APPENDIX A

2010 Federal and Ontario Tax Return

Appendix A

Canada Revenue Agency / Agence du revenu du Canada

200

T2 CORPORATION INCOME TAX RETURN

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, paragraphs, and subparagraphs mentioned on this return refer to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) 001 87440 4726 RC0001

Corporation's name
002 Atikokan Hydro Inc.

Address of head office
Has this address changed since the last time you filed your T2 return? .... 010 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 117 Gorrie Street
012 PO Box 1480
City: 015 Atikokan
Province, territory, or state: 016 ON
Country (other than Canada): 017 CA
Postal code/Zip code: 018 P0T 1C0

Mailing address (if different from head office address)
Has this address changed since the last time you filed your T2 return? .... 020 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028.)
021 c/o
022 117 Gorrie Street
023 PO Box 1480
City: 025 Atikokan
Province, territory, or state: 026 ON
Country (other than Canada): 027 CA
Postal code/Zip code: 028 P0T 1C0

Location of books and records
Has the location of books and records changed since the last time you filed your T2 return? .... 030 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
031 117 Gorrie Street
032 PO Box 1480
City: 035 Atikokan
Province, territory, or state: 036 ON
Country (other than Canada): 037 CA
Postal code/Zip code: 038 P0T 1C0

040 **Type of corporation at the end of the tax year**
1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. 043 ________ YYYY MM DD

To which tax year does this return apply?
Tax year start 060 2010-01-01 YYYY MM DD
Tax year-end 061 2010-12-31 YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? .... 063 1 Yes [ ] 2 No [X]
If **yes**, provide the date control was acquired .... 065 ________ YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? .... 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? .... 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? .... 070 1 Yes [ ] 2 No [X]
Amalgamation? .... 071 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? .... 072 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? .... 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? .... 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used .... 079 ________

Is the corporation a resident of Canada?
080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081 ________

Is the non-resident corporation claiming an exemption under an income tax treaty? .... 082 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **Yes** response, **attach** to the T2 return the schedule that applies.

		Yes	Schedule
Is the corporation related to any other corporations?	150		9
Is the corporation an associated CCPC?	160		23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation (or its associated corporations) claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233		
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234		
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265		55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

		1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281		X

What is the corporation's major business activity? (only complete if **yes** was entered at line 281) 282

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 1 Wholesale ☐ 2 Retail ☐

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

	Product		%
284	Retail Electricity	285	100.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ____ YYYY MM DD

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes ☐ 2 No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.		300	2,253	A
Deduct: Charitable donations from Schedule 2	311			
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal		▶		B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			2,253	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions		355		D
Taxable income (amount C **plus** amount D)		360	2,253	
Income exempt under paragraph 149(1)(t)		370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			2,253	Z

* This amount is equal to 3.2 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	2,253	A
Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 1/(0.38 - X**) 3.57143 times the amount on line 636***, and **minus** any amount that, because of federal law, is exempt form Part I tax	405	2,253	B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

400,000	x	Number of days in the tax year before 2009 / Number of days in the tax year	/ 365	=	1
500,000	x	Number of days in the tax year after 2008 / Number of days in the tax year	365 / 365	= 500,000	2
		Add amounts at lines 1 and 2		500,000	4

Business limit (see notes 1 and 2 below)	410	500,000	C

Notes:
1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x 415 **** / 11,250 D = E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0")	425	500,000	F

Small business deduction

Amount A, B, C, or F, whichever is the least 2,253 x 17 % =	430	383	G

Enter amount G on line 1.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** General rate reduction percentage for the tax year. It has to be pro-rated.

*** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

**** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360		2,253	A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		B	
Amount QQ from Part 13 of Schedule 27		C	
Amount used to calculate the credit union deduction from Schedule 17		D	
Amount from line 400, 405, 410, or 425, whichever is the least	2,253	E	
Aggregate investment income from line 440*		F	
Total of amounts B to F	2,253 ▶	2,253	G
Amount A **minus** amount G (if negative, enter "0")			H

Amount H		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x 8.5 %	=	I
Amount H		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 365	x 9 %	=	J
Amount H		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	365 / 365	x 10 %	=	K
Amount H		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 365	x 11.5 %	=	L
Amount H		x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x 13 %	=	L.1

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L.1 .... M
Enter amount M on line 638.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)			N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		O	
Amount QQ from Part 13 of Schedule 27		P	
Amount used to calculate the credit union deduction from Schedule 17		Q	
Total of amounts O to Q	▶		R
Amount N **minus** amount R (if negative, enter "0")			S

Amount S		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x 8.5 %	=	T
Amount S		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 365	x 9 %	=	U
Amount S		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	365 / 365	x 10 %	=	V
Amount S		x	Number of days in the tax year after December 31, 2010, and before January 2012 / Number of days in the tax year	/ 365	x 11.5 %	=	W
Amount S		x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x 13 %	=	W.1

General tax reduction – Total of amounts T to W.1 X
Enter amount X on line 639.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . 440 ______ x 26 2 / 3 % = ... ______ A

Foreign non-business income tax credit from line 632 . . . . ______

Deduct:
Foreign investment income from Schedule 7 . . . . 445 ______ x 9 1 / 3 % = ______
(if negative, enter "0") ______ ▶ ______ B

Amount A **minus** amount B (if negative, enter "0") . . . . ______ C

Taxable income from line 360 2,253

Deduct:
Amount from line 400, 405, 410, or 425, whichever is the least 2,253

Foreign non-business income tax credit from line 632 . . . . ______ x 25 / 9 = ______

Foreign business income tax credit from line 636 . . . . ______ x 1(0.38 - X*) / 3.57143 = ______

2,253 ▶ 2,253

x 26 2 / 3 % = ______ D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780) . . . . 248 E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least . . . . 450 ______ F

* General rate reduction percentage for the tax year. It has to be pro-rated.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . 460 ______

Deduct: Dividend refund for the previous tax year . . . . 465 ______

______ ▶ ______ G

Add the total of:

Refundable portion of Part I tax from line 450 above . . . . ______

Total Part IV tax payable from Schedule 3 . . . . ______

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . 480 ______

______ ▶ ______ H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H . . . . 485 ______

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 of Schedule 3 . . . . ______ x 1 / 3 ______ I

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . ______ J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784) . . . . ______

Part I tax

Base amount of Part I tax – Taxable income (line 360 or amount Z, whichever applies) **multiplied** by 38 %		550	856	A
Recapture of investment tax credit from Schedule 31		602		B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440			i
Taxable income from line 360	2,253		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least	2,253		
Net amount		▶	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii	604		C
Subtotal (**add** lines A to C)		856	D

Deduct:

Small business deduction from line 430		383	1		
Federal tax abatement	608	225			
Manufacturing and processing profits deduction from Schedule 27	616				
Investment corporation deduction	620				
Taxed capital gains 624					
Additional deduction – credit unions from Schedule 17	628				
Federal foreign non-business income tax credit from Schedule 21	632				
Federal foreign business income tax credit from Schedule 21	636				
General tax reduction for CCPCs from amount M	638				
General tax reduction from amount X	639				
Federal logging tax credit from Schedule 21	640				
Federal qualifying environmental trust tax credit	648				
Investment tax credit from Schedule 31	652				
Subtotal		608	▶	608	E

Part I tax payable – Line **D minus** line E	248	F

Enter amount F on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	248
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		248

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	113	
Provincial tax on large corporations (New Brunswick* and Nova Scotia)	765		
		113 ▶	113
Total tax payable	770		361 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	20,805
Total credits	890	20,805 ▶ 20,805 B

Refund code 894 1 Overpayment 20,444

Balance (line A **minus** line B) -20,444

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . . ______

Enclosed payment 898 ______

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 ______ Branch number

914 ______ Institution number 918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . . 896 1 Yes [X] 2 No [ ]

* The New Brunswick tax on large corporations is eliminated effective January 1, 2009.

Certification

I, 950 Thorburn (Last name in block letters) 951 Wilf (First name in block letters) 954 Director (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2011-08-31 (Date (yyyy/mm/dd)) ______ (Signature of the authorized signing officer of the corporation) 956 (807) 597-6600 (Telephone number)

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . . 957 1 Yes [ ] 2 No [X]

958 Wilf Thorburn (Name in block letters) 959 (807) 597-6600 (Telephone number)

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

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SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Atikokan Hydro Inc.	87440 4726 RC0001	2010-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	950,717	1,189,907
	Total tangible capital assets	2008	+	5,169,636	4,804,894
	Total accumulated amortization of tangible capital assets	2009	–	2,936,880	2,756,093
	Total intangible capital assets	2178	+	4,974	7,819
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+		625,701
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	3,188,447	3,872,228
	Liabilities				
	Total current liabilities	3139	+	44,238	745,625
	Total long-term liabilities	3450	+	2,216,053	2,114,829
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	2,260,291	2,860,454
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	928,156	1,011,774
	Total liabilities and shareholder equity	3640	=	3,188,447	3,872,228
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	-349,744	-266,126

* Generic item

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SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Atikokan Hydro Inc.	87440 4726 RC0001	2010-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence Number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	3,452,601	3,302,406
	Cost of sales	8518	–	1,913,140	1,824,212
	Gross profit/loss	8519	=	1,539,461	1,478,194
	Cost of sales	8518	+	1,913,140	1,824,212
	Total operating expenses	9367	+	1,571,756	1,292,200
	Total expenses (mandatory field)	9368	=	3,484,896	3,116,412
	Total revenue (mandatory field)	8299	+	3,474,843	3,311,948
	Total expenses (mandatory field)	9368	–	3,484,896	3,116,412
	Net non-farming income	9369	=	-10,053	195,536
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	-10,053	195,536
	Total other comprehensive income	9998	=		
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	-1,063	22,229
	Deferred income tax provision	9995	–		
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	-8,990	173,307

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SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year-end Year Month Day
Atikokan Hydro Inc.	87440 4726 RC0001	2010-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI) for Corporations* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule, and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant preparing or reporting on the financial statements

		1 Yes	2 No
Does the accountant have a professional designation?	095	X	
Is the accountant connected* with the corporation?	097		X

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note: If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: 198

Completed an auditor's report	1	X
Completed a review engagement report	2	
Conducted a compilation engagement	3	

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement with the financial statements** above, answer the following question:

		1 Yes	2 No
Has the accountant expressed a reservation?	099		X

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: 110

Prepared the tax return (financial statements prepared by client)	1	
Prepared the tax return and the financial information contained therein (financial statements have not been prepared)	2	

		1 Yes	2 No
Were notes to the financial statements prepared?	101	X	
If **yes**, complete lines 102 to 107 below:			
Are any values presented at other than cost?	102		X
Has there been a change in accounting policies since the last return?	103		X
Are subsequent events mentioned in the notes?	104	X	
Is re-evaluation of asset information mentioned in the notes?	105		X
Is contingent liability information mentioned in the notes?	106	X	
Is information regarding commitments mentioned in the notes?	107		X
Does the corporation have investments in joint venture(s) or partnership(s)?	108		X
If **yes**, complete line 109 below:			
Are you filing financial statements of the joint venture(s) or partnership(s)?	109		

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
Atikokan Hydro Inc.	87440 4726 RC0001	2010-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125			-8,990 A
Add:			
Provision for income taxes – current	101	-1,063	
Amortization of tangible assets	104	218,243	
Amortization of intangible assets	106	2,845	
Non-deductible meals and entertainment expenses	121	6,635	
Subtotal of additions		226,660 ▶	226,660
Other additions:			
Miscellaneous other additions:			
604			
Total	294		
Subtotal of other additions	199	▶	
Total additions	500	226,660 ▶	226,660
Deduct:			
Capital cost allowance from Schedule 8	403	214,505	
Cumulative eligible capital deduction from Schedule 10	405	912	
Subtotal of deductions		215,417 ▶	215,417
Other deductions:			
Miscellaneous other deductions:			
704			
Total	394		
Subtotal of other deductions	499	0 ▶	0
Total deductions	510	215,417 ▶	215,417
Net income (loss) for income tax purposes – enter on line 300 of the T2 return			2,253

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SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
Atikokan Hydro Inc.	87440 4726 RC0001	2010-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations*.
- For more information, see the *T2 Corporation – Income Tax Guide*.
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ______ Enter the regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2 (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☐	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking centre; the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

T2 SCH 5 E (10)

Canada

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
2,253	2,253	2,253	113

	Line	Amount		Total	
Ontario basic income tax (from Schedule 500)	270	293			
Deduct: Ontario small business deduction (from schedule 500)	402	180			
Subtotal (if negative, enter "0")		113	▶	113	A6
Add:					
Surtax re Ontario small business deduction (from Schedule 500)	272				
Ontario additional tax re Crown royalties (from Schedule 504)	274				
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal			▶		B6
Subtotal (amount A6 **plus** amount B6)				113	C6
Deduct:					
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario transitional tax credits (from Schedule 506)	414				
Ontario political contributions tax credit (from Schedule 525)	415				
Subtotal			▶		D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")				113	E6
Deduct: Ontario research and development tax credit (from Schedule 508)			416		
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")				113	F6
Deduct: Ontario corporate minimum tax credit (from schedule 510)			418		
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")				113	G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278				
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies)	282				
Subtotal			▶		H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)				113	I6
Deduct:					
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452				
Ontario apprenticeship training tax credit (from Schedule 552)	454				
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario sound recording tax credit (from Schedule 562)	464				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Other Ontario tax credits					
Subtotal			▶		J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.			290	113	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits	255	113

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Atikokan Hydro Inc.	87440 4726 RC0001	2010-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? 101 1 Yes ☐ 2 No ☒

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (column 7 **multiplied** by column 8; or a lower amount) (line 403 of Schedule 1)**** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1	BUILDINGS	405,560	88,197		0	44,099	449,658	4	0	0	17,986	475,771
2.	1	TRANS/DIST EQUIPMENT	1,911,150	34,001		0	17,001	1,928,150	4	0	0	77,126	1,868,025
3.	8	TOOLS & EQUIPMENT	41,952	9,892		0	4,946	46,898	20	0	0	9,380	42,464
4.	10	ROLLING STOCK	31,793	342,337		0	171,169	202,961	30	0	0	60,888	313,242
5.	10	COMPUTER	4,793			0		4,793	30	0	0	1,438	3,355
6.	45	New Computers	1,936			0		1,936	45	0	0	871	1,065
7.	50	Computer Hardware	8,390			0		8,390	55	0	0	4,615	3,775
8.	47	Transmission and distribution afi	496,308	32,458		0	16,229	512,537	8	0	0	41,003	487,763
9.	12	Computer Software		2,397		0	1,199	1,198	100	0	0	1,198	1,199
		Total	2,901,882	509,282			254,643	3,156,521				214,505	3,196,659

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) plus or minus certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		509,282		
Additions for tax purposes – Schedule 8 leasehold improvements	+			
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+			
Additions for tax but not for accounting - Rate Reg Rules	+	-32,458		
Total additions per books	=	476,824	▶	476,824
Proceeds up to original cost – Schedule 8 regular classes				
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
Prior period adjustment	+	74,628		
Total proceeds per books	=	74,628	▶ –	74,628
Depreciation and amortization per accounts – Schedule 1			–	218,243
Loss on disposal of fixed assets per accounts			–	
Gain on disposal of fixed assets per accounts			+	
Net change per tax return			=	183,953

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		2,217,168
Opening net book value	–	2,033,215
Net change per financial statements	=	183,953

If the amounts from the tax return and the financial statements differ, explain why below.

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
Atikokan Hydro Inc.	87440 4726 RC0001	2010-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

	Line	Amount		Line	Amount	
Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")				200	13,027	A
Add: Cost of eligible capital property acquired during the taxation year	222					
Other adjustments	226					
Subtotal (line 222 plus line 226)			x 3 / 4 =			B
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228		x 1 / 2 =			C
amount B minus amount C (if negative, enter "0")			▶			D
Amount transferred on amalgamation or wind-up of subsidiary				224		E
Subtotal (add amounts A, D, and E)				230	13,027	F
Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242		G			
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244		H			
Other adjustments	246		I			
(add amounts G,H, and I)			x 3 / 4 =	248		J
Cumulative eligible capital balance (amount F minus amount J) (if amount K is negative, enter "0" at line M and proceed to Part 2)					13,027	K
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business				249		
amount K		13,027				
less amount from line 249						
Current year deduction		13,027	x 7.00 % =	250	912 *	
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)					912 ▶ 912	L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")				300	12,115	M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)						N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4			
Line 3 minus line 4 (if negative, enter "0")			▶		5	
Total of lines 1, 2 and 5					6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8			
Subtotal (line 7 plus line 8)	409		▶		9	
Line 6 minus line 9 (if negative, enter "0")					▶	O
Line N minus line O (if negative, enter "0")						P
Line 5				x 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")						R
Amount R				x 2 / 3 =		S
Amount N or amount O, whichever is less						T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)					410	

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Atikokan Hydro Inc.	87440 4726 RC0001	2010-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	TOWNSHIP OF ATIKOKAN (Corporation)		NA		100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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SCHEDULE 500

ONTARIO CORPORATION TAX CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Atikokan Hydro Inc.	87440 4726 RC0001	2010-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- References to subsections and paragraphs are from the federal *Income Tax Act*.
- This schedule is a worksheet only and does not have to be filed with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic rate of tax for the year

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	181 / 365	x	14.00 %	=	6.94247 %	A1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	184 / 365	x	12.00 %	=	6.04932 %	A2
Number of days in the tax year after June 30, 2011, and before July 1, 2012 / Number of days in the tax year	/ 365	x	11.50 %	=	%	A3
Number of days in the tax year after June 30, 2012, and before July 1, 2013 / Number of days in the tax year	/ 365	x	11.00 %	=	%	A4
Number of days in the tax year after June 30, 2013 / Number of days in the tax year	/ 365	x	10.00 %	=	%	A5

Ontario basic rate of tax for the year (total of rates A1 to A5) 12.99179 ▶ 12.99179 % A6

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . 2,253 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A6 from Part 1) . . . . 293 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit, in addition to Ontario basic income tax, or has Ontario corporate minimum tax, Ontario special additional tax on life insurance corporations or Ontario capital tax payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)					2,253	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)					2,253	2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return)	500,000	x	500,000 / 500,000 (line 4 on page 4 of the T2 return)	=	500,000	3
Enter the least of amounts 1, 2, and 3					2,253	D
Ontario domestic factor:	Ontario taxable income * / taxable income earned in all provinces and territories **		2,253.00 / 2,253	=	1.00000	E
Ontario small business income (amount D **multiplied** by amount E)					2,253	F

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	181 / 365	x	8.50 %	=	4.21507 %	G1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	184 / 365	x	7.50 %	=	3.78082 %	G2
Number of days in the tax year after June 30, 2011, and before July 1, 2012 / Number of days in the tax year	/ 365	x	7.00 %	=	%	G3
Number of days in the tax year after June 30, 2012, and before July 1, 2013 / Number of days in the tax year	/ 365	x	6.50 %	=	%	G4
Number of days in the tax year after June 30, 2013 / Number of days in the tax year	/ 365	x	5.50 %	=	%	G5
OSBD rate for the year (total of rates G1 to G5)					7.99589 %	G6

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G6) . . . . . 180 H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Calculation of surtax re Ontario small business deduction

Complete this part if the corporation is claiming the OSBD and its adjusted taxable income, **plus** the adjusted taxable income of each corporation with which the corporation was associated during its tax year, is greater than $500,000. If the corporation is a member of an associated group, complete Schedule 501, *Ontario Adjusted Taxable Income of Associated Corporations to Determine Surtax re Ontario Small Business Deduction.*

Note: For days in the tax year after June 30, 2010, the small business surtax rate is 0%. You do not have to complete this part if the corporation's tax year begins after June 30, 2010.

Adjusted taxable income *	2,253 I		
Adjusted taxable income of all associated corporations (amount from line 500 of Schedule 501)	J		
Aggregate adjusted taxable income (amount I **plus** amount J)	2,253 ▶	2,253	K
Deduct:			
Ontario business limit		500,000	
Subtotal (amount K **minus** Ontario business limit) (if negative, enter "0" on this line and on line P)			L

Small business surtax rate for the year:

Number of days in the tax year before July 1, 2010 / Number of days in the tax year: 181 / 365 x 4.25 % = 2.10753 % M

Amount L x % on line M =			N
Amount N ______ x Ontario small business income (amount F from Part 3) / 500,000	2,253 / 500,000 =		O
Surtax re Ontario small business deduction: lesser of amount O and OSBD (amount H from Part 3)			P

Enter amount P on line 272 of Schedule 5.

* Adjusted taxable income is equal to the corporation's taxable income or taxable income earned in Canada for the year **plus** the amount of the corporation's adjusted Crown royalties for the year **minus** the amount of the corporation's notional resource allowance for the year (from Schedule 504, *Ontario Resource Tax Credit and Ontario Additional Tax re Crown Royalties*).

  If the tax year of the corporation is less than 51 weeks, **multiply** the adjusted taxable income of the corporation for the year by 365 and **divide** by the number of days in the tax year.

Part 5 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Amount D from Part 3		2,253	Q
Surtax payable (amount P from Part 4) / Ontario domestic factor (amount E from Part 3) x OSBD rate (rate G6 from Part 3) 7.99589 %	______ / 0.07996 =		R

Note: Enter "0" on line R for tax years beginning after June 30, 2010.

Ontario adjusted small business income (amount Q **minus** amount R) (if negative, enter "0")	2,253	S

Enter amount S on line U in Part 6 or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 6 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17			T
Deduct:			
Ontario adjusted small business income (amount S from Part 5)			U
Subtotal (amount T **minus** amount U) (if negative, enter "0")			V
OSBD rate for the year (rate G6 from Part 3)	7.99589 %		
Amount V **multiplied** by the OSBD rate for the year			W
Ontario domestic factor (amount E from Part 3)		1.00000	X
Ontario credit union tax reduction (amount W **multiplied** by amount X)			Y

Enter amount Y on line 410 of Schedule 5.

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SCHEDULE 510

ONTARIO CORPORATE MINIMUM TAX

Name of corporation	Business Number	Tax year-end Year Month Day
Atikokan Hydro Inc.	87440 4726 RC0001	2010-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	3,188,447
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	
Total assets (total of lines 112 to 116)		3,188,447
Total revenue of the corporation for the tax year **	142	3,474,843
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	
Total revenue (total of lines 142 to 146)		3,474,843

The corporation is subject to CMT if:
– for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
– for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.
If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Calculation of adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	-8,990
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220			
Provision for deferred income taxes (debits)/cost of future income taxes	222			
Equity losses from corporations	224			
Financial statement loss from partnerships and joint ventures	226			
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230			
Other additions (see note below):				
Share of adjusted net income of partnerships and joint ventures **	228			
Total patronage dividends received, not already included in net income/loss	232			
281	282			
283	284			
Subtotal				A
Deduct (to the extent reflected in income/loss):				
Provision for recovery of current income taxes/benefit of current income taxes	320	1,063		
Provision for deferred income taxes (credits)/benefit of future income taxes	322			
Equity income from corporations	324			
Financial statement income from partnerships and joint ventures	326			
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330			
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332			
Gain on donation of listed security or ecological gift	340			
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342			
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344			
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346			
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348			
Other deductions (see note below):				
Share of adjusted net loss of partnerships and joint ventures **	328			
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334			
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336			
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338			
381	382			
383	384			
385	386			
387	388			
389	390			
Subtotal		1,063		1,063 B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	-10,053

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

– Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide.*

Part 3 – Calculation of CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)		515		
Deduct:				
CMT loss available (amount R from Part 7)	224,388			
Minus: Adjustment for an acquisition of control *	518			
Adjusted CMT loss available	224,388 ▶		224,388	C
Net income subject to CMT calculation (if negative, enter "0")		520		

Amount from line 520 ______ x (Number of days in the tax year before July 1, 2010 / Number of days in the tax year) 181 / 365 x 4 % = ______ 1

Amount from line 520 ______ x (Number of days in the tax year after June 30, 2010 / Number of days in the tax year) 184 / 365 x 2.7 % = ______ 2

Subtotal (amount 1 **plus** amount 2) ______ 3

Gross CMT: amount on line 3 above x OAF **	540		
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")			D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		113	
Net CMT payable (if negative, enter "0")			E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations,* and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** ______ = ______

Ontario allocation factor 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*****Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *				G
Deduct:				
CMT credit expired *	600			
CMT credit carryforward at the beginning of the current tax year * (see note below)		▶ 620		
Add:				
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)		650		
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)				H
Deduct:				
CMT credit deducted in the current tax year (amount P from Part 5)				I
Subtotal (amount H **minus** amount I)				J
Add:				
Net CMT payable (amount E from Part 3)				
SAT payable (amount O from Part 6 of Schedule 512)				
Subtotal		▶		K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)		670		L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)					M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		113	1		
For a corporation that is not a life insurance corporation:					
CMT after foreign tax credit deduction (amount D from Part 3)	2				
For a life insurance corporation:					
Gross CMT (line 540 from Part 3)	3				
Gross SAT (line 460 from Part 6 of Schedule 512)	4				
The **greater** of amounts 3 and 4	5				
Deduct: line 2 or line 5, whichever applies:			6		
Subtotal (if negative, enter "0")		113	▶	113	N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		113			
Deduct:					
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)					
Subtotal (if negative, enter "0")		113	▶	113	O
CMT credit deducted in the current tax year (least of amounts M, N, and O)					P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year *		224,388 Q		
Deduct:				
CMT loss expired *	700			
CMT loss carryforward at the beginning of the tax year * (see note below)		224,388 ▶	720	224,388
Add:				
CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below)			750	
CMT loss available (line 720 **plus** line 750)				224,388 R
Deduct:				
CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3)				
Subtotal (if negative, enter "0")				224,388 S
Add:				
Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount)			760	10,053
CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760)			770	234,441 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not transfer a loss on a vertical amalgamation under subsection 87(2.11) of the federal Act or other amalgamation of a parent and its subsidiary.
Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

– the tax year includes January 1, 2009; or

– the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Atikokan Hydro Inc.	87440 4726 RC0001	2010-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
Atikokan Hydro Inc.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	110 Date of incorporation or amalgamation, whichever is the most recent — Year Month Day	120 Ontario Corporation No.
Ontario	2000-03-07	1383704

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	220 Street name/Rural route/Lot and Concession number	230 Suite number
	Gorrie Street	

240 Additional address information if applicable (line 220 must be completed first)
PO Box 1480

250 Municipality (e.g., city, town)	260 Province/state	270 Country	280 Postal/zip code
Atikokan	ON	CA	P0T 1C0

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 1 If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 Thorburn — Last name
451 Wilf — First name

454 ______________________, — Middle name(s)

460 3 Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number | 530 Street name/Rural route/Lot and Concession number | 540 Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town) | 570 Province/state | 580 Country | 590 Postal/zip code

Part 6 – Language of preference

600 Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Corporate Taxpayer Summary

Corporate information

Corporation's name: Atikokan Hydro Inc.

Taxation Year: 2010-01-01 to 2010-12-31

Jurisdiction: Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
☐	☐	☐	☐	X	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

Corporation is associated: N

Corporation is related: N

Number of associated corporations:

Type of corporation: Canadian-Controlled Private Corporation

Total amount due (refund) federal and provincial*: -20,444

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income	2,253
Taxable income	2,253
Donations	
Calculation of income from an active business carried on in Canada	2,253
Dividends paid	
Dividends paid – Regular	
Dividends paid – Eligible	
Balance of the low rate income pool at the end of the previous year	
Balance of the low rate income pool at the end of the year	
Balance of the general rate income pool at the end of the previous year	
Balance of the general rate income pool at the end of the year	
Part I tax (base amount)	856

Credits against part I tax		Summary of tax		Refunds/credits	
Small business deduction	383	Part I	248	ITC refund	
M&P deduction		Part IV		Dividends refund	
Foreign tax credit		Part III.1		Instalments	20,805
Investment tax credits		Other*		Surtax credit	
Abatement/Other*	225	Provincial or territorial tax	113	Other*	
				Balance due/refund (–)	-20,444

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryforward balances

Cumulative eligible capital: 12,115

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	2,253		
Taxable income	2,253		
% Allocation	100.00		
Attributed taxable income	2,253		
Surtax		N/A	N/A
Tax payable before deduction*	293		
Deductions and credits	180		
Net tax payable	113		
Attributed taxable capital	928,156		N/A
Capital tax payable**			N/A
Total tax payable***	113		
Instalments and refundable credits			
Balance due/Refund (-)	113		

* For Québec, this includes special taxes and logging operations.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

Summary of provincial carryforward amounts

Other carryforward amounts

Ontario

Corporate minimum tax loss that can be carried forward over 20 years – Schedule 510	10,053
Corporate minimum tax loss that can be carried forward over 10 years – Schedule 510	224,388

Summary – taxable capital

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
Atikokan Hydro Inc.	3,409,727	3,409,727	928,156	928,156
Total	3,409,727	3,409,727	928,156	928,156

Québec

Corporate name	Paid-up capital used to calculate the deduction relating to income-averaging for forest producers (CO-726.30)	Paid-up capital used to calculate the exemption for small and medium-sized manufacturing businesses (CO-737.18.18)	Paid-up capital used to calculate the Québec business limit reduction (CO-771 and CO-771.1.3)	Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN)	Paid-up capital used to calculate the 1 million deduction (CO-1137.A and CO-1137.E)
Total					

Ontario

Corporate name	Taxable capital used to calculate the capital deduction – Ontario capital tax on financial institutions (Schedule 514)	Taxable capital used to calculate the capital deduction – Ontario capital tax on other than financial institutions (Schedule 515)	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
Atikokan Hydro Inc.		928,156	
Total		928,156	

Other provinces

Corporate name	Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306)	Taxable capital used to calculate the Nova Scotia capital deduction on large corporations (Schedule 343)	Net paid up capital – BC capital tax on financial institutions (FIN 689)	BC paid up capital – BC capital tax on financial institutions (FIN 689)
Total				

Five-Year Comparative Summary

Federal information (T2)

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Taxation year end	**2010-12-31**	**2009-12-31**	**2008-12-31**	**2007-12-31**	**2006-12-31**
Net income	2,253	224,411	73,406	46,318	127,070
Taxable income	2,253	126,095			
Active business income	2,253	224,411	73,406	46,318	127,070
Dividends paid					
Dividends paid – Regular					
Dividends paid – Eligible					
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year					
GRIP – end of the year					
Donations					
Balance due/refund (-)	-20,444	20,805			

Federal taxes

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Part I before surtax	248	13,870			
Surtax					
Part I.3					
Part IV					
Part I & Surtax	248	13,870			
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Credits against part I tax

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Small business deduction	383	21,436			
M&P deduction					
Foreign tax credit					
Political contribution					
Investment tax credit					
Abatement/other*	225	12,610			

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Refunds/credits

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
ITC refund					
Dividend refund					
Instalments	20,805				
Surtax credit					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Ontario

Taxation year end	2010-12-31	2009-12-31	2008-12-31	2007-12-31	2006-12-31
Net income	2,253				
Taxable income	2,253				
% Allocation	100.00	100.00			
Attributed taxable income	2,253				
Surtax					
Income tax payable before deduction	293	17,653			
Income tax deductions /credits	180	10,718			
Net income tax payable	113	6,935			
Taxable capital	928,156	3,409,727	935,286		
Capital tax payable					
Total tax payable*	113	6,935			
Instalments and refundable credits					
Balance due/refund**	113	6,935			

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

Attached Notes – Summary

Name of the cell	Federal – Additions – (1/2 year rule)	Form	Sch. 8 - Capital cost allowance (CCA) workchart
Description of the attached note		Keep this note when rolling forward the file	☐
952 + 33,049			

Appendix B

Agreement between Atikokan Hydro and Atikokan Enercom

SERVICE AGREEMENT

117 Gorrie Street, Box 1480
Atikokan, Ontario P0T 1C0

Telephone (807) 597-6600
Fax (807-597-6988

Dates this day January 4, 2011

BETWEEN: ATIKOKAN HYDRO INC.
(hereinafter called "Hydro"
of the first part)

and

ATIKOKAN ENERCOM INC.
(hereinafter called "Enercom"
of the second part)

WHEREAS Hydro is an electricity distributor licensed under Part 5 of the *Ontario Energy Board Act*, *1998*

AND WHEREAS Enercom is currently involved in various business activities including the cellular phone business, in Northwestern Ontario:

AND WHEREAS Hydro and Enercom are affiliates as described in the Affiliate Relationships Code and the *Ontario Energy Board Act, 1998*.

NOW THEREFORE THIS AGREEMENT WITNESSETH that in consideration of the mutual covenants herein contained, the parities hereto agree as follows:

1. Hydro is a utility with the resources necessary to perform as required by the Ontario Energy Board:

2. Enercom is a cellular phone dealer for TBaytel and does contract work for TBaytel and line maintenance of hydro lines in Northwestern Ontario;

3. In order to achieve financial viability, Enercom rents space and shares certain staff with Hydro. In particular:

    - Enercom occupies 150 square feet of space in the building Owned by Hydro and pays to Hydro the sum of $96.00 per month plus its proportionate share of operating costs. At a rate of 5% of yearly cost.
    - Equipment: Enercom rents equipment from Hydro on an as need basis.
    - Employees: Enercom pays Hydro for the work provided by secretarial and other staff of Hydro the sum of $800.00 per pay. (26 x 800.00 = $20.800.00). Enercom may also be billed for related services after hours.
    - Inventory: Enercom maintains its own separate inventory of supplies required to carry out its task;
    - Bookkeeping: Enercom maintains separate financial records from Hydro and separate books of account. While the actual data entry for Enercom bookkeeping is provided by employees of Hydro, confidentiality is maintained because the customers of Enercom and the customers of Hydro are unrelated and the services required are so different that the communication of any information as between the two affiliates is of no benefit whatsoever to the other. Customer lists of Hydro and Enercom are not shared and there is no distribution of these lists to any other person or group within the Town or any other person or organization. Staff of the Town of Atikokan is not permitted access to the customer list or any other information relating to Enercom and Hydro.
    - Pricing: the cost of any resource, product, or service provided to Enercom by Hydro or by Hydro to Enercom is at fair market value for the service, resource, or product available elsewhere.

4. Enercom maintains appropriate computer data management and data access protocols protecting all confidential information from Hydro access.

5. In the event that there is any breach of any access protocol or any disagreement arising over the terms or implementation of this agreement, the parties agree to submit such issue to arbitration pursuant to the Arbitrations Act of Ontario and the determination under such arbitration shall be binding upon the parties. In the determination of any arbitration issues, the terms of the Affiliate Relationships Code in the *Ontario Energy Board* Act, its rules and regulations shall form the basis of any such arbitration.

IN WITNESS WHEREOF the parties have hereunto affixed their corporate seals.

ATIKOKAN HYDRO INC.

Per: ________________________________

Name/Title: ___________________________

Per: ________________________________

Name/Title:___________________________

I/We have authority to bind the Corporation.

ATIKOKAN ENERCOM INC.

Per: ________________________________

Name/Title:___________________________

Per: ________________________________

Name/Title:___________________________

I/We have authority to bind the Corporation.

OVERVIEW:

The purpose of this evidence is to summarize the method and cost of financing capital requirements for the 2012 test years.

Capital Structure:

Atikokan Hydro has a current deemed capital structure of 4% short term debt with a return of 4.47%, 56% long-term debt with a return of 5.15%, and 40% equity with a return of 8.57% as approved in the 2008 cost of service rate decision (EB-2008-0014).

Atikokan Hydro has prepared this rate application with a deemed capital structure of 56% Long Term Debt with a return of 4.58%, 4% Short Term Debt with a return of 2.46%, and 40% Equity with a return of 9.58%.

Return on Equity:

Atikokan Hydro is requesting a return on equity ("ROE") for the 2012 Test year of 9.58% in accordance with the Cost of Capital Parameter Updates for 2011 Cost of Service Applications issued by the OEB on March 3, 2011. Atikokan Hydro understands that the OEB will be finalizing the ROE for 2012 rates based on January 2012 market interest rate information. Atikokan Hydro's use of an ROE of 9.58% assumes it will be revised to the ROE that will be adopted by the OEB in early 2012.

COST OF DEBT:

Long Term Debt

Atikokan Hydro is requesting a return on Long Term Debt for the 2012 Test Year of 4.58%. Atikokan Hydro is currently paying a rate of 5.0% on a promissory note of $1,270,334 with the Town of Atikokan. In addition Atikokan Hydro is currently paying rates of 4.00% and 4.25% on two existing Long Term Loans negotiated with TD Canada Trust Bank valued at $268,915 and $207,317, respectively. Finally, Atikokan Hydro has a loan of $400,000 at a rate of prime + 0.5% with Atikokan Enercom Inc. which has been used to fund the smart meter program. For the purposes of this application it is assumed the interest on the $400,000 loan is 3.75%. The terms and conditions for each of these debt instruments are provided in Appendix A. The balances shown in Appendix A are as at December 31, 2010 while the balances discussed above are as at December 31, 2011. The following table shows the weighted average debt rate of these instruments is 4.58%.

Debt Holder	Principal	Rate%	Interest
Town of Atikokan	$1,270,334	5.00%	$63,838
TD Canada Trust	$268,915	4.00%	$11,892
TD Canada Trust	$207,317	4.25%	$9,270
Atikokan Enercom Inc	$400,000	3.75%	$12,310
Total	$2,146,566	4.58%	$97,310

Short Term Debt

Atikokan Hydro is requesting a return on Short Term Debt for the 2012 Test year of 2.46% in accordance with the Cost of Capital Parameter Updates for 2011 Cost of Service Applications issued by the OEB on March 3, 2011. Atikokan Hydro understands that the OEB will be finalizing the return on short term debt for 2012 rates based on January 2012 market interest rate information. Atikokan Hydro's use of a Return on Short Term Debt of 2.46% assumes a revised Short Term Debt rate will be adopted by the OEB in early 2012.

Rate Base and Rate of Return

The following table details Atikokan Hydro's rate base, deemed debt/equity ratios and deemed rates of return from 2008 to 2012.

1 # DEEMED CAPITAL STRUCTURE -2008 to 2012

Deemed Capital Structure for 2008

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	1,151,972	49.30%	5.15%	59,327
Unfunded Short Term Debt	93,466	4.00%	4.47%	4,178
Total Debt	1,245,438	53.30%		63,504
Common Share Equity	1,091,219	46.70%	8.57%	93,517
Total equity	1,091,219	46.70%		93,517
Total Rate Base	2,336,657	100.00%	6.72%	157,022

Deemed Capital Structure for 2009

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	1,242,649	52.70%	5.15%	63,996
Unfunded Short Term Debt	94,319	4.00%	4.47%	4,216
Total Debt	1,336,967	56.70%		68,212
Common Share Equity	1,021,000	43.30%	8.57%	87,500
Total equity	1,021,000	43.30%		87,500
Total Rate Base	2,357,967	100.00%	6.60%	155,712

Deemed Capital Structure for 2010

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	1,422,704	56.00%	5.15%	73,269
Unfunded Short Term Debt	101,622	4.00%	4.47%	4,542
Total Debt	1,524,326	60.00%		77,812
Common Share Equity	1,016,217	40.00%	8.57%	87,090
Total equity	1,016,217	40.00%		87,090
Total Rate Base	2,540,543	100.00%	6.49%	164,902

Deemed Capital Structure for 2011

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	1,485,669	56.00%	5.15%	76,512
Unfunded Short Term Debt	106,119	4.00%	4.47%	4,744
Total Debt	1,591,789	60.00%		81,256
Common Share Equity	1,061,192	40.00%	8.57%	90,944
Total equity	1,061,192	40.00%		90,944
Total Rate Base	2,652,981	100.00%	6.49%	172,200

Deemed Capital Structure for 2012

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	1,631,720	56.00%	4.57%	74,559
Unfunded Short Term Debt	116,551	4.00%	2.46%	2,867
Total Debt	1,748,272	60.00%		77,426
Common Share Equity	1,165,515	40.00%	9.58%	111,656
Total equity	1,165,515	40.00%		111,656
Total Rate Base	2,913,786	100.00%	6.49%	189,083

2

Appendix A : Atikokan Hydro Debt Instruments – Terms & Conditions

Debt Instrument	Terms and Conditions	Balance: December 31, 2010
Loan with Town of Atikokan - Unsecured	Principal amount: $1,309,297. Interest at 5%. Monthly payments of $6,300 (principal and interest)	$1,282,096
TD Canada Trust Bank Loan- Secured with Equipment	Principal amount: 339,683.29 Due December 2017. Interest; prime plus 1.0%. Monthly principal payments of $3,538.37. Interest paid separately.	$311,376
TD Canada Trust Bank Loan – Secured with Equipment	Principal amount: 228,939.12 Due December 2024. Interest; prime plus 1.25%. Monthly principal payments of $1,271.89. Interest paid separately.	$222,580
Loan with Atikokan Enercom Inc. - Unsecured	Principal amount: $400,000. Prime plus 0.5%; no set terms of repayment. Resolution 389 dated January 21, 2009.	$400,000

REVENUE DEFICIENCY - OVERVIEW:

Atikokan Hydro's net revenue deficiency is $307,589 and when grossed up for PILs Atikokan Hydro’s revenue deficiency is $364,011. This deficiency is calculated as the difference between the 2012 Test Year Revenue Requirement of $1,579,603 and the Forecast 2012 Test Year Revenue, based on the 2011 approved rates, at $1,215,592. Table 6-1 on the following page provides the revenue deficiency calculations.

Revenue Requirement:

Atikokan Hydro’s Revenue Requirement consists of the following:

- Administrative & General, Billing & Collecting Expense
- Operation & Maintenance Expense
- Depreciation Expense
- Property Taxes
- PILS’
- Deemed Interest & Return on Equity

Atikokan Hydro’s revenue requirement is primarily received through electricity distribution rates and offset by revenue from OEB-approved specific service charges, late payment charges, and other miscellaneous revenues.

Table 6.1 Revenue Deficiency

ATIKOKAN HYDRO INC
Revenue Deficiency Determination

Description	2012 Test Existing Rates	2012 Test - Required Revenue
Revenue		
Revenue Deficiency		364,011
Distribution Revenue	1,090,357	1,090,357
Other Operating Revenue (Net)	125,235	125,235
Total Revenue	1,215,592	1,579,603
Costs and Expenses		
Administrative & General, Billing & Collecting	703,625	703,625
Operation & Maintenance	471,526	471,526
Depreciation & Amortization	197,456	197,456
Deemed Interest	77,426	77,426
Total Costs and Expenses	1,450,033	1,450,033
Less OCT Included Above	0	0
Total Costs and Expenses Net of OCT	1,450,033	1,450,033
Utility Income Before Income Taxes	-234,441	129,570
Income Taxes:		
Corporate Income Taxes	-38,508	17,914
Total Income Taxes	-38,508	17,914
Utility Net Income	-195,933	111,656
Capital Tax Expense Calculation:		
Total Rate Base	2,913,786	2,913,786
Exemption	0	0
Deemed Taxable Capital	2,913,786	2,913,786
Ontario Capital Tax	0	0
Income Tax Expense Calculation:		
Accounting Income	-234,441	129,570
Tax Adjustments to Accounting Income	-13,997	-13,997
Taxable Income	-248,438	115,573
Income Tax Expense	-38,508	17,914
Tax Rate Refecting Tax Credits	15.50%	15.50%
Actual Return on Rate Base:		
Rate Base	2,913,786	2,913,786
Interest Expense	77,426	77,426
Net Income	-195,933	111,656
Total Actual Return on Rate Base	-118,507	189,083
Actual Return on Rate Base	-4.07%	6.49%
Required Return on Rate Base:		
Rate Base	2,913,786	2,913,786
Return Rates:		
Return on Debt (Weighted)	4.43%	4.43%
Return on Equity	9.58%	9.58%
Deemed Interest Expense	77,426	77,426
Return On Equity	111,656	111,656
Total Return	189,083	189,083
Expected Return on Rate Base	6.49%	6.49%
Revenue Deficiency After Tax	307,589	-0
Revenue Deficiency Before Tax	364,011	-0

COST DRIVERS ON REVENUE DEFICIENCY

Atikokan Hydro notes that main contributor to the net revenue deficiency of $307,589 for the 2012 Test Year is a result of an increase in OM&A expenses from the 2008 Board approved amount of $809,045 to $1,175,151 in the 2012 Test Year. This represents an increase of $336,106 which explains more the net revenue deficiency. As outlined in Exhibit 4, the rationale for the increase of $336,106 can be summarized into the following categories

• Smart meter related OM&A costs	$107,573
• Change in capitalization policy in 2010 to be aligned with MIFRS	$169,035
• ¼ of the costs to prepare and support this application	$50,000
• Staff changes	$39,498
• Total	$366,106

Exhibit	Tab	Schedule	Appendix	Contents
7 – Cost Allocation				
	1	1		Cost Allocation Overview
	1	2		Summary of Results and Proposed Changes
			A	2012 Updated Cost Allocation Study

COST ALLOCATION OVERVIEW:

Introduction:

On September 29, 2006, the OEB issued its directions on Cost Allocation Methodology for Electricity Distributors (the “Directions”). On November 15, 2006, the Board issued the Cost Allocation Information Filing Guidelines for Electricity Distributors (“the Guidelines”), the Cost Allocation Model (the “Model”) and User Instructions (the “Instructions”) for the Model. Atikokan Hydro prepared a cost allocation information filing consistent with Atikokan Hydro’s understanding of the Directions, the Guidelines, the Model and the Instructions. Atikokan Hydro submitted this filing to the OEB on June 22, 2007.

One of the main objectives of the filing was to provide information on any apparent cross-subsidization among a distributor’s rate classifications. It was felt that this would give an indication of cross-subsidization from one class to another and this information would be useful as a tool in future rate applications.

In Atikokan Hydro's 2008EDR CoS Application (EB-2008-0014), the results of the original cost allocation study filed on June 22, 2007 were updated to remove the Intermediate class from the analysis since this class was proposed to be eliminated as part of the 2008EDR CoS Application. The result of this updated study was used as a basis for Atikokan Hydro to propose reallocations of distribution costs across customer classes to address the issue of cross-subsidization. The reallocations were based on the objective of moving the revenue to cost ratios to be within the Board's acceptable range as outlined in the “Report on Application of Cost Allocation for Electricity Distributors” (the Cost Allocation Report”) issued by the OEB on November 28, 2007.

On September 2, 2010, the Board began a proceeding, EB-2010-0219, with the mandate to review and revise the existing Cost Allocation policy as needed. On March 31, 2011, the Report of the Board was released in relation to EB-2010-0219. In the letter accompanying report, the Board indicated that a Working Group would be formed to revise the original Cost Allocation Model to address the revision highlighted in the March 31st Board Report. On August 5, 2011, the Board released the new Cost Allocation model and instructed 2012 Cost of Service filers to use the revised model in their applications. In the March 31st Board Report, the Board stated that "default weighting factors should now be utilized only in exceptional circumstances". Distributors are therefore now expected to develop their own weighting factors.

For the purposes of this Application, Atikokan Hydro has submitted the revised cost allocation study to reflect 2012 test year costs, customer numbers and demand values. The 2012 demand values are based on the weather normalized load forecast used to design rates. Atikokan Hydro has developed weighting factors as outlined below based on discussions with staff experienced in the subject area.

Services (Account 1855) – Not applicable for Atikokan Hydro as no cost are recorded in account 1855

Billing and Collection (Accounts 5315 – 5340, except 5335)

Rate Class	Billing Weighting Factor
Residential	1
General Service < 50kW	1
General Service ≥ 50 kW	10
Street Lighting	3

Meter Capital (Sheet I7.1)

Meter Type	Installation Cost per Meter
Smart Meter	$250
Demand with IT and Interval Capability - Secondary	$2,100

Meter Reading (Sheet I7.2)

Meter Type	Meter Reading Weighting Factor
Smart Meter	1
Interval Meter	10

SUMMARY OF RESULTS AND PROPOSED CHANGES:

The data used in the updated cost allocation study is consistent with Atikokan Hydro's cost data that supports the proposed 2012 revenue requirement outlined in this application. Consistent with the Guidelines, Atikokan Hydro's assets were broken out into primary and secondary distribution functions using breakout percentages consistent with the original cost allocation informational filing. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to Atikokan Hydro, its engineering records, and its customer and financial information systems. The cost allocation study has been included in Appendix A.

Capital contributions, depreciation and accumulated depreciation by USoA is consistent with the information provided in the 2012 continuity statement shown in Exhibit 2. The rate class customer data used in the updated cost allocation study is consistent with the 2012 customer forecast outlined in Exhibit 3. The load profiles for all other rate class are the same as those used in the original information filing but have been scaled to match the load forecast. The following outlines the scaling factors used by rate class.

Table 7-1: Load Profile Scaling Percentages

Rate Class	2004 Weather Normal Values used in Original Filing (kWh)	2012 Weather Normal Values (KWh)	Scaling Factor
Residential	12,135,846	11,395,913	93.9%
GS < 50	6,155,695	6,387,021	103.8%
GS > 50 kW	7,663,602	5,343,698	69.7%
Street Lighting	531,698	466,493	87.7%
Total	**26,486,841**	**23,593,125**	**89.1%**

The allocated cost by rate class for the cost allocation study updated in the 2008EDR CoS Application and the 2012 updated study are provided in the following Table 7-2.

Table 7-2: Allocated Cost - (Consistent with Appendix 2-O: Allocated Costs)

Rate Class	Updated Cost Allocation Informational Filing provided in the 2008 Rate Application	%	Cost Allocated in the 2012 Study	%
Residential	$487,763	54.0%	$979,747	62.0%
GS < 50 kW	$197,094	21.8%	$267,509	16.9%
GS > 50 kW	$129,041	14.3%	$181,539	11.5%
Sentinel Lighting	$2,215	0.2%	$0	0.0%
Street Lighting	$85,231	9.4%	$150,809	9.5%
Unmetered Scattered Load	$1,735	0.2%	$0	0.0%
Total	$903,079	100.0%	$1,579,603	100.0%

The results of a cost allocation study are typically presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

In the Report of the Board on Cost Allocation released in relation to EB-2010-0219, dated March 31, 2011, the OEB established what it considered to be the appropriate ranges of revenue to cost ratios which are summarized in Table 7-3 below. In addition Table 7-3 provides Atikokan Hydro's revenue to cost ratios from the 2010 IRM application, the updated 2012 cost allocation study and the proposed 2012 to 2014 ratios. Information from the 2010 IRM application has been included as this was the last year of a three year program to move the revenue to cost ratios to the Board's acceptable ranges.

Table 7-3 Revenue to Cost Ratios - (Consistent with Appendix 2-O: Revenue to Cost Ratios)

Class	2010 IRM Application	2012 Updated Cost Allocation Study	2012 Proposed Ratios	2013 Proposed Ratios	2014 Proposed Ratios	Board Targets Min to Max	
Residential	101.0%	97.6%	98.1%	98.1%	98.1%	85.0%	115.0%
GS < 50 kW	100.0%	134.8%	120.0%	120.0%	120.0%	80.0%	120.0%
GS > 50 kW	80.0%	82.3%	82.3%	82.3%	82.3%	80.0%	120.0%
Sentinel Lighting	70.0%						
Street Lighting	70.0%	75.0%	98.1%	98.1%	98.1%	70.0%	120.0%
Unmetered Scattered Load	80.0%						

Atikokan Hydro is proposing in this application to re-align its revenue to cost ratios by adjusting the allocations of revenue among rate classes in order to reduce some of the cross-subsidization that is occurring. Atikokan Hydro is also proposing to eliminate the Sentinel Lighting and Unmetered Scattered Load classes as there are no customers in these classes.

The following table 7-4 provides information on calculated class revenue. The resulting 2012 proposed base revenue will be the amount used in Exhibit 8 to design the proposed distribution charges in this application.

Table 7-4 Calculated Class Revenue - (Consistent with Appendix 2-O: Calculated Class Revenue)

Class	2012 Base Revenue at Existing Rates	2012 Proposed Base Revenue Allocated at Existing Rates Proportion	2012 Proposed Base Revenue	Miscellaneous Revenue
Residential	$660,258	$880,682	$885,536	$75,624
GS < 50 kW	$254,263	$339,147	$299,438	$21,572
GS > 50 kW	$101,818	$135,810	$135,810	$13,674
Street Lighting	$74,018	$98,729	$133,584	$14,364
Total	$1,090,357	$1,454,368	$1,454,368	$125,235

Appendix A

2012 Updated Cost Allocation Study

2012 COST ALLOCATION STUDY

Atikokan Hydro Inc.

EB-2011-0293

September-30-11

Sheet I6.1 Revenue Worksheet - Initial Application

Total kWhs from Load Forecast	23,593,125
Total kWs from Load Forecast	15,521
Deficiency from RRWF	- 364,011
Miscellaneous Revenue	125,235

	ID	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light
Billing Data						
Forecast kWh	CEN	23,593,125	11,395,913	6,387,021	5,343,698	466,493
Forecast kW	CDEM	15,521	-	-	14,205	1,316
Forecast kW, included in CDEM, of customers receiving line transformer allowance		6,684			6,684	
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-				
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	23,593,125	11,395,913	6,387,021	5,343,698	466,493
kWh - 30 year weather normalized amount		23,593,125	11,395,913	6,387,021	5,343,698	466,493
Existing Monthly Charge			$30.58	$70.02	$440.74	$8.13
Existing Distribution kWh Rate			$0.0121	$0.0089		
Existing Distribution kW Rate					$1.7161	$10.0266
Existing TFOA Rate					$0.17	
Additional Charges						
Distribution Revenue from Rates		$1,091,504	$660,258	$254,263	$102,966	$74,018
Transformer Ownership Allowance		$1,147	$0	$0	$1,147	$0
Net Class Revenue	CREV	$1,090,357	$660,258	$254,263	$101,818	$74,018
Data Mismatch Analysis						
Revenue with 30 year weather normalized kWh		1,090,357	660,258	254,263	101,818	74,018

Weather Normalized Data from Hydro One

	Total	Residential	GS <50	GS>50-Regular	Street Light
kWh - 30 year weather normalized amount	23,593,125	11,395,913	6,387,021	5,343,698	466,493
Loss Factor		**1.0000**	1.0000	1.0000	1.0000

2012 COST ALLOCATION STUDY

Atikokan Hydro Inc.

EB-2011-0293

September-30-11

Sheet I6.2 Customer Data Worksheet - Initial Application

			1	2	3	7
	ID	Total	Residential	GS <50	GS>50-Regular	Street Light
Billing Data						
Bad Debt 3 Year Historical Average	BDHA	$5,444	$2,497	$2,490	$457	$0
Late Payment 3 Year Historical Average	LPHA	$6,024	$3,907	$1,530	$585	$3
Number of Bills	CNB	20,104	17,082	2,819	178	24
Number of Devices						623
Number of Connections (Unmetered)	CCON	623				623
Total Number of Customers	CCA	1,673	1,424	235	15	
Bulk Customer Base	CCB	1,673	1,424	235	15	
Primary Customer Base	CCP	1,673	1,424	235	15	
Line Transformer Customer Base	CCLT	1,668	1,424	235	10	
Secondary Customer Base	CCS	1,673	1,424	235	15	
Weighted - Services	CWCS	2,297	1,424	235	15	623
Weighted Meter -Capital	CWMC	446,114	355,875	58,739	31,500	-
Weighted Meter Reading	CWMR	30,600	17,082	2,819	10,699	-
Weighted Bills	CWNB	21,757	17,082	2,819	1,783	72

Bad Debt Data

Historic Year:	2009	5,444	2,497	2,490	457	
Historic Year:	2010	5,444	2,497	2,490	457	
Historic Year:	2011	5,444	2,497	2,490	457	
Three-year average		**5,444**	**2,497**	**2,490**	**457**	**-**

2012 COST ALLOCATION STUDY

Atikokan Hydro Inc.

EB-2011-0293

September-30-11

Sheet I8 Demand Data Worksheet - Initial Application

This is an input sheet for demand allocators.

CP TEST RESULTS	4 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light
CO-INCIDENT PEAK						
1 CP						
Transformation CP	TCP1	4,376	2,511	1,136	614	116
Bulk Delivery CP	BCP1	4,376	2,511	1,136	614	116
Total Sytem CP	DCP1	4,376	2,511	1,136	614	116
4 CP						
Transformation CP	TCP4	16,526	9,081	4,446	2,592	407
Bulk Delivery CP	BCP4	16,526	9,081	4,446	2,592	407
Total Sytem CP	DCP4	16,526	9,081	4,446	2,592	407
12 CP						
Transformation CP	TCP12	43,008	21,896	12,524	8,004	583
Bulk Delivery CP	BCP12	43,008	21,896	12,524	8,004	583
Total Sytem CP	DCP12	43,008	21,896	12,524	8,004	583
NON CO_INCIDENT PEAK						
1 NCP						
Classification NCP from Load Data Provider	DNCP1	5,562	2,637	1,551	1,258	116
Primary NCP	PNCP1	5,562	2,637	1,551	1,258	116
Line Transformer NCP	LTNCP1	5,151	2,637	1,551	847	116
Secondary NCP	SNCP1	5,562	2,637	1,551	1,258	116
4 NCP						
Classification NCP from Load Data Provider	DNCP4	20,497	9,671	5,797	4,565	464
Primary NCP	PNCP4	20,497	9,671	5,797	4,565	464
Line Transformer NCP	LTNCP4	19,004	9,671	5,797	3,072	464
Secondary NCP	SNCP4	20,497	9,671	5,797	4,565	464
12 NCP						
Classification NCP from Load Data Provider	DNCP12	51,412	24,116	14,915	10,990	1,391
Primary NCP	PNCP12	51,412	24,116	14,915	10,990	1,391
Line Transformer NCP	LTNCP12	47,818	24,116	14,915	7,396	1,391
Secondary NCP	SNCP12	51,412	24,116	14,915	10,990	1,391

2012 COST ALLOCATION STUDY
Atikokan Hydro Inc.
EB-2011-0293
September-30-11

Ontario

Sheet O1 Revenue to Cost Summary Worksheet - Initial Application

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

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light
crev	Distribution Revenue at Existing Rates	$1,090,357	$660,258	$254,263	$101,818	$74,018
mi	Miscellaneous Revenue (mi)	$125,235	$75,624	$21,572	$13,674	$14,364
		Miscellaneous Revenue Input equals Output				
	Total Revenue at Existing Rates	$1,215,592	$735,882	$275,835	$115,493	$88,382
	Factor required to recover deficiency (1 + D)	1.3338				
	Distribution Revenue at Status Quo Rates	$1,454,368	$880,682	$339,147	$135,810	$98,729
	Miscellaneous Revenue (mi)	$125,235	$75,624	$21,572	$13,674	$14,364
	Total Revenue at Status Quo Rates	$1,579,603	$956,307	$360,720	$149,484	$113,093
	Expenses					
di	Distribution Costs (di)	$361,956	$195,936	$67,869	$39,726	$58,424
cu	Customer Related Costs (cu)	$262,740	$195,465	$34,340	$32,598	$337
ad	General and Administration (ad)	$550,455	$344,697	$90,248	$63,679	$51,831
dep	Depreciation and Amortization (dep)	$197,456	$118,242	$36,979	$22,689	$19,546
INPUT	PILs (INPUT)	$17,914	$10,853	$3,295	$1,977	$1,789
INT	Interest	$77,426	$46,908	$14,241	$8,546	$7,732
	Total Expenses	$1,467,947	$912,101	$246,972	$169,215	$139,659
	Direct Allocation	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$111,656	$67,646	$20,536	$12,324	$11,150
	Revenue Requirement (includes NI)	$1,579,603	$979,747	$267,509	$181,539	$150,809
		Revenue Requirement Input equals Output				
	Rate Base Calculation					
	Net Assets					
dp	Distribution Plant - Gross	$3,724,663	$2,125,027	$730,258	$442,833	$426,544
gp	General Plant - Gross	$1,937,188	$1,173,631	$356,299	$213,813	$193,445
accum dep	Accumulated Depreciation	($3,253,626)	($1,839,653)	($643,622)	($390,844)	($379,507)
co	Capital Contribution	$0	$0	$0	$0	$0
	Total Net Plant	$2,408,225	$1,459,006	$442,935	$265,803	$240,482
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$2,195,257	$1,060,350	$594,290	$497,212	$43,406
	OM&A Expenses	$1,175,151	$736,098	$192,458	$136,003	$110,592
	Directly Allocated Expenses	$0	$0	$0	$0	$0
	Subtotal	*$3,370,408*	*$1,796,447*	*$786,747*	*$633,216*	*$153,998*
	Working Capital	$505,561	$269,467	$118,012	$94,982	$23,100
	Total Rate Base	$2,913,786	$1,728,473	$560,947	$360,785	$263,581
		Rate Base Input equals Output				
	Equity Component of Rate Base	$1,165,515	$691,389	$224,379	$144,314	$105,433
	Net Income on Allocated Assets	$111,656	$44,206	$113,748	($19,731)	($26,566)
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0
	Net Income	$111,656	$44,206	$113,748	($19,731)	($26,566)
	RATIOS ANALYSIS					
	REVENUE TO EXPENSES STATUS QUO%	100.00%	97.61%	134.84%	82.34%	74.99%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($364,011)	($243,865)	$8,327	($66,046)	($62,427)
		Deficiency Input equals Output				
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	($23,441)	$93,211	($32,054)	($37,716)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.58%	6.39%	50.69%	-13.67%	-25.20%

Ontario

2012 COST ALLOCATION STUDY

Atikokan Hydro Inc.

EB-2011-0293

September-30-11

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

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7
	Residential	**GS <50**	**GS>50-Regular**	**Street Light**
Customer Unit Cost per month - Avoided Cost	$13.94	$13.52	$199.34	-$0.02
Customer Unit Cost per month - Directly Related	$25.71	$25.31	$373.14	$0.02
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$43.61	$44.62	$399.09	$20.09
Existing Approved Fixed Charge	$30.58	$70.02	$440.74	$8.13

Ontario

2012 COST ALLOCATION STUDY
Atikokan Hydro Inc.
EB-2011-0293
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Sheet O2.1 Line Transformer Worksheet - Initial Application

Line Transformers Demand Unit Cost for PLCC
Adjustment to Customer Related Cost
Allocation by rate classification

Description	Total	1 Residential	2 GS <50	3 GS>50-Regular	4 GS> 50-TOU	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor
Depreciation on Acct 1850 Line Transformers	$1,615	$752	$552	$311	$0	$0	$0	$0	$0	$0	$0
Depreciation on General Plant Assigned to Line Transformers	$2,576	$1,200	$880	$496	$0	$0	$0	$0	$0	$0	$0
Acct 5035 - Overhead Distribution Transformers- Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5055 - Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5160 - Maintenance of Line Transformers	$726	$338	$248	$140	$0	$0	$0	$0	$0	$0	$0
Allocation of General Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Admin and General Assigned to Line Transformers	$640	$298	$219	$123	$0	$0	$0	$0	$0	$0	$0
PILs on Line Transformers	$541	$252	$185	$104	$0	$0	$0	$0	$0	$0	$0
Debt Return on Line Transformers	$2,336	$1,088	$798	$450	$0	$0	$0	$0	$0	$0	$0
Equity Return on Line Transformers	$3,369	$1,569	$1,151	$649	$0	$0	$0	$0	$0	$0	$0
Total	**$11,802**	**$5,497**	**$4,032**	**$2,273**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Line Tranformer NCP	15,871	7,393	5,422	3,056	0	0	0	0	0	0	0
PLCC Amount	3,133	2,278	376	16	0	0	0	464	0	0	0
Adjustment to Customer Related Cost for PLCC	**$1,985**	**$1,694**	**$280**	**$12**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant - Gross Assets	$1,937,188	$1,173,631	$356,299	$213,813	$0	$0	$0	$193,445	$0	$0	$0
General Plant - Accumulated Depreciation	($1,193,357)	($722,986)	($219,489)	($131,714)	$0	$0	$0	($119,167)	$0	$0	$0
General Plant - Net Fixed Assets	$743,832	$450,645	$136,810	$82,099	$0	$0	$0	$74,278	$0	$0	$0
General Plant - Depreciation	$85,367	$51,719	$15,701	$9,422	$0	$0	$0	$8,525	$0	$0	$0
Total Net Fixed Assets Excluding General Plant	**$1,664,393**	**$1,008,361**	**$306,125**	**$183,704**	**$0**	**$0**	**$0**	**$166,204**	**$0**	**$0**	**$0**
Total Administration and General Expense	$550,455	$344,697	$90,248	$63,679	$0	$0	$0	$51,831	$0	$0	$0
Total O&M	**$624,696**	**$391,401**	**$102,210**	**$72,324**	**$0**	**$0**	**$0**	**$58,761**	**$0**	**$0**	**$0**
Line Transformer Rate Base											
Acct 1850 - Line Transformers - Gross Assets	$200,711	$93,496	$68,563	$38,651	$0	$0	$0	$0	$0	$0	$0
Line Transformers - Accumulated Depreciation	($150,487)	($70,101)	($51,407)	($28,980)	$0	$0	$0	$0	$0	$0	$0
Line Transformers - Net Fixed Assets	$50,224	$23,395	$17,156	$9,672	$0	$0	$0	$0	$0	$0	$0
General Plant Assigned to Line Transformers - NFA	$22,445	$10,456	$7,667	$4,322	$0	$0	$0	$0	$0	$0	$0
Line Transformer Net Fixed Assets Including General Plant	$72,669	$33,851	$24,824	$13,994	$0	$0	$0	$0	$0	$0	$0
General Expenses											
Acct 5005 - Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5010 - Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5085 - Miscellaneous Distribution Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5105 - Maintenance Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1850 - Line Transformers - Gross Assets	$200,711	$93,496	$68,563	$38,651	$0	$0	$0	$0	$0	$0	$0
Acct 1815 - 1855	$1,553,722	$672,026	$490,435	$390,824	$0	$0	$0	$438	$0	$0	$0

11	12	13	14	15	16	17	18	19	20
Back-up/Standby Power	**Rate Class 1**	**Rate class 2**	**Rate class 3**	**Rate class 4**	**Rate class 5**	**Rate class 6**	**Rate class 7**	**Rate class 8**	**Rate class 9**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
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$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
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$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

2012 COST ALLOCATION STUDY
Atikokan Hydro Inc.
EB-2011-0293
September-30-11

Sheet O2.2 Primary Cost PLCC Adjustment Worksheet - Initial Application

Primary Conductors and Poles Cost Pool Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Allocation by Rate Classification

		1	2	3	4	5	6	7	8	9	10
Description	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**GS> 50-TOU**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
Depreciation on Acct 1830-4 Primary Poles, Towers & Fixtures	$14,951	$6,369	$4,670	$3,912	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1835-4 Primary Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1840-4 Primary Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1845-4 Primary Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation on General Plant Assigned to Primary C&P	$10,786	$4,594	$3,369	$2,822	$0	$0	$0	$0	$0	$0	$0
Primary C&P Operations and Maintenance	$83,897	$35,737	$26,207	$21,953	$0	$0	$0	$0	$0	$0	$0
Allocation of General Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Admin and General Assigned to Primary C&P	$73,942	$31,473	$23,140	$19,329	$0	$0	$0	$0	$0	$0	$0
PILs on Primary C&P	$2,263	$964	$707	$592	$0	$0	$0	$0	$0	$0	$0
Debt Return on Primary C&P	$9,783	$4,167	$3,056	$2,560	$0	$0	$0	$0	$0	$0	$0
Equity Return on Primary C&P	$14,108	$6,009	$4,407	$3,691	$0	$0	$0	$0	$0	$0	$0
Total	**$209,730**	**$89,314**	**$65,556**	**$54,860**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Primary NCP	17,356	7,393	5,422	4,541	0	0	0	0	0	0	0
PLCC Amount	3,141	2,278	376	24	0	0	0	464	0	0	0
Adjustment to Customer Related Cost for PLCC	**$32,348**	**$27,515**	**$4,546**	**$287**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant - Gross Assets	$1,937,188	$1,173,631	$356,299	$213,813	$0	$0	$0	$193,445	$0	$0	$0
General Plant - Accumulated Depreciation	($1,193,357)	($722,986)	($219,489)	($131,714)	$0	$0	$0	($119,167)	$0	$0	$0
General Plant - Net Fixed Assets	$743,832	$450,645	$136,810	$82,099	$0	$0	$0	$74,278	$0	$0	$0
General Plant - Depreciation	$85,367	$51,719	$15,701	$9,422	$0	$0	$0	$8,525	$0	$0	$0
Total Net Fixed Assets Excluding General Plant	**$1,664,393**	**$1,008,361**	**$306,125**	**$183,704**	**$0**	**$0**	**$0**	**$166,204**	**$0**	**$0**	**$0**
Total Administration and General Expense	**$550,455**	**$344,697**	**$90,248**	**$63,679**	**$0**	**$0**	**$0**	**$51,831**	**$0**	**$0**	**$0**
Total O&M	**$624,696**	**$391,401**	**$102,210**	**$72,324**	**$0**	**$0**	**$0**	**$58,761**	**$0**	**$0**	**$0**
<u>Primary Conductors and Poles Gross Assets</u>											
Acct 1830-4 Primary Poles, Towers & Fixtures	$497,261	$211,816	$155,330	$130,115	$0	$0	$0	$0	$0	$0	$0
Acct 1835-4 Primary Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-4 Primary Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-4 Primary Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	*$497,261*	*$211,816*	*$155,330*	*$130,115*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*
<u>Primary Conductors and Poles Accumulated Depreciation</u>											
Acct 1830-4 Primary Poles, Towers & Fixtures	($286,968)	($122,238)	($89,640)	($75,089)	$0	$0	$0	$0	$0	$0	$0
Acct 1835-4 Primary Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-4 Primary Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-4 Primary Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***($286,968)***	***($122,238)***	***($89,640)***	***($75,089)***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Primary Conductor & Pools - Net Fixed Assets	$210,293	$89,577	$65,689	$55,026	$0	$0	$0	$0	$0	$0	$0
General Plant Assigned to Primary C&P - NFA	$93,982	$40,033	$29,357	$24,592	$0	$0	$0	$0	$0	$0	$0
Primary C&P Net Fixed Assets Including General Plant	$304,275	$129,610	$95,047	$79,618	$0	$0	$0	$0	$0	$0	$0
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***

Acct 1830-5 Secondary Poles, Towers & Fixtures	$348,133	$148,293	$108,747	$91,094	$0	$0	$0	$0	$0	$0	$0
Acct 1835-5 Secondary Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-5 Secondary Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-5 Secondary Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$348,133***	***$148,293***	***$108,747***	***$91,094***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Operations and Maintenance											
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$106,037	$45,168	$33,123	$27,746	$0	$0	$0	$0	$0	$0	$0
Acct 5025 Overhead Distribution Lines & Feeders - Other	$17,166	$7,312	$5,362	$4,492	$0	$0	$0	$0	$0	$0	$0
Acct 5040 Underground Distribution Lines & Feeders - Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5045 Underground Distribution Lines & Feeders - Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5120 Maintenance of Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5125 Maintenance of Overhead Conductors & Devices	$2,363	$1,007	$738	$618	$0	$0	$0	$0	$0	$0	$0
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$17,068	$7,270	$5,331	$4,466	$0	$0	$0	$0	$0	$0	$0
Acct 5145 Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5150 Maintenance of Underground Conductors & Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$142,634**	**$60,757**	**$44,555**	**$37,322**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Expenses											
Acct 5005 - Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5010 - Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5085 - Miscellaneous Distribution Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5105 - Maintenance Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Primary Conductors and Poles Gross Assets	$497,261	$211,816	$155,330	$130,115	$0	$0	$0	$0	$0	$0	$0
Acct 1815 - 1855	$1,553,722	$672,026	$490,435	$390,824	$0	$0	$0	$438	$0	$0	$0

11	12	13	14	15	16	17	18	19	20
Back-up/Standby Power	**Rate Class 1**	**Rate class 2**	**Rate class 3**	**Rate class 4**	**Rate class 5**	**Rate class 6**	**Rate class 7**	**Rate class 8**	**Rate class 9**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
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$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
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$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

2012 COST ALLOCATION STUDY
Atikokan Hydro Inc.
EB-2011-0293
September-30-11
Sheet O2.3 Secondary Cost PLCC Adjustment Worksheet - Initial Application

Secondary Conductors and Poles Cost Pool Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Allocation by Rate Classification

Description		1	2	3	4	5	6	7	8	9	10
	Total	Residential	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
Depreciation on Acct 1830-5 Secondary Poles, Towers & Fixtures	$10,467	$4,459	$3,270	$2,739	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1835-5 Secondary Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1840-5 Secondary Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1845-5 Secondary Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation on General Plant Assigned to Secondary C&P	$7,551	$3,217	$2,359	$1,976	$0	$0	$0	$0	$0	$0	$0
Secondary C&P Operations and Maintenance	$58,737	$25,020	$18,348	$15,369	$0	$0	$0	$0	$0	$0	$0
Allocation of General Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Admin and General Assigned to Primary C&P	$51,767	$22,034	$16,200	$13,532	$0	$0	$0	$0	$0	$0	$0
PILs on Secondary C&P	$1,585	$675	$495	$415	$0	$0	$0	$0	$0	$0	$0
Debt Return on Secondary C&P	$6,849	$2,917	$2,139	$1,792	$0	$0	$0	$0	$0	$0	$0
Equity Return on Secondary C&P	$9,877	$4,207	$3,085	$2,584	$0	$0	$0	$0	$0	$0	$0
Total	**$146,832**	**$62,529**	**$45,896**	**$38,407**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Secondary NCP	17,356	7,393	5,422	4,541	0	0	0	0	0	0	0
PLCC Amount	3,141	2,278	376	24	0	0	0	464	0	0	0
Adjustment to Customer Related Cost for PLCC	**$22,647**	**$19,263**	**$3,182**	**$201**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant - Gross Assets	$1,937,188	$1,173,631	$356,299	$213,813	$0	$0	$0	$193,445	$0	$0	$0
General Plant - Accumulated Depreciation	($1,193,357)	($722,986)	($219,489)	($131,714)	$0	$0	$0	($119,167)	$0	$0	$0
General Plant - Net Fixed Assets	$743,832	$450,645	$136,810	$82,099	$0	$0	$0	$74,278	$0	$0	$0
General Plant - Depreciation	$85,367	$51,719	$15,701	$9,422	$0	$0	$0	$8,525	$0	$0	$0
Total Net Fixed Assets Excluding General Plant	$1,664,393	$1,008,361	$306,125	$183,704	$0	$0	$0	$166,204	$0	$0	$0
Total Administration and General Expense	$550,455	$344,697	$90,248	$63,679	$0	$0	$0	$51,831	$0	$0	$0
Total O&M	$624,696	$391,401	$102,210	$72,324	$0	$0	$0	$58,761	$0	$0	$0
Secondary Conductors and Poles Gross Plant											
Acct 1830-5 Secondary Poles, Towers & Fixtures	$348,133	$148,293	$108,747	$91,094	$0	$0	$0	$0	$0	$0	$0
Acct 1835-5 Secondary Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-5 Secondary Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-5 Secondary Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$348,133***	***$148,293***	***$108,747***	***$91,094***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Secondary Conductors and Poles Accumulated Depreciation											
Acct 1830-5 Secondary Poles, Towers & Fixtures	($200,907)	($85,579)	($62,757)	($52,570)	$0	$0	$0	$0	$0	$0	$0
Acct 1835-5 Secondary Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-5 Secondary Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-5 Secondary Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***($200,907)***	***($85,579)***	***($62,757)***	***($52,570)***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Secondary Conductor & Pools - Net Fixed Assets	$147,227	$62,713	$45,989	$38,524	$0	$0	$0	$0	$0	$0	$0
General Plant Assigned to Secondary C&P - NFA	$65,797	$28,027	$20,553	$17,217	$0	$0	$0	$0	$0	$0	$0
Secondary C&P Net Fixed Assets Including General Plant	$213,023	$90,741	$66,542	$55,741	$0	$0	$0	$0	$0	$0	$0
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Acct 1830-4 Primary Poles, Towers & Fixtures	$497,261	$211,816	$155,330	$130,115	$0	$0	$0	$0	$0	$0	$0

Acct 1835-4 Primary Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-4 Primary Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-4 Primary Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$497,261***	***$211,816***	***$155,330***	***$130,115***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Operations and Maintenance											
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$106,037	$45,168	$33,123	$27,746	$0	$0	$0	$0	$0	$0	$0
Acct 5025 Overhead Distribution Lines & Feeders - Other	$17,166	$7,312	$5,362	$4,492	$0	$0	$0	$0	$0	$0	$0
Acct 5040 Underground Distribution Lines & Feeders - Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5045 Underground Distribution Lines & Feeders - Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5120 Maintenance of Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5125 Maintenance of Overhead Conductors & Devices	$2,363	$1,007	$738	$618	$0	$0	$0	$0	$0	$0	$0
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$17,068	$7,270	$5,331	$4,466	$0	$0	$0	$0	$0	$0	$0
Acct 5145 Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5150 Maintenance of Underground Conductors & Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$142,634**	**$60,757**	**$44,555**	**$37,322**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Expenses											
Acct 5005 - Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5010 - Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5085 - Miscellaneous Distribution Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5105 - Maintenance Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Secondary Conductors and Poles Gross Assets	$348,133	$148,293	$108,747	$91,094	$0	$0	$0	$0	$0	$0	$0
Acct 1815 - 1855	$1,553,722	$672,026	$490,435	$390,824	$0	$0	$0	$438	$0	$0	$0

11	12	13	14	15	16	17	18	19	20
Back-up/Standby Power	**Rate Class 1**	**Rate class 2**	**Rate class 3**	**Rate class 4**	**Rate class 5**	**Rate class 6**	**Rate class 7**	**Rate class 8**	**Rate class 9**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0
$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

RATE DESIGN OVERVIEW:

This Exhibit documents the calculation of Atikokan Hydro's proposed distribution rates by rate class for the 2012 test year, based on the rate design as proposed in this Exhibit.

Atikokan Hydro has determined its total 2012 service revenue requirement to be $1,579,603 The total revenue offsets in the amount of $125,235 reduce Atikokan Hydro's total service revenue requirement to a base revenue requirement to $1,454,368 which is used to determine the proposed distribution rates. The revenue requirement is summarized in the table below:

Table 8-1 Calculation of Base Revenue Requirement

Description	Amount
OM&A Expenses	$1,175,151
Amortization Expenses	$197,456
Regulated Return On Capital	$189,083
PILs	$17,914
Service Revenue Requirement	$1,579,603
Less: Revenue Offsets	$125,235
Base Revenue Requirement	**$1,454,368**

The outstanding base revenue requirement is allocated to the various rate classes using the proposed revenue to cost ratios outlined in Exhibit 7 – Cost Allocation. The following table shows how the base revenue requirement has been allocated to the rate classes.

TABLE 8-2 Rate Class Base Revenue Requirement

Rate Classification	2012 Base Revenue Requirement
Residential	$885,536
GS < 50 kW	$299,438
GS > 50 kW	$135,810
Street Lighting	$133,584
Total	**$1,454,368**

In this application, Atikokan Hydro is proposing to eliminate the Sentinel Lighting and Unmetered Scattered Load class since there are no longer any customers in these classes.

Determination of Monthly Fixed Charges:

Based on apply the existing approved monthly service charges to the forecasted number of customers for 2012 and applying the existing approved distribution volumetric charge excluding the adjustment for transformation allowance, to 2012 forecasted volumes the following table outlines the Atikokan Hydro's current split between fixed and variable distribution revenue.

Table 8-3 Current Fixed Variable Split

Rate Classification	2012 Fixed Base Revenue with 2011 Approved Rates	2012 Variable Base Revenue with 2011 Approved Rates	2012 Total Base Revenue with 2011 Approved Rates	Fixed Revenue Proportion	Variable Revenue Proportion
Residential	$522,368	$137,891	$660,258	79.1%	20.9%
GS < 50 kW	$197,418	$56,844	$254,263	77.6%	22.4%
GS > 50 kW	$78,589	$23,229	$101,818	77.2%	22.8%
Street Lighting	$60,822	$13,196	$74,018	82.2%	17.8%
Total	**$859,197**	**$231,161**	**$1,090,357**	**78.8%**	**21.2%**

Atikokan Hydro submits that it is appropriate for 2012 to maintain the same fixed/variable proportions assumed in the current rates to all customer classifications.

In its November 28, 2007 Report on Application of Cost Allocation for Electricity Distributors, the OEB addressed a number of "Other Rate Matters", including the treatment of the fixed rate component (the Monthly Service Charge, or 'MSC') of the bill. At page 12 of the Report, the OEB determined that the floor amount for the MSC should be the avoided costs, as that term is defined in the September 29, 2006 report of the OEB entitled "Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors". Atikokan Hydro's MSCs exceed that floor amount by rate class. With respect to the upper bound for the MSC, the OEB considered it to be inappropriate to make changes to the MSC ceiling at this time, given the number of issues that remain to be examined within the scope of the OEB's Rate Review proceeding (EB-2008-0031). The OEB indicated that for the time being, it does not expect distributors to make changes to the MSC that result in a charge that is greater than the ceiling as defined in the Methodology for the MSC; and that distributors that are currently above that value are not required to make changes to their current MSC to bring it to or below that level at this time. In accordance with the filing requirements the following information has been provided with regards to the MSC. The following table provides the current monthly service charges compared to the floor and ceiling as calculated in the cost allocation study.

Table 8-4 Monthly Service Charge Information from Cost Allocaiton Model

Rate Classification	2011 Approved Monthly Service Charge	Customer Unit Cost per month - Avoided Cost	Customer Unit Cost per month - Minimum System with PLCC Adjustment
Residential	$30.58	$13.94	$43.61
GS < 50 kW	$70.02	$13.52	$44.62
GS > 50 kW	$440.74	$199.34	$399.09
Street Lighting	$8.13	-$0.02	$20.09

Consistent with recent Board Decision on 2011 cost of service rate applications for Hydro One Brampton, Kenora Hydro and Horizon Utilities this Application proposes to maintain the current fixed/variable proportions for all rate classes in the design of the proposed distribution rates. The following table provides the calculation of monthly fixed charge assuming the fixed/variable split is maintained.

Table 8-5 Proposed Monthly Service Charge

Rate Classification	Total Base Revenue Requirement	Fixed Revenue Proportion	Fixed Revenue	Annualized Customers / Connections	Proposed Monthly Service Charge
Residential	$885,536	79.1%	$700,598	17,082	$41.01
GS < 50 kW	$299,438	77.6%	$232,494	2,819	$82.46
GS > 50 kW	$135,810	77.2%	$104,826	178	$587.88
Street Lighting	$133,584	82.2%	$109,768	7,481	$14.67
Total	**$1,454,368**				

Proposed Volumetric Charges:

The volumetric distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement by the appropriate 2012 Test Year usage, kWh or kW, as the class charge determinant.

The following Table provides Atikokan Hydro's calculations of its proposed volumetric distribution charges for the 2012 Test Year which maintains the same fixed/variable split used in designing the current approved rates.

Table 8-6 Proposed Distribution Volumetric Charge

Rate Classification	Total Base Revenue Requirement	Fixed Revenue	Variable Revenue	Annualized kWh or kW as required	Unit of Measure	Proposed Volumetric Distribution Charge before Transformer Allowance
Residential	$885,536	$700,598	$184,938	11,395,913	kWh	$0.0162
GS < 50 kW	$299,438	$232,494	$66,944	6,387,021	kWh	$0.0105
GS > 50 kW	$135,810	$104,826	$30,985	14,205	kW	$2.1813
Street Lighting	$133,584	$109,768	$23,816	1,316	kW	$18.0955
Total	**$1,454,368**	**$1,147,685**	**$306,683**			

Proposed Adjustment for Transformer Allowance:

Currently, Atikokan Hydro provides a Transformer Allowance to those customers that own their transformation facilities. Atikokan Hydro proposes to maintain the current approved transformer ownership allowance of 10% of the distribution volumetric rate for the GS > 50 kW class (i.e. $0.17 per kW). The Transformer Allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the customer's utilization voltage level. Since the distributor provides electricity at utilization voltage, the cost of this transformation is captured in and recovered through the distribution rates. Therefore, when a customer provides its own step down transformation from primary to secondary, it should receive a credit of these costs already included in the distribution rates.

The amount of the Transformer Allowance expected to be provided to those GS > 50 kW customers that own their transformers is included in the GS > 50 kW volumetric charge. As a result, the proposed volumetric charge of $2.1813 per kW for the GS > 50 kW customer class is increased by $0.0808 per kW to include the amount of the Transformer Allowance in the GS > 50 kW class distribution volumetric rate This means the total proposed distribution volumetric charge for the GS > 50 kW class will be $2.2621.

Proposed Distribution Rates:

The following table sets out Atikokan Hydro's proposed 2011 electricity distribution rates based on the foregoing calculations.

Table 8-7 Proposed Distribution Rates

Rate Classification	Proposed Monthly Service Charge	Unit of Measure	Proposed Volumetric Distribution Charge incl Transformer Allowance Adjustment
Residential	$41.01	kWh	$0.0162
GS < 50 kW	$82.46	kWh	$0.0105
GS > 50 kW	$587.88	kW	$2.2621
Street Lighting	$14.67	kW	$18.0955
Transformer Discount		kWh	($0.17)

RETAIL TRANSMISSION SERVICE RATES

Electricity distributors are charged the Ontario Uniform Transmission Rates (UTRs) at the wholesale level and subsequently pass these charges on to their distribution customers through Retail Transmission Service Rates (RTSRs). For each distribution rate class there are two RTSRs, one for network and one for connection. The RTSR network charge recovers the UTR wholesale network service charge, and the RTSR connection charge recovers the UTR wholesale line and transformation connection charges. Deferral accounts capture timing and rate differences between the UTR's paid at the wholesale level and RTSR's billed to distribution customers.

The Board has provided a Microsoft Excel workbook "2012_RTSR_Adjustment_Work_Form" and instructions for distributors to complete as part of their 2012 electricity rate applications. Atikokan Hydro has completed this workbook to determine the RTSR's and has filed the model as part of this application. Table 8.8 is reproduced from the Board model and indicates the new RTSR's**.**

Table 8-8

Proposed 2012 Retail Transmission Service Rates

Rate Class	Unit	Proposed RTSR Network		Proposed RTSR Connection	
Residential	kWh	$	0.0056	$	0.0035
General Service Less Than 50 kW	kWh	$	0.0051	$	0.0030
General Service 50 to 4,999 kW	kW	$	2.0445	$	1.2016
General Service 50 to 4,999 kW – Interval Metered	kW	$	2.1690	$	1.3281
Street Lighting	kW	$	1.5421	$	0.9288

LOSS FACTOR

DETERMINATION OF LOSS ADJUSTMENT FACTORS:

Total Loss Factor:

Atikokan Hydro has calculated the total loss factor to be applied to customers' consumption based on the average wholesale and retail kWh for the years 2006 to 2010. The calculations are summarized in Table 8-9 below.

Table 8-9 Line Loss Calculation

Total Loss Factor Calculations

		Historical Years					5-Year
		2006	2007	2008	2009	2010	Average
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	46,231,560	40,722,040	27,014,076	25,781,622	24,708,723	32,891,604
A(2)	"Wholesale" kWh delivered to distributor (lower value)	46,024,450	40,539,612	26,893,057	25,666,124	24,598,032	32,744,255
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	0	0	0	0	0	0
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	46,024,450	40,539,612	26,893,057	25,666,124	24,598,032	32,744,255
D	"Retail" kWh delivered by	43,320,424	38,478,814	24,562,881	23,302,413	22,917,248	30,516,356
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	0	0	0	0	0	0
F	Net "Retail" kWh delivered by distributor = **D - E**	43,320,424	38,478,814	24,562,881	23,302,413	22,917,248	30,516,356
G	Loss Factor in Distributor's system = **C / F**	1.0624	1.0536	1.0949	1.1014	1.0733	1.0730
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045
	Total Losses						
I	Total Loss Factor = **G x H**	1.0672	1.0583	1.0998	1.1064	1.0782	1.0778

Supply Facility Loss Factor:

As indicated in table 8-9, row H Atikokan Hydro's Supply Facility Loss Factor is 1.0045. This is the default value assigned an LDC directly connected to the IESO grid which is the situation for for Atikokan Hydro for the supply of all load.

Materiality Analysis on Distribution Losses:

Atikokan Hydro's Distribution Loss Adjustment factor is 7.3%. Pursuant to the Filing Requirements, as the Distribution Loss Adjustment factor is greater than 5%. Atikokan Hydro provides the following explanation of its loss factor.

Atikokan Hydro is somewhat unique in being directly connected to the IESO grid, and maintaining 23 kilometers of 44 kV sub transmission line. Atikokan Hydro's wholesale meters are located at Moose Lake TS, which is the Hydro One source for our supply. Since Atikokan's Distribution system is at the end of the sub transmission lines, and Atikokan Hydro's purchases are actual metered measurements at the source of supply, there is no way to separate the sub transmission losses from the distribution losses. The result is a total loss factor of 7.3%.

The following table outlines Atikokan Hydro's proposed loss factors

Table 8-10 Total Loss Factor by Class

Supply Facility Loss Factor	1.0045
Distribution Loss Factor	
Distribution Loss Factor - Secondary Metered Customers	1.0730
Distribution Loss Factor - Primary Metered Customers	1.0623
Total Loss Factor	
Total Loss Factor - Secondary Metered Customers	1.0778
Total Loss Factor - Primary Metered Customers	1.0671

RATE MITIGATION:

Atikokan Hydro has reviewed the bill impacts and recognizes that a rate mitigation plan needs to be implemented in order to limit the bill impacts to the Residential class to 10%. In its 2011 rate application, Parry Sound Power Corporation (PSPC) also had a bill impact issue. In order to address this issue, PSPC proposed a method to limit the bill impacts to 10% which was accepted and approved by the Board. Please refer to PSPC's Rate Order EB-2010-0140 dated August 9, 2011. In similar manner, Atikokan Hydro is proposing a two step mitigation plan in order to limit the bill impact to a Residential customer using 800 kWh per month to 10%

- Step 1: Provide a rate mitigation rate rider for Residential customer of ($0.0034) per kWh to limit the bill impacts to just under 10% for a Residential customer using 800 kWh per month per month. This rider will defer about $38,700 in distribution revenue for one year and Atikokan Hydro is proposing to book this amount in account 1574 Deferred Rate Impact Amounts for future recovery.

- Step 2: Defer the disposition of the 2010 Group 1 and 2 deferral and variance account balances until the 2013 IRM application. By the time Atikokan Hydro is preparing its 2013 IRM application, the audited 2011 balances for deferral and variances account should be known. In order to support the rate mitigation plan Atikokan Hydro is seeking approval from the Board to bring forward its audited 2011 Group 1 and 2 deferral and variances accounts balance for disposition in its 2013 IRM application. In addition, at the time this application was being prepared Atikokan Hydro's 2010 deferral and variance account balances were under an audit review by Board staff from the Regulatory Audit & Accounting department. The outcome of this audit could impact the 2010 balances which suggest to Atikokan Hydro that seeking disposition of these amounts would not be prudent at this time. This provides additional support to deferring the disposition of the Group 1 and 2 deferral and variance account balances until the 2013 IRM application.

EXISTING TARIFF OF RATES AND CHARGES

Atikokan Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0064

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. 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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It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	30.58
Smart Meter Funding Adder - effective until April 30, 2012	$	3.50
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.29
Distribution Volumetric Rate	$/kWh	0.0121
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kWh	(0.0028)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kWh	(0.0018)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0060
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0037

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Atikokan Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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EB-2010-0064

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	70.02
Smart Meter Funding Adder - effective until April 30, 2012	$	3.50
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.71
Distribution Volumetric Rate	$/kWh	0.0089
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2012		
Applicable only for Non-RPP Customers	$/kWh	(0.0028)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kWh	(0.0018)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0032

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Atikokan Hydro Inc.
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EB-2010-0064

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Note that for the application of the Retail Transmission Rate – Network Service Rate and the Retail Transmission Rate – Line and Transformation Connection Service Rate the following sub-classifications apply:

General Service 50 to 999 kW non-interval metered
General Service 50 to 999 kW interval metered
General Service 1,000 to 4,999 kW interval metered

Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	440.74
Smart Meter Funding Adder - effective until April 30, 2012	$	3.50
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	2.51
Distribution Volumetric Rate	$/kW	1.7161
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2012		
Applicable only for Non-RPP Customers	$/kW	(1.0474)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kW	(0.6885)
Retail Transmission Rate – Network Service Rate	$/kW	2.1742
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.3089
Retail Transmission Rate – Network Service Rate – Interval Metered ≥ 1,000 kW	$/kW	2.3066
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2723
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.3987
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered ≥ 1,000kW	$/kW	1.4062

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Atikokan Hydro Inc.
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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone boots, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per account)	$	373.42
Distribution Volumetric Rate	$/kWh	0.0480
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kWh	(0.0018)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0032

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Atikokan Hydro Inc.
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SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification applies to safety/security lighting. This is typically exterior lighting, and often unmetered. Consumption is estimated based on the equipment rating and estimated hours of use. 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 (per connection)	$	12.56
Distribution Volumetric Rate	$/kW	102.3181
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kW	(2.5605)
Retail Transmission Rate – Network Service Rate	$/kW	1.6480
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0041

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Atikokan Hydro Inc.
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STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	8.13
Distribution Volumetric Rate	$/kW	10.0266
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2012		
Applicable only for Non-RPP Customers	$/kW	(0.8735)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kW	(0.5742)
Retail Transmission Rate – Network Service Rate	$/kW	1.6399
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9834

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Atikokan Hydro Inc.
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microFIT GENERATOR SERVICE CLASSIFICATION

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

APPLICATION

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

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

Atikokan Hydro Inc.
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EB-2010-0064

ALLOWANCES

Transformer Allowance for Ownership – per kW of billing demand/month – customer shall be credited at a rate of 10% of the applicable Distribution Volumetric Rate		
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.

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Customer Administration		
Returned Cheque charge (plus bank charges) 25.00		$
Account set up charge / change of occupancy charge (plus credit agency costs if applicable)	$	25.00
Special Meter reads	$	25.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	25.00
Disconnect/Reconnect at Meter – during regular hours	$	28.00
Disconnect/Reconnect at Meter – after regular hours	$	315.00
Disconnect/Reconnect at Pole – during regular hours	$	28.00
Disconnect/Reconnect at Pole – after regular hours	$	315.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Atikokan Hydro Inc.
TARIFF OF RATES AND CHARGES
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EB-2010-0064

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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

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

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

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

LOSS FACTORS

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

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0753
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0645
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

PROPOSED TARIFF OF RATES AND CHARGES

Atikokan Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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EB-2011-0293

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	40.97
Smart Meter Cost Recovery Rider – effective until April 30, 2015	$	3.54
Stranded Meter Rate Rider - effective until April 30, 2015	$	0.39
Distribution Volumetric Rate	$/kWh	0.0162
Rate Mitigation Rate Rider - effective until April 30, 2013	$/kWh	(0.0030)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0056
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0035

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Atikokan Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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EB-2011-0293

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	82.37
Smart Meter Cost Recovery Rider – effective until April 30, 2015	$	3.54
Stranded Meter Rate Rider - effective until April 30, 2015	$	0.39
Distribution Volumetric Rate	$/kWh	0.0105
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0030

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Atikokan Hydro Inc.
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0293

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. 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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	587.93
Smart Meter Cost Recovery Rider – effective until April 30, 2015	$	3.54
Stranded Meter Rate Rider - effective until April 30, 2015	$	0.39
Distribution Volumetric Rate	$/kW	2.2262
Retail Transmission Rate – Network Service Rate	$/kW	2.0445
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.1690
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2016
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.3281

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Atikokan Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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

EB-2011-0293

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	14.67
Distribution Volumetric Rate	$/kW	18.0972
Retail Transmission Rate – Network Service Rate	$/kW	1.5421
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9288

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Atikokan Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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

EB-2011-0293

microFIT GENERATOR SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

ALLOWANCES

Transformer Allowance for Ownership – per kW of billing demand/month – customer shall be credited at a rate of 10% of the applicable Distribution Volumetric Rate		
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Atikokan Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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

EB-2011-0293

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

Customer Administration		
Returned Cheque charge (plus bank charges)		$ 25.00
Account set up charge / change of occupancy charge (plus credit agency costs if applicable)	$ 25.00	
Special Meter reads	$ 25.00	
Non-Payment of Account		
Late Payment - per month	% 1.50	
Late Payment - per annum	% 19.56	
Collection of account charge – no disconnection	$ 25.00	
Disconnect/Reconnect at Meter – during regular hours	$ 28.00	
Disconnect/Reconnect at Meter – after regular hours	$ 315.00	
Disconnect/Reconnect at Pole – during regular hours	$ 28.00	
Disconnect/Reconnect at Pole – after regular hours	$ 315.00	
Specific Charge for Access to the Power Poles – per pole/year	$ 22.35	

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

Atikokan Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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

EB-2011-0293

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

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

LOSS FACTORS

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 Customers	1.0778
Total Loss Factor – Primary Metered Customers	1.0671

1 **RECONCILIATION OF RATE CLASS REVENUE**

The following table provides a reconciliation between the 2012 distribution rate calculations based on the 2012 Proposed Rates and the total base revenue required.

Table 8-11

Rate Classification	Customers/ Connections	Annualized Average Number of Customer Connections	Test Year Consumption		Proposed Rates		
			kWh	kW	Monthly Service Charge	Volumetric kWh	Volumetric kW
Residential	Customers	17,082	11,395,913		$41.01	$0.0162	
GS < 50 kW	Customers	2,819	6,387,021		$82.46	$0.0105	
GS > 50 kW	Customers	178		14,205	$587.88		$2.2621
Street Lighting	Connections	7,481		1,316	$14.67		$18.0955
Total							

Revenues at Proposed Rates	Service Revenue Requirement	Transformer Allowance Credit	Total	Difference
$885,536	$885,536		$885,536	$ -
$299,438	$299,438		$299,438	$ -
$136,957	$135,810	$1,147	$136,957	$ -
$133,584	$133,584		$133,584	$ -
$1,455,515	$1,454,368	$1,147	$1,455,515	$ -

RATE AND BILL IMPACTS:

This schedule presents the results of the assessment of customer total bill impacts by level of consumption by customer per rate class and per the total customer class.

Impacts are shown using the applicable current approved rates and the proposed 2012 distribution rates, including rate riders for the disposition of Deferral and Variance Accounts, as discussed in Exhibit 9.

The total bill impacts are calculated for each rate class at various levels of consumption. The rate impacts are assessed on the basis of moving to the proposed distribution rates.

BILL IMPACTS

Atikokan Hyrod Inc, License Number EB-2003-001 , File Number EB-2011-0293 0 0

BILL IMPACTS *(Monthly Consumptions)*

RESIDENTIAL

		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			30.58			41.01	10.43	34.11%	64.88%
100 kWh	Distribution (kWh)	100	0.0121	1.21	100	0.0162	1.62	0.41	33.88%	2.56%
	Late Payment Rate Rider			0.29			0.00	(0.29)	(100.00%)	0.00%
	Smart Meter Rider (per month)			3.50			3.54	0.04	1.28%	5.61%
	Rate Mitigation Rider (kWh)	100	0.0000	0.00	100	(0.0034)	(0.34)	(0.34)	#DIV/0!	(0.54%)
	Stranded Meter Rider (per month)						0.39	0.39	#DIV/0!	0.61%
	Deferrral & Variance Acct (kWh)	100	(0.0018)	(0.18)	100	0.0000	0.00	0.18	(100.00%)	0.00%
	Distribution Sub-Total			**35.40**			**46.22**	**10.82**	**30.57%**	**73.13%**
	Retail Transmisssion (kWh)	108	0.0097	1.04	108	0.009136578	0.98	(0.06)	(5.59%)	1.56%
	Delivery Sub-Total			**36.44**			**47.21**	**10.76**	**29.54%**	**74.68%**
	Other Charges (kWh)	108	0.0130	1.40	108	0.0130	1.40	0.00	0.12%	2.22%
	Cost of Power Commodity (kWh)	108	0.0680	7.31	108	0.0680	7.33	0.02	0.24%	11.60%
	SPC (kWh)	108	0.0000	0.00	108	0.0000	0.00	0.00	#DIV/0!	0.00%
	Total Bill Before Taxes			**45.15**			**55.94**	**10.84**	**24.01%**	**88.50%**
	HST		13.00%	5.87		13.00%	7.27	1.40	23.88%	11.50%
	Total Bill			**51.02**			**63.21**	**12.24**	**24.00%**	**100.00%**

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RESIDENTIAL

		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			30.58			41.01	10.43	34.11%	50.11%
250 kWh	Distribution (kWh)	250	0.0121	3.03	250	0.0162	4.05	1.03	33.88%	4.95%
	Late Payment Rate Rider			0.29			0.00	(0.29)	(100.00%)	0.00%
	Smart Meter Rider (per month)			3.50			3.54	0.04	1.28%	4.33%
	Rate Mitigation Rider (kWh)	250	0.0000	0.00	250	(0.0034)	(0.85)	(0.85)	#DIV/0!	(1.04%)
	Stranded Meter Rider (per month)						0.39	0.39	#DIV/0!	0.47%
	Deferrral & Variance Acct (kWh)	250	(0.0018)	(0.45)	250	0.0000	0.00	0.45	(100.00%)	0.00%
	Distribution Sub-Total			**36.95**			**48.14**	**11.20**	**30.31%**	**58.82%**
	Retail Transmisssion (kWh)	269	0.0097	2.61	269	0.009136578	2.46	(0.15)	(5.59%)	3.01%
	Delivery Sub-Total			**39.55**			**50.60**	**11.05**	**27.94%**	**61.83%**
	Other Charges (kWh)	269	0.0130	3.50	269	0.0130	3.50	0.00	0.12%	4.28%
	Cost of Power Commodity (kWh)	269	0.0680	18.28	269	0.0680	18.32	0.04	0.24%	22.39%
	SPC (kWh)	269	0.0000	0.00	269	0.0000	0.00	0.00	#DIV/0!	0.00%
	Total Bill Before Taxes			**61.33**			**72.43**	**11.25**	**18.34%**	**88.50%**
	HST		13.00%	7.97		13.00%	9.42	1.44	18.10%	11.50%
	Total Bill			**69.30**			**81.85**	**12.69**	**18.31%**	**100.00%**

RESIDENTIAL

Consumption: 500 kWh	2011 BILL Volume	RATE $	CHARGE $	2012 BILL Volume	RATE $	CHARGE $	IMPACT Change $	Change %	% of Total Bill
Monthly Service Charge			30.58			41.01	10.43	34.11%	36.32%
Distribution (kWh)	500	0.0121	6.05	500	0.0162	8.10	2.05	33.88%	7.17%
Late Payment Rate Rider			0.29			0.00	(0.29)	(100.00%)	0.00%
Smart Meter Rider (per month)			3.50			3.54	0.04	1.28%	3.14%
Rate Mitigation Rider (kWh)	500	0.0000	0.00	500	(0.0034)	(1.70)	(1.70)	#DIV/0!	(1.51%)
Stranded Meter Rider (per month)						0.39	0.39	#DIV/0!	0.34%
Deferrral & Variance Acct (kWh)	500	(0.0018)	(0.90)	500	0.0000	0.00	0.90	(100.00%)	0.00%
Distribution Sub-Total			**39.52**			**51.34**	**11.82**	**29.92%**	**45.47%**
Retail Transmisssion (kWh)	538	0.0097	5.22	539	0.009136578	4.92	(0.29)	(5.59%)	4.36%
Delivery Sub-Total			**44.74**			**56.27**	**11.53**	**25.78%**	**49.84%**
Other Charges (kWh)	538	0.0130	6.99	539	0.0130	7.00	0.01	0.12%	6.20%
Cost of Power Commodity (kWh)	538	0.0680	36.56	539	0.0680	36.65	0.09	0.24%	32.46%
SPC (kWh)	538	0.0000	0.00	538	0.0000	0.00	0.00	#DIV/0!	0.00%
Total Bill Before Taxes			**88.29**			**99.92**	**11.92**	**13.50%**	**88.50%**
HST		13.00%	11.48		13.00%	12.99	1.51	13.17%	11.50%
Total Bill			**99.77**			**112.91**	**13.43**	**13.46%**	**100.00%**

RESIDENTIAL

Consumption
680 kWh

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			30.58			41.01	10.43	34.11%	260.35%
Distribution (kWh)	680	0.0121	8.23	680	0.0162	11.02	2.79	33.88%	69.93%
Late Payment Rate Rider			0.29			0.00	(0.29)	(100.00%)	0.00%
Smart Meter Rider (per month)			3.50			3.54	0.04	1.28%	22.50%
Rate Mitigation Rider (kWh)	680	0.0000	0.00	680	(0.0034)	(2.31)	(2.31)	#DIV/0!	(1.69%)
Stranded Meter Rider (per month)			0.00			0.39	0.39	#DIV/0!	0.28%
Deferrral & Variance Acct (kWh)	680	(0.0018)	(1.22)	680	0.0000	0.00	1.22	(100.00%)	0.00%
Distribution Sub-Total			**41.37**			**53.65**	**12.27**	**29.66%**	**39.18%**
Retail Transmisssion (kWh)	731	0.0097	7.09	733	0.009136578	6.70	(0.40)	(5.59%)	4.89%
Delivery Sub-Total			**48.47**			**60.34**	**11.88**	**24.50%**	**44.07%**
Other Charges (kWh)	731	0.0130	9.51	733	0.0130	9.52	0.01	0.12%	6.96%
Cost of Power Commodity (kWh)	600	0.0680	40.80	600	0.0680	40.80	0.00	0.00%	29.80%
Cost of Power Commodity (kWh)	131	0.0790	10.37	133	0.0790	10.50	0.14	1.31%	7.67%
SPC (kWh)	731	0.0000	0.00	731	0.0000	0.00	0.00	#DIV/0!	0.00%
Total Bill Before Taxes			**109.14**			**121.17**	**12.02**	**11.02%**	**88.50%**
HST		13.00%	14.19		13.00%	15.75	1.56	11.02%	11.50%
Total Bill			**123.33**			**136.92**	**13.59**	**11.02%**	**100.00%**

RESIDENTIAL

Consumption
800 kWh

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			30.58			41.01	10.43	34.11%	26.73%
Distribution (kWh)	800	0.0121	9.68	800	0.0162	12.96	3.28	33.88%	8.45%
Late Payment Rate Rider			0.29			0.00	(0.29)	(100.00%)	0.00%
Smart Meter Rider (per month)			3.50			3.54	0.04	1.28%	2.31%
Rate Mitigation Rider (kWh)	800	0.0000	0.00	800	(0.0034)	(2.72)	(2.72)	#DIV/0!	(1.77%)
Stranded Meter Rider (per month)			0.00			0.39	0.39	#DIV/0!	0.25%
Deferrral & Variance Acct (kWh)	800	(0.0018)	(1.44)	800	0.0000	0.00	1.44	(100.00%)	0.00%
Distribution Sub-Total			**42.61**			**55.18**	**12.57**	**29.51%**	**35.96%**
Retail Transmisssion (kWh)	860	0.0097	8.34	862	0.009136578	7.88	(0.47)	(5.59%)	5.13%
Delivery Sub-Total			**50.95**			**63.06**	**12.11**	**23.76%**	**41.10%**
Other Charges (kWh)	860	0.0130	11.19	862	0.0130	11.20	0.01	0.12%	7.30%
Cost of Power Commodity (kWh)	600	0.0680	40.80	600	0.0680	40.80	0.00	0.00%	26.59%
Cost of Power Commodity (kWh)	260	0.0790	20.56	262	0.0790	20.72	0.16	0.78%	13.50%
SPC (kWh)	860	0.0000	0.00	860	0.0000	0.00	0.00	#DIV/0!	0.00%
Total Bill Before Taxes			**123.50**			**135.78**	**12.28**	**9.94%**	**88.50%**
HST		13.00%	16.06		13.00%	17.65	1.60	9.94%	11.50%
Total Bill			**139.56**			**153.44**	**13.88**	**9.94%**	**100.00%**

RESIDENTIAL

Consumption
1,000 kWh

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			30.58			41.01	10.43	34.11%	22.66%
Distribution (kWh)	1,000	0.0121	12.10	1,000	0.0162	16.20	4.10	33.88%	8.95%
Late Payment Rate Rider			0.29			0.00	(0.29)	(100.00%)	0.00%
Smart Meter Rider (per month)			3.50			3.54	0.04	1.28%	1.96%
Rate Mitigation Rider (kWh)	1,000	0.0000	0.00	1,000	(0.0034)	(3.40)	(3.40)	#DIV/0!	(1.88%)
Stranded Meter Rider (per month)			0.00			0.39	0.39	#DIV/0!	0.21%
Deferrral & Variance Acct (kWh)	1,000	(0.0018)	(1.80)	1,000	0.0000	0.00	1.80	(100.00%)	0.00%
Distribution Sub-Total			**44.67**			**57.74**	**13.07**	**29.27%**	**31.91%**
Retail Transmisssion (kWh)	1,075	0.0097	10.43	1,078	0.009136578	9.85	(0.58)	(5.59%)	5.44%
Delivery Sub-Total			**55.10**			**67.59**	**12.49**	**22.67%**	**37.35%**
Other Charges (kWh)	1,075	0.0130	13.99	1,078	0.0130	14.01	0.02	0.12%	7.74%
Cost of Power Commodity (kWh)	600	0.0680	40.80	600	0.0680	40.80	0.00	0.00%	22.55%
Cost of Power Commodity (kWh)	475	0.0790	37.55	478	0.0790	37.75	0.20	0.53%	20.86%
SPC (kWh)	1,075	0.0000	0.00	1,075	0.0000	0.00	0.00	#DIV/0!	0.00%
Total Bill Before Taxes			**147.44**			**160.15**	**12.71**	**8.62%**	**88.50%**
HST		13.00%	19.17		13.00%	20.82	1.65	8.62%	11.50%
Total Bill			**166.61**			**180.96**	**14.36**	**8.62%**	**100.00%**

RESIDENTIAL

Consumption
1,500 kWh

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			30.58			41.01	10.43	34.11%	16.42%
Distribution (kWh)	1,500	0.0121	18.15	1,500	0.0162	24.30	6.15	33.88%	9.73%
Late Payment Rate Rider			0.29			0.00	(0.29)	(100.00%)	0.00%
Smart Meter Rider (per month)			3.50			3.54	0.04	1.28%	1.42%
Rate Mitigation Rider (kWh)	1,500	0.0000	0.00	1,500	(0.0034)	(5.10)	(5.10)	#DIV/0!	(2.04%)
Stranded Meter Rider (per month)			0.00			0.39	0.39	#DIV/0!	0.16%
Deferrral & Variance Acct (kWh)	1,500	(0.0018)	(2.70)	1,500	0.0000	0.00	2.70	(100.00%)	0.00%
Distribution Sub-Total			**49.82**			**64.14**	**14.32**	**28.75%**	**25.68%**
Retail Transmisssion (kWh)	1,613	0.0097	15.65	1,617	0.009136578	14.77	(0.87)	(5.59%)	5.91%
Delivery Sub-Total			**65.47**			**78.91**	**13.45**	**20.54%**	**31.59%**
Other Charges (kWh)	1,613	0.0130	20.98	1,617	0.0130	21.01	0.02	0.12%	8.41%
Cost of Power Commodity (kWh)	600	0.0680	40.80	600	0.0680	40.80	0.00	0.00%	16.33%
Cost of Power Commodity (kWh)	1,013	0.0790	80.02	1,017	0.0790	80.32	0.30	0.38%	32.16%
SPC (kWh)	1,613	0.0000	0.00	1,613	0.0000	0.00	0.00	#DIV/0!	0.00%
Total Bill Before Taxes			**207.27**			**221.05**	**13.77**	**6.65%**	**88.50%**
HST		13.00%	26.95		13.00%	28.74	1.79	6.65%	11.50%
Total Bill			**234.22**			**249.78**	**15.56**	**6.65%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
2,000 kWh

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			70.02			82.46	12.44	17.77%	23.05%
Distribution (kWh)	2,000	0.0089	17.80	2,000	0.0105	21.00	3.20	17.98%	5.87%
Late Payment Rate Rider			0.71			0.00	(0.71)	(100.00%)	0.00%
Smart Meter Rider (per month)			3.50			3.54	0.04	1.28%	0.99%
LRAM & SSM Rider (kWh)	2,000	0.0000	0.00	2,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Stranded Meter Rider (per month)			0.00			0.39	0.39	#DIV/0!	0.11%
Deferrral & Variance Acct (kWh)	2,000	(0.0018)	(3.60)	2,000	0.0000	0.00	3.60	(100.00%)	0.00%
Distribution Sub-Total			**88.43**			**107.39**	**18.96**	**21.44%**	**30.02%**
Retail Transmisssion (kWh)	2,151	0.0086	18.50	2,156	0.008100144	17.46	(1.03)	(5.59%)	4.88%
Delivery Sub-Total			**106.93**			**124.85**	**17.93**	**16.77%**	**34.90%**
Other Charges (kWh)	2,151	0.0130	27.98	2,156	0.0130	28.01	0.03	0.12%	7.83%
Cost of Power Commodity (kWh)	600	0.0680	40.80	600	0.0680	40.80	0.00	0.00%	11.41%
Cost of Power Commodity (kWh)	1,551	0.0790	122.50	1,556	0.0790	122.90	0.40	0.33%	34.36%
SPC (kWh)	2,151	0.0000	0.00	2,151	0.0000	0.00	0.00	#DIV/0!	0.00%
Total Bill Before Taxes			**298.20**			**316.56**	**$18.36**	**6.16%**	**88.50%**
HST		13.00%	38.77		13.00%	41.15	2.39	6.16%	11.50%
Total Bill			**336.97**			**357.72**	**$20.75**	**6.16%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
5,000 kWh

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			70.02			82.46	12.44	17.77%	10.86%
Distribution (kWh)	5,000	0.0089	44.50	5,000	0.0105	52.50	8.00	17.98%	6.92%
Late Payment Rate Rider			0.71			0.00	(0.71)	(100.00%)	0.00%
Smart Meter Rider (per month)			3.50			3.54	0.04	1.28%	0.47%
LRAM & SSM Rider (kWh)	5,000	0.0000	0.00	5,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Stranded Meter Rider (per month)			0.00			0.39	0.39	#DIV/0!	0.05%
Deferrral & Variance Acct (kWh)	5,000	(0.0018)	(9.00)	5,000	0.0000	0.00	9.00	(100.00%)	0.00%
Distribution Sub-Total			**109.73**			**138.89**	**29.16**	**26.58%**	**18.30%**
Retail Transmisssion (kWh)	5,377	0.0086	46.24	5,389	0.008100144	43.65	(2.58)	(5.59%)	5.75%
Delivery Sub-Total			**155.97**			**182.55**	**26.58**	**17.04%**	**24.05%**
Other Charges (kWh)	5,377	0.0130	69.95	5,389	0.0130	70.03	0.08	0.12%	9.23%
Cost of Power Commodity (kWh)	600	0.0680	40.80	600	0.0680	40.80	0.00	0.00%	5.38%
Cost of Power Commodity (kWh)	4,777	0.0790	377.34	4,789	0.0790	378.34	1.00	0.27%	49.84%
SPC (kWh)	5,377	0.0000	0.00	5,377	0.0000	0.00	0.00	#DIV/0!	0.00%
Total Bill Before Taxes			**644.06**			**671.72**	**$27.66**	**4.29%**	**88.50%**
HST		13.00%	83.73		13.00%	87.32	3.60	4.29%	11.50%
Total Bill			**727.79**			**759.04**	**$31.26**	**4.29%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption 10,000 kWh	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			70.02			82.46	12.44	17.77%	5.77%
Distribution (kWh)	10,000	0.0089	89.00	10,000	0.0105	105.00	16.00	17.98%	7.35%
Late Payment Rate Rider			0.71			0.00	(0.71)	(100.00%)	0.00%
Smart Meter Rider (per month)			3.50			3.54	0.04	1.28%	0.25%
LRAM & SSM Rider (kWh)	10,000	0.0000	0.00	10,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Stranded Meter Rider (per month)			0.00			0.39	0.39	#DIV/0!	0.03%
Deferrral & Variance Acct (kWh)	10,000	(0.0018)	(18.00)	10,000	0.0000	0.00	18.00	(100.00%)	0.00%
Distribution Sub-Total			**145.23**			**191.39**	**46.16**	**31.79%**	**13.40%**
Retail Transmisssion (kWh)	10,753	0.0086	92.48	10,778	0.008100144	87.31	(5.17)	(5.59%)	6.11%
Delivery Sub-Total			**237.71**			**278.70**	**40.99**	**17.25%**	**19.52%**
Other Charges (kWh)	10,753	0.0130	139.89	10,778	0.0130	140.06	0.16	0.12%	9.81%
Cost of Power Commodity (kWh)	600	0.0680	40.80	600	0.0680	40.80	0.00	0.00%	2.86%
Cost of Power Commodity (kWh)	10,153	0.0790	802.09	10,178	0.0790	804.09	2.00	0.25%	56.31%
SPC (kWh)	10,753	0.0000	0.00	10,753	0.0000	0.00	0.00	#DIV/0!	0.00%
Total Bill Before Taxes			**1,220.49**			**1,263.65**	**$43.16**	**3.54%**	**88.50%**
HST		13.00%	158.66		13.00%	164.27	5.61	3.54%	11.50%
Total Bill			**1,379.15**			**1,427.92**	**$48.77**	**3.54%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption 12,500 kWh	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			70.02			82.46	12.44	17.77%	4.68%
Distribution (kWh)	12,500	0.0089	111.25	12,500	0.0105	131.25	20.00	17.98%	7.45%
Late Payment Rate Rider			0.71			0.00	(0.71)	(100.00%)	0.00%
Smart Meter Rider (per month)			3.50			3.54	0.04	1.28%	0.20%
LRAM & SSM Rider (kWh)	12,500	0.0000	0.00	12,500	0.0000	0.00	0.00	#DIV/0!	0.00%
Stranded Meter Rider (per month)			0.00			0.39	0.39	#DIV/0!	0.02%
Deferrral & Variance Acct (kWh)	12,500	(0.0018)	(22.50)	12,500	0.0000	0.00	22.50	(100.00%)	0.00%
Distribution Sub-Total			**162.98**			**217.64**	**54.66**	**33.54%**	**12.35%**
Retail Transmisssion (kWh)	13,441	0.0086	115.59	13,473	0.008100144	109.13	(6.46)	(5.59%)	6.19%
Delivery Sub-Total			**278.57**			**326.78**	**48.20**	**17.30%**	**18.54%**
Other Charges (kWh)	13,441	0.0130	174.87	13,473	0.0130	175.07	0.21	0.12%	9.93%
Cost of Power Commodity (kWh)	600	0.0680	40.80	600	0.0680	40.80	0.00	0.00%	2.32%
Cost of Power Commodity (kWh)	12,841	0.0790	1,014.46	12,873	0.0790	1,016.96	2.50	0.25%	57.70%
SPC (kWh)	13,441	0.0000	0.00	13,441	0.0000	0.00	0.00	#DIV/0!	0.00%
Total Bill Before Taxes			**1,508.70**			**1,559.61**	**$50.91**	**3.37%**	**88.50%**
HST		13.00%	196.13		13.00%	202.75	6.62	3.37%	11.50%
Total Bill			**1,704.83**			**1,762.36**	**$57.53**	**3.37%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
15,000 kWh

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			70.02			82.46	12.44	17.77%	3.93%
Distribution (kWh)	15,000	0.0089	133.50	15,000	0.0105	157.50	24.00	17.98%	7.51%
Late Payment Rate Rider			0.71			0.00	(0.71)	(100.00%)	0.00%
Smart Meter Rider (per month)			3.50			3.54	0.04	1.28%	0.17%
LRAM & SSM Rider (kWh)	15,000	0.0000	0.00	15,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Stranded Meter Rider (per month)			0.00			0.39	0.39	#DIV/0!	0.02%
Deferrral & Variance Acct (kWh)	15,000	(0.0018)	(27.00)	15,000	0.0000	0.00	27.00	(100.00%)	0.00%
Distribution Sub-Total			**180.73**			**243.89**	**63.16**	**34.95%**	**11.63%**
Retail Transmisssion (kWh)	16,130	0.0086	138.71	16,168	0.008100144	130.96	(7.75)	(5.59%)	6.25%
Delivery Sub-Total			**319.44**			**374.85**	**55.41**	**17.35%**	**17.88%**
Other Charges (kWh)	16,130	0.0130	209.84	16,168	0.0130	210.09	0.25	0.12%	10.02%
Cost of Power Commodity (kWh)	600	0.0680	40.80	600	0.0680	40.80	0.00	0.00%	1.95%
Cost of Power Commodity (kWh)	15,530	0.0790	1,226.83	15,568	0.0790	1,229.83	3.00	0.24%	58.65%
SPC (kWh)	16,130	0.0000	0.00	16,130	0.0000	0.00	0.00	#DIV/0!	0.00%
Total Bill Before Taxes			**1,796.92**			**1,855.58**	**$58.66**	**3.26%**	**88.50%**
HST		13.00%	233.60		13.00%	241.22	7.63	3.26%	11.50%
Total Bill			**2,030.52**			**2,096.80**	**$66.29**	**3.26%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption
30,000 kWh
100 kW

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			440.74			587.88	147.14	33.38%	13.79%
Distribution (kW)	100	1.7161	171.61	100	2.2621	226.21	54.60	31.82%	5.31%
Late Payment Rate Rider			2.51			0.00	(2.51)	(100.00%)	0.00%
Smart Meter Rider (per month)			3.50			3.50	0.00	0.00%	0.08%
LRAM & SSM Rider (kW)	0		0.00	0	0.0000	0.00	0.00	#DIV/0!	0.00%
Stranded Meter Rider (per month)			0.00			0.39	0.39	#DIV/0!	0.01%
Deferrral & Variance Acct (kW)	100	(0.6885)	(68.85)	100	0.0000	0.00	68.85	(100.00%)	0.00%
Distribution Sub-Total			**549.51**			**817.98**	**268.47**	**48.86%**	**19.18%**
Retail Transmisssion (kW)	100	3.4465	344.65	100	3.246138452	324.61	(20.04)	(5.81%)	7.61%
Delivery Sub-Total			**894.16**			**1,142.59**	**248.43**	**27.78%**	**26.80%**
Other Charges (kWh)	32,259	0.0130	419.68	32,335	0.0130	420.18	0.49	0.12%	9.85%
Cost of Power Commodity (kWh)	32,259	0.0684	2,205.55	32,335	0.0684	2,210.75	5.20	0.24%	51.85%
SPC (kWh)	32,259	0.0000	0.00	32,259	0.0000	0.00	0.00	#DIV/0!	0.00%
Total Bill Before Taxes			**3,519.39**			**3,773.52**	**254.13**	**7.22%**	**88.50%**
HST		13.00%	457.52		13.00%	490.56	33.04	7.22%	11.50%
Total Bill			**3,976.91**			**4,264.07**	**287.16**	**7.22%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption		2011 BILL			2012 BILL			IMPACT		
75,000 kWh		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
250 kW	Monthly Service Charge			440.74			587.88	147.14	33.38%	6.09%
	Distribution (kW)	250	1.7161	429.03	250	2.2621	565.53	136.50	31.82%	5.86%
	Late Payment Rate Rider			2.51			0.00	(2.51)	(100.00%)	0.00%
	Smart Meter Rider (per month)			3.50			3.50	0.00	0.00%	0.04%
	LRAM & SSM Rider (kW)	0		0.00	0	0.0000	0.00	0.00	#DIV/0!	0.00%
	Stranded Meter Rider (per month)			0.00			0.39	0.39	#DIV/0!	0.00%
	Deferrral & Variance Acct (kW)	250	(0.6885)	(172.13)	250	0.0000	0.00	172.13	(100.00%)	0.00%
	Distribution Sub-Total			**703.65**			**1,157.29**	**453.64**	**64.47%**	**11.98%**
	Retail Transmisssion (kW)	250	3.4465	861.63	250	3.246138452	811.53	(50.09)	(5.81%)	8.40%
	Delivery Sub-Total			**1,565.28**			**1,968.83**	**403.55**	**25.78%**	**20.39%**
	Other Charges (kWh)	80,648	0.0130	1,049.21	80,838	0.0130	1,050.44	1.24	0.12%	10.88%
	Cost of Power Commodity (kWh)	80,648	0.0684	5,513.87	80,838	0.0684	5,526.87	13.00	0.24%	57.23%
	SPC (kWh)	80,648	0.0000	0.00	80,648	0.0000	0.00	0.00	#DIV/0!	0.00%
	Total Bill Before Taxes			**8,128.35**			**8,546.14**	**417.79**	**5.14%**	**88.50%**
	HST		13.00%	1,056.69		13.00%	1,111.00	54.31	5.14%	11.50%
	Total Bill			**9,185.04**			**9,657.14**	**472.10**	**5.14%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption		2011 BILL			2012 BILL			IMPACT		
100,000 kWh		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
350 kW	Monthly Service Charge			440.74			587.88	147.14	33.38%	4.61%
	Distribution (kW)	350	1.7161	600.64	350	2.2621	791.74	191.10	31.82%	6.21%
	Late Payment Rate Rider			2.51			0.00	(2.51)	(100.00%)	0.00%
	Smart Meter Rider (per month)			3.50			3.50	0.00	0.00%	0.03%
	LRAM & SSM Rider (kW)	0		0.00	0	0.0000	0.00	0.00	#DIV/0!	0.00%
	Stranded Meter Rider (per month)			0.00			0.39	0.39	#DIV/0!	0.00%
	Deferrral & Variance Acct (kW)	350	(0.6885)	(240.98)	350	0.0000	0.00	240.98	(100.00%)	0.00%
	Distribution Sub-Total			**806.41**			**1,383.50**	**577.09**	**71.56%**	**10.85%**
	Retail Transmisssion (kW)	350	3.4465	1,206.28	350	3.246138452	1,136.15	(70.13)	(5.81%)	8.91%
	Delivery Sub-Total			**2,012.69**			**2,519.65**	**506.97**	**25.19%**	**19.75%**
	Other Charges (kWh)	107,530	0.0130	1,398.95	107,784	0.0130	1,400.59	1.65	0.12%	10.98%
	Cost of Power Commodity (kWh)	107,530	0.0684	7,351.83	107,784	0.0684	7,369.16	17.33	0.24%	57.77%
	SPC (kWh)	107,530	0.0000	0.00	107,530	0.0000	0.00	0.00	#DIV/0!	0.00%
	Total Bill Before Taxes			**10,763.46**			**11,289.40**	**525.95**	**4.89%**	**88.50%**
	HST		13.00%	1,399.25		13.00%	1,467.62	68.37	4.89%	11.50%
	Total Bill			**12,162.71**			**12,757.03**	**594.32**	**4.89%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption
800,000 kWh
2,000 kW

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			440.74			587.88	147.14	33.38%	0.64%
Distribution (kW)	2,000	1.7161	3,432.20	2,000	2.2621	4,524.20	1,092.00	31.82%	4.90%
Late Payment Rate Rider			2.51			0.00	(2.51)	(100.00%)	0.00%
Smart Meter Rider (per month)			3.50			3.50	0.00	0.00%	0.00%
LRAM & SSM Rider (kW)	0		0.00	0	0.0000	0.00	0.00	#DIV/0!	0.00%
Stranded Meter Rider (per month)			0.00			0.39	0.39	#DIV/0!	0.00%
Deferrral & Variance Acct (kW)	2,000	(0.6885)	(1,377.00)	2,000	0.0000	0.00	1,377.00	(100.00%)	0.00%
Distribution Sub-Total			**2,501.95**			**5,115.97**	**2,614.02**	**104.48%**	**5.54%**
Retail Transmisssion (kW)	2,000	3.4465	6,893.00	2,000	3.246138452	6,492.28	(400.72)	(5.81%)	7.03%
Delivery Sub-Total			**9,394.95**			**11,608.24**	**2,213.29**	**23.56%**	**12.56%**
Other Charges (kWh)	860,240	0.0130	11,191.56	862,268	0.0130	11,204.74	13.18	0.12%	12.13%
Cost of Power Commodity (kWh)	860,240	0.0684	58,814.61	862,268	0.0684	58,953.28	138.67	0.24%	63.81%
SPC (kWh)	860,240	0.0000	0.00	860,240	0.0000	0.00	0.00	#DIV/0!	0.00%
Total Bill Before Taxes			**79,401.12**			**81,766.27**	**2,365.15**	**2.98%**	**88.50%**
HST		13.00%	10,322.15		13.00%	10,629.61	307.47	2.98%	11.50%
Total Bill			**89,723.26**			**92,395.88**	**2,672.62**	**2.98%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption
1,600,000 kWh
4,000 kW

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			440.74			587.88	147.14	33.38%	0.32%
Distribution (kW)	4,000	1.7161	6,864.40	4,000	2.2621	9,048.40	2,184.00	31.82%	4.91%
Late Payment Rate Rider			2.51			0.00	(2.51)	(100.00%)	0.00%
Smart Meter Rider (per month)			3.50			3.50	0.00	0.00%	0.00%
LRAM & SSM Rider (kW)	0		0.00	0	0.0000	0.00	0.00	#DIV/0!	0.00%
Stranded Meter Rider (per month)			0.00			0.39	0.39	#DIV/0!	0.00%
Deferrral & Variance Acct (kW)	4,000	(0.6885)	(2,754.00)	4,000	0.0000	0.00	2,754.00	(100.00%)	0.00%
Distribution Sub-Total			**4,557.15**			**9,640.17**	**5,083.02**	**111.54%**	**5.24%**
Retail Transmisssion (kW)	4,000	3.4465	13,786.00	4,000	3.246138452	12,984.55	(801.45)	(5.81%)	7.05%
Delivery Sub-Total			**18,343.15**			**22,624.72**	**4,281.57**	**23.34%**	**12.29%**
Other Charges (kWh)	1,720,480	0.0130	22,383.12	1,724,536	0.0130	22,409.49	26.37	0.12%	12.17%
Cost of Power Commodity (kWh)	1,720,480	0.0684	117,629.22	1,724,536	0.0684	117,906.55	277.34	0.24%	64.04%
SPC (kWh)	1,720,480	0.0000	0.00	1,720,480	0.0000	0.00	0.00	#DIV/0!	0.00%
Total Bill Before Taxes			**158,355.49**			**162,940.76**	**4,585.27**	**2.90%**	**88.50%**
HST		13.00%	20,586.21		13.00%	21,182.30	596.09	2.90%	11.50%
Total Bill			**178,941.70**			**184,123.06**	**5,181.36**	**2.90%**	**100.00%**

Street Lighting

Billing Determinants
6,677 Connections
2,400,000 kWh
6,800 kW

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge	6,677	8.1300	54,284.01	6,677	14.6726	97,968.95	43,684.94	80.47%	20.09%
Distribution (kW)	6,800	10.0266	68,180.88	6,800	18.0955	123,049.40	54,868.52	80.47%	25.24%
Late Payment Rate Rider			0.00			0.00	0.00	#DIV/0!	0.00%
LRAM & SSM Rider (kW)	0		0.00	0	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kW)	0	(0.5742)	0.00	0	0.0000	0.00	0.00	#DIV/0!	0.00%
Distribution Sub-Total			**122,464.89**			**221,018.35**	**98,553.46**	**80.47%**	**45.33%**
Retail Transmisssion (kW)	0	2.6233	0.00	0	2.47085609	0.00	0.00	#DIV/0!	0.00%
Delivery Sub-Total			**122,464.89**			**221,018.35**	**98,553.46**	**80.47%**	**45.33%**
Other Charges (kWh)	2,580,720	0.0130	33,574.68	2,586,805	0.0130	33,614.23	39.55	0.12%	6.89%
Cost of Power Commodity (kWh)	2,580,720	0.0684	176,443.83	2,586,805	0.0684	176,859.83	416.00	0.24%	36.27%
SPC (kWh)	2,580,720	0.0000	0.00	2,580,720	0.0000	0.00	0.00	#DIV/0!	0.00%
Total Bill Before Taxes			**332,483.40**			**431,492.41**	**99,009.01**	**29.78%**	**88.50%**
HST		13.00%	43,222.84		13.00%	56,094.01	12,871.17	29.78%	11.50%
Total Bill			**375,706.24**			**487,586.42**	**111,880.19**	**29.78%**	**100.00%**

Street Lighting

Billing Determinants
1 Connections
62.47 kWh
0.17 kW

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge	1	8.1300	8.13	1	14.6726	14.67	6.54	80.47%	55.90%
Distribution (kW)	0	10.0266	1.70	0	18.0955	3.08	1.37	80.47%	11.72%
Late Payment Rate Rider			0.00			0.00	0.00	#DIV/0!	0.00%
LRAM & SSM Rider (kW)	0		0.00	0	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kW)	0	(0.5742)	0.00	0	0.0000	0.00	0.00	#DIV/0!	0.00%
Distribution Sub-Total			**9.83**			**17.75**	**7.91**	**80.47%**	**67.62%**
Retail Transmisssion (kW)	0	2.6233	0.00	0	2.47085609	0.00	0.00	#DIV/0!	0.00%
Delivery Sub-Total			**9.83**			**17.75**	**7.91**	**80.47%**	**67.62%**
Other Charges (kWh)	67	0.0130	0.87	67	0.0130	0.87	0.00	0.12%	3.33%
Cost of Power Commodity (kWh)	67	0.0684	4.59	67	0.0684	4.60	0.01	0.24%	17.54%
SPC (kWh)	67	0.0000	0.00	67	0.0000	0.00	0.00	#DIV/0!	0.00%
Total Bill Before Taxes			**15.30**			**23.23**	**7.93**	**51.80%**	**88.50%**
HST		13.00%	1.99		13.00%	3.02	1.03	51.80%	11.50%
Total Bill			**17.29**			**26.25**	**8.96**	**51.80%**	**100.00%**

DEFERRAL AND VARIANCE ACCOUNT BALANCES:

The information contained in this exhibit includes the status and description of Atikokan Hydro's deferral and variance accounts and the proposed disposition plan of the account balances.

Atikokan Hydro has completed the 2012 EDDVAR Continuity Schedule and a working copy of the schedule will be filed as part of this application. The following table below lists the Deferral and Variance Accounts (DVA's) as at December 31, 2010 consistent with the audited 2010 Financial Statement and the information present in the continuity statement.

Table 9-1

Deferral and Variance Accounts as at December 31, 2010

Account Description	Account #	Principal Dec 31/10	Interest Dec 31/10	Total Principal & Interest Dec 31/10
.RSVA Accounts				
RSVA – Wholesale Market Service	1580	(21,531)	(724)	(22,255)
RSVA-RT-Network Service	1584	4,774	(305)	4,469
RSVA-RT Connection Service	1586	25,161	174	25,335
RSVA-Power	1588	7,722	8,745	16,467
RSVA-Global	1588	8,935	(234)	8,701
Disposition and Recovery of Regulatory Balances (2008)	1595	(148,837)	27,763	(121,074)
Disposition and Recovery of Regulatory Balances (2009	1595	139,879	(1,520)	138,359
Subtotal-RSVA Accounts		**16,103**	**33,900**	**50,003**
Non-RSVA Accounts				
Other Regulatory Assets Cost Assessment	1508	9,061	924	9,985
Other Regulatory Assets OMERS	1508	137,278	9,247	146,524
Retail Cost – Retail Costs	1518	6,879	22	6,901
Special Purpose Charge Assess	1521	4477	33	4,510
Retail Cost – STR Processing	1548	20,293	563	20,856
Smart Meters - Capital	1555	456,146	5,283	461,429
Smart Meters - Recoveries	1555	(65,282)	(1,154)	(66,436)
Smart Meters Operation/Maintenance	1556	68,449	115	68,564
Subtotal-non RSVA Accounts		**$637,301**	**$15,032**	**$652,333**

DEFERRAL AND VARIANCE ACCOUNT EXPLANATIONS

Within the 2012 EDDVAR Continuity Schedule there are variance between the RRR 2.1.7 Trial Balance as at December 31, 2010 and the 2010 Deferral and Variance account balances shown in the above table for the RSVA (Group 1) accounts. The following provides an explanation for those variances.

Accounts 1580, 1584 and 1586:

The variance for these accounts between the RRR 2.1.7 Trial Balance and the Continuity Statement results from the 2009 Deferral and Variance account balances not being moved into sub account 1595 in the RRR 2.1.7 Trial Balance. However, this movement has been assumed in the Continuity Statements to reflect the Board's decision in EB-2010-0064 for Atikokan Hydro's 2011 rates in regards to 2008 and 2009 Group 1 balances. In that Decision the Board allowed the disposition rider for 2008 Group 1 balances to continue until April 30, 2012. It is expected that as of the end of April 30, 2012, the balance of 2008 Group 1 accounts will be around $127,000 owing to the customer. It is also expected the 2009 Group 1 balances as April 30, 2012 will be around $138,000 being owed to Atikokan Hydro. As a result one should essentially offset the other. In EB-2010-0064, the Board approved the approach to basically wait until after April 30, 2012 to true-up the 2008 and 2009 Group 1 balances together. The details of this approach are outline later on this evidence.

Account 1588 - RSVA-Power (excluding Global Adjustment)

The variance between RRR 2.1.7 Trial Balance and the Continuity Statement above is ($15,115). Adjustments were made to RPP and non-RPP balances as a result of the OEB 1598 Audit completed in 2010. These net adjustments are included in the Continuity Statements to reflect the 2010 year-end adjustments made to true-up reconciliation for the period of 2005 through the period ending October 2010. The true-up required was to address OEB’s concerns:

- *"Our review of the 1598 claims process indicated that Atikokan Hydro Inc. (AHI) used the estimated instead of the actual global adjustment (GA) in the true-up* *reconciliation for December 2005, November and December 2006, all of 2007, June to December 2008, all of 2009 and from January to May 2010.*

- *Additionally, we noted that incorrect kWhs were also used for the November and December 2005 true-up reconciliation and*
- *An incorrect RPP rates for the May and November 2006 true-up reconciliation."*

Account 1588 - RSVA-Power sub-account- Global Adjustment)

The variance between RRR 2.1.7 Trial Balance and the Continuity Statement above is $965. This reason for this difference is consistent with the explanations given for account 1588; RSVA – Power (excluding Global Adjustment).

Disposition and Recovery of Regulatory Balances (2008)

The variance between RRR 2.1.7 Trial Balance and the Continuity Statement above is $108,526. This account still has active riders in progress, with the rider ending April 30, 2012; as per Board Decision and Order EB-2010-0185. These rate riders are expected to refund the 2008 Group 1 balance for a total of $120,510 to Atikokan Hydro customers by April 30, 2012. The approved approach to dispose of the remaining 2008 Group 1 accounts and the 2009 Group 1 accounts is discussed later on in this evidence.

Disposition and Recovery of Regulatory Balances (2009):

The variance between RRR 2.1.7 Trial Balance and the Continuity Statement above is $138,359. This balance is yet to be disposed of through the 1595 sub-account. The Board's Decision and Order EB-2010-0064 accepted Atikokan Hydro's proposal in that as of May 1, 2012 the amount of the 2008 balances owed to customers would be used to offset the 2009 balances of $138,360 owed to Atikokan Hydro.

BOARD APPROVED APPROACH FOR 2008 AND 2009 GROUP 1 ACCOUNTS IN ACCORDANCE WITH BOARD DECISION EB-2010-0064

The following information is provided to explain how the 2008 and 2009 deferral and variance accounts are currently being handled

The tables below reflect Atikokan Hydro's December 31, 2008 and, December 31, 2009 Group 1 account balances outlined in Atikokan Hydro's 2011 Rate Application.

Table 9-2

2008 Group 1 Deferral and Variance Account Balances – Interim

EB-2009-0212 (i.e. Atikokan Hydro's IRM 2010 Rate Application)

Account Description	Account Numbers	Principle Amounts	Interest Amounts	Total Claim
RSVA – Wholesale Market Service Charges	1580	(65,776)	(12,312)	(78,088)
RSVA – Retail Transmission Network Charge	1584	(43,059)	(10,442)	(53,501)
RSVA – Retail Transmission Connection Charge	1586	(3,370)	(47,232)	(50,602)
RSVA – Power (Excl. Global Adjustment)	1588	78,303	16,871	95,174
RSVA – Power (Global Adjustment Sub-account)	1588	(31,083)	(2,400)	(33,483)
Recovery of Regulatory Asset Balances	1590	(824)	814	(10)
Total		(65,809)	(54,701)	(120,510)

Table 9-3

2008 Group 1 Deferral and Variance Account Balances –Finalized

EB-2010-0064 (i.e Atikokan Hydro's 2011 IRM Rate Application)

Account Description	Account Numbers	Principle Amounts	Interest Amounts	Total Claim
RSVA – Wholesale Market Service Charges	1580	(81,638)	3,342	(78,296)
RSVA – Retail Transmission Network Charge	1584	(43,839)	(9,673)	(53,512)
RSVA – Retail Transmission Connection Charge	1586	(15,661)	(35,104)	(50,764)
RSVA – Power (Excl. Global Adjustment)	1588	(63,918)	15,006	(48,913)
RSVA – Power (Global Adjustment sub-account)	1588	(13,385)	(2,148)	(15,533)
Recovery of Regulatory Asset Balances	1590	(824)	814	(10)
Total		(219,265)	(27,763)	(247,027)

Table 9-4

2009 Group 1 Deferral and Variance Account Balances EB-2010-0064

Account Description	Account Numbers	Principle Amounts	Interest Amounts	Total Claim
RSVA – Wholesale Market Service Charges	1580	458	(999)	(541)
RSVA – Retail Transmission Network Charge	1584	4,279	(438)	3,841
RSVA – Retail Transmission Connection Charge	1586	22,087	220	22,306
RSVA – Power (Excl. Global Adjustment)	1588	128,790	649	129.439
RSVA – Power (Global Adjustment Sub-account)	1588	(17,007)	(328)	(17,334)
Recovery of Regulatory Asset Balances	1590	1,274	(626)	648
Total		139,879	(1,520)	138,360

In the 2011 IRM filing, Decision and Order EB-2010-0064, Atikokan Hydro had a 2008 Group 1 Deferral and Variance account interim balance of ($120,510) and a revised balance of ($247,027) owed to its customers and a 2009 Group 1 balance owed to Atikokan Hydro in the amount of $138,360. See table 2, 3 and 4 for these balances in this exhibit. To address the disposition of the 2008 and 2009 Group 1 Deferral and Variance account balances, the Board approved in EB-2010-0064, the following approach to address the disposition of the 2008 and 2009 Group 1 Deferral and Variance Account balances.

- For the 2008 Group 1 account balances, the approved 2010 rate riders would continue until April 30, 2012. These rate riders are expected to refund Atikokan Hydro's customers $120,510 of the $247,027 owed to them.
- For the 2009 Group 1 account balances, the $138,360 owed by customers would not be disposed until after April 30, 2012. As of May 1, 2012 the remaining amount of the 2008 balances owed to the customers (i.e. $247,027 minus $120,510 = $126,517) would be used to offset the 2009 balances of $138,360 owed to Atikokan Hydro. (EB-2010-0064)

Atikokan Hydro proposed this unconventional approach as a means for the best interest of its customers because this would ensure no change in the existing rate riders until April 30, 2012; the 2009 Group 1 account debit balance would offset by the 2008 Group 1 account balance owed to its customers leaving a projected amount owed to Atikokan Hydro as of December 31, 2009 of $11,843. Atikokan Hydro currently projects this balance to be $11,000 as of April 30, 2012. Atikokan Hydro will carry this account balance and take the difference owing into consideration for the IRM filing which will address 2012 audited deferral and variance account balances.

DISPOSITION OF 2010 DEFERRAL AND VARIANCE ACCOUNT BALANCES

As discussed in detail in Exhibit 8 under rate mitigation, except for accounts 1555 and 1556 which are addressed under the smart meter cost recovery section, Atikokan Hydro is proposing to defer the disposition of the 2010 Group 1 and 2 deferral and variance account balances until the 2013 IRM application. As a rate mitigation plan, in order to limit the bill impacts to under 10% for a Residential customer using 800 kWh per month per month Atikokan Hydro is proposing to not seek disposition of the 2010 deferral and variance account balances in this application. In addition, the rate mitigation plan includes a proposed rate mitigation rate rider for Residential customer of ($0.0034) per kWh to limit the bill impacts to 10%. This rider will defer about $38,700 in distribution revenue for one year and Atikokan Hydro is proposing to book this amount in account 1574 Deferred Rate Impact Amounts for future recovery.

In addition, at the time this application was being prepared Atikokan Hydro's 2010 deferral and variance account balances were under an audit review by Board staff from the Regulatory Audit & Accounting department. The outcome of this audit could impact the 2010 balances which suggest to Atikokan Hydro that seeking disposition of these amounts would not be prudent at this time.

By the time Atikokan Hydro is preparing its 2013 IRM application, the audited 2011 balances for deferral and variances account should be known and should be in line with direction from Board staff. In order to support the rate mitigation plan and to ensure the deferral and variance accounts are in line with Board staff direction, Atikokan Hydro is seeking approval from the Board to bring forward its audited 2011 Group 1 and 2 deferral and variances accounts balance for disposition in its 2013 IRM application.

SMART METER PROPOSAL

Atikokan Hydro hereby applies for the recovery of costs related to smart metering in its service area by way of smart meter rate rider and the elimination of its current smart meter funding adder effective May 1, 2012. Atikokan Hydro, in co-operation with Thunder Bay Hydro, and the Northwest Group continue to work toward being ready for Time-of-Use billing for the fall of 2011.

This application includes the complete amount of incremental expense required to implement the smart meter program. Expenses are based on actual costs from inception to June 30, 2011 and projected costs from July 1, 2011 to December 31, 2011. This application is made in accordance with the Board's Smart Meter Funding and Cost Recovery guideline (G-2008-002) issued October 22, 2008.

Atikokan Hydro is specifically requesting the following:

- An actual cost recovery rate rider for the difference between the smart meter adder collected from May 1, 2006 until April 30, 2012 and the revenue requirement related to these smart meters up to December 31, 2011, through a rider of $3.54 per month per metered customer, for three years.

- A stranded meter rate rider of $0.39 per month per metered customer, for three years to recover the net book value of $23,375 for stranded meters as at December 31, 2011.

- Approval to include smart meter capital deployed as of December 31, 2011 in the 2012 rate base that supports the 2012 revenue requirement and distribution rates which is the subject of this rate application.

- Approval to include smart meter operation and maintenance expenses in the 2012 revenue requirement associated with the smart meters deployed.

- Approval to discontinue the current smart meter funding adder of $3.50 per month per metered customer, as of May 1, 2012.
- Approval to remove the net book value of $23,375 for stranded meters as at December 31, 2011 from the rate base and include this amount in account 1555.

Smart Meter Program Status

Atikokan Hydro was authorized to install smart meters by virtue of paragraph 9 of section 1(1) of O.Reg. 427/06.

In 2009 physical installation of meters began with the installation of 1591 meters installed by Dec 31 2009. 103 smart meters were installed in 2010. In the first 6 months of 2011 an additional 6 smart meters were installed, to complete the installation of all smart meters. Atikokan Hydro has also installed all non-RRP-Eligible Commercial customers with smart meters. There is one commercial customer who stands alone with an Interval Meter.

Atikokan Hydro, as part of the Northwest group worked with Thunder Bay Hydro to ensure that the testing of the various components of the billing system would be ready to work with the MDM/R to be able to provide TOU billing in early Q4 of 2011.

Atikokan Hydro has also made the necessary upgrades to its billing system to allow connection with the MDM/R and provide Time of Use (TOU). Atikokan Hydro is expecting to begin TOU billing on October's 2011 consumption.

Procurement of Smart Meters and Installation Services

Elster Metering

Atikokan Hydro was an active participant in the London RFP smart meter procurement process and through the co-operation with Thunder Bay Hydro, and the Northwest Group Elster Metering was identified as the preferred vendor. As a named distributor in the London Hydro RFP, on May 30, 2008 [letter from Fairness

Commissioner] the government authorized Atikokan Hydro via Regulation 427/06 to proceed with “metering activities pursuant to the Request for Proposal (RFP) for Advanced Metering Infrastructure (AMI) – Phase I Smart Meter Deployment issued August 14, 2008 by London Hydro Inc.” Protracted legal/contract negotiations between Elster and several Ontario LDCs took place throughout 2008 and into 2009 On February 1, 2009; Atikokan Hydro finalized the details of the Energy/Axis Supply Contract with Elster Metering. In addition to addressing the supply of goods, software and professional services to provide an automated metering infrastructure (AMI) system (meters, gatekeepers/collectors and head-end communications and meter-data-collection server) in the initial project phase, Elster worked with Thunder Bay Hydro to provide MAS system operation and meter data collection services to facilitate integration with the provincial MDM/R. Elster will be providing ongoing maintenance and support of Atikokan Hydro’s AMI system. System Acceptance testing of the fully-installed and operational Elster solution is ongoing.

Util-Assist – Consulting Assistance

In early 2007, Atikokan Hydro entered into a professional services agreement with Util-Assist, an Ontario consulting firm specializing in metering solutions and technologies. In mid-2008, with Util-Assist’s support, various preliminary project activities were undertaken. Most critically, the processing of Requests for Proposal for mass installation of residential smart meters, the supply and support of a meter-data operational data store (ODS) and the Wide Area Network (WAN) communications network for the Elster metering system were issued and evaluated culminating in the selection of a successful vendor. Util-Assist remained actively involved in the implementation and rollout phases of the mass deployment contract and WAN implementation, as well as the ODS contract negotiation through to the end of 2009 and into Q1 and Q2 2010.

Util-Assist’s services to Atikokan Hydro were expanded in 2009 to include project management assistance and training services related to our internal preparations and readiness for MDM/R enrolment. We continued to utilize Util-Assist’s services in 2011 during our integration to the MDM/R.

Elster Gatekeeper Deployment

In the early days of the smart meter project, Elster surveyed Atikokan Hydro's service territory and provided a detailed layout of the recommended number and location for regional collectors. At the end of 2009, five (5) collectors / gatekeepers had been installed in keeping with Elster's recommendations. In Q1 2011, Elster, Thunder Bay Hydro and Atikokan Hydro worked through a small number of gatekeeper communication issues which are now resolved. The network is operating reliably with all gatekeepers consistently communicating.

TBay Tel Wireless WAN Communications Network

Elster is responsible for providing meters, collectors and the data collection system, and the meters communicate with each other and the collectors through Elster's "mesh network". However, an Elster smart meter system also requires a wide-area network (WAN) to facilitate communication between the collectors and the data collection system (which is located at Thunder Bay Hydro's headquarters). The Northwest Group RFP response from TBay Tel was identified in early Q2 of 2009 as the successful solution for the WAN RFP process. TBay Tel worked with Elster to ensure the CDMA cellular modems were installed and provisioned in the Elster collectors prior to the collectors being delivered to Atikokan Hydro for installation. The implementation of the WAN, including installation, testing and training, took place in Fall 2009, in conjunction with the installation of all of the collectors/gatekeepers and increasing volumes of smart meters throughout the remainder of 2009 and 2010. The system has been operating reliably since Fall 2009 and is now considered highly stable.

Residential and Commercial Deployment of Elster Smart Meters

Atikokan Hydro researched the effort required and costs associated with the mass deployment and concluded that the most cost-effective approach to converting the required meters was to utilize a third-party contractor. Olameter [after purchasing

Triliant] received the contract to perform the mass installation as a result of the 2008 RFP process, and the installations got underway on May 25, 2009 with a completion date of 2009. By the end of 2009, due to good weather and a highly-competent installation team, Atikokan Hydro was significantly ahead of schedule with the mass installations, with all 1452 residential meters installed along with all 234 commercial meters. By January 2011, the remaining non Rpp commercial meter installations were completed.

Data Collection Services / MAS Head-end System

The data captured by the smart meter is relayed through the collectors/gatekeepers to Elster's MAS software. In late 2009, the troubleshooting goals of Atikokan Hydro's operations team were best met by providing access to the wealth of information that MAS can provide about the meters, collectors, and overall connectivity and communication effectiveness. As noted previously, Atikokan Hydro is a member of the Northwest Group. Thunder Bay Hydro is the lead entity and hosts all MAS servers as well as provides technical assistance in troubleshooting communication and operational issues. Atikokan Hydro personnel have begun training on the MAS head-end system. An additional benefit of this transition is that Atikokan Hydro's installation is on Elster's Energy Axis Version 7.0, the most recently-released software version available and one which resolves a number of identified MDM/R data-integration issues.

Annual Security Audit

With the mass deployment of AMI systems, security of the AMI network is critical to prevent utilities from becoming susceptible to new levels of potential security breaches and to ensure customer privacy and acceptance of the network. By installing network infrastructure in the field, there is now a requirement for additional security measures in order to ensure that utility data and equipment are kept secure from manipulation or other forms of control. As networks are deployed throughout North America, cyber security articles with reports of the potential for smart-grid hacking are becoming commonplace in the media. The minimum Functional

Specification for an Advanced Metering Infrastructure (AMI) released in July 2007 identified the need for security within the AMI network - Section 2.11 Security and Authentication: "The AMI shall have security features to prevent unauthorized access to the AMI and meter data and to ensure authentication to all AMI elements." Some of the privacy and network security infrastructure concerns that have been raised include:

- Monitoring a consumer's usage;
- Modifying one's own, or another consumer's usage;
- Interrupting the power of one or more consumers; and
- Tampering with demand side management tools which can be controlled through smart meters.

Since early 2010, Ontario utilities have been working with their smart meter providers to understand the security features of the networks, best practices for their deployment and new features that are being developed for future implementation within the smart meter networks. In November of 2010 the Information and Privacy Commissioner of Ontario released the report Smart Privacy for the Smart Grid which identified areas of concern to be addressed in the area of smart meter and smart grid devices.

Going forward, Atikokan Hydro has budgeted for an annual security audit, as this is a prudent approach to satisfying the due diligence requirements for protection not only of customer information, but also to ensure that access to the infrastructure is properly protected, thereby securing against unwanted modifications to data collection and/or load-control functionality. Security of the network and ensuring that customer data is protected at all times has resulted in the development of governance standards requiring extensive security measures such as NERC (North American Electric Reliability Corporation). The NERC reliability standards are developed by the electricity industry using a balanced, open, fair and inclusive process managed by the NERC Standards Committee.

For many Ontario LDCs, including Atikokan Hydro, completing a security audit at a NERC, NIST or comparable level would be a cost-prohibitive exercise. Therefore, Atikokan Hydro joined a consortium of Ontario Util-Assist LDC customers in the issuance of the October 2010 "Smart Meter Network Security Audit Services" Request for Proposal.

The objective of the RFP was to select an audit partner who would complete a security audit of the Elster AMI systems for consortium members with Elster technology in place, and to then work with Elster towards the implementation of viable countermeasures to resolve all security concerns. N-Dimensions was the selected audit firm and completed an in-depth security review at one participating utility that has the Elster solution. This review is complete, and the audit firm reviewed the technology at all remaining participating utilities to confirm that their Elster AMI systems are configured to the same standard as that declared as the standard for the group audit. Audits are anticipated to include meter-to-collector communications (across the Elster mesh network), collector to AMI headend communications (across the WAN), AMI headend to other utility systems and home area network (HAN) considerations.

Operational Data Store (ODS)

Atikokan Hydro fully supports the IESO MDM/R system and is committed to facilitating enrolment as quickly as possible with the MDM/R.

As Atikokan Hydro moved into the implementation of its AMI systems, a need was recognized for an application that supported full integration with the MDM/R and enabled our team to audit, validate, interact with and gain valuable business information from the wealth of meter data that was being collected by the MAS head-end system. The MAS system, while fully capable of collecting meter read data and forwarding that raw data to the MDM/R, does not provide all of the functionality necessary to operate the AMI and interpret and/or leverage the information it is providing in an educated and meaningful fashion.

Atikokan Hydro, with Util-Assist's support, issued an RFP for an operational data store (ODS) in Q3 2009. Following the RFP process, shortlisted vendors delivered software demonstrations in January 2009, leading to the selection of Savage Data. Contract negotiations were completed in Q2 2009 and the deployment of the ODS was finalized in Q4 2009. The software is web-based and will be hosted by Savage Data following an ASP model.

The primary requirements and features of the operational data store (ODS) are:

a) **Dashboard of Field Issues Possibly Requiring Intervention** - Dashboard visibility to the real-time performance of the smart meter system to provide field staff with visibility to troubleshooting priorities such as non-communicating meters, non-communicating gatekeepers/collectors, meters with a high number of hops, etc.

b) **AMI SLA Audit** - Audit and reporting / real-time notification capabilities to monitor AMI performance and therefore ensure that data collection and submission service-level agreements (SLAs) with the centralized MDM/R are consistently met

c) **Read Re-submission** - The ODS will provide a data repository to facilitate backfilling reads after a meter installation, front-filling reads after a meter removal, and replacing reads labeled as NVE (Needs Verification or Edit) by the IESO MDM/R system. The ODS will provide a mechanism for meter data editing and VEE (Validation, Estimation and Editing) processes (in keeping with the MDM/R specifications), such data can then be re-submitted to the MDM/R. Features such as "register read validation failure resolution" will be invaluable to Atikokan Hydro, particularly given the fact that Elster technology presents challenges with respect to timing of register and interval reads.

d) **IESO MDM/R Report Integration / Issue Resolution Automation** - The MDM/R produces a large volume of reports on a daily or regular basis each potentially containing large amounts of information. Smart Meter Assistant will load the MDM/R reports, and filter the information they provide in order to provide manageable, meaningful action items that can be prioritized, investigated and resolved.

e) **Automation of Manual Meter Reading** - The ODS ability to automate the collection of meter-read data and transition away from manual meter reads before enrolment with the MDM/R has been finalized.

f) **Meter Event Monitoring** - Dashboard visibility to report meter events and indicators such as outages, restorations, tampers, voltage changes, etc., many of which will afford Atikokan Hydro the opportunity to improve the safety and reliability of the distribution system.

g) **Revenue Protection** – Atikokan Hydro will be able to identify and respond to meter tampers which historically would have resulted in unidentified theft of power.

h) **Outage Reporting** - Real-time outage information to facilitate faster response time, and therefore improved system reliability.

Business Process Redesign

Throughout the first half of 2010, the Util-Assist training team delivered a series of education sessions covering the MDM/R design specifications, meter read data, VEE and other billing processes, and the design of a testing/cutover strategy. LDCs have widely recognized that a number of business processes, including new account setup, meter installations, meter changes, move-in/move-out and final billing all require scrutiny and procedural modifications to ensure that MDM/R integrations are optimized. Atikokan Hydro at present is relying on Thunder Bay Hydro personnel who attended 6 IESO-led training on business process redesign in Q4 2010. Actual business process redesign consultations are well underway at Atikokan Hydro and are scheduled to be complete by Fall 2011.

System Changes

Atikokan Hydro uses the SunGard H T E Billing System, which is used by several Ontario LDCs including some who have completed their smart meter deployment and implemented TOU billing. Atikokan Hydro expects the SunGard system to be fully capable of supporting MDM/R integration and TOU billing within defined regulatory timelines. In order to participate in the Northwest Group operational consortium, it was necessary for Atikokan Hydro to convert its billing system to the SunGard H T E system. This billing system change was running for February of 2009. Atikokan Hydro's SunGard H T E system is hosted by Thunder Bay Hydro on their Main frame. Atikokan Hydro does its own bill printing and data entry from its office in Atikokan. All necessary module procurement and in depth testing will be performed by Thunder Bay Hydro. Atikokan Hydro staff are kept up to date on all module changes that may result in process changes.

Integration with MDM/R

By mid-2010, internal committee members had begun attending relevant IESO training sessions regarding Atikokan Hydro's future integration to the provincial Meter Data Management Repository (MDM/R) and we have remained active and involved participants, attending the majority of IESO-hosted sessions on a variety of topics pertaining to the MDM/R.

Atikokan Hydro filed its registration paperwork and integration project plan with the IESO in Q1 2008. AS2 connectivity software to facilitate date integration with the MDM/R was selected and installed by Thunder Bay Hydro on behalf of Atikokan Hydro. Connectivity testing was completed with the IESO by March 2010. The project plan calls for Unit Testing to be executed in September 2010 and System Integration (SIT) and Qualification Testing (QT) in October 2010, in preparation for cutover to live data transfer with the MDMR by November 12, 2010. These timelines were submitted to the IESO and the proposed enrolment wave has been approved. With many technical steps still on the horizon for the final half of 2011, Atikokan

Hydro's ability to meet these targeted timelines is to a large extent contingent upon various software systems delivering the promised functionality and suppliers meeting their contractual obligations. There were delays and Unit Testing was completed on March 7, 2011; System Integration Testing [SIT] was completed on March 29, 2011; and Qualification Testing [QT] was completed March 18, 2011. Atikokan Hydro received acceptance of its Self Certification Cutover on May 11, 2011. Atikokan Hydro believes that an October 2011 cutover to production date is achievable from the perspective of the availability of internal resources, the current (relatively healthy) state of the AMI network, and the progress made on various technology / IT fronts regarding the installation of the various software systems that will support the project into the future.

Transition to TOU Pricing

In mid-2009, the government articulated an expectation that 1 million RPP customers would be billed using TOU pricing by Summer 2010, rising to 3.6 million customers by June 2011. On June 24, 2010, the Ontario Energy Board issued a proposed determination regarding mandated time-of-use pricing for regulated price plan customers (Board File No. EB-2010-0218), suggesting that distributor-specific TOU dates would be the most appropriate approach, as it allows for the deadline to logically follow MDM/R enrolment activities.

Under the proposed determination, Atikokan Hydro fell into the category of a distributor that "had not yet commenced MDM/R enrolment testing and whose meter enrolment date has passed". Therefore, according to the proposal, Atikokan Hydro's mandatory TOU date would be the first day of the first billing period that commences 10 months from the date identified in our baseline plan for the commencement of meter enrolment. Atikokan Hydro was not able to complete the transition to TOU pricing as mandated for June 2011, but will have completed the transition by October 2011.

Web Presentment

The Ministry of Energy and Infrastructure has indicated that electricity customers should ideally have web access to their consumption data with which to make informed decisions about future usage as part of a utility's rollout of TOU pricing. Accordingly, the SME Transition Committee formally requested a proposal from an established web presentment service provider, Whitecap Canada Inc., as they are already providing an effective solution to several LDCs in Ontario. Atikokan Hydro identified the security features, ease of implementation, ease of use, existing integration with the provincial MDM/R, low cost-per-customer advantages, and the consistent user experience for customers as they relocate within Ontario as key benefits of the Whitecap portal solution. Atikokan Hydro anticipates implementing the Whitecap solution in Q4 2011 once our MDM/R enrolment is complete and reliable data (current and to some extent historical) is readily available for our customers. While Atikokan Hydro realizes that the Board may have envisioned web presentment, Atikokan Hydro seeks further guidance for this process from the Board. Whitecap's setup fee of $7,000 to $15,000 may be a manageable cost, but the ongoing flat rate of $7,400 per year licencing plus $.035 per installed smart meter works out to be a cost of 40 cents per month per customer at present rates. Basic research has indicated that less than 2% of customer base actually use the web presentment information. Given that Atikokan Hydro needs to entertain rate mitigation strategies, Atikokan Hydro would suggest the cost of Whitecap service may not be appropriate and should be eliminated. This in turn would mean a presentment service would not be offered to Atikokan Hydro's customer base.

Consumer Education Plan

Atikokan Hydro leveraged the significant development efforts undertaken by the Ministry of Energy to support LDC-specific communications tools and resources related to Time-of-Use (TOU) roll-out to electricity customers. In keeping with our mission statement to deliver exceptional customer service to the ratepayers in our service territory, Atikokan Hydro executed an extensive customer education and outreach campaign aligned with our time-of-use (TOU) pricing rollout. Up to that point, we continued to keep customers informed about our smart meter project and TOU pricing through our corporate website.

SMART METER COSTS

Atikokan Hydro is seeking recovery of actual costs related to smart meter activity as of June 30, 2011 and estimated costs from July 1, 2011 to December 31, 2011, for the installation of 1,673 meters. A summary of total expense and expense per customer is provided in Table 9-5.

Table 9-5: Smart Meter Capital and Operating Expenses as of December 31, 2011

Description	Total Cost	Cost Per Meter
Smart Meter and related fixed assets	$507,378	$303
Incremental Operating Expenses	$149,136	$89
Total Cost per Meter		$392

Atikokan Hydro has not incurred any costs for functionality beyond the minimum functionality adopted in O.Reg. 425/06. Atikokan Hydro does not have a billing MDM/R system and uses only the Smart Meter Entity MDM/R system for billing Time of Use customers.

Smart Meter Actual Cost Recovery Calculation

Atikokan Hydro has used a model obtained from Board Staff which has been used by other distributors for smart meter actual cost recovery calculations. A working copy of the Smart Meter Cost Recovery Model has been filed as part of this application.

The model calculates the revenue requirement amounts for purposes of the cost recovery to December 31, 2011 and offsets this amount with the value of the smart meter funding adder collected over the period May 1, 2006 to April 30, 2012. Table 9-6 summarizes the results of the model.

Table 9-6: Smart Meter Cost Recovery to December 31, 2011	
Revenue Requirement 2009	$81,271
Revenue Requirement 2010	$109,240
Revenue Requirement 2011	$153,067
Revenue Requirement Total	$343,578
Smart Meter Rate Adder	($132,653)
Carrying Cost	$2,610
Smart Meter True-up	$213,535

Atikokan Hydro is seeking approval of the smart meter costs in this Application and of the transfer of the approved amounts from the smart meter deferral accounts to the appropriate fixed asset, revenue and expense accounts. As shown in Table 9.8, there is a difference of $213,535 between the revenue requirement related to the smart meter costs and the corresponding smart meter adder collected from May 1, 2006 to April 30, 2012.

STRANDED METER COSTS

Atikokan Hydro is also seeking disposition of its stranded meter costs. Atikokan Hydro has continued to record the costs of the stranded meters in Account 1860 and has continued to depreciate these assets over a 25 year period. In 2009, 1,659 stranded meters which had been removed from use up to that time, were disposed of in an "Environmentally acceptable" manner by Greenport Environmental for a fee of $1,122. Table 9.7 contains the asset and accumulated depreciation balances for the stranded meters at the end 2011.

Table 9-7: Stranded Meter Net Book Value December 31, 2011	
Stranded Meter Cost	$104,713
Accumulated Depreciation	($81,338)
Net Book Value	$23,375

Atikokan Hydro is requesting recovery of the $23,375 in residual net book value of the assets. Atikokan Hydro is also requesting these assets be removed from the rate base as at December 31, 2011, placed in account 1555 and the disposition of the $23,375 be recorded in account 1555.

SMART METER COST RECOVERY RATE RIDER AND STRANDED METER ASSET RATE RIDER CALCULATION

As detailed in this Exhibit, Atikokan Hydro is requesting recovery of a Smart Meter True-up amount of $213,535 and a Stranded Asset amount of $23,375. Atikokan Hydro proposes to recover these amounts through a fixed monthly rider from metered customers. Based on Atikokan Hydro's 2012 customer forecast a smart meter cost recovery rate rider of $10.63 per month and a stranded meter asset rate rider of $1.16 per month would be required to recover these amounts in one year. To reduce customer impact Atikokan Hydro proposes to recover this amount over three years at a rate of $3.54 per month per metered customer for smart meter cost recovery and a rate of $0.39 per month per metered customer for stranded meter asset recovery. Table 9-8 summarizes the calculation of these rates.

Table 9-8: Rate Rider Calculation December 31, 2011	
Smart Meter Cost Recovery	$213,535
Number of Metered Customers	1,673
Period of Recover in Months	36
Smart Meter Cost Recovery Rider	$3.54
Stranded Meter Cost Recovery	$23,375
Number of Metered Customers	1,673
Period of Recover in Months	36
Smart Meter Cost Recovery Rider	$0.39