Tillsonburg Hydro Inc.

2009 EDR Application

EB-2008-0246

Submitted: 22 August, 2008

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Tillsonburg Hydro Inc.

Ontario Energy Board
2300 Yonge St, Suite 2701
P. O. Box 2319
Toronto, ON M4P 1E4
Attn: K. Walli
Board Secretary

August 22, 2008

Dear Ms. Walli

Re: EB-2008-0246

Please find enclosed Tillsonburg Hydro Inc.'s 2009 Electricity Distribution Rates Application.

Sincerely

cc. M. Renaud, Vice Chair Tillsonburg Hydro Inc.
S. Lund, General Manager Tillsonburg Hydro Inc.

Application

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

AND IN THE MATTER OF an Application by Tillsonburg Hydro Inc. for an Order or Orders approving just and reasonable rates and other service charges for the distribution of electricity, effective May 1, 2009.

APPLICATION

1. Tillsonburg Hydro Inc. ("THI") is an Ontario business corporation with its office located in the Town of Tillsonburg. THI carries on the business of distributing electricity within the Town of Tillsonburg.

2. THI hereby applies to the Ontario Energy Board, pursuant to section 78 of the Ontario Energy Board Act, 1998, for approval of its proposed distribution rates and other charges, effective May 1, 2009.

3. THI seeks an order of the Board authorizing its 2009 Test Year rate base.

4. THI also applies for an Order of the Board authorizing its current rates on an interim basis effective May 1, 2009 if the Board has not authorized final rates on or before that date.

5. This application is supported by written prefiled evidence, prepared in accordance with the Board's filing requirements for rates based on a forward test year. A summary of the application is found at E1/T1/S3 and a summary of the orders requested is found at E1/T1/S8.

6. The proposed rates and charges are just and reasonable and will support THI recovering the ongoing costs incurred to provide electricity distribution services to its customers at an appropriate level of quality and provide THI with an opportunity to earn a reasonable return on its invested capital.

7. The proposed rates will result in a monthly bill increase of 5.7% or $6.02 per residential customer consuming 1000 kWh.

8. Contact information for the Application is provided below:

Tillsonburg Hydro Inc.		Town of Tillsonburg	
200 Broadway, 2nd Floor		200 Broadway, 2nd Floor	
Tillsonburg, ON N4G 5A7		Tillsonburg, ON N4G 5A7	
Steve Lund, P.Eng		John Gott, C.A.	
General Manager		Finance and Regulatory Affairs Manager	
Tel:	519.842.9200 x 3228	Tel:	519.842.6428 x 3229
Fax:	519.842.9431	Fax:	519.842.5931
Email:	slund@town.tillsonburg.ca	Email:	jgott@town.tillsonburg.on.ca

DATED at Tillsonburg, Ontario, August 21, 2008.

S. Lund, General Manager, Tillsonburg Hydro Inc.

M. Renaud, Chair, Tillsonburg Hydro Inc.

Summary of Application

THI seeks Board authorization to charge increased electricity distribution rates effective May 1, 2009 that will recover an additional $747k during the 2009TY. THI requests this change so that:

- its 2009 rates are just and reasonable,
- its 2009 rates recover the ongoing costs of providing distribution service to the inhabitants of the Town of Tillsonburg at an appropriate level of quality; and
- its 2009 rates permit an opportunity to earn the allowed rate of return.

THI also seeks Board authorization to charge rate riders that will dispose of the balances recorded in certain variance and deferral accounts and will recover THI's LRAM and SSM claims and revised loss factors.

THI forecasts a 2009TY service revenue requirement of $3,313k and proposes to recover it by charging:

- revised distribution rates that will recover $3,184k in revenue; and
- the currently authorized other regulated rates and charges that will recover $129k.
-

In the case that the Board's Final Rate Order is not able to be implemented effective May 1, 2009 THI seeks an Order of the Board authorizing its current rates as Interim Rates effective May 1, 2009.

THI has consistently under earned versus the Board's allowed rate of return. THI incurred a gross revenue deficiency in 2006, when it last rebased, of $814k, and a revenue deficiency has been incurred in every year since. In the period 2004-2009 THI's period costs (OM&A, Depreciation, Payments in Lieu of Taxes) increased by $1,057k while its revenues recovered through distribution rates and other regulated rates and charges increased by $986k. Also in that period THI's eligible rate base increased by $729k and the allowed return has decreased from 8.125% to 7.11%. Through this application THI seeks rates that will eliminate this long standing revenue deficiency.

THI will invest $556k in net capital in the 2009TY; $207k relates to the investment required to attach over 100 new residential customers and the remainder, $349k supports the ongoing renewal of THI's distribution system infrastructure. Because THI is 100% equity financed it

relies on internally generated funds to support its investment requirements. For rate making purposes THI has relied on the Board's hypothetical capital structure.

THI is a 'virtual' utility – it does not have any employees and it does not own all the assets required to provide distribution service on a commercial basis (eg., Information Technology assets). The Town of Tillsonburg, THI's sole shareholder, makes several of its employees and many of its assets available to THI. This arrangement is governed by a Master Service Agreement ("MSA") under which THI pays fixed charges that recover the Town's directly incurred costs (operating and capital) and a Management Fee that supports the recovery of indirectly incurred costs and contributes towards the recovery of the cost of capital.

THI's distribution license is in good standing and THI complies with all regulatory instruments.

THI's service quality typically ranks in the top quartile. In 2002-05 its reported SAIDI and SAIFI were in top quintile and in 2006 it ranked in top third. THI's achieved Service Quality is provided at E1/T1/S3/AttA. THI's overall cost per kWh delivered amounts to $0.015/kWh. Pacific Economics Group's benchmarking analysis, based on an analysis of period costs only, ranks THI as 46th and 62nd among all distributors in the Province. This ranking may be lower than is appropriate because THI's operating costs are overstated. This is because THI pays for the capital employed by the Town through the charges paid under the MSA that are recorded as operating costs. In addition, THI provides its customers with enhanced services, such as extended hours cashiering services, staffed telephone contact 24 hours a day and trouble trucks also on a 24 hours a day basis.

This application, if granted, will support THI continuing to provide high quality distribution at rates that recover the ongoing costs of providing service to the inhabitants of the Town of Tillsonburg and permit an opportunity to earn the allowed rate of return.

Current Rates Schedule

A copy of THI's current rate order is provided at E1/T1/S4/AttA.

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2007-0860

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Schedule B;

AND IN THE MATTER OF an Application by Tillsonburg Hydro Inc. pursuant to section 78 of the Ontario Energy Board Act seeking approval to amend electricity distribution rates.

BEFORE: Paul Vlahos
Presiding Member

Paul Sommerville
Member

RATE ORDER

Tillsonburg Hydro Inc. ("Tillsonburg Hydro") is a licensed distributor of electricity providing service to consumers within its licensed service area. Tillsonburg Hydro filed an application with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, to be effective May 1, 2008.

On March 14, 2008, the Board issued its Decision (the "Decision") regarding Tillsonburg Hydro's application.

The Board directed that Tillsonburg Hydro file with the Board a proposed Tariff of Rates and Charges reflecting the Board's Decision, within 7 days of the date of the Decision.

Tillsonburg Hydro has provided the Board with a proposed Tariff of Rates and Charges.

The Board is satisfied that the document accurately reflects the Decision.

For completeness of the regulated charges, the Board has included in the Tariff of Rates and Charges the charges pertaining to services provided to retailers or consumers regarding the supply of competitive electricity, which are referenced in Chapter 12 of the 2006 Electricity Distribution Rate Handbook.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix "A" of this Rate Order is approved, effective May 1, 2008, for electricity consumed or estimated to have been consumed on and after May 1, 2008.

2. The Tariff of Rates and Charges set out in Appendix "A" of this Order supersedes all previous distribution rate schedules approved by the Board for Tillsonburg Hydro and is final in all respects.

3. Tillsonburg Hydro shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, April 17, 2008.

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix “A”
To The Rate Order Arising from Decision
EB-2007-0860
Tillsonburg Hydro Inc.

April 17, 2008

Tillsonburg Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2008

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

EB-2007-0860

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders 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, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2008 for all charges incurred by customers on or after that date.
RETAIL SERVICE CHARGES – May 1, 2008 for all charges incurred by retailers or customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2008 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification applies to an account in one of three categories of residential services: single-family or single-unit homes, multi-family buildings, and subdivision developments. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

General Service Less Than 50 kW
This classification applies to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

General Service 50 to 499 kW
This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 500 kW. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

General Service 500 to 4,999 kW
This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 500 kW but less than 5,000 kW. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

Unmetered Scattered Load
This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

Sentinel Lighting
This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

Street Lighting
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 Tillsonburg Hydro's Conditions of Service.

Tillsonburg Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2008

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

EB-2007-0860

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.65
Distribution Volumetric Rate	$/kWh	0.0159
Retail Transmission Rate – Network Service Rate	$/kWh	0.0045
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	25.03
Distribution Volumetric Rate	$/kWh	0.0100
Retail Transmission Rate – Network Service Rate	$/kWh	0.0041
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 499 kW

Service Charge	$	111.76
Distribution Volumetric Rate	$/kW	0.8315
Retail Transmission Rate – Network Service Rate	$/kW	1.5822
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5008
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 500 to 4,999 kW

Service Charge	$	1,158.42
Distribution Volumetric Rate	$/kW	0.4773
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.0773
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.0442
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	12.38
Distribution Volumetric Rate	$/kWh	0.0100
Retail Transmission Rate – Network Service Rate	$/kWh	0.0041
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Tillsonburg Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2008

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

EB-2007-0860

Sentinel Lighting

Service Charge (per connection)	$	1.18
Distribution Volumetric Rate	$/kW	7.3155
Retail Transmission Rate – Network Service Rate	$/kW	1.3027
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2357
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per customer)	$	1,336.76
Distribution Volumetric Rate	$/kW	4.4791
Retail Transmission Rate – Network Service Rate	$/kW	1.2993
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2324
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Returned Cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special Meter Reads	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect Charge - at Meter - During Regular Hours	$	65.00
Disconnect/Reconnect Charge - at Meter - After Regular Hours	$	185.00
Disconnect/Reconnect Charge at Pole – During Regular Hours	$	185.00
Install/Remove Load Control Device – After Regular Hours	$	185.00
Service Call – After Regular Hours	$	165.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Tillsonburg Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2008

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

EB-2007-0860

Retail Service Charges (if applicable)

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

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

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0422
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0317
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Proposed Rates Schedule

A copy of THI's proposed distribution rates and other regulated rates and charges is provided at E1/T1/S5/AttA.

Appendix 1-1

		Effective May 1/09
Residential		
Service Charge	$	14.30
Distribution Volumetric Rate	$/kWh	0.0184
Regulatory Asset Recovery	$/kWh	0.0012
Retail Transmission Rate – Network Service Rate	$/kWh	0.0045
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
General Service < 50 kW		
Service Charge	$	29.15
Distribution Volumetric Rate	$/kWh	0.0144
Regulatory Asset Recovery	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0041
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
General Service >50 kW, <500 kW		
Service Charge	$	111.00
Distribution Volumetric Rate	$/kW	1.6646
Regulatory Asset Recovery	$/kW	0.0311
Retail Transmission Rate – Network Service Rate	$/kW	1.5822
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5008
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Appendix 1-1

		Effective May 1/09
Street Lighting		
Service Charge	$	1,150.00
Distribution Volumetric Rate	$/kW	3.0855
Regulatory Asset Recovery	$/kW	0.1530
Retail Transmission Rate – Network Service Rate	$/kW	1.2993
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2324
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
Unmetered Scattered Load		
Service Charge	$	20.00
Distribution Volumetric Rate	$/kWh	0.0036
Regulatory Asset Recovery	$/kWh	0.0008
Retail Transmission Rate – Network Service Rate	$/kWh	0.0041
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
General Service >500 kW, <1,500 kW		
Service Charge	$	751.00
Distribution Volumetric Rate	$/kW	1.3820
Regulatory Asset Recovery	$/kW	0.0352
Retail Transmission Rate – Network Service Rate	$/kW	2.0773
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0442
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
General Service >1,500 kW		
Service Charge	$	1,151.00
Distribution Volumetric Rate	$/kW	1.9937
Regulatory Asset Recovery	$/kW	0.0146
Retail Transmission Rate – Network Service Rate	$/kW	2.0773
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0442
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Appendix 1-1

		Effective May 1/09
Specific Service Charges		
Returned Cheque charge (plus bank charges)	$	15.00
Account set up charge / change of occupancy charge	$	30.00
Special Meter reads	$	30.00
Late Payment - per month	%	1.50
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Install / remove load control device – after regular hours	$	185.00
Service call – after regular hours	$	165.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Transformer Allowance for Ownership - per kW of billing demand/month	$	0.60
Retailer Service Agreement -- standard charge	$	100.00
Retailer Service Agreement -- monthly fixed charge (per retailer)	$	20.00
Retailer Service Agreement -- monthly variable charge (per customer)	$	0.50
Distributor-Consolidated Billing -- monthly charge (per customer)	$	0.30
Retailer-Consolidated Billing -- monthly credit (per customer)	$	-0.30
Service Transaction Request -- request fee (per request)	$	0.25
Service Transaction Request -- processing fee (per processed request)	$	0.50
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	-0.60
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	-1.00
LOSS FACTORS		
Primary Metered Customer < 5,000 kW		1.0284
Secondary Metered Customer < 5,000 kW		1.0388

Summary of Bill Impact

The following table summarizes the estimated bill impacts for each customer class

- according to the Board's consumption scenarios; and
- for THI's forecast average energy and demand.

The detailed calculations of the bill impacts are provided at E1/T1/S6/AttA.

RateMaker 2009 release 1.1 © Elenchus Research Associates

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Residential

Volume		RPP	Distribution Charges		Total Bill	
kWh *	kW	Rate Class	$ change	% change	$ change	% change
250		Summer	$3.28	21.0%	$3.51	10.2%
1,500		Summer	$6.40	18.0%	$7.70	4.9%
500		Summer	$3.90	19.9%	$4.36	7.6%
1,000		Summer	$5.15	18.7%	$6.02	5.7%
1,000		Winter	$5.15	18.7%	$6.02	5.9%
2,000		Winter	$7.65	17.6%	$9.38	4.6%
2,000		Summer	$7.65	17.6%	$9.38	4.5%

** Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)*

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service < 50

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
1,000		n/a	$8.52	24.3%	$8.50	7.5%
2,000		n/a	$12.92	28.7%	$12.89	6.4%
5,000		n/a	$26.12	34.8%	$26.07	5.6%
10,000		n/a	$48.12	38.5%	$48.03	5.3%
15,000		n/a	$70.12	40.1%	$69.99	5.2%
3,256		n/a	$18.45	32.0%	$18.42	5.9%

** Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)*

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service >50

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
15,000	60	n/a	$49.23	30.5%	$47.00	3.4%
25,000	100	n/a	$82.55	42.4%	$78.83	3.5%
100,000	500	n/a	$415.79	78.8%	$404.02	4.4%
		n/a				
		n/a				
42,574	124	n/a	$102.54	47.7%	$94.77	2.6%

** Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)*

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
655,475	1,390	n/a				
1,889,257	3,706	n/a				
742,137	1,595	n/a				

** Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)*

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
150	1.00	Non-res.				
200	1.00	Non-res.				
72	0.20	n/a				
78	0.20	Non-res.				

** Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)*

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Street Lighting

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
150	1.00	n/a	($188.15)	(14.0%)	($188.04)	(13.9%)
110,842	320.00	n/a	($632.71)	(22.8%)	($614.03)	(5.4%)
110,842	320.00	Non-res.	($632.71)	(22.8%)	($616.28)	(5.2%)

** Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)*

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Unmetered Scattered

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
730		n/a	$2.95	15.0%	$3.31	4.3%
2,226		Non-res.	($6.63)	(19.1%)	($5.59)	(2.6%)

** Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)*

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service >500

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
225,000	500.00	n/a	$44.93	3.2%	$2,061.83	12.0%
335,000	750.00	n/a	$271.11	17.9%	$3,297.13	13.1%
450,000	1,000.00	n/a	$497.28	30.4%	$4,531.06	13.6%
575,000	1,250.00	n/a	$723.46	41.2%	$5,762.27	13.7%
650,000	1,500.00	n/a	$949.63	50.7%	$7,007.13	14.7%

** Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)*

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F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service >1,5

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
666,666	1,500	n/a	$2,267.18	>100%	$8,050.97	16.6%
1,000,000	2,500	n/a	$3,783.58	>100%	$13,493.27	18.6%
1,500,000	3,500	n/a	$5,299.98	>100%	$18,830.50	17.4%
2,900,000	4,500	n/a	$6,816.38	>100%	$23,600.23	11.4%

** Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)*

List of Issues

THI proposes the following List of Issues:

Revenues

- Is THI's forecasted level of revenues for the 2009TY appropriate for rate making purposes?
- Are THI's weather normalization and revenue forecasting methodologies appropriate?
- What revenues will be recovered in the 2009TY through other regulated rates and charges?

Rate Base

- Is THI's methodology for estimating the Net Distribution Physical Plant appropriate?
- Is THI's methodology for estimating Working Cash Allowance appropriate?
- Is THI's 2009TY capital budget appropriate?
- Are THI's 2009TY Contributions in Aid of Construction appropriate?
- Is THI's capitalization policy appropriate for rate making purposes?
- Is the proposed rate base for the 2009TY appropriate for rate making purposes?

Period expenses including Operations, Maintenance and Administration costs, Depreciation expense and Payments in Lieu of Taxes expense

- Are THI's forecast 2009TY period expenses - OM&A, depreciation, PILs – appropriate for rate making purposes?
- Are the goods and services procured from or through affiliated entities provided in accordance with the transfer pricing requirements of the Board's Affiliate Relationships Code of Conduct?

Cost of Capital

- Has THI correctly implemented the Board's policies on capital structure and cost of capital?
- Is the proposed capital structure appropriate for the 2009TY appropriate for rate making purposes?
- Is the proposed cost of capital appropriate for the 2009TY appropriate for rate making purposes?

Revenue Deficiency

- Is THI's methodology for estimating the gross revenue deficiency appropriate?

Deferral and Variance Accounts

- Is THI's methodology for estimating the balances recorded in each deferral or variance account appropriate?
- Are the accounts that THI propose to dispose of through rates correctly identified?
- Are the balances recorded in the variance and deferral accounts to be disposed of through rates appropriate?
- Has THI correctly estimated the Lost Revenue Adjustment Mechanism and Shared Savings Mechanism for the years 2005, 2006 and 2007?
- Are the proposed rate riders to be charged during the 2009TY appropriate?

Smart Meter Rate Adder

- Is THI's proposed 2009TY Smart Meter Rate Adder appropriate?

Cost Allocation

- Has THI correctly implemented the Board approved Cost Allocation methodology?
- Are the Cost:Revenue ratios estimated by the 2004 Cost Allocation Review - Informational Filing appropriate for rate making purposes for the 2009TY?
- Has THI appropriately revised its 2004 CAR-IF for the following proposed customer classes:
    - General Service >500 kW, <1,500 kW;
    - General Service >1,500 kW; and
    - To eliminate the Sentinel Lighting class.

Rate Design

- Are THI's proposed 2009TY rate design changes appropriate for rate making purposes?
- Is THI's proposed standby service rate appropriate?
- Are THI's proposed other rates and charges appropriate?

Other

- Is THI's methodology for determining distribution loss factors appropriate?
- Are the proposed 2009TY distribution loss factors appropriate for rate making purposes?

List of Specific Approvals Requested

THI seeks Board authorization to:

- Establish General Service >500 kW, <1,500 kW and General Service >1,500 kW customer classes
- Eliminate its existing General Service 500 – 4,999 kW customer class;
- Include the customers in THI's existing Sentinel Lighting customer class into its Unmetered Scattered Load customer class and to eliminate the Sentinel Lighting customer class;
- Charge revised distribution rates, both fixed in the period and varying based on the level of service;
- Charge rate riders that recover the balances recorded in certain variance and deferral accounts as of December 31, 2007 and the associated carrying charges as of April 30, 2009 and to recover THI's Lost Revenue Adjustment Mechanism and Shared Savings Mechanism awards;
- Charge a revised Smart Meter Rate Adder; and
- Apply revised distribution loss factors.

THI seeks the Board's determination of its 2009TY Rate Base and an order of the Board authorizing it in that amount.

Schedule of Overall Revenue Deficiency/Sufficiency

THI estimates that is 2009TY gross revenue deficiency will amount to $747k; the derivation is provided at E1/T1/S9/AttA.

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G7 Variance Analysis: Revenue Sufficiency / Deficiency

		2009 Projection	2008 Projection	Var #	Var %
Utility Income	*(see below)*	-38,758	294,224	-332,982	(113.2%)
Utility Rate Base	*from sheet G6*	8,947,080	8,444,703	502,377	5.9%
Indicated Rate of Return		(0.43%)	3.48%	(3.92%)	(112.4%)
Requested / Approved Rate of Return	*from sheet D3*	7.11%	7.11%		
Sufficiency / (Deficiency) in Return		(7.54%)	(3.62%)	(3.92%)	(108.2%)
Net Revenue Sufficiency / (Deficiency)		**-674,460**	**-305,783**	**-368,677**	**(120.6%)**
Provision for PILs/Taxes *		-72,332		-72,332	
Gross Revenue Sufficiency / (Deficiency)		**-746,792**	**-305,783**	**-441,009**	**(144.2%)**
Deemed Overall Debt Rate	*from sheet D3*	*5.98%*	*7.25%*	*(1.27%)*	*(17.4%)*
Deemed Cost of Debt	*from sheet D3*	*303,437*	*306,120*	*-2,683*	*(0.9%)*
Utility Income less Deemed Cost of Debt		*-342,195*	*-11,896*	*-330,299*	*(2776.5%)*
Return On Deemed Equity		*(8.83%)*	*(0.33%)*	*(8.50%)*	

UTILITY INCOME	*from sheets E1 & E2 (except PILS / Income Taxes)*				
Total Net Revenues		2,566,138	2,541,622	24,516	1.0%
OM&A Expenses		2,103,292	1,695,427	407,866	24.1%
Depreciation & Amortization		501,604	472,579	29,025	6.1%
Taxes other than PILs / Income Taxes					
Total Costs & Expenses		2,604,896	2,168,005	436,891	20.2%
Utility Income before Income Taxes / PILs		-38,758	373,616	-412,374	(110.4%)
PILs / Income Taxes	*from sheet E4*		79,392	-79,392	(100.0%)
Utility Income		**-38,758**	**294,224**	**-332,982**	**(113.2%)**

** In 2009: difference between amounts on sheet E4 for 2009 at existing rates vs. 2009 at new revenue requirement; in 2008: Net Sufficiency / (Deficiency) multiplied by grossed-up effective tax rate on Utility Income.*

Causes of the Deficiency/Sufficiency

THI's 2009TY gross revenue deficiency is caused by:

- The continuation of the gross revenue deficiency of the 2008BY being $306k;
- increased distribution revenue of $25k;
- increased period expenses of $437k;
- decreased PILs expense of $7k; and
- changes to Rate Base that in combination with changes to the hypothetical capital structure and deemed costs of capital give rise to a $36k increase/decrease in return.

These causes of the deficiency are further explained through the variance analysis provided at E1/T1/S9/AttA and at Exhibit 7.

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Board Findings and Directions from 2007 EDR

The Board's decisions EB-2007-0581 and EB-2007-0860 did not direct or require THI to take any specific action. These decisions are provided at E1/T1/S11/AttA and E1/T1/S11/AttB respectively.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2007-0581

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

AND IN THE MATTER OF an application by Tillsonburg Hydro Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2007.

BEFORE: Paul Sommerville
Presiding Member

Paul Vlahos
Member

Ken Quesnelle
Member

DECISION AND ORDER

Tillsonburg Hydro Inc. ("Tillsonburg Hydro") is a licensed distributor providing electrical service to consumers within its licensed service area. Tillsonburg Hydro filed an application with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, to be effective May 1, 2007.

Tillsonburg Hydro is one of 85 electricity distributors in Ontario that are regulated by the Board. To streamline the process for the approval of distribution rates and charges for these distributors, the Board issued its *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Report") on December 20, 2006. The Report contained the relevant guidelines for 2007 rate adjustments ("the guidelines") for distributors applying for rates only on the basis of the cost of capital and 2nd generation incentive regulation mechanism policies set out in the Report.

Public notice of Tillsonburg Hydro's rate application was given through newspaper publication in Tillsonburg Hydro's service area. The evidence filed as part of the rate application was made available to the public. Both Tillsonburg Hydro and interested parties had the opportunity to file written submissions in relation to the rate application. The Board received no submissions. While the Board has considered the entire record in this rate application, it has made reference only to such evidence as is necessary to provide context to its findings.

Tillsonburg Hydro's rate application was filed on the basis of the guidelines. In fixing new rates and charges for Tillsonburg Hydro, the Board has applied the policies described in the Report.

After confirming the accuracy of the 2006 rate tariff and accompanying materials submitted in the rate application, the Board applied its approved price cap index adjustment to distribution rates (fixed and variable) uniformly across all customer classes. The price cap index is calculated as a price escalator less an X-factor of 1.0%, intended to represent input price and productivity trends. Based on the final 2006 data published by Statistics Canada, the Board has established the price escalator to be 1.9%. The resulting price cap index adjustment is therefore 0.9%.

The price cap index adjustment was not applied to the following components of the rates:

- the specific service charges;
- the regulatory asset recovery rate rider; and
- the smart meter rate adder (an amount in the fixed components of the rates associated with smart meter cost recovery).

Tillsonburg Hydro requested an amount of $0.26 for smart meter costs. Regulation 153/07 under the *Electricity Act, 1998*, which amends regulation 427/06 under the same Act, was filed on April 10, 2007. As a result, it is the Board's understanding that Tillsonburg Hydro will not be undertaking any smart metering activity (i.e. discretionary metering activity) in 2007.

However, the Board has approved the amount of $0.26 per month per metered customer to be collected through a smart meter rate adder. This nominal funding amount was calculated using the Board's model for inactive distributors, as described in the Smart Metering Rates Addendum to the Report. The amount collected through the smart meter rate adder will be booked into the existing variance accounts, and retained

in those accounts, to help fund future smart meter activity. As the notice of this application indicated, the Board will be holding a combined proceeding to consider, among other things, appropriate recovery of smart meter costs.

The Board has made the necessary adjustments to Tillsonburg Hydro's filed 2006 Tariff of Rates and Charges to produce a new Tariff of Rates and Charges to be effective May 1, 2007. The Board finds the rates and charges in the Tariff of Rates and Charges attached as Appendix A to this decision to be just and reasonable.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix A of this order is approved, effective May 1, 2007, for electricity consumed or estimated to have been consumed on and after May 1, 2007.

2. The Tariff of Rates and Charges set out in Appendix A of this order supersedes all previous distribution rate schedules approved by the Ontario Energy Board for Tillsonburg Hydro, and is final in all respects.

3. Tillsonburg Hydro shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, April 12, 2007.

ONTARIO ENERGY BOARD

Original signed by

Peter H. O'Dell
Assistant Board Secretary

Appendix A

EB-2007-0581

April 12, 2007

ONTARIO ENERGY BOARD

Tillsonburg Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2007

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

EB-2007-0581

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders 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, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2007 for all charges incurred by customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification applies to an account in one of three categories of residential services: single-family or single-unit homes, multi-family buildings, and subdivision developments. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

General Service Less Than 50 kW
This classification applies to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

General Service 50 to 499 kW
This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 500 kW. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

General Service 500 to 4,999 kW
This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 500 kW but less than 5,000 kW. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

Unmetered Scattered Load
This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

Sentinel Lighting
This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

Street Lighting
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 Tillsonburg Hydro's Conditions of Service.

Tillsonburg Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2007

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

EB-2007-0581

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.65
Distribution Volumetric Rate	$/kWh	0.0159
Regulatory Asset Recovery	$/kWh	0.0045
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	25.03
Distribution Volumetric Rate	$/kWh	0.0100
Regulatory Asset Recovery	$/kWh	0.0020
Retail Transmission Rate – Network Service Rate	$/kWh	0.0050
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 499 kW

Service Charge	$	111.76
Distribution Volumetric Rate	$/kW	0.8315
Regulatory Asset Recovery	$/kW	0.6184
Retail Transmission Rate – Network Service Rate	$/kW	1.9295
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5798
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 500 to 4,999 kW

Service Charge	$	1,158.42
Distribution Volumetric Rate	$/kW	0.4773
Regulatory Asset Recovery	$/kW	0.5778
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.5333
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.1518
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	12.38
Distribution Volumetric Rate	$/kWh	0.0100
Regulatory Asset Recovery	$/kWh	0.0046
Retail Transmission Rate – Network Service Rate	$/kWh	0.0050
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Tillsonburg Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2007

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

EB-2007-0581

Sentinel Lighting

Service Charge (per connection)	$	1.18
Distribution Volumetric Rate	$/kW	7.3155
Regulatory Asset Recovery	$/kW	1.3819
Retail Transmission Rate – Network Service Rate	$/kW	1.5886
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3007
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	1,336.76
Distribution Volumetric Rate	$/kW	4.4791
Regulatory Asset Recovery	$/kW	0.2615
Retail Transmission Rate – Network Service Rate	$/kW	1.5845
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2973
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Returned Cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special Meter Reads	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect Charge - at Meter - During Regular Hours	$	65.00
Disconnect/Reconnect Charge - at Meter - After Regular Hours	$	185.00
Disconnect/Reconnect Charge at Pole – During Regular Hours	$	185.00
Install/Remove Load Control Device – After Regular Hours	$	185.00
Service Call – After Regular Hours	$	165.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0422
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0317
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2007-0860

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

AND IN THE MATTER OF an application by Tillsonburg Hydro Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2008.

BEFORE: Paul Vlahos
Presiding Member

Paul Sommerville
Member

DECISION

Introduction

Tillsonburg Hydro Inc. is a licensed distributor of electricity providing service to consumers within its licensed service area. Tillsonburg Hydro Inc. filed an application with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, to be effective May 1, 2008.

Tillsonburg Hydro Inc. is one of over 80 electricity distributors in Ontario that are regulated by the Board. In 2006, the Board announced the establishment of a multi-year electricity distribution rate-setting plan for the years 2007-2010. As part of the plan, Tillsonburg Hydro Inc. is one of the electricity distributors to have its rates adjusted for 2008 on the basis of the 2nd Generation Incentive Rate Mechanism ("IRM") process.

To streamline the process for the approval of distribution rates and charges for distributors, the Board issued its *Report of the Board on Cost of Capital and 2nd*

Generation Incentive Regulation for Ontario's Electricity Distributors (the "Report") on December 20, 2006. Among other things, the Report contained the relevant guidelines for 2008 rate adjustments ("the Guidelines") for distributors applying for rate adjustments pursuant to the IRM process.

Notice of Tillsonburg Hydro Inc.'s rate application was given through newspaper publication in Tillsonburg Hydro Inc.'s service area advising of the availability of the rate application and advising how interested parties may intervene in the proceeding or comment on the application. There were no intervention requests and no comments were received. The Board proceeded by way of a written hearing. Board staff participated actively in the proceeding.

While the Board has considered the entire record in this rate application, it has made reference only to such evidence as is necessary to provide context to its findings.

Price Cap Index Adjustment

Tillsonburg Hydro Inc.'s rate application was filed on the basis of the Guidelines. In fixing new rates and charges for Tillsonburg Hydro Inc., the Board has applied the policies described in the Report.

As outlined in the Report, distribution rates under the 2nd Generation IRM are to be adjusted by a price escalator less a productivity factor (X-factor) of 1.0%. Based on the final 2007 data published by Statistics Canada, the Board has established the price escalator to be 2.1%. The resulting price cap index adjustment is therefore 1.1%. The rate model was adjusted to reflect the newly calculated price cap adjustment. This price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes. An adjustment for the transition to a common deemed capital structure of 60% debt and 40% equity was also effected. In addition, a change in the federal income tax rate effective January 1, 2008 was also incorporated into the rate model and reflected in distribution rates.

The Board also considered the reduction in Ontario capital tax and the increase in capital cost allowance (CCA) applicable to certain buildings and computers acquired after March 2007. The Board has decided that adjustments related to

these items are not required, either because the changes are not of general application, or because they do not appear to be material.

The price cap index adjustment does not apply to the following components of the rates:

- the specific service charges;
- the smart meter rate adder (an amount in the fixed components of the rates associated with smart meter cost recovery); and
- any continuing rate riders.

Accordingly, the Board is providing Tillsonburg Hydro Inc. with a rate model (spreadsheet) that reflects the price cap adjustments described above. Tillsonburg Hydro Inc. is required to review the rate model (spreadsheet) and to confirm its completeness and accuracy with the Board at the time it files its Draft Rate Order. Tillsonburg Hydro Inc. shall file with the Board a Draft Rate Order attaching the proposed Tariff of Rates and Charges which will reflect the Board's price cap adjustments as verified by Tillsonburg Hydro Inc. and any other Board findings contained in this decision that would impact 2008 rates. Tillsonburg Hydro Inc. shall also provide the rate model (spreadsheet) that underpins the Tariff of Rates and Charges. Any changes to the Board's rate model (spreadsheet) shall be clearly identified and explained.

Rate Riders

When the Board approved new rates for distributors for 2006, it also approved the recovery of regulatory asset balances on a final basis. The Board approved rate riders to facilitate the recovery of the approved balances over the two remaining years of the four-year recovery period mandated by the Minister of Energy (i.e. May 1, 2004 to April 30, 2008) . The rate rider(s) associated with the recovery of regulatory assets will cease on May 1, 2008 and shall be removed from the Tariff of Rates and Charges, unless a previous Board decision authorized the continuation of such riders beyond April 30, 2008. No such authorization has been previously provided by the Board for Tillsonburg Hydro Inc.. The final balance in account 1590 cannot be confirmed until after the current recovery period has expired, i.e. after April 30, 2008. Once the residual

balance in deferral account 1590 is finalized, the residual balance will be disposed in a future proceeding.

Smart Meter Rate Adder

Tillsonburg Hydro Inc. requested the continuation of the smart meter rate adder previously approved by the Board in order to provide funding for possible future implementation of smart meter costs and to minimize future rate impacts. The Board-approved rate adder for Tillsonburg Hydro Inc. of $0.26 month per metered customer shall continue. Tillsonburg Hydro Inc.'s variance accounts for smart meter program implementation costs, previously authorized by the Board, shall also be continued.

Retail Transmission Service Rates

On October 17, 2007, the Board issued its EB-2007-0759 Rate Order setting new Uniform Transmission Rates for Ontario transmitters, effective November 1, 2007. The Board approved a decrease of 18% to the wholesale transmission network rate, a decrease of 28% to the wholesale transmission line connection rate, and an increase of 7% to the wholesale transformation connection rate. The combined change in the wholesale transmission line connection and transformation connection rates is a reduction to the connection rate of 5%.

On October 29, 2007, the Board issued a letter to all electricity distributors directing them to propose an adjustment to their retail transmission service (RTS) rates to reflect the new Uniform Transmission Rates for Ontario transmitters effective November 1, 2007. The objective of resetting the rates was to minimize the prospective balance in variance accounts 1584 and 1586 and also to mitigate intergenerational inequities.

Tillsonburg Hydro Inc. did not file a proposal to adjust its RTS rates. Given the magnitude of the changes in wholesale transmission rates, the Board directs Tillsonburg Hydro Inc. to reduce its RTS – Network Service Rates by 18% and its RTS – Line and Transformation connection Service Rates by 5%. Tillsonburg Hydro Inc. is required to include this change in its rate model (spreadsheet) to be filed with the Board.

Implementation

Tillsonburg Hydro Inc.'s new distribution rates are effective May 1, 2008. The Board directs that:

1. Tillsonburg Hydro Inc. shall file with the Board a Draft Rate Order attaching the proposed Tariff of Rates and Charges and the supporting rate model (spreadsheet) within seven (7) days of the date of this Decision. The proposed Tariff of Rates and Charges shall be filed in a Word format. The adjusted rate model shall be filed in an Excel format.

DATED at Toronto, March 14, 2008.

Original signed by

_____
Paul Vlahos
Presiding Member

Original signed by

_____
Paul Sommerville
Member

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2007-0860

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Schedule B;

AND IN THE MATTER OF an Application by Tillsonburg Hydro Inc. pursuant to section 78 of the Ontario Energy Board Act seeking approval to amend electricity distribution rates.

BEFORE: Paul Vlahos
Presiding Member

Paul Sommerville
Member

RATE ORDER

Tillsonburg Hydro Inc. ("Tillsonburg Hydro") is a licensed distributor of electricity providing service to consumers within its licensed service area. Tillsonburg Hydro filed an application with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, to be effective May 1, 2008.

On March 14, 2008, the Board issued its Decision (the "Decision") regarding Tillsonburg Hydro's application.

The Board directed that Tillsonburg Hydro file with the Board a proposed Tariff of Rates and Charges reflecting the Board's Decision, within 7 days of the date of the Decision.

Tillsonburg Hydro has provided the Board with a proposed Tariff of Rates and Charges.

The Board is satisfied that the document accurately reflects the Decision.

For completeness of the regulated charges, the Board has included in the Tariff of Rates and Charges the charges pertaining to services provided to retailers or consumers regarding the supply of competitive electricity, which are referenced in Chapter 12 of the 2006 Electricity Distribution Rate Handbook.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix "A" of this Rate Order is approved, effective May 1, 2008, for electricity consumed or estimated to have been consumed on and after May 1, 2008.

2. The Tariff of Rates and Charges set out in Appendix "A" of this Order supersedes all previous distribution rate schedules approved by the Board for Tillsonburg Hydro and is final in all respects.

3. Tillsonburg Hydro shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, April 17, 2008.

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix “A”
To The Rate Order Arising from Decision
EB-2007-0860
Tillsonburg Hydro Inc.

April 17, 2008

Tillsonburg Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2008

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

EB-2007-0860

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders 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, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2008 for all charges incurred by customers on or after that date.
RETAIL SERVICE CHARGES – May 1, 2008 for all charges incurred by retailers or customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2008 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification applies to an account in one of three categories of residential services: single-family or single-unit homes, multi-family buildings, and subdivision developments. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

General Service Less Than 50 kW
This classification applies to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

General Service 50 to 499 kW
This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 500 kW. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

General Service 500 to 4,999 kW
This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 500 kW but less than 5,000 kW. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

Unmetered Scattered Load
This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

Sentinel Lighting
This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

Street Lighting
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 Tillsonburg Hydro's Conditions of Service.

Tillsonburg Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2008

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

EB-2007-0860

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.65
Distribution Volumetric Rate	$/kWh	0.0159
Retail Transmission Rate – Network Service Rate	$/kWh	0.0045
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	25.03
Distribution Volumetric Rate	$/kWh	0.0100
Retail Transmission Rate – Network Service Rate	$/kWh	0.0041
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 499 kW

Service Charge	$	111.76
Distribution Volumetric Rate	$/kW	0.8315
Retail Transmission Rate – Network Service Rate	$/kW	1.5822
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5008
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 500 to 4,999 kW

Service Charge	$	1,158.42
Distribution Volumetric Rate	$/kW	0.4773
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.0773
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.0442
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	12.38
Distribution Volumetric Rate	$/kWh	0.0100
Retail Transmission Rate – Network Service Rate	$/kWh	0.0041
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Tillsonburg Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2008

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

EB-2007-0860

Sentinel Lighting

Service Charge (per connection)	$	1.18
Distribution Volumetric Rate	$/kW	7.3155
Retail Transmission Rate – Network Service Rate	$/kW	1.3027
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2357
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per customer)	$	1,336.76
Distribution Volumetric Rate	$/kW	4.4791
Retail Transmission Rate – Network Service Rate	$/kW	1.2993
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2324
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Returned Cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special Meter Reads	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect Charge - at Meter - During Regular Hours	$	65.00
Disconnect/Reconnect Charge - at Meter - After Regular Hours	$	185.00
Disconnect/Reconnect Charge at Pole – During Regular Hours	$	185.00
Install/Remove Load Control Device – After Regular Hours	$	185.00
Service Call – After Regular Hours	$	165.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Tillsonburg Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2008

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

EB-2007-0860

Retail Service Charges (if applicable)

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

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

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0422
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0317
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Board Findings and Directions from 2006 EDR

The Board did not make any specific findings or issue directions to THI in its 2006 EDR Decision (RP-2005-0020/EB-2005-0420). The Board's Decision on THI's 2006EDR application is provided at Ex1/T1/S12/AttA.

Ontario Energy Board

Commission de l'Énergie de l'Ontario

RP-2005-0020
EB-2005-0420

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

AND IN THE MATTER OF an Application by Tillsonburg Hydro Incorporated for an order or orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2006.

BEFORE: Paul Vlahos
Presiding Member

Bob Betts
Member

DECISION AND ORDER

Tillsonburg Hydro Incorporated ("Tillsonburg Hydro" or the "Applicant") is a licensed distributor providing electrical service to consumers within its defined service area. Tillsonburg Hydro filed an Application (the "Application") with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other matters, to be effective May 1, 2006.

Tillsonburg Hydro is one of over 90 electricity distributors in Ontario that are regulated by the Board. To streamline the process for the approval of distribution rates and charges for these distributors, the Board developed and issued the 2006 Electricity Distribution Rate Handbook (the "Handbook") and complementary spreadsheet-based models. These materials were developed after extensive public consultation with distributors, customer groups, public and environmental interest groups, and other

interested parties. The Handbook contains requirements and guidelines for filing an application. The models determine the amounts to be included for the payments in lieu of taxes ("PILs") and calculate rates based on historical financial and other information entered by the distributor.

Also included in this process was a methodology and model for the final recovery of regulatory assets flowing from the Board's decision dated December 9, 2004 on the Review and Recovery of Regulatory Assets – Phase 2 for Toronto Hydro, London Hydro, Enersource Hydro Mississauga and Hydro One Networks Inc. ("Hydro One"). In Chapter 10 of the decision, the Board outlined a Phase 2 process for the remaining distributors. By letter of July 12, 2005, the Board provided guidance and a spreadsheet-based model to the distributors for the inclusion of this recovery as part of their 2006 distribution rate applications.

In its preliminary review of the 2006 rate applications received from the distributors, the Board identified several issues that appeared to be common to many or all of the distributors. As a result, the Board held a hearing (EB-2005-0529) to consider these issues (the "Generic Issues Proceeding") and released its decision (the "Generic Decision") on March 21, 2006. The rulings flowing from that Generic Decision apply to this Application, except to the extent noted in this Decision. The Board notes that pursuant to ss. 21 (6.1) of the *Ontario Energy Board Act, 1998*, and to the extent that it is pertinent to this Application, the evidentiary record of the Generic Issues Proceeding is part of the evidentiary record upon which the Board is basing this Decision.

In December 2001, the Board authorized the establishment of deferral accounts by the distributors related to the payments that the distributors make to the Ministry of Finance in lieu of taxes. The Board is required, under its enabling legislation, to make an order with respect to non-commodity deferral accounts once every twelve months. The Board has considered the information available with respect to these accounts and orders that the amounts recorded in the accounts will not be reflected in rates as part of the Rate Order that will result from this Decision. The Board will continue to monitor the accounts with a view to clearing them when appropriate.

Public notice of the rate Application made by Tillsonburg Hydro was given through newspaper publication in its service area. The evidence filed was made available to the public. Interested parties intervened in the proceeding. The evidence in the Application was tested through written interrogatories from Board staff and intervenors, and

intervenors and Tillsonburg Hydro had the opportunity to file written argument. While the Board has considered the entire record in this proceeding, it has made reference in this Decision only to such evidence and argument as is necessary to provide context to its findings.

Tillsonburg Hydro has requested an amount of $3,043,176 as revenue to be recovered through distribution rates and charges. Included in this amount is a debit of $487,088 for the recovery of regulatory assets. Except where noted in this Decision, the Board finds that Tillsonburg Hydro has filed its Application in accordance with the Handbook and the guidelines for the recovery of regulatory assets.

Notwithstanding Tillsonburg Hydro's general compliance with the Handbook and associated models, in considering this Application the Board reviewed the following matters in detail:

- Large User Rate; and
- Consequences of the Generic Decision (EB-2005-0529).

Large User Rate

Tillsonburg Hydro proposed a new Large User rate for application to an existing customer in the GS>50 TOU rate class and a potential new customer in the service territory.

The Board appreciates the need for large user customer classes in most utilities and strives to create consistency among distributors where it is reasonable. However, having reviewed the evidence supporting the proposed Large User rate, the Board is not satisfied with the amount of detail that has been provided in the filing. The Board is concerned that the introduction of a new class, as distinct from the re-setting of rates for an existing class, would invariably have effects on cost allocation for the entire customer base which are not sufficiently documented, and may be changed in the near term through the Board's cost allocation review. Therefore, the Board does not approve the proposed Large User rate at this time. It is open to Tillsonburg Hydro to propose such a rate in future rate filings, and it is the expectation of the Board that a detailed cost allocation will be required.

The consequences of the Board's finding on this matter are reflected in the Tariff of Rates and Charges appended to this Decision.

Consequences of the Generic Decision on this Application

The Generic Decision contains findings relevant to funding for smart meters for electricity distributors. The Applicant did not file a specific smart meter investment plan or request approval of any associated amount in revenue requirement. Absent a specific plan or discrete revenue requirement, the Generic Decision provides that $0.30 per residential customer per month be reflected in the Applicant's revenue requirement. The Board finds that this increase in the revenue requirement amount will be allocated equally to all metered customers and recovered through their monthly service charge. This increment is reflected in the approved monthly service charges contained in the Tariff of Rates and Charges appended to this Decision. Pursuant to the Generic Decision, a variance account will be established, the details of which will be communicated in due course.

Resulting Revenue Requirement

As a result of the Board's determinations on these issues, the Board has adjusted the revenue requirement to be recovered through distribution rates and charges to $3,063,058, including a debit amount of $487,088 for the recovery of Regulatory Assets.

In its letter of December 20, 2004 to electricity distributors, the Board indicated that it would consider the disposition of the 2005 OEB dues recorded in Account 1508 in this proceeding. However, given that the final 2005 OEB dues are not available because of the difference in fiscal years for the Board and the distributors, and given that the model used to develop the Application does not incorporate this provision, the Board will review and dispose of the 2005 OEB dues at a later time.

Cost Awards

This Application is one of a number of applications before the Board dealing with 2006 rates chargeable by distributors. Intervenors may be parties to multiple applications and, if eligible, their costs associated with a specific distributor may not be separable. Therefore, for these applications, the matter of intervenor cost awards will be addressed by the Board at a later date, upon the conclusion of the current rate applications. If an

intervenor that is eligible to recover its costs is able to uniquely identify its costs associated with this Application, it must file its cost claim within 10 days from the receipt of this Decision.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix "A" of this Order is approved, effective May 1, 2006, for electricity consumed or estimated to have been consumed on and after May 1, 2006. The application of the revised distribution rates shall be prorated to May 1, 2006. If Tillsonburg Hydro Incorporated's billing system is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors shall be implemented upon the first subsequent billing for each billing cycle.

2. The Tariff of Rates and Charges set out in Appendix "A" of this Order supersedes all previous distribution rate schedules approved by the Ontario Energy Board for Tillsonburg Hydro Incorporated, and is final in all respects.

3. Tillsonburg Hydro Incorporated shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, April 12, 2006.

ONTARIO ENERGY BOARD



John Zych
Board Secretary

Appendix “A”

RP-2005-0020
EB-2005-0420

April 12, 2006

ONTARIO ENERGY BOARD

Tillsonburg Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2006

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

RP-2005-0020
EB-2005-0420

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders 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, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2006 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2006 for all charges incurred by customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2006 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification applies to an account in one of three categories of residential services: single-family or single-unit homes, multi-family buildings, and subdivision developments. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

General Service Less Than 50 kW
This classification applies to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

General Service 50 to 499 kW
This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 500 kW. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

General Service 500 to 4,999 kW
This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 500 kW but less than 5,000 kW. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

Unmetered Scattered Load
This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

Sentinel Lighting
This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

Street Lighting
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 Tillsonburg Hydro's Conditions of Service.

Tillsonburg Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2006

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

RP-2005-0020
EB-2005-0420

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.55
Distribution Volumetric Rate	$/kWh	0.0158
Regulatory Asset Recovery	$/kWh	0.0045
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

General Service Less Than 50 kW

Service Charge	$	24.81
Distribution Volumetric Rate	$/kWh	0.0099
Regulatory Asset Recovery	$/kWh	0.0020
Retail Transmission Rate – Network Service Rate	$/kWh	0.0050
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

General Service 50 to 499 kW

Service Charge	$	110.77
Distribution Volumetric Rate	$/kW	0.8241
Regulatory Asset Recovery	$/kW	0.6184
Retail Transmission Rate – Network Service Rate	$/kW	1.9295
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5798
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

General Service 500 to 4,999 kW

Service Charge	$	1,148.09
Distribution Volumetric Rate	$/kW	0.4730
Regulatory Asset Recovery	$/kW	0.5778
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.5333
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.1518
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	12.27
Distribution Volumetric Rate	$/kWh	0.0099
Regulatory Asset Recovery	$/kWh	0.0046
Retail Transmission Rate – Network Service Rate	$/kWh	0.0050
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Tillsonburg Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2006

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

RP-2005-0020
EB-2005-0420

Sentinel Lighting

Service Charge (per connection)	$	1.17
Distribution Volumetric Rate	$/kW	7.2502
Regulatory Asset Recovery	$/kW	1.3819
Retail Transmission Rate – Network Service Rate	$/kW	1.5886
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3007
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	1,324.84
Distribution Volumetric Rate	$/kW	4.4391
Regulatory Asset Recovery	$/kW	0.2615
Retail Transmission Rate – Network Service Rate	$/kW	1.5845
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2973
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Returned Cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special Meter Reads	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect Charge - at Meter - During Regular Hours	$	65.00
Disconnect/Reconnect Charge - at Meter - After Regular Hours	$	185.00
Disconnect/Reconnect Charge at Pole – During Regular Hours	$	185.00
Install/Remove Load Control Device – After Regular Hours	$	185.00
Service Call – After Regular Hours	$	165.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0422
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0317
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Status of Board Directives

THI has not been directed by the Board to undertake any specific action actions.

Company Overview

Utility Description

THI is licensed by the Board to distribute electricity to the inhabitants of the Town of Tillsonburg (license ED-2003-0026).

THI relies on approximately 135 km of circuits and 900 transformers to re-deliver approximately 225,000,000 kWh of energy and 325,000 kW of power to approximately 6,500 customers. THI's circuits include approximately 90 km of overhead lines and 45 km of buried conductor.

THI provides electricity distribution service to approximately 6,500 customers situated in the Town of Tillsonburg made up of residential, general service and specialized customers (eg., street lighting). 89% of the customers are residential, 10% are Commercial and 1% are Large Commercial or Industrial. The Large Commercial or Industrial customers consume over half of the energy delivered and account for 2/3rds of the power delivered. The residential customers account for approximately 25% of the energy redelivered. The load attributable to Street Lighting, Sentinel Lighting and Unmetered Scattered Load applications is relatively small.

THI provides its customers with high quality energy redelivery service. This is demonstrated by THI's reported Service Quality Indicator data that is provided at E1/T1/S3/AttA. THI is consistently in the top quartile of performance for reported Service Quality.

THI is 100% owned by the Town of Tillsonburg. The Town provides all services required to:

- operate and maintain the distribution system;
- provide electricity distribution service; and
- provide an appropriate level of service to the customers.

The provision of these services is governed by the Master Services Agreement. This contract between THI and the Town sets out the services provided as well as the level of quality, the consideration payable and the legal remedies available to both parties; it is provided at E1/T2/S1/AttA.

THI has realized economies of scale and scope through the provision of services by the Town. Specifically, THI owns and is responsible for assets that are unique to the provision of electricity distribution services and acquires common services (eg., IT, financial management) from the Town of Tillsonburg. This approach to conducting business has allowed THI to enjoy access to appropriately skilled management and executive and access to a commercial infrastructure that it could not otherwise cost effectively provide on a stand-alone basis.

The prices paid under the MSA are negotiated. During negotiations each party has access to the costs reported by the Town. THI's system and business plans for the next period are relied on to negotiate the appropriate level of service for the upcoming period. The costs of the prior period are relied on as baseline data for the upcoming period and are adjusted consistent with THI's plans.

Through this approach, THI provides its customers with a consistently high quality of distribution service, prudently incurs costs and charges just and reasonable rates.

Contact Information

Contact information for the subject application is provided below:

Steve Lund, P.Eng.
General Manager
Tillsonburg Hydro Inc.
200 Broadway, 2nd Floor
Tillsonburg, ON N4G 5A7
Tel: 519.842.9200 x 3228
Fax: 519.842.9431
Email: slund@town.tillsonburg.ca

John Gott, C.A.
Finance and Regulatory Affairs Manager
Town of Tillsonburg
200 Broadway, 2nd Floor
Tillsonburg, ON N4G 5A7
Tel: 519.842.6428 x 3229
Fax: 519.842.5931
Email: jgott@town.tillsonburg.on.ca

THI's consultant
Elenchus Research Associates Inc.
34 King Street East, Suite 600
Toronto, ON M5C 2X8
K. Litt
Tel: 416.345.0015
Email: klitt@era-inc.ca

Neighbouring Utilities

THI is embedded within Hydro One Networks Inc.'s licensed service area. There are no other neighbouring electricity distribution utilities. The Town of Tillsonburg is served with natural gas delivery service by Union Gas Limited.

Host or Embedded Utilities

THI is directly connected to Hydro One's transmission system and is not an embedded LDC that takes delivery of electricity from another LDC.

THI is not a host LDC to any other LDC.

CORPORATION OF THE

TOWN OF TILLSONBURG

BY-LAW NO. 3024

BEING A BY-LAW TO AUTHORIZE THE MAYOR AND CLERK TO EXECUTE A MASTER SERVICE AGREEMENT BETWEEN THE TOWN OF TILLSONBURG AND THE TILLSONBURG HYDRO INC.

WHEREAS the Council of the Corporation of the Town of Tillsonburg is desirous of entering into a Master Service Agreement with Tillsonburg Hydro Inc. for the provision of electric utility related services pursuant to the *Energy Competition Act, 1998.*

NOW THEREFORE THE COUNCIL OF THE CORPORATION OF THE TOWN OF TILLSONBURG ENACTS AS FOLLOWS:

1. **THAT** the Council of the Town of Tillsonburg hereby authorizes the entering into of a Master Service Agreement between the Corporation of the Town of Tillsonburg and Tillsonburg Hydro Inc. for the provision of electric utility related services in accordance with the Agreement attached hereto as Schedule "A" to this by-law.

2. **THAT** Schedule "A" attached hereto is hereby declared to be part of this by-law as if written and incorporated herein.

3. **THAT** the Mayor and Clerk be and are hereby authorized to execute, on behalf of the Corporation of the Town of Tillsonburg, the Agreement attached as Schedule "A" to this by-law.

4. **THAT** this By-law shall come into full force and effect upon enactment.

READ A FIRST, SECOND AND THIRD TIME AND FINALLY PASSED this 8th day of July, 2002.

MAYOR

CLERK

MASTER SERVICES AGREEMENT

THIS AGREEMENT made this____day of _____ , 2002.

BETWEEN:

THE CORPORATION OF THE TOWN OF TILLSONBURG

(hereinafter referred to as the "Town")

OF THE FIRST PART

- and -

TILLSONBURG HYDRO INC.

(hereinafter referred to as the "Utility")

OF THE SECOND PART

WHEREAS the Utility is a duly incorporated electric Utility pursuant to the *Energy Competition Act, 1998;*

AND WHEREAS both the Town and the Utility are separate corporate entities, notwithstanding the provisions of this Agreement;

AND WHEREAS the Parties have agreed that the Town will provide services as listed in Schedule A to the Utility on a fee-for-service basis and the Town shall provide such further and other products and services as may be agreed by the parties from time to time;

AND WHEREAS the Parties acknowledge and agree that in providing goods and services the Town acts as an independent contractor and not as an agent, partner, or servant;

AND WHEREAS the Parties shall consult as frequently as may be desirable to ensure that the Utility receives adequate, economical and effective services as listed in Schedule A as attached to this document.

NOW THEREFORE IN CONSIDERATION of the mutual covenants and agreements set forth, and for other good valuable consideration and the sum of two ($2.00) dollars of lawful money of Canada now paid by each of the Parties to the other (the receipt and sufficiency of which is hereby expressly acknowledged), the Parties covenant and agree, and with each other, as follows:

1. Definitions

1.01 **"Customer Service Costs"** means the cost incurred by a party to bill and collect and to provide related customer services.

1.02 **"Customer Services"** means all services related to customer services, which without limiting the generality of the foregoing shall include customer billing collection of unpaid accounts, and customer relations, etc.

1.03 **"Direct Costs"** means the cost incurred directly by the Utility for its own operations including but not limited to electrical power costs for Standard Supply Services, IMO costs, Ontario Hydro Transmission costs, Competition Transition Charge, Retail/Wholesale Settlement costs, Ministry of Finance OEB Regulatory costs, EDA dues, MEARIE insurance and other insurance premiums, legal, accounting and audit fees, etc.

1.04 **"Effective Date"** means April 2, 2002.

1.05 **"Extraordinary Costs"** means those unusual and unanticipated costs as more particularly described in Section 9.

1.06 **"Parties"** means the Town and the Utility.

1.07 **"Person"** means any other businesses or persons with which the Town chooses to establish a business relationship.

1.08 **"Transition Costs"** means one-time costs of reconfiguring or adding any system, policy, procedure, legal arrangement, employee relationship, etc. necessary for the Parties to operate under this Agreement and under electric Utility industry restructuring as defined in the *The Energy Competition Act, 1998* and its associated regulations.

2. Term

2.01 Unless terminated in accordance with Section 23, the term of this Agreement shall be from April 2, 2002 to and including December 31, 2005. The term shall be extended automatically for a further period of three years, unless either party gives the other notice in writing not less than ninety (90) days prior to the end of the term, or the end of renewal as the case may be, that the Agreement is not to be extended.

2.02 In providing regulatory, market readiness, business, customer service support, maintenance and construction services as identified in Schedule A for the Utility, the Town shall be responsible for maintaining regulated and non-regulated performance standards as determined by the Utility and the Ontario Energy Board as the case may be and shall not discriminate in its performance and delivery of identified services.

3. Force Majeure

3.01 It shall not be a breach of this agreement if the parties to this agreement fail to perform their obligations to provide services, work, or the supply of goods or materials to either party by reason of war, insurrection, tempest, or any other event beyond the reasonable control of the parties. The foregoing shall not apply to an obligation to pay money.

4. Covenants of the Town

4.01 Subject to the obligations of the Town hereunder, the Town shall be free to offer services to any other person.

4.02 The Town shall be responsible for obtaining all necessary licences and permits and for complying with all applicable federal, provincial and municipal laws, codes and regulations in connection with the provision of the services hereunder and the Town shall when requested provide the Utility with adequate evidence of its compliance with this Section.

4.03 The Town shall comply, while on the premises used by the Utility, with all the rules and regulations of the Utility from time to time in force which are brought to its notice or of which it could reasonably be aware.

4.04 The Town shall pay for and maintain for the benefit of the Utility appropriate insurance concerning the operations and liabilities of the Town relevant to this Agreement.

4.05 The Town shall indemnify and save the Utility harmless from and against all claims, actions, losses, expenses, costs or damages of every nature and kind whatsoever which the Utility or its officers, employees or agents may suffer as a result of the negligence of the Town in the performance or non-performance of this Agreement.

4.06 The Town shall not (either during the term of this Agreement or at any time thereafter) disclose any information relating to the private or confidential affairs of the Utility or relating to any secrets of the Utility to any person other than with the consent of the Utility.

5. Confidentiality and Ownership of Information

5.01 It is agreed that confidential information from the Utility shall be kept in strict confidence by the Town, and details of the operations of the Utility shall not be shared.

5.02 The Town shall take such measures as are necessary in order to comply with the confidentiality obligations under subsection 5.01 above.

5.03 Information stored or produced by any party to this agreement on the sole behalf of any other party to this agreement, shall be the property of the party on whose sole behalf such information is stored or produced. Where such information consists of an original report, computer program, information, or intellectual property produced by a party to this agreement for the sole purpose of supplying services to that other party and the cost of producing such report is included in the remuneration payable by such other party, the property (including copyright and moral rights) to such original report, computer program, information, or intellectual property shall belong to such other party. The foregoing shall not apply where information is stored or produced by a party to this agreement on behalf of a third party to this agreement, or where the information is stored and produced by a party to this agreement for the mixed benefit of another party and the party which produced the information.

6. Costs

6.01 The Utility shall pay the Town the fees and charges more particularly outlined in Schedule A as attached.

6.02 The costing provisions are set out in Schedule "A" which includes a 5% management fee. Further, the Town shall be entitled to additional remuneration, including a 5% management fee, if:

(a) It has agreed to provide, or has been required by law to provide, Services which exceed those described in Schedule "A";

(b) It has agreed to provide, or has been required by law to provide, Services at a level which exceeds the level described in Schedule "A".

(c) Where the Town provides Services to the Utility, it shall use its best efforts to minimize the actual costs of providing such services while still complying with all applicable standards.

(d) It is acknowledged that there will be some duplication in the description of services. Such duplication is insignificant, does not imply that there is multiple costing for those services, and the parties agree that no such multiple costing is present.

6.03 Upon renewal of the term of this Agreement and any subsequent renewals, the Town may adjust their fees upon ninety (90) days prior notice in writing to the Utility provided that, if the Utility does not accept the adjusted costs and the Parties are unable to agree after negotiating in good faith, the adjusted costs may be submitted to arbitration pursuant to Section 13 of this agreement.

7. Remuneration

7.01 The Utility shall pay remuneration to the Town in accordance with the costs experienced by the Town in performing the services of managing, administering, and staffing the Utility as set forth in the schedules.

7.02 The aggregate remuneration payable to the Town in respect of the services provided by the Town to the Utility shall, so long as the Town continues to provide full treasury and financial services, be recovered from the applicable party by direct transfers of funds from and to the appropriate accounts at times convenient to the Town Treasurer in accordance with proper principles of contract administration and generally accepted accounting and business principles. The parties to this agreement specifically authorize that such transfers may be performed by the Town Treasurer or his/her designate, and such authorization shall remain in effect during the full term of this agreement. The Town shall provide a report to the Board of Directors of the Utility (or otherwise as the Utility may direct) on a timely basis following each such direct transfer to document same.

7.03 In the event that the Town ceases to provide full treasury and financial services, the aggregate remuneration payable to the Town in respect of the services provided by the Town shall be requested in periodic invoices delivered by the Town, such invoices to be delivered not more frequently than monthly. The terms of any such invoice, whether so marked or not, shall be net 30 days.

7.04 The presence of subsection 7.03 shall not be interpreted to mean the Utility has unilateral ability, without the agreement of the Town, to terminate its use of full treasury and financial services from the Town.

7.05 The remuneration payable to the Boards of Directors shall be an expense of the Utility and shall be processed by the Town pursuant to the Schedules.

8. Annual Review of Schedules

8.01 The parties shall review the contents of each Schedule on an annual basis. The purpose of such review shall be to determine whether the activities described in each Schedule continue to be accurate.

8.02 In the event that during such a review, disagreements arise with respect to suggested amendments to any Schedule and these disagreements cannot be settled by the parties, any party shall have the ability to require the contents of the Schedule or Schedules under disagreement to be submitted to arbitration in accordance with Section 13 of this agreement.

8.03 The review described in 8.01 above shall be commenced within sufficient time so that the parties might reasonably have completed their review in time for the annual Town budget and estimates process.

9. Extraordinary Costs

9.01 The Utility agrees to reimburse the Town for any extraordinary costs over and above normal customer service costs to which the Town may be put resulting from extraordinary unanticipated events such as fire, major storms, tornadoes, equipment failures, and the like provided such equipment failures are not caused by negligence on the part of the Town to perform services as outlined in Schedule "A" of this agreement.

10. Invoicing

10.01 The Town shall submit an invoice within five (5) days from the end of each month to the Utility for payment for all costs incurred by the Town in performing its services. All monthly invoices shall provide sufficient detail of the costs incurred and the description of the services undertaken by the Town. All invoices shall be paid by the Utility within ten (10) days from the date of receipt. A charge of one and one-half (1.5%) per month will be levied against all late payments.

10.02 The Town will submit details of any extraordinary costs to the Utility for review before invoicing. Invoices for extraordinary costs will be paid by the Utility within ten (10) days of receipt.

11. Easements

11.01 The Utility represents that it has secured all requisite easements necessary for the delivery of electrical services for the distribution of electric power throughout the Utility's service area.

11.02 The Utility shall indemnify and save the Town harmless from any claims, demands, actions and applications brought against the Town arising from the failure of the Utility to have secured easements or from any defect or deficiency in the easements secured by the Utility prior to the effective date of this Agreement.

11.03 If further easements are required for the distribution of electric power throughout the Utility service area, the Utility shall acquire such easements at its expense provided that prior to acquiring such Easements, the Utility shall consult with the Town to determine the Town's minimum technical requirements for such easements.

11.04 After the effective date of this Agreement, the Town shall act on behalf of the Utility to secure all easements required for the performance of the expansion or upgrade of electrical distribution services pursuant to this Agreement. Any costs related to the acquisition of easements, including appraisal and legal costs, shall be paid by the Utility.

12. Customer Billing

12.01 The Town shall bill the Utility's customers for electricity supplied to them but such bills shall be issued in the Utility's name.

12.02 The Utility shall be responsible for all costs related to any billing errors and uncollectable hydro bills incurred on or before the commencement of this Agreement and shall indemnify and save the Town harmless in respect thereof.

12.03 The Town shall assume responsibility for any billing errors arising after the commencement of this Agreement only to the extent that the hydro costs arising from the billing errors are unrecoverable from the Utility's customer and only if the billing error is attributable to the Town's negligence or the negligence of its servants, agents or representatives.

13. Arbitration

13.01 The parties agree to consult with each other and to negotiate in good faith to resolve any differences or disputes which either party may have relating to the interpretation, application or implementation of this agreement, or any dispute which may arise over any costs, fees or other costs incurred and failing agreement the parties agree to resolve their disputes by arbitration as provided in subsection 13.02.

13.02 Arbitration of a dispute shall be commenced by written notice by a party requesting arbitration to the other, which notice shall identify the issue or issues it wishes to submit to arbitration. Within thirty (30) days of the date of the notice, the parties shall agree upon a single arbitrator and failing agreement then each party shall appoint an arbitrator and the two appointees shall within 45 days of the date of the notice of arbitration appoint a third person who shall act as Chair of the Arbitration Panel, and failing agreement the Chair shall be appointed by a Judge of the Superior Court of Ontario pursuant to the provisions of the Arbitration Act, SO 1991 c.A.17

13.03 The commencement of the arbitration and all rules of procedure for the arbitration shall be by agreement of the Parties, or failing agreement, as determined by the arbitrator or Chair of the arbitrator panel. The provisions of the Arbitration's Act, RSO 1991 c.A.17, as amended or any successor legislation shall apply to the arbitration.

13.04 All decisions of the arbitrator or arbitrators, as the case may be, shall be made in writing and shall be delivered to all Parties within ten (10) days from the conclusion of the arbitration. All decisions shall be final and binding upon the Parties, their respective successors and assigns, and shall not be subject to appeal.

13.05 Each Party shall pay its own costs incurred in respect of the arbitration including the payment of its appointee to the arbitration panel, and in the case of a three person panel the parties agree to share the fees of the Chair and other related costs equally.

14. Insurance

14.01 The Utility shall provide and maintain a Comprehensive General Liability policy in the amount of not less than twenty million dollars. The policy shall name the Corporation of the Town of Tillsonburg as an Additional Named Insured but only with respect to operations and services performed by the Town on behalf of the Utility.

14.02 The Utility agrees to endorse its insurance coverage with the Town as an Additional Named Insured to cover any liability of the Town resulting or arising from any claims of injury, including injury resulting in death, third party property damage arising from the operations of the Named Insured and/or the operations and services performed by the Town on behalf of the Utility.

14.03 The Town agrees to provide a copy of the endorsement to the Town's liability policy adding the Utility as an Additional Named Insured to cover any liability of the Utility resulting or arising from any claims of injury, including injury resulting in death, loss of property, or damage due to the negligence of the Utility, or to those for whom the Utility is at law responsible.

14.04 All policies referred to in subsection 14.01 and 14.02 shall contain a clause requiring each insurer to give the Town or the Utility, as the case may be, one hundred eighty-four (184) days written notice prior to canceling insurance coverage.

14.05 Both parties will notify the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE) of any occurrence, claim, suit and/or accident pertaining to the operations of he Named Insured and/or the operations performed by the Town on behalf of the Named Insured.

15. Warranty

15.01 The Town provides no warranty or guarantee for any defective or deficient equipment or materials utilized except for the manufacturer's or supplier's warranties or guarantees applicable to the defective or deficient equipment or materials.

16. Notices

16.01 All notices required to be given to either of the Parties under this Agreement shall be in writing and shall be delivered by prepaid unregistered post or hand delivery to the following:

(a) The Corporation of the Town of Tillsonburg
200 Broadway, 2nd Floor
Tillsonburg, ON N4G 5A7

Telephone: (519) 842-6428
Fax: (519) 842-9431

Attention: Chief Administrative Officer/Clerk (CAO/Clerk)

and

b) Tillsonburg Hydro Inc.
200 Broadway, 2nd Floor
Tillsonburg, ON N4G 5A7

Telephone: (519) 842-6428
Fax: (519) 842-9431

Attention: General Manager

or to such other address or individual as may be designated by written notice to the other Party. Any notice given by personal delivery shall be deemed to have been given on the day of actual delivery hereof and if sent by prepaid post, on the third day after mailing.

17. Successors

17.01 This Agreement shall inure to the benefit of and be binding upon the Parties and their successors and assigns, respectively.

17.02 The Parties explicitly acknowledge and agree that the term of this Agreement shall remain in full force and effect and be binding upon new business corporations incorporated under the Business Corporations Act to whom assets and liabilities will be transferred as required pursuant to the provisions of the Energy Competition Act, 1998.

17.03 For the purposes of this Agreement, whenever the term the Town or the Utility is used, the term shall be deemed to include all successor business corporations incorporated to whom assets and liabilities are transferred for the purpose of the installation, operation and maintenance of the Parties' electrical distribution systems.

18. Regulatory Changes

18.01 The Parties acknowledge that substantial changes to legislation and regulations and government policies are likely to occur during the term of this Agreement which are likely to affect the nature of the relationship between them, and as consequence, the parties hereby agree to consult and negotiate in good faith any amendments to this Agreement which may be necessitated by changes in the regulatory environment, and failing agreement to submit their differences to arbitration as provided in Section 13.

19. Entire Agreement

19.01 This agreement, including Schedule A, constitute the entire agreement between the parties.

20. Amendments

20.01 Amendments to this Agreement shall be in writing and executed by the Parties duly authorized signing officers.

21. Headings

21.01 The headings in this Agreement are for purposes of reference only and shall not be read or construed so as to abridge or modify the meaning of any provision in the main test of this Agreement.

22. Governing Law

22.01 This agreement shall be construed in accordance with the laws of the Province of Ontario.

23. Termination

23.01 In the event of non-performance by either party of its obligations under this Agreement, the other party may at its sole option elect to terminate this Agreement provided that the defaulting party shall be given written notice of the default and shall be given sixty (60) days to cure the default, and then only upon failure to cure the default the Agreement may be terminated.

24. Responsibility and Indemnification

24.01 While the Utility continues to be a wholly owned subsidiary of the Town, as it is as of the date of this agreement:

(a) The Town shall have no responsibility for any actions, causes of action, claims or demands which may be advanced against the Utility even where the said action, cause of action, claim or demand arose partly or entirely out of any misfeasance or nonfeasance on the part of the Town in the performance of its operations pertaining to the distribution of electricity. The Utility shall indemnify, release and save harmless the Town in respect of any such action, cause of action, claim or demand save and except when operations pertain to the operations other than those pertaining to the distribution of electricity and save and except for any action, causes of action, claims or demands due to the gross negligence act(s) or omission(s) or willful misconduct by the Town, or its agents, officers and/or employees;

(b) The Utility shall not have any action, causes of action, claims or demands which may be asserted against the Town save and except for any action, cause of action, claim or demand due to gross negligence act(s) or omission(s) or willful misconduct by the Town, or its agents, officers and/or employees;

(c) The Utility shall bear all risks associated with any assets owned by it, including environmental risks;

(d) In situations where the Town and the Utility are jointly liable to any person otherwise than in contract, the Utility shall absorb all such liability pertaining to the operations of electrical distribution and shall indemnify and save harmless the Town in relation there to save and except for any liability arising out of gross negligence act(s) or omission(s) or willful misconduct of the Town, or its agents and/or its employees; and

(e) The Utility shall reimburse, indemnify and save harmless the Town against any costs, courses of action, claims, demands, expenses or liabilities of any description incurred by the Town for the benefit of the Utility, whether such reimbursement and indemnification is complicit with this agreement or otherwise, save and except for any costs, causes of action, claims, demands, expenses or liabilities of any description incurred as a result of the gross negligence act(s) or omission(s) or willful misconduct of the Town, or its agents and/or its employees.

25. Joint Management Committee

25.01 It is a matter of importance to the parties that there shall be proper consultation and involvement by the Utility in the performance of services under this agreement. For that reason, the following committee shall be formed and shall meet on a regular basis, and otherwise as necessary, in order to identify, resolve, and coordinate matters of common concern in relation to the services performed hereunder:

(a) The Joint Management Committee shall consist of the CAO/Clerk of the Town, the Director of Operations of the Town/General Manager of the Utility, and a further member who may, at the option of the Board, be appointed by the Board of the Directors of the Utility from amongst its members from time to time.

(b) Either party to this agreement shall have the right to requisition a meeting of the said Joint Management Committee at any time upon five (5) days notice to the other.

(c) Where a member is unable to be present at any meeting of the said Joint Management Committee, he or she may substitute another individual to attend and participate at any such meeting in his or her stead.

26. Relationship

26.01 Parties acknowledge and agree that the Town shall act as an independent contractor providing its services under this Agreement and the Parties further acknowledge and agree that nothing in this Agreement shall be deemed or construed to be the formation of a partnership between the Town and the Utility.

IN WITNESS WHEREOF the Parties have duly executed this Agreement on the date first above written:

The Corporation of the Town of Tillsonburg

Per: _____
Mayor

Per: _____
CAO/Clerk

Tillsonburg Hydro Inc.

Per: _____
Board Chair

Per: _____
General Manager

SCHEDULE A – LIST OF SERVICES

A.1 HYDRO OPERATIONS

(a) FULL DESCRIPTION OF THE SERVICE:

Provision of a General Manager of Tillsonburg Hydro Inc.

- Provision of a General Manager of Tillsonburg Hydro Inc. for the Utility who is a Town Employee shall be supplied for such purpose to the Utility

Substation Maintenance

- Maintain all the substations, substation buildings and substation fixtures. Test, inspect and take monthly readings.

Overhead Maintenance

- To provide labour and supervision to maintain and repair all overhead lines, hardware, poles, switches, etc. To render repairs at any time to facilitate restoration or power with the least amount of inconvenience to the customer.

Underground Maintenance

- To provide labour and supervision to maintain and repair all Underground Lines, hardware, and switches etc. To render repairs at any time to facilitate restoration or power with the least amount of inconvenience to the customer.

Inspection

- Provide inspection and testing of the electrical plant to the present standards maintained by the former Tillsonburg PUC.

Emergency Response

- Provide 24 hour 7 day a week trouble crew with the possibility of providing up to 4 people and supervision within 1 hour in response to all trouble calls. To provide supervision on a 24 hour 7 day a week.

Transformer Installation and Repair

- Provide qualified crews and supervision to install overhead, underground and pad mount transformers. To insure proper voltage to customers.

Service Installations

- Provide qualified labour and supervision to install all types of services from 3 phase 27.6 KV primary to 120/240 volt single phase underground or overhead.

Service Repairs

- Repair all secondary and primary services to reestablish power 24 hours 365 days a year.

Relocation Work

- To provide the tools necessary to move, remove, shift, or build electrical plant for the purpose of road, sidewalk or any other project on town streets.

PCB Management

- Provide expertise in PCB Management, testing and reclassification of transformers when required. Control and store all material until decommissioning under Ministry Guideline. Provide labour for spill cleanup.

Billable Work

- To provide qualified crews and people and supervision to perform work to private individuals on behalf of the Town of Tillsonburg. To help citizens of Tillsonburg with expertise and knowledge and render service to customers on a 24 hours basis on behalf of the Town of Tillsonburg.

Customer Relations

- To provide help to the citizens of Tillsonburg with their concerns such as no power calls, Cats on trees, Kites in wire and all other similar instances on behalf of the Town of Tillsonburg.

Supervision

- To arrange and facilitate all high voltage switching. To set standards and arrange all duties that crews require to perform to standards and are done to EUSA, Ministry of Labour and Town of Tillsonburg rules and regulations.

Memberships and Licence Fees

- Maintain memberships of the benefiting parties in OEB, EUSA and EDA

Vehicles/Fleet

- Maintaining and fueling vehicles owned by the Town of Tillsonburg as necessary to complete all maintenance and construction work as required to maintain service for the Town of Tillsonburg

Line Locate

- Provide line locate to all requests for line locates within the Town of Tillsonburg

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

Substation Maintenance
- Create a standard monthly report of substation status report attached. (NOTE Distribution Code will define the inspection requirements)

Overhead Maintenance
- Maintain system to PBR standard or better in responding to calls

Underground Maintenance
- Maintain system to PBR standard or better in responding to calls

Inspection
- Provide inspection reports for switches, vaults (3 year rotation), and poles (10 year rotation)(NOTE Distribution Code will define the inspection requirements this may increase staff)

Emergency Response
- Emergency response will be in accordance to PBR Guidelines

Transformer Installation and Repair
- Maintain voltage ranges to customer to CSA standards (NOTE Distribution Code will define the inspection requirements this may increase staff)

Service Installations
- Installations will be made to PBR requirements

Service Repairs
- To PBR requirements

Relocation Work
- Perform work to PBR requirements and general Utility standards

PCB Management
- All activity to within the Ministry of Environment and energy guideline.

Billable Work
- Perform work to PBR requirements and general Utility standards

Customer Relations
- To PBR requirements

Supervision

- To meet or exceed Ministry of Labour and EUSA's requirements. To meet OEB requirements

Line Locate

- Locates will be done to meet the OEB PBR requirements

REMUNERATION PAYABLE TO THE CORPORATION OF THE TOWN OF TILLSONBURG:

$240,992 – operations
$88,883 - maintenance

A.2 ELECTRICAL ENGINEERING SERVICES

(a) FULL DESCRIPTION OF THE SERVICE:

- Maintain engineering files and records, both digital and hard copy;
- Installation, support and licensing of the following engineering software;
    - AutoCad 2 licenses
    - LRIS 2 licenses
- Prepare and track the engineering budget and capital construction budget from concept to final estimates;
- Review and comment on plans for proposed developments submitted by property owners and the Town of Tillsonburg Planning Services and other agencies;
- Review and comment on plans for proposed new electrical services, over 150kVA, submitted by property owners;
- Plan revisions and extensions to the electrical distribution system.

DESIGN SERVICES

- Plan, design and supervise the installation of all new electrical plant and equipment related to capital and operations work.

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- The above services will be provided in an expedient manner and according to OEB codes and PBR standards.

REMUNERATION PAYABLE TO THE CORPORATION OF THE TOWN OF TILLSONBURG:

$173,732

A.3 METER SERVICES

(a) FULL DESCRIPTION OF THE SERVICE:

- Provide qualified Meter Technicians
- Install/remove all residential electric meters
- Install/remove all General Service Meters
- Install/remove all Data recorders
- Install/remove CT and PT and prepare meter installations
- Provide technical advise on the procurement of all meters required by the Utility.
- Maintain, verify or re-verify all meters according to schedule.
- Maintain the appropriate meter database as required by Measurement Canada, OEB or Utility.
- Identify all meters that have malfunctioned and assist in the corrective actions required
- Recommend to Utility management any technological advances that should be implemented at the Utility to comply with all rules and regulations set out my Measurement Canada or other legislation.
- Test or have tested all meters according to general accepted principals for an Utility meter shop as set out by the MEA courses for Meter Technicians
- Provide technical assistance to customers and consultants on meter installation requirements.
- Provide regular reports to Utility management
- Provide management and supervision
- Provide safety training and ensure all employees work to EUSA safety Standards
- Provide required insurance
- Provide necessary vehicles and equipment of a general nature
- Meet any PBR requirement set out by Utility
- Promote public safety and awareness using external communication

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED

- Meter readings to be accurate.
- Service provided to the schedule set out by the Utility.
- All OEB codes to be met.
- All Measurement Canada rules to be met.
- Meters to be purchased using industry standards including MEA, EUSA, CSA and UL.
- Supply and testing to meet Utility schedule and OMB PBR requirements.

REMUNERATION PAYABLE TO THE CORPORATION OF THE TOWN OF TILLSONBURG:

$22,628 - operations
$15,750 - maintenance

A.4 METER DATA MANAGEMENT

(a) FULL DESCRIPTION OF THE SERVICE:

- Read all residential and commercial meters except interval meters.
- Handle all customer complaints regarding incorrect readings or performance of meter readers.
- Provide meter reading software and system.
- Read all residential electric meters according to schedule using MVRS handheld provided by Utility.
- Read all General Service meters and reset demand meters according to schedule using MVRS handheld provided by Utility.
- Read all General Service or residential electric telemeters according to schedule using MV90 software.
- Read all wholesale meters using MV90 Standard
- Read all embedded generation using MV90 Standard
- Provide, maintain, administer and operate MV90 or similar software
- Provide standard (MVRS and MV90) file formats for all scheduled readings for import into Utility's CIS/billing package, retail settlement package or service, and posting as required for retailer access.
- Provide Verified, Edited or Estimated readings to the Utility's CIS/billing package, retail settlement package or service, and posting as required for retailer access.
- Maintain backup copies for the periods scheduled by the Utility.
- Ensure compliance with all OEB and PBR requirements
- Provide all supervision and management functions
- Provide all required equipment and supplies for employees
- Provide safety training and monitoring
- Provide regular reports to Utility management.

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED

- Meter readings to be accurate to reasonable industry standards.
- Service provided to the schedule set out by the UTILITY to reasonable industry standards.
- All OEB codes to be met
- All Measurement Canada rules to be met.
- Services of an MDMA as set out in the retail technical panel volume 4 report to be adhered to as they become OEB code or legislation.

- Ensure that all readings are obtained as per schedule of the Town

REMUNERATION PAYABLE TO THE CORPORATION OF THE TOWN OF TILLSONBURG:

$34,125

A.5 TREE TRIMMING

(a) FULL DESCRIPTION OF THE SERVICE:

- Trim trees to insure that hydro line are clear of any obstruction. The hydro lines will be cleared of any tree contact.
- Provide supervision and control to insure that proper clearances are maintained

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- The Town will be cleared on a rotational basis once every three years.

REMUNERATION PAYABLE TO THE CORPORATION OF THE TOWN OF TILLSONBURG:

$30,450

A.6 CUSTOMER SERVICES

A.6.1 BILLING ADMINISTRATION

(a) FULL DESCRIPTION OF THE SERVICE:

- Calculation of monthly bills for existing customer base of +/- 6,000 customers.
- Answer all customer enquiries including inquiries regarding bill calculation, type and cost of services offered, high consumption and power outages, during the hours of 8:00 a.m. and 8:00 p.m. Monday to Friday and 9:00 a.m. to 12:00 p.m. Saturday
- Provide for over the counter service at the Customer Service Centre, between the hours of 8:00 a.m. and 8:00 p.m. Monday to Friday and 9:00 a.m. to 12:00 p.m. Saturday
- Hours of operations subject to change upon mutual agreement between the Town and the Utility
- Handle all customer requests for connection and disconnection of services, roll-outs, and spot services.

- Handle all customer complaints.
- Ensure proper update of CIS system of all information, concerning, rate, consumer, location and retailer information.
- Provide after hours answering service to dispatch emergency calls.
- Monitor and report on telephone accessibly, appointments and written responses to inquiries as required by the OEB to meet the Performance Based Regulations.
- Promote policies, and programs which encourage high levels of service.
- Notification to retailers of changes in customer accounts.

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- Maintain high levels of customer satisfaction.
- Ensure Performance Based Regulations are met.
- Enforce the Standard Application of Rates and/or policies of Regulator are followed.
- Ensure all accounts are billed monthly as per schedule.

A.6.2 DISPATCH

(a) FULL DESCRIPTION OF THE SERVICE:

- Provide radio dispatch service and necessary record keeping for customer service needs.

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- In accordance with established policy and procedures

A.6.3 GENERAL MAIL SERVICES

(a) FULL DESCRIPTION OF THE SERVICE:

- Provision of mail and courier services excluding invoice mailings and including pick-up or receipt, processing, distribution and delivery; includes daily pick-up and delivery to and from the Tillsonburg Customer Service Centre (CSC).

(b) STANDARDS TO WHICH THE SERVICE WILL BE PROVIDED:

• Pick-up and delivery to and from the CSC	Daily
• Delivery to work locations	Daily by 10:00 a.m.
• Pick-up from work locations	Daily by 3:30 p.m.

All mail will be processed by the end of the working day on which they have been received.

A.6.4 REMITTANCE PROCESSING

(a) FULL DESCRIPTION OF THE SERVICE:

- Processing of all payments, including opening/sorting mail, data capture, encoding and preparing deposit.
- Providing cashiering services at the Tillsonburg Customer Service Centre from 8:00 a.m - 8:00 p.m. Monday to Friday and 9:00 a.m. to 12:00 p.m. on Saturday
- Daily reconciliation of monies collected to system records.

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- All payments will be posted the day they were received.
- Bank deposits to be made daily.
- Reconciliation of posted amounts and cash received daily and monitored for errors.
- All payment investigations to be done on a timely basis.
- Payment types to be accepted are Interac, Cash, cheque, telebanking and bank payments.

A.6.5 BILL DESIGN, PRINTING, INSERTING AND MAILING INVOICES

(a) FULL DESCRIPTION OF THE SERVICE:

- Design of a customer driven bill and collection notices.
- Printing of all monthly bills and notices for existing customer base of +/- 6,000 customers
- Inserting and preparing bills/notices for mailing including up to 3 additional inserts and business return envelopes and delivery to post office, including postal charges, at current rates.

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- All mail will be delivered to Canada Post daily
- Mailing addresses will be verified for address accuracy
- Bills will be responsive to the customers' needs and will conform to the requirements of the Regulator.

A.6.6 COLLECTION SERVICES

(a) FULL DESCRIPTION OF THE SERVICE:

- Notify customers of overdue payments by telephone, mail and continue notification processes until payment is received or discontinuation of services, for consumer and miscellaneous receivable accounts.
- Field Collection Services to obtain payment, notify of impending disconnection, and disconnection of hydro services when payment is not received.
- Recommend and co-ordinate legal actions where payment is not received.
- Trace and locate debtors on final accounts.
- Administer the contract and co-ordinate services with the Credit Bureau and external Collection Agency.
- Maintain accurate system records on all collection activity.
- Collect deposits and/or other forms of security as required by the policies of Hydro Corporations.
- Report on collection activity as required.
- Recommend Collection Policies to reduce bad debts.
- Recommend accounts to be written off. The UTILITY will assume the expense of bad debt write-offs.

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- Ensure regulations of Regulator and/or Standards Application of Rates are followed.
- Ensure the collection and deposit policies of the Hydro Corporations are followed.

A.6.7 CUSTOMER RELATIONS, ADMINISTRATION AND MARKETING

(a) FULL DESCRIPTION OF THE SERVICE:

Administration, customer relations, and marketing for all Hydro functions not covered in other schedules.

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

REMUNERATION PAYABLE TO THE CORPORATION OF THE TOWN OF TILLSONBURG:

$152,657

A.7 MANAGEMENT SERVICES

A.7.1 MEETING MANAGEMENT SERVICES

(a) FULL DESCRIPTION OF THE SERVICE:

- Provision of a Corporate Secretary to the Utility.
- Preparation and distribution of agendas
- Take minutes of board meetings
- Minute preparation, distribution and retention
- General administrative support to Board members including correspondence, reports, bookings and other related tasks arising from board meetings
- Provision of suitable meeting room accommodations including a conference table and seating for Board members and other attendees

(b) STANDARDS TO WHICH THE SERVICE WILL BE PROVIDED:

- Agendas will be prepared and distributed five working days prior to meetings
- Minutes will be prepared and distributed within five working days following the meeting
- Minutes and all related documentation will be retained in secured storage

A.7.2 INSURANCE & RISK MANAGEMENT SERVICES

(a) FULL DESCRIPTION OF THE SERVICE:

Placement and management of: (a) Liability and Property Insurance; (b) Directors and Officers liability insurance providing coverage for the directors of the Utility; (c) insurance claims administration and adjusting services; (d) assistance to the Board of Directors in the development of risk management procedures.

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- Town of Tillsonburg to be an additional named insured on all policies where such coverage is available.
- Liability and property insurance will be obtained with the level of coverage to be determined by the Board of Directors. The Town's Director of Corporate Services shall provide in consultation with the Insurance Company(s), advice and assistance to the Board in connection with such policy limits.
- Claims administration will be undertaken by the Town's Director of Corporate Services or his or her designate
- Adjusting Services for Claims will be provided when necessary
- Timely updates on matters of risk management, events, and occurrences

A.7.3 TELEPHONE SERVICES

(a) FULL DESCRIPTION OF THE SERVICE:

- Provision of the necessary telephones for all staff involved in hydro services, including required telephone lines, voice mail where necessary, and specialized telephone equipment (i.e. headsets) for customer service personnel as may be required.

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- A fully functional telephone system with voice mail will be provided including system support and repair.
- The telephone system will be administered by Corporate Services of the Town.

A.7.4 ACCOUNTS PAYABLE PROCESSING

(a) FULL DESCRIPTION OF THE SERVICE:

- Accounts payable processing

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- Invoices are paid within their due dates. Discounts should be taken when possible.
- Bank reconciliations should be completed on a timely basis.

A.7.5 PAYROLL FUNCTIONS

(a) FULL DESCRIPTION OF THE SERVICE:

- Payroll functions.

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- Employee(s) paid/filings (WSIB, Rec. General &c.) all done on a timely basis.
- Bank reconciliations completed to support financial statements.

A.7.6 MISCELLANEOUS ACCOUNTS RECEIVABLE ADMINISTRATION

(a) FULL DESCRIPTION OF THE SERVICE:

- Miscellaneous (non-consumer) accounts receivable administration

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- Billings completed on a timely basis.

A.7.7 RECORDS MANAGEMENT SERVICES

(a) FULL DESCRIPTION OF THE SERVICE:

Provision of records management services using records management software to:

- Maintain file plans and retention schedules
- Transfer and store of inactive records
- Destroy records
- Retrieve and deliver inactive records
- Train records coordinators and other records service users
- Customize reports

(b) STANDARDS TO WHICH THE SERVICE WILL BE PROVIDED:

- File plans and retention schedules reviewed with Records Coordinator and revised annually
- Includes annual file generation
- Transfer and storage of records:
- Transfers to storage including on-site processing but excluding packing and transportation on an annual basis
- Secured transportation and storage of inactive records
- Provision of storage equipment and supplies
- Destruction of records
- Secure and confidential destruction of records on an annual basis
- Certification of records destruction provided
- Records are destroyed in accordance with records retention schedules and only upon review and approval of the originator
- Records retrieval services
- Retrieval, delivery and refiling of records from inactive storage during normal working hours and within 24 hours of receiving the request
- Rush services within one hour of receiving the request during normal working hours provided on as required basis
- Rush services within one hour of receiving request outside of normal working hours provided on an as required basis
- Training
- Records coordinator training including records management procedures [file plan maintenance, transfer and destruction procedures, records retrievals, report and

label production], software training and follow-up support provided for each new record coordinator
- General services users to request and retrieve records as required and upon request
- Documentation provided
- Preparation of customized reports including customized label formats as requested

A.7.8 FINANCIAL STATEMENT PREPARATION

(a) FULL DESCRIPTION OF THE SERVICE:

- Financial Statement Preparation

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- Quarterly statements presented to the Board on a timely basis.
- Audited financial statements to be completed on a timely basis.

A.7.9 OTHER FINANCIAL SERVICES

(a) FULL DESCRIPTION OF THE SERVICE:

- Other financial services including rate applications, budgets, reports to the regulator and others as needed
- Includes provision of a Treasurer to the Utility, which Treasurer shall either be or, shall report to and, receive direction from the Treasurer of the Town.

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- All rate applications/budgets and submissions will be prepared in accordance with the requirements of the regulator and the Boards of Directors.

A.7.10 TREASURY SERVICES

(a) FULL DESCRIPTION OF THE SERVICE:

- Treasury services including financial systems integrity, internal controls, investment and banking administration and policy, cheques and disbursement of funds, financial management and analysis, payroll and accounting administrative functions, purchasing services and policy and hydro collection administrative services.

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- All treasury services to be provided to standards in accordance with town policy and those of the regulator and Boards of Directors.

A.7.11 LEGAL SERVICES

(a) FULL DESCRIPTION OF THE SERVICE:

- Basic legal representation and advice only.
- Consultants and outside solicitors engaged as deemed necessary but supervised and instructed by the Town's Director of Corporate Services.
- Also provides in-house legal representation and advice to municipal departments which perform hydro services, whether directly or indirectly.

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- Basic legal services, on an as-needed basis.
- Matters which can be resolved quickly and require a minimum of research will be handled entirely in-house.
- Most other matters will be referred to outside solicitors with supervision performed by the Town's Director of Corporate Services.

A.7.12 HUMAN RESOURCE SERVICES

(a) FULL DESCRIPTION OF THE SERVICE:

- Services will be supplied in respect of Town employees performing hydro-related services.
- Payroll and benefit management.
- Salary Administration & Pay equity
- Labour Relations management.
- Health and Safety. OHSA compliance. Injury and loss prevention. WSIB management including modified work program.
- Employment Services. Job Descriptions and job evaluations. Recruitment, interviewing, selection.

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- Consistent with service level provided to all Town departments.

A.7.13 MISCELLANEOUS SERVICES

(a) FULL DESCRIPTION OF THE SERVICE:

- Miscellaneous services, not specified as services in any schedule, but provided to any of the foregoing at their request and upon the agreement of the Town.

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- Good and workmanlike standard.

A.7.14 SENIOR MANAGEMENT SERVICES

(a) FULL DESCRIPTION OF THE SERVICE:

Senior Management Services not necessarily included within any other service schedule. Includes but is not limited to:

- Services of Director of Corporate Services;
- Services of Director of Operations.

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- As required, when required.

A.7.15 MANAGEMENT ADMINISTRATION

(a) FULL DESCRIPTION OF THE SERVICE:

Management and administrative services and support

- switchboard
- file
- identify projects
- project priority
- Provide professional engineer for design, approval, equipment review and approval, and system analysis and recommendations

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

A.7.16 INVENTORY & DISTRIBUTION - STORES

(a) FULL DESCRIPTION OF THE SERVICE:

- Maintain inventory levels to satisfy hydro operations and engineering needs.
- distribution of materials and costs to hydro operations as released

- reconciliation of physical count v. book value

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- sufficient inventory levels to meet operating and emergency needs as required
- keep $ value at a reasonable and manageable level

A.7.17 PURCHASING - HYDRO STORES

(a) FULL DESCRIPTION OF THE SERVICE:

- provide purchasing needs for stores & inventory
- provide purchasing needs for hydro operations external to stores

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- timely purchasing and delivery to satisfy needs and maintain inventory levels

A.7.18 IT SERVICES

(a) FULL DESCRIPTION OF THE SERVICE:

- Installation and maintenance of all hardware including desktops, servers, and mainframes necessary for ongoing operations.
- Installation, support, and licensing of all software applications.
- Provision of network, email, and Internet access.
- Programming support for custom applications. This includes design/implementation of new development as well as maintenance of current modules.
- Database installation, support and licensing.
- Security: Nightly, weekly, and monthly backups. Firewall. Maintenance of employee profiles, access rights, and permissions.
- Technical guidance for meetings, committees and projects.

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

Hardware, Software, Database, Communications Availability
Available 24 hours a day 7 days a week except for scheduled backups, maintenance, month end and year-end procedures.

Problem Resolution

Priority 1 - Hardware, software, database, or communication failure which causes 1 person to be unable to carry out their main job function. An ITS support technician will respond within 1 working day.

Priority 2 - Problems which do not cause an employee to be unable to carry out their main job functions are logged, prioritized and dealt with as soon as possible, depending on the availability of staff due to number of priority 1 and priority 2 problems.

Programming Requests
All programming requests are submitted to ITS and logged and prioritized. Small requests are handled on a combined priority and FIFO basis. Large requests are prioritized and scheduled after discussion with the Town.

REMUNERATION PAYABLE TO THE CORPORATION OF THE TOWN OF TILLSONBURG:

$277,149

A.8 USE OF THE CUSTOMER SERVICE CENTRE, DISPATCH AND PROPERTY MANAGEMENT

(a) FULL DESCRIPTION OF THE SERVICE:

- Buildings, property, equipment, or other depreciable assets used by the Town to provide services to the Utility.
- All aspects of Property Management relating to the Customer Service Centre, including janitorial, mechanical, electrical, plumbing, security systems, window cleaning, mats, pest control, fire plans.
- Project management for renovations and mechanical replacement.
- Cost of providing building/facility for stores, dispatch and hydro operations

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- Available during normal office hours and on call 24 hours a day, 7 days a week.
- sufficient to house and provide necessary services

REMUNERATION PAYABLE TO THE CORPORATION OF THE TOWN OF TILLSONBURG:

$75,000

A.9 RETAIL/WHOLESALE SETTLEMENT & ENERGY MANAGEMENT

(a) FULL DESCRIPTION OF THE SERVICE:

- Retail Settlement
- Receive inputs from MDMA, IMO,
- Operate and maintain the Retail Settlement System to meet the billing requirements of the Corporation, OEB and Retailers
- Meet timelines established by Corporation, OEB, Retailers
- Supply and maintain a modern settlement system or service
- Retain and Maintain required records
- Provide supervision and Management
- Provide energy management advice to customers and staff.
- Inform UTILITY management of energy management trends and recommend programs
- Perform, Manage and Investigate Energy misappropriation providing the UTILITY with a proper Theft of Energy Program.
- Provide Customer Education including education in the schools
- Maintain diversion programs in accordance with industry standards.
- Maintain evidence to prosecute to the full extent of the law.
- Meet all OEB, UTILITY or Ministry guidelines for Customer Education.

REMUNERATION PAYABLE TO THE CORPORATION OF THE TOWN OF TILLSONBURG:

$130,358

A.10 CAPITAL SERVICES

A.10.1 CAPITAL PROJECTS

(a) FULL DESCRIPTION OF THE SERVICE:

- Labour, equipment and applicable materials to perform capital projects, the result of which will be to produce capital assets owned by the Utility.

- Labour and equipment to perform capital projects, the result of which will be to produce capital assets owned by the Town but used in whole or in part for the benefit of the Utility.

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- While the staff levels maintained by the Town permits a portion of that staff to be utilized for normal operating functions and for the performance of capital projects, the exact amount of in-house labour available to perform such capital projects will vary from time to time because of workload issues and other pertinent factors.

- Town staff will make appropriate recommendations to the Utility from year to year and from time to time with respect to the capacity of Town staff to undertake projects on an in-house basis, and which projects (or which portions of projects) will need to be performed by outside forces under contract to the Utility. Where such outside forces are contracted by an Utility, Town staff shall provide contract administration and management services in connection with such contracts to the Utility.

A.10.2 ACQUISITION & DISPOSITION OF REAL PROPERTY

(a) FULL DESCRIPTION OF THE SERVICE:

- Estimate value, obtain appraisals, declare surplus, negotiate, receive appropriate approvals and ensure closings for any required purchases on fee simple or easements.
- Negotiate the sale of any surplus properties through tender or listing.

(b) STANDARD(S) TO WHICH THE SERVICE WILL BE PROVIDED:

- Services available on request of the Utility.
- Service requirements expected to be minimal due to the fact that most plant is located within municipal road allowances.

REMUNERATION PAYABLE TO THE CORPORATION OF THE TOWN OF TILLSONBURG:

PROJECT	BUDGET
Simcoe Street	$205,013
Potters Road	93,975
Bloomer Street	47,250
Wellmaster	22,523
Eberhard	22,102
Noma	22,102
Future Subdivision	118,650
Miscellaneous	160,020
TOTAL	**$691,635**

LDC's Distribution License

THI's Board issued distribution license is provided at E1/T2/S2/AttA.

There are no conditions attached to the distribution license.

Ontario

Electricity Distribution Licence

ED-2003-0026

Tillsonburg Hydro Inc.

Valid Until
December 21, 2023

M.C. Garner

Mark C. Garner
Secretary
Ontario Energy Board

Date of Issuance: December 22, 2003

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
26th. Floor
Toronto, ON M4P 1E4

Commission de l'Énergie de l'Ontario
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1 Definitions

In this Licence:

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

"**distribution services**"means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order;

"**Distribution System Code**" means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**Licensee**" means: Tillsonburg Hydro Inc.;

"**Market Rules**" means the rules made under section 32 of the Electricity Act;

"**Performance Standards**" means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

"**Rate Order**" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge;

"**regulation**" means a regulation made under the Act or the Electricity Act;

"**Retail Settlement Code**" means the code approved by the Board which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers; 14

"**service area**" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity; 15

"**Standard Supply Service Code**" means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act; 16

"**wholesaler**" means a person that purchases electricity or ancillary services in the IMO-administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IMO-administered markets or directly to another person other than a consumer. 17

2 Interpretation 18

2.1 In this Licence words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this licence where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day. 19

3 Authorization 20

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence: 21

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence; 22

b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and 23

c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act. 24

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Obligation to Provide Non-discriminatory Access

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee's distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence.

7 Obligation to Connect

7.1 The Licensee shall connect a building to its distribution system if:

a) the building lies along any of the lines of the distributor's distribution system; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.2 The Licensee shall make an offer to connect a building to its distribution system if:

a) the building is within the Licensee's service area as described in Schedule 1; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee's Rate Order as approved by the Board.

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the *Act* or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence.

8 Obligation to Sell Electricity

8.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee's Rate Order as approved by the Board.

9 Obligation to Maintain System Integrity

9.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board.

10 Market Power Mitigation Rebates

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence.

11 Distribution Rates

11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order of the Board.

12 Separation of Business Activities

12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board.

13 Expansion of Distribution System

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules.

13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine.

14 Provision of Information to the Board

14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

14.2 Without limiting the generality of condition 14.1 the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

14.3 The licensee shall inform the Board as soon as possible of any material changes to the service agreement with The Corporation of the Town of Tillsonburg (the "Service Agreement").

14.4 If either party to the Service Agreement provides notice of its intention to exercise a right to terminate or discontinue any services under the services agreement, the Licensee shall:

a) Immediately notify the Board in writing of the notice; and

b) provide a plan to the Board as soon as possible, but no later than ten (10) days after the receipt of the notice, as to how the affected distribution services will be maintained in compliance with the terms of this licence. 67

14.5 In the event of termination of the Service Agreement for any reason, the Licensee shall: 68

a) ensure there is no interruption of distribution services to the consumers as a result of the termination, 69

b) notify the Board of the name of the new company that will provide the distribution services, and 70

c) file with the Board the distribution services agreement with the new company. 71

15 Restrictions on Provision of Information 72

15.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator. 73

15.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed: 74

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence; 75

b) for billing, settlement or market operations purposes; 76

c) for law enforcement purposes; or 77

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator. 78

15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified. 79

15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent. 80

15.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed. 81

16 Customer Complaint and Dispute Resolution 82

16.1 The Licensee shall: 83

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner; 84

b) publish information which will make its customers aware of and help them to use its dispute resolution process; 85

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee's premises during normal business hours; 86

d) give or send free of charge a copy of the process to any person who reasonably requests it; and 87

e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective. 88

17 Term of Licence 89

17.1 This Licence shall take effect on December 22, 2003 and expire on December 21, 2023. The term of this Licence may be extended by the Board. 90

18 Fees and Assessments 91

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board. 92

19 Communication 93

19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change. 94

19.2 All official communication relating to this Licence shall be in writing. 95

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee: 96

a) when delivered in person to the addressee by hand, by registered mail or by courier; 97

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and 98

c) when received by facsimile transmission by the addressee, according to the sender's transmission report. 99

20 Copies of the Licence 100

20.1 The Licensee shall: 101

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and 102

b) provide a copy of the Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies. 103

104

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

105

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence.

106

The Town of Tillsonburg as of November 7, 1998.

107

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

108

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act.

109

The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with condition 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders.

110

SCHEDULE 3 LIST OF CODE EXEMPTIONS

111

This Schedule specifies any specific Code requirements from which the Licensee has been exempted.

112

The Licensee is exempt from the requirements of section 2.5.3 of the Standard Supply Service Code with respect to the price for small volume/residential consumers, subject to the Licensee offering an equal billing plan as described in its application for exemption from Fixed Reference Price, and meeting all other undertakings and material representations contained in the application and the materials filed in connection with it.

113

APPENDIX A MARKET POWER MITIGATION REBATES

114

1 Definitions and Interpretation

115

In this Licence,

116

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

117

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

118

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

119

In this Licence, a reference to the payment of a rebate amount by the IMO includes interim payments made by the IMO.

120

2 Information Given to IMO

121

a Prior to the payment of a rebate amount by the IMO to a distributor, the distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with information in respect of the volumes of electricity withdrawn by the distributor from the IMO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

122

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

123

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998.*

124

b Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IMO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

125 i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

126 ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*.

127 c Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

128 The IMO may issue instructions or directions providing for any information to be given under this section. The IMO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

129 For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IMO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IMO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

130 ## 3 Pass Through of Rebate

131 A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IMO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

132 a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented;

133 b consumers who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

134 c embedded distributors to whom the distributor distributes electricity.

135 The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

136 If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

137 "ONTARIO POWER GENERATION INC. rebate"

138 Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IMO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

139 Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

140 Pending pass-through or return to the IMO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

AFFIDAVIT

I, BRYAN DRINKWATER, Operations Utility Manager of Tillsonburg Hydro Inc., MAKE OATH AND SAY AS FOLLOWS:

1. A Notice of Application and Notice of Proposal to Renew Electricity Distribution Licence was published in the Tillsonburg News on Wednesday, April 9, 2003 headed with the Ontario Government logo and the words "Ontario Energy Board".

2. The Tillsonburg News is an English-language newspaper having the highest circulation in our service area.

3. The application (with the exception of the confidential information contained in Section A7 of the application form), the Notice of Application and the Notice of Proposal to Renew Electricity Distribution Licence, and the draft Electricity Distribution Licence were all mailed on April 4, 2003 to:

   Mr. Glen MacDonald
   Hydro One Networks
   13C6, 483 Bay St.
   Toronto, Ontario
   M5G 2P5

4. There are no adjoining distributors and therefore no notices were sent to any other distributors.

SWORN BEFORE ME at the Town of)
)
Tillsonburg, in the County of Oxford,)
)
This 17th day of December 2003)
)

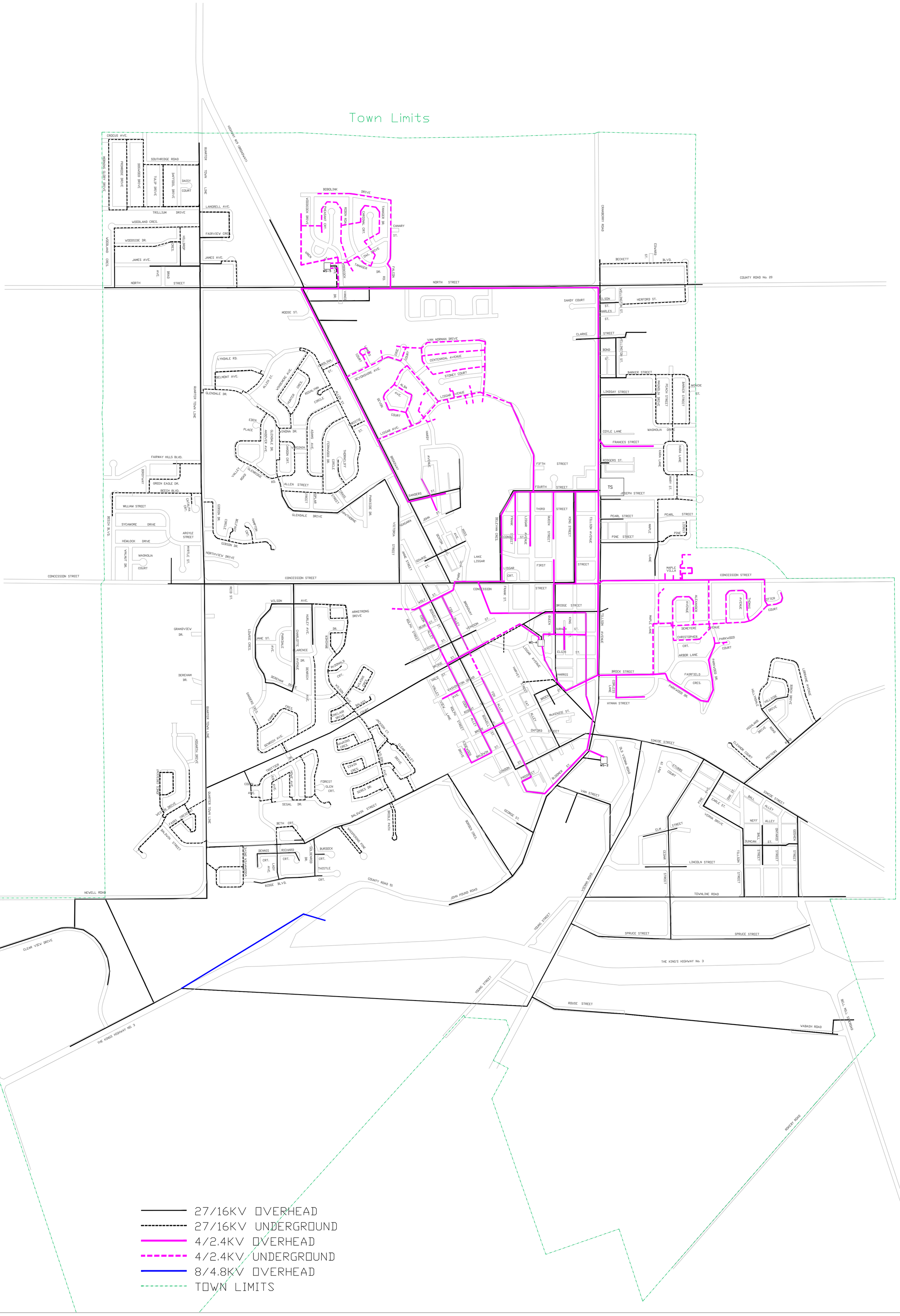
A Commissioner, etc.

BRYAN DRINKWATER

Map of LDC's Distribution System

A diagram of THI's distribution system overlain with a street map of the licensed service area is provided at E1/T2/S3/AttA.

OVERVIEW OF HYDRO DISTRIBUTION IN TOWN OF TILLSONBURG



Utility Organizational Chart

THI does not have employees.

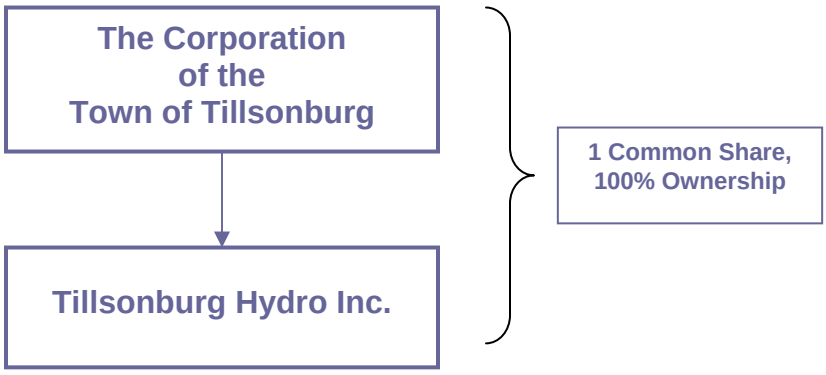
The Town of Tillsonburg makes a number of its employees available to THI. In the 2008BY it will provide 9.6 technical employees who will be dedicated to THI and another 7.45 FTE Town employees will provide other aspects of service to THI. Detailed information is provided at E1/T2/S4/AttA.

Title	Full Time Equivalent Allocated to THI		
	2006HY	2007HY	2008BY
Director of Operations	0.25	0.25	0.25
Manager, Utility Operations	0.50	0.50	0.50
Foreman	1.00	1.00	1.00
Manager Engineering	0.20	0.20	0.20
Utility Engineers	0.40	0.40	0.40
Instrument Technician	1.00	1.00	1.00
Linesmen	3.00	4.00	4.00
Linesmen - Apprentice	1.00	1.00	1.00
Operations Technologist	0.00	0.20	1.00
Asset Management Technologist	0.00	0.25	0.25
Sub-total - Technical staff	7.35	8.80	9.60
Customer Service Representative	5.30	5.80	5.80
Chief Administrative Officer	0.00	0.00	0.10
Director of Finance	0.10	0.10	0.10
Director of Corporate Services	0.10	0.10	0.10
Manager Customer Service	0.10	0.10	0.28
Finance Regulatory Affairs Manager	0.70	0.70	0.73
Senior Accountant	0.15	0.15	0.05
Accounts payable Clerk/Payroll	0.15	0.15	0.15
Records Management Clerk	0.05	0.05	0.05
Deputy Treasurer	0.15	0.15	0.10
Payroll Clerk	0.08	0.00	0.00
Sub-total - non-Technical Staff	6.88	7.30	7.45
Total	**14.23**	**16.10**	**17.05**

Corporate Entities Relationships Chart

THI is a legal affiliate of the Town of Tillsonburg and of no other party. The following chart documents this relationship.

Chart 1 – THI Corporate Relationships Chart



Planned Changes in Corporate or Operational Structure

THI does not plan any changes to its corporate structure. THI proposes to recruit a Manager, Regulatory Affairs and two Apprentice Linesmen during the 2008BY; THI does not propose to make any other changes to its corporate or operational structure in the 2009TY.

Conditions of Service/Service Charges

THI's current Conditions of Service are provided at E1/T2/S8/AttA.



Conditions of Service

Revised April 22, 2008

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1 INTRODUCTION

1.1 Identification of Distributor and Territory

Tillsonburg Hydro Inc. referred to herein as either Tillsonburg Hydro or the Distributor is a Corporation, incorporated under the laws of the Province of Ontario to distribute electricity.

Tillsonburg Hydro is licensed by the Ontario Energy Board (OEB) to supply electricity to its Customers as described in the Transitional Distribution Licence issued on April 1, 1999 by the OEB. Additionally there are requirements imposed on Tillsonburg Hydro by the various codes referred to in the Licence and by the Electricity Act and the Ontario Energy Board Act.

Tillsonburg Hydro operates distribution facilities within its licensed territory as defined in the Transitional Distribution Licence, generally within the boundaries of the Municipality of the Town of Tillsonburg.

Tillsonburg Hydro will normally provide one electrical service to each Customer's location at a nominal service voltage. For new or upgraded electrical services, the Customer or their representative shall make application and shall consult with Tillsonburg Hydro concerning the availability of supply, the voltage of supply, service location, metering and other details as described in these Conditions of Service. These requirements are separate from and in addition to those of the Electrical Safety Authority. Customers may be required to pay capital contributions for the addition of new electrical services in accordance with the policies and procedures outlined elsewhere in this document.

1.2 Related Codes and Governing Laws

Tillsonburg Hydro scope of operation is defined by:

1. Electricity Pricing, Conservation and Supply Act, 2002
2. Electricity Act, 1998
3. Ontario Energy Board Act, 1998
4. Transitional Distribution Licence No. ED-1999 -0162
5. Affiliate Relationships Code
6. Transmission System Code
7. Distribution System Code
8. Retail Settlements Code
9. Standard Service Supply Code

In the event of a conflict between this document and the Transitional Distribution Licence or regulatory Codes issued by the OEB, or the Electricity Act, the provisions of the Act, the Transitional Distribution Licence and associated regulatory Codes shall prevail.

When planning and designing an electricity service, Customers and their agents must refer to all applicable provincial and Canadian electrical codes, and all other applicable federal, provincial, and municipal laws, regulations, codes and by-laws to also ensure compliance with their requirements. The work shall be conducted in accordance with the Occupational Health and Safety Act, the Regulations for Construction Projects and the E&USA Rulebook.

1.3 Interpretations

Questions as to the interpretation or intent of any part of this document should be directed to Tillsonburg Hydro and Tillsonburg Hydro shall have the sole right to make such interpretation.

Headings and underlining are for convenience only and do not affect the interpretation of these Conditions of Service. Words referring to the singular include the plural and vice versa and words referring to a gender include any gender.

1.4 Amendments and Changes

Tillsonburg Hydro reserves the right to make changes to these Conditions of Service at any time. In the event of changes, a public notice shall be made in the form of either a notice in the local newspaper, or a notice on The Town of Tillsonburg Website (www.town.tillsonburg.on.ca). Suggestions for revisions or improvement can be directed to Tillsonburg Hydro Engineering Department at 519-688-3009 Ext. 2232.

The Customer is responsible for contacting Tillsonburg Hydro to ensure they have the latest version of these Conditions of Service.

1.5 Contact Information

Tillsonburg Hydro and its agents can be contacted during normal working hours Monday to Friday 8:00 A.M. - 6:00 P.M. Saturday 9:00 A.M. – 12:00 P.M. at 519-842-9200. (Customer Service Centre)

For repairs and service or in event of an emergency outside of normal working hours, please call 519-842-9200 (Fire Dispatch)

For new services and connections, contact the Manager of Engineering at 519 -688-3009 ext. 2232 or Hydro Personnel 519-688-3009 ext. 2225 Utility Manager or 2226 Hydro Technologist or 2227 Hydro Foreman

The business offices and a department directory can be reached at 519-842-6428.

Tillsonburg Hydro's mailing address is:

200 Broadway, 2nd floor,
Tillsonburg Ontario,
N4G 5A7

1.6 Customer Rights

All Customers shall have non -discriminatory access to Tillsonburg Hydro distribution system and services in accordance with the terms of these Conditions of Service and the applicable Acts, Regulations and Codes.

Tillsonburg Hydro shall only be liable to a Customer for any damages that arise directly out of the wilful misconduct or negligence of Tillsonburg Hydro and its agents and employees in providing distribution services to the Customer, on being connected to Tillsonburg Hydro distribution system, meeting the respective obligations under this Conditions of Service, their licences, and any other applicable law.

Notwithstanding the above, neither Tillsonburg Hydro, shall be liable under any circumstances whatsoever for any loss of profits or revenue, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages whatsoever, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in contract, tort, or otherwise.

A Customer or Embedded Generator shall indemnify and hold harmless Tillsonburg Hydro, its Directors, Officers, Employees and Agents from any claims made by any third parties in connection with the construction and installation of a generator by or on behalf of the Customer or Embedded Generator.

The provisions of these Conditions of Service and any amendments made from time to time form part of any Contract made between a connected Customer, Retailer, or Generator, and Tillsonburg Hydro.

1.7 Distributor's Rights

The supply of electricity is conditional upon Tillsonburg Hydro being permitted and able to provide such a supply, obtaining the necessary apparatus and material, and constructing works to provide the service. Should Tillsonburg Hydro not be permitted to supply or not be able to do so, it is under no responsibility to the Customer.

The Customer is required to provide Tillsonburg Hydro with sufficient lead time (16 - 20 weeks) in order to ensure the timely provision of supply to new and updated premises or the availability of adequate capacity for additional loads to be connected at existing premises. If special equipment is required or equipment delivery problems occur, then longer lead times may be necessary. The Customer will be notified of any extended lead times.

Customers will be required to pay the cost of repair or replacement of Tillsonburg Hydro equipment that has been damaged or lost by the direct or indirect act or omission of the Customer or its agents.

Nothing contained in this document or in any contract for the supply of electricity by Tillsonburg Hydro shall prejudice or affect any rights, privileges, or power vested in Tillsonburg Hydro by law under any Act of the Legislature of Ontario or the Parliament of Canada, or any Regulations there under.

Tillsonburg Hydro assumes no risk and will not be liable for damages resulting from the presence of its equipment on the Customer's premises or approaches thereto, or action, omission or

occurrence beyond its control, or negligence of any Persons over whom Tillsonburg Hydro has no control.

Unless they are an Employee or an agent of Tillsonburg Hydro, or other Person lawfully entitled to do so, no Person shall remove, replace, alter, repair, inspect or tamper with Tillsonburg Hydro equipment. Other rights respecting access to equipment, payment of arrears, etc. are covered elsewhere in this document.

1.8 Disputes

Any dispute between Customers and retailers and the distributor shall be settled according to the dispute resolution process specified in the Distributor Licence. In this section, the Distributor should outline the Customer complaint and Dispute resolution processes that have been established as a condition of licence.

Any dispute between Customers or Retailers and the Distributor shall be settled according to the dispute resolution process in Section 23 of the Transitional Distribution Licence or, once permanent licences are issued, by the relevant section of the permanent licence.

If a customer or other Market Participant has a complaint about Tillsonburg Hydro Inc. regarding services provided under its Distribution Licence, the Customer may contact Tillsonburg Hydro Inc. at (519) 842-9200.

Upon receipt of a complaint, Tillsonburg Hydro Inc. will contact the Customer to acknowledge receipt of the complaint and if possible resolve or investigate and follow up on the complaint as required.

To resolve disputes, Tillsonburg Hydro Inc. will follow the terms of Section 23 of the Transitional Distribution Licence.

Section 23 states:

The Licensee shall:

a) Establish proper administrative procedures for resolving complaints by consumers and other market participants' complaints regarding services provided under the terms of this licence;

b) Publish information which will facilitate its Customers accessing its complaints resolution process.

c) Refer unresolved complaints and subscribe to an independent third party complaints resolution agency which has been approved by the Board.

d) Make a copy of complaints resolution procedure available for inspection by members of the public at each of the Licensee's premises during normal business hours.

e) Give or send free of charge a copy of the procedure to any person who reasonably requests it; and

f) Keep a record of all complaints whether or not including the name of the complainant, the nature of the complaint, the date resolved or referred and the result of the dispute resolution.

1.8.1 Dispute Resolution Process

If, following good faith negotiations between a Customer or other market participant and Tillsonburg Hydro Inc., a resolution cannot be reached, the dispute may be submitted to a dispute resolution process.

Any dispute which shall arise between Tillsonburg Hydro Inc. and a Customer(s) and other market participants subject to the terms of these Conditions of Service concerning the rights, duties or obligations of Tillsonburg Hydro Inc. or others subject to these Conditions of Service, shall be subject to the following dispute resolution procedure:

Mediation

- Either party (the “Initiating Party”) may invoke the dispute resolution procedure by sending a written notice to the other party (the “Respondent Party”) describing the nature of the dispute and designating a representative of the Initiating Party with appropriate authority to be its representative in negotiations relating to the dispute. The responding Party shall, within five business days of the receipt of such notice, send a written notice to the Initiating Party, designating a representative of the Responding Party with the appropriate authority to be its representative in negotiations relating to the dispute.

- Within ten business days of the receipt by the Initiating Party of the written notice of the Responding Party the designated representatives shall enter into goof faith negotiations with a view to resolving the dispute. If the dispute is not resolved in thirty days of the commencement of such negotiations, or such longer period as may be agreed upon, either party may, be written notice to the other party require that the parties be assisted in their negotiations by a mediator. The mediator shall be acceptable to both parties and have knowledge and experience in the matter under dispute, or professional qualifications, or experience in alternative dispute resolution, or both. The parties shall thereafter participate in mediation with the mediator through such process as the mediator, in consultation with the parties, may determine.

- None of the parties shall be deemed to be in default of any matter being mediated until effective on or after the date mediation fails.

Referral to Dispute Resolution

Any dispute that is not resolves through mediation as described above shall be referred to a third party dispute resolution agency according to the following procedure:

- Upon the written demand of either of the parties, the dispute shall be referred to an independent third party disputes resolution agency that has been approved by the Board.

- An independent third party disputes resolution agency that has been approved by the Board, shall be selected within ten days of the receipt of the demand by the other party.

- The third party disputes resolution agency selected to hear the dispute shall be qualified by education and training to pass on the particular question in dispute.

- The third party disputes resolution agency selected shall immediately proceed to hear the matter or matters in dispute. The decision of the third party disputes resolution agency

shall be made within 45 days of the selection, subject to any reasonable delay due to unforeseen circumstances. Notwithstanding the forgoing, if the third party disputes resolution agency fails to make a decision within 60 days of the selection, then either party may elect to have another third party disputes resolution agency hear the matter or matters as if none had previously heard the matter or matters.

- The decision of the third party disputes resolution agency shall be in writing and signed by the agency. It shall be final and binding upon all the parties hereto as to any matter or matters so submitted to the third party disputes resolution agency and shall observe and implement the terms and conditions thereof.

- The compensation and expenses of the third party disputes resolution agency (unless otherwise determined by the agency) shall be paid equally by the parties.

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2 DISTRIBUTION ACTIVITIES (GENERAL)

2.1 Connections

This section includes information that is applicable to all Customer classes. Information applicable to specific Customer classes can be found in Section 3.

2.1.1 Building That Lies Along

Tillsonburg Hydro, as the Distributor, has an obligation to connect any building that "lies along" its distribution system as stated in Section 28 of the Electricity Act 1998.

Sections 2.3 and 3 outline the conditions under which Tillsonburg Hydro will provide service to a Customer that "lies along" an existing distribution line. Customers that meet these conditions will not be denied service save and except as provided in this document. Conditions for connection refusal are outlined in Section 2.1.3.

A building "lies along" a distribution line if it is within the boundaries of Tillsonburg Hydro licensed service territory, can be connected to Tillsonburg Hydro distribution system without an Expansion or Enhancement, and meets the conditions of service outlined in this document.

2.1.2 Expansions / Offer to Connect

2.1.2.1 Rationale

Extending the distribution system to connect new Customers requires a capital investment. The revenue generated by the new load may or may not offset the capital investment and on-going maintenance costs of the system expansion. If there is a shortfall between the anticipated revenue and the capital and maintenance costs, the Customer is required to make up the difference through a capital contribution. (See OEB Distribution System Code Section 3.2) Due to the uncertainty of load projections and changing market conditions, Tillsonburg Hydro requires a deposit from the customer equal to the total estimated capital investment, to be paid prior to ordering material. One year after the system has been installed, actual costs for the capital investment will be known and a load projection can be more accurately determined. An economic calculation (known as a Net Present Value calculation or NPV) will be used to determine what portion of the deposit, if any, will be returned to the Customer. Since the system expansion may benefit other Customers not included in the original load forecast, the OEB allows for a five year window during which the NPV calculation may be reviewed to account for un-forecasted Customer connections.

2.1.2.2 Definitions

To connect a building that does not "lie along" the distribution system, a system expansion is required. A system expansion is defined as being that part of the Tillsonburg Hydro distribution system that needs to be extended or reinforced to feed a new load or Customer, and in future, could be used to feed additional Customers. Normally, this includes the distribution plant (primary and secondary conductors, poles, transformers, etc) installed along Town of Tillsonburg streets and roadways to service present and future load additions. It does not include that part of the system installed on private property for the exclusive use of the Customer(s) on that specific property. For example, the primary cable and transformation installed on private property to serve a specific Customer or group of Customers are considered connection assets (see Section 3) and are not considered a system expansion.

Note**:** Connection assets are not subject to the NPV calculation and therefore, no rebates apply.

2.1.2.3 Process

Customers requiring a system expansion must submit detailed plans and specifications to the Engineering Department and or Operations/Utility Manager well in advance of the anticipated project start date. At a minimum, the plans must show property lines, building outlines, roadways, curbs, sidewalks, deep services, and preferred location(s) for transformation and/or service entrance. The specifications must indicate if servicing will be overhead or underground, the required voltage, estimated kW peak by year for 5 years, and desired in -service date.

Within 60 days of receipt of all relevant information, Tillsonburg Hydro will present the Customer with a written "Offer to Connect". This Offer to Connect will contain an estimated cost to connect the service, including all upstream costs necessary to expand the system to meet the Customers' load requirement. Depending on location and timing, Tillsonburg Hydro may choose to make an investment in the distribution system to enhance performance (such as oversized conductors, automated switches, etc). The incremental costs associated with the system enhancements will not be included in the estimated cost to connect the service. A tentative schedule for installation and energization will be provided, subject to receipt of deposit and completion of other deep

services. The projected rebate, if any, will be estimated by Tillsonburg Hydro and written in the Offer to Connect. The required deposit amount will be identified, and must be paid by certified cheque prior to ordering material.

Tillsonburg Hydro will provide one free estimate and Offer to Connect for any new project. If owners or contractors wish to explore alternative scenarios for servicing, Tillsonburg Hydro can provide additional estimates on a time and material cost recovery basis.

2.1.2.4 Deposits

Tillsonburg Hydro requires a security deposit equal to the total estimated cost of providing service to the Customer. The estimated cost will be calculated at Tillsonburg Hydro discretion by using unit pricing (such as a charge per lot for residential subdivisions) or a detailed design / estimate. The estimated rebate will be calculated using the total estimated cost of providing service, and a load projection determined by Tillsonburg Hydro in accordance with Appendix B of the Distribution System Code.

2.1.2.5 Rebates

One year after the service has been energized Tillsonburg Hydro will review the actual cost to provide the service and the amount of actual load that was connected during the first 12 months. A revised load forecast will be created to reflect the amount of actual load connected and the present market conditions. Using the actual costs and revised forecast, the NPV calculation will determine the revised amount of the rebate. If there are no other financial constraints (i.e. account in good standing, etc) a cheque in the amount of the revised rebate will be issued to the Customer. During the next four years, and at 12 month intervals, the Customer may request Tillsonburg Hydro to review the NPV calculation if additional load has been added. An administrative fee will be charged to review the NPV calculation**.** No rebates will be issued for additional load added after five years from the day the system was energized. Interest will not be paid on any rebates.

2.1.2.6 Additional/Un-forecasted Load

Within the first five years, if new Customers not included in the original development plan to connect to the system expansion, the original Customer may be entitled to an additional rebate. New Customers connecting to the expanded facilities will be charged a proportional share of the original cost of the expanded facilities based on their load and location, and the original Customer will be entitled to a rebate. At 12 month intervals, the original Customer may request Tillsonburg Hydro to review the NPV calculation if additional Customers have been added. This review will be completed at the same time as the review based on the Customer's load and will be covered by the administrative fee to have the NPV calculation reviewed. No rebates will be issued for additional load added after five years from the day the system was energized.

2.1.2.7 Phased Developments

If a development will be constructed in phases over several years, the estimated cost of servicing the first phase may reflect costs associated with the installation of equipment to accommodate the future phases. At Tillsonburg Hydro discretion, these costs may be excluded from the cost of servicing the first phase and proportioned to the future phases as they develop. Customers must clearly identify the timing and scope of future phases with their original submittal. In the “Offer to Connect”, Tillsonburg Hydro will identify any costs associated with accommodating future phases

and specify if these costs are included in the servicing cost estimate, or if they are excluded but will be charged when the next phase proceeds.

2.1.2.8 Examples

The following examples will illustrate the above mentioned definitions and procedures.

i) Connection versus Expansion – Example #1

A new commercial plaza is to be built in an area where a three phase line is already in service along the street. The plaza requires an 800 A, 347/600 V three phase service, underground distribution with the transformer located at the side of the building. Tillsonburg Hydro prepares an Offer to Connect with a cost estimate for the three phase primary riser, underground primary cables, and a pad-mount transformer. These components are considered connection assets since they will provide service to the commercial plaza only. No rebates are applicable.

ii) Connection versus Expansion – Example #2

A new residential home is to be built on acreage outside the core area of the Town of Tillsonburg. The existing Tillsonburg Hydro distribution system stops 600m from the property line. The home requires a 200 A, 120/240 V single phase service, with overhead construction. The home will be built 200m back from the edge of the road. Tillsonburg Hydro prepares an Offer to Connect with a cost estimate for the following: 600m of single phase primary overhead distribution along the roadway, 200m of single phase primary overhead distribution on private property including a drop service (transformation and up to 30m of secondary at no charge). The 600m of distribution along the roadway are considered a system expansion since additional Customers could be added if more lots develop. The 200m of distribution on private property are considered connection assets since they provide service only to this specific Customer. The NPV calculation is completed for the 600m section only. If additional Customers make use of this section within the next five years, the NPV calculation will be reviewed (see next example).

(Note: Since the 200m section on private property exceeds the limit identified in Section 3.1, the Customer is required to build and maintain this section).

iii) Additional Customers – Example

Two years after the line extension in the previous example has been in service, a nearby landowner decides to develop a property. The point of connection is at the mid-point of the expansion which was paid for by the original Customer. Tillsonburg Hydro prepares an Offer to Connect for the new Customer which includes 25% of the actual cost to build the 600m extension (50% of the cost to build the shared portion of the line extension). After the new Customer has been connected, the original Customer pays the administrative fee to have the NPV calculation reviewed. With the additional load added and the money collected for the shared portion of the line extension, the NPV calculation reveals the original Customer is entitled to an additional rebate.

Phased Development – Example

A new subdivision is planned with approximately 500 residential lots, zoning for a school and a commercial plaza. The first phase will only be 100 residential lots, with 100 lots to be added each year until all 500 are serviced. The developer has indicated the commercial plaza will be built

within 2 years, and the school will be built in 4 years. Tillsonburg Hydro prepares an Offer to Connect for the first phase with an estimate based on 100 lots x the unit price per lot. The design also includes provision for three phase power for the future commercial plaza and school. The additional cost for installing additional cables and equipment to service the future three phase loads is then added to the total cost of the first phase. The developer pays the full amount of the deposit and the first phase is constructed.

One year after being energized, only 15 lots have been sold. Tillsonburg Hydro revises the load forecast to allow for 20 lots per year instead of 100 lots per year. The actual cost of servicing the first 100 lots is determined. The NPV calculation is completed using the actual cost and the revised load forecast. The developer receives a small rebate. During the next two years, the first phase has sold out and the developer initiates phase 2. At the developer's request and after payment of an administrative fee, the NPV calculation for phase 1 is reviewed to account for the actual load connected. The NPV calculation reveals the developer is entitled to another small rebate. A separate Offer to Connect is made for phase 2. The developer pays the required deposit for phase 2 and the process continues. In year 6, the commercial plaza is constructed adding a significant load to the system. Since the provision for this three phase load was installed and paid for with phase 1 more than five years previously, the NPV calculation for phase 1 will not be reviewed.

2.1.3 Connection Denial

Tillsonburg Hydro has the right to refuse to connect, or continue to connect, a Customer for any of the following reasons as specified in the Distribution System Code:

- Contravention of the laws of Canada or the Province of Ontario.
- Violation of conditions in Tillsonburg Hydro Distributor's Licence.
- Use of a distribution system line for a purpose that it does not serve and that Tillsonburg Hydro does not intend it to serve. (e.g., using a pole to mount a sign or as a support for a fence, etc.)
- Adverse effect on the reliability or safety of the distribution system.
- Imposition of an unsafe work situation beyond normal risks inherent in the operation of the distribution system.
- A material decrease in the efficiency of Tillsonburg Hydro distribution system.
- A materially adverse effect on the quality of distribution services received by an existing connection.
- Discriminatory access to distribution services.
- If the person or business requesting the connection, or an associated business owes Tillsonburg Hydro money for distribution services.
- If an electrical connection to the Tillsonburg Hydro distribution system does not meet Tillsonburg Hydro design requirements.
- Violation of any other conditions in this Conditions of Service document.

If Tillsonburg Hydro refuses to connect a building or facility that lies along one of its distribution lines, Tillsonburg Hydro will inform the person requesting the connection of the reasons for not connecting, and where Tillsonburg Hydro is able to provide a remedy, will make an Offer to Connect. If Tillsonburg Hydro is unable to provide a remedy to resolve the issue, it is the responsibility of the Customer to do so before a connection may be made.

2.1.4 Inspection before Connection

All Customers electrical installations shall be inspected and approved by the Electrical Safety Authority and must also meet Tillsonburg Hydro requirements. It is the responsibility of the Customer to contact the Electrical Safety Authority in this regard, and to pay all costs associated with such inspection and approval. Tillsonburg Hydro requires notification from the Electrical Safety Authority of this approval prior to the energization of a Customer's supply of electricity.* N.B. Services that have been disconnected for a period of six months or longer must also be re-inspected and approved by the Electrical Safety Authority prior to reconnection. The Customer is responsible for any reconnection fees.

In the event the Customer's existing service mast is damaged (for example, during a storm), the Customer is responsible for re-installing and re-anchoring the service mast and the installation must be re-inspected and approved by the Electrical Safety Authority before Tillsonburg Hydro can re-install the service conductors.

Temporary services, typically used for construction purposes, must be approved by the Electrical Safety Authority for a period of twelve months and must be re-inspected should the period of use exceed twelve months.

Tillsonburg Hydro reserves the right to inspect and witness the construction of any equipment or facilities that will be connected to the Tillsonburg Hydro distribution system. Tillsonburg Hydro will notify the Customer in advance if any witness testing or inspections will be required during construction.

All electrical equipment and materials used by the Customer will be subject to approval by Tillsonburg Hydro, the Electrical Safety Authority and the Canadian Standards Association (CSA) failing which, Tillsonburg Hydro reserves the right to withhold connection to the supply.

2.1.4.1 Overlap of Electrical Services

In certain situations where an existing service is being upgraded or relocated, Tillsonburg Hydro may allow two services to be energized for a period of up to 15 days to provide the owner with adequate time to transfer all internal circuits to the new system.

Prior to any overlap of services, the owner must obtain approval from Tillsonburg Hydro and they reserve the right to disconnect the non-permanent service should the 15 day overlap period be exceeded.

2.1.5 Relocation of Plant

Anyone other than a Road Authority requesting Tillsonburg Hydro to relocate its plant or equipment will be required to pay 100**%** of the costs incurred by Tillsonburg Hydro. The above

costs would include all engineering, labour, material, equipment, trucking, easements, applicable burdens, administrative costs, and taxes associated with the required plant modifications.

An exception to the 100% recovery of costs would occur in cases where Tillsonburg Hydro decided to modify or enhance its distribution system for its own purposes and did not replace or relocate the equipment in a "like for like" manner. Relocating plant "like for like" is defined as new plant built to the latest Tillsonburg Hydro standards that has the capacity to perform the same function as the plant that it replaces. In those cases, where the equipment is not relocated in a "like for like" manner, the differential in cost will be absorbed by Tillsonburg Hydro.

Anyone requesting the relocation of Tillsonburg Hydro plant or equipment must submit a written request to Tillsonburg Hydro in order to initiate the relocation process. Tillsonburg Hydro will provide a cost estimate and must receive either a certified cheque in advance or a Letter of Credit for the full amount of the estimate from a chartered bank, trust company or credit union prior to any work being done.

If the relocation is from public to private property or is within the requestor's private properties, then the requestor must supply Tillsonburg Hydro with equivalent property rights in the form of a new registered easement, tree cutting rights, etc. if applicable. This shall be done at the requestor's cost.

The requestor is responsible for plotting the new locations of all plant to be relocated as agreed to by Tillsonburg Hydro. The costs for any subsequent relocations required due to improper plotting will be at the expense of the person requesting the locate.

If a Customer installs a new driveway and Tillsonburg Hydro overhead structure does not have adequate clearance because of the location of the new driveway, Tillsonburg Hydro will raise or relocate its plant at no cost to the Customer. Where a Customer requires an aerial service to be relocated because of a proposed addition or swimming pool, Tillsonburg Hydro will normally relocate and attach the service to the most secure point along the distribution system where feasible. Normally an aerial service will be relocated to the property line between two neighbouring Customers to avoid further relocation.

Should a Customer require relocation of an underground service cable and/or a high voltage primary cable to clear a proposed addition or swimming pool, the Customer is required to provide a new trench between Tillsonburg Hydro distribution point and the point of connection at the Customer's meter stack. Tillsonburg Hydro must be consulted to determine the location of the distribution point. The Customer will be responsible for 100% of the costs incurred.

2.1.6 Easements and Access to Equipment

The Customer shall grant, at no cost to Tillsonburg Hydro, where requested, a registered easement to permit the installation and maintenance of service. The width and extent of this easement shall be determined by Tillsonburg Hydro. In the case of multi-dwelling units such as town homes or condominiums, a registered blanket easement on the entire property shall be provided to Tillsonburg Hydro by the Customer. The easement shall be granted prior to installation of the service.

To maintain the reliability, structural integrity and efficiency of the distribution system, Tillsonburg Hydro has the right to have supply facilities on private property registered against title to the property. Easements are required whenever Tillsonburg Hydro underground or overhead plant is

to be located on or above private property and crosses over to an adjacent property to service a Customer other than the owner of the original property. An easement may also be required if a property will be severed or if service locations require Tillsonburg Hydro to gain access from adjacent properties (e.g. mutual driveways, narrow side setbacks, land locked properties, etc.).

The Customer will prepare at their cost a reference plan and associated easement document(s) to the satisfaction of Tillsonburg Hydro solicitor prior to its registration and will register the easement plan and Transfer/Deed of easement. Details will be provided upon application for service.

Tillsonburg Hydro requires access to a Customer's premises at all reasonable times to read meters, or to inspect, repair, or remove meters, wires, cables, or equipment owned by Tillsonburg Hydro. Customers must also provide sufficient access and clearance to permit Tillsonburg Hydro to adequately service its equipment including pad-mounted transformers, switching units, vaults, meters, etc.

For pad-mounted equipment, each side of the concrete pad must have at least 1 metre of clearance except any side with an access door which must have 2.5 metres of clearance in front. A clear path must be available to provide access to the equipment. No landscaping, bushes, sheds, or equipment should encroach on this area. Concrete pads must remain at least 5 cm above the surrounding grade and the grade of the immediate area should be sloped in such a manner that water does not collect around the pad.

Tillsonburg Hydro is not responsible for any damage or removal of any Customer-owned landscaping or equipment within the access area or on the easement. Where Tillsonburg Hydro is required to perform surface restoration following any repairs or maintenance to a Customer's service, Tillsonburg Hydro will provide only soil, sod, gravel or asphalt repairs.

Where a Customer owns a private structure that impedes access to their own underground secondary service cable (e.g. a shed, deck, concrete pad, landscaping, etc.), they will be responsible for all costs to remove the obstruction or relocate the service cable in the event repairs need to be made. Tillsonburg Hydro reserves the right to leave the premises without power until a remedy has been agreed to.

Where a Customer's service entrance is located more than 100m from the right-of-way and the Customer has elected to transfer the ownership and future maintenance of the primary line to Tillsonburg Hydro, the Customer will be responsible for maintaining and clearing an all weather roadway for vehicle access along the length of line.

2.1.7 Contracts

Generators and Customers with Customer-owned substations will be required to sign a Connection Agreement prior to commencement of service. Tillsonburg Hydro may require, at its discretion, other Customers with unusual conditions to also sign a Connection Agreement. In addition to contracting for the conveyance of electricity and the use of Tillsonburg Hydro distribution system, Connection Agreements will typically define boundaries and responsibilities for the ownership, operation and maintenance of equipment at the Customer’s location.

In all cases, notwithstanding the absence of a formal contract, or Connection Agreement, the taking and using of electrical energy from Tillsonburg Hydro by any Person or Persons implies and constitutes the acceptance of the terms and conditions of all regulations and rates as established by Tillsonburg Hydro. Such acceptance and use of energy shall be deemed to be the acceptance

of a binding contract with Tillsonburg Hydro and the Person so accepting shall be liable for payment for all services and energy received and the contract shall be binding upon the Person's heirs, administrators, executors, successors or assigns.

2.1.7.1 Payment by Building Owner

The Building Owner is responsible for paying for the supply of electricity by Tillsonburg Hydro to the building except in the case of multi-tenant buildings with individual meters where the occupants have contracted for supply with Tillsonburg Hydro. In the case of multi-tenant buildings with bulk metering, the Building Owner must pay the total cost of the electrical account. The Building Owner may then apportion the bill among individual tenants according to their consumption as a percentage of the total consumption.

A Building Owner wishing to terminate the supply of electricity to their building must notify Tillsonburg Hydro in writing. Until Tillsonburg Hydro receives such written notice from the Owner, the Building Owner or the Occupant(s), as applicable, shall be responsible for paying for the supply of electricity to the building. Tillsonburg Hydro reserves the right to refuse to terminate the supply of electricity to a Building, Owner's building when there are occupant(s) in the building (e.g. during certain periods of the winter).

2.1.8 Customers with Dual Feeds

There are a number of different circumstances under which a Customer may require or request two sources of primary supply and/or two high voltage connections. Various situations are described below:

2.1.8.1 Customer Load Greater than 10 MW

The largest load that can be fed by a single primary supply at 16/27.6Y kV is 10 MW because of the limitations of the largest primary metering unit and current transformer used by Tillsonburg Hydro (200/100-5 A current rating).

If a Customer's load is predicted to exceed 10 MW then a second primary supply must be provided. The Customer will be permitted to totalize the load fed from the two supplies for peak demand metering purposes and will be responsible for paying the connection charges for both sources of supply as described in Section 3.

If a Customer required two primary connections because of load reasons, normal design practice would suggest that if possible, the two connections should also come from two separate sources of supply. This may not always be possible without a system expansion. If for security purposes, a Customer requires their two connections to be fed from separate sources of supply and if a system expansion is required to provide this, the Customer will be responsible for contributing to the cost of the expansion as outlined in Section 2.1.2.

2.1.8.2 Dual Feed due to Tillsonburg Hydro Loop-through Design

At times, the design of Tillsonburg Hydro distribution system will call for a loop-through design that results in a Customer having two high voltage connections.

In the case of a loop-through pad-mount transformer for example, if Tillsonburg Hydro has chosen to put the Customer's transformer on a loop to enable the circuit to continue to feed other Customers, the first Customer receives the benefit of two high voltage connections at no extra charge.

In a case where a Customer owns their own switchgear and substation, if Tillsonburg Hydro chooses to add another cell to the switchgear to permit the primary circuit to continue to feed other Customers, Tillsonburg Hydro will pay for the cost of the additional switchgear cell. Tillsonburg Hydro could also elect to provide a separate switching unit with a tap to the Customer's equipment to allow for the loop through design. The Customer would therefore benefit from having two high voltage connections at no extra cost.

In these situations, it will be solely at Tillsonburg Hydro judgement whether or not a loop-through circuit is required to allow the servicing of additional Customers.

2.1.8.3 Backup Supply and Standby Charges

For an amount of load less than their normal load requirement at that connection point, proof of procedures for load shedding will be required to ensure that automatic load transfers do not exceed the contracted amount.

If the Customer wishes to be able to transfer more than one megawatt (1MW) between its two high voltage connections, and is willing to first notify Tillsonburg Hydro of their desire and request permission to make the load transfer, and if Tillsonburg Hydro reserves the right to deny the transfer because of loading conditions at the time, then the Customer will not be required to pay the standby charge. However, the Customer must be prepared to accept that their request to transfer load can be denied by Tillsonburg Hydro at any time since there would be no special planning guidelines in place to ensure that spare capacity was available on the second source of supply.

Also see Section 2.3.4 for a further discussion of billing arrangements for Customers with more than one metered service connection. Customers who have two high voltage connections must also decide how much transfer capability they require internally between the two connections and whether or not they require a true second source of supply.

As discussed earlier, normal design practice would attempt to connect a Customer's two high voltage connections to two separate feeders if such feeders were available. However, there is no guarantee in the future that those two feeders will actually remain as separate feeders. As loads change and as work on Tillsonburg Hydro system progresses, switching of the system could result in both high voltage connections being actually fed from the same feeder. In some cases, a long term review of the distribution system in the area could result in such a situation becoming permanent. Therefore, if a Customer requires a true second source of supply, this must be identified during the planning stages, and arrangements must be made to ensure that the second high voltage connection will always be fed from a second source.

Tillsonburg Hydro also has restrictions on how much load can be automatically transferred between feeders. If a Customer has auto transfer capability within their premises, Tillsonburg Hydro will permit the Customer to transfer up to one megawatt (1MW) of load (at 27.6 kV) from one high voltage connection to the other at any time without charge.

If a Customer has a need to transfer more than one megawatt (1 MW) of load between its two high voltage connections, and needs to perform that transfer either automatically or manually without first obtaining permission from Tillsonburg Hydro, there will be a standby charge per kilowatt that will be charged every month for the amount of load the Customer wishes to be able to transfer. This standby charge recovers the cost to Tillsonburg Hydro of reserving that amount of system capacity on the second source of supply at all times.

2.1.9 Pole Attachments

Customers will not be permitted to make any attachments to Tillsonburg Hydro poles without written consent. Generally, consent will only be provided to the Town of Tillsonburg and Town of Tillsonburg licensed franchisees, such as Bell Canada, Rogers Cable, and others. Each pole attachment is subject to a yearly joint use charge and the use of Tillsonburg Hydro poles for Customer-owned service cables or equipment will only be permitted under special circumstances.

Unacceptable attachments include privately-owned electrical service equipment and lighting, private signs, banners and notices, and privately-owned brackets and planters. Any such attachments not approved by Tillsonburg Hydro will be removed at the owner's expense.

Notwithstanding this policy, Tillsonburg Hydro will cooperate with community groups to allow the use of Tillsonburg Hydro poles for certain community purposes. In all cases the design of the attachment must meet strict requirements to minimize wind loading and damage to the pole and all such installations must have full approval by the Town of Tillsonburg who control the use of the right-of-way. All costs and liability for the attachments are the responsibility of the community group.

2.2 Disconnection

Tillsonburg Hydro reserves the right to disconnect the supply of electrical energy for causes not limited to:

- Contravention of the laws of Canada or the Province of Ontario.
- Adverse effect on the reliability and safety of the distribution system.
- Imposition of an unsafe worker situation beyond normal risks inherent in the operation of the distribution system.
- A material decrease in the efficiency of the Distributor's distribution system.
- A materially adverse effect on the quality of distribution services received by an existing connection.
- Discriminatory access to distribution services.
- Inability of Tillsonburg Hydro to perform planned inspections and maintenance.
- Failure of the Customer to comply with a directive by Tillsonburg Hydro that makes for purposes meeting its licence obligations.
- Failure of the Customer to maintain Customer owned equipment that Tillsonburg Hydro believes poses a safety or system reliability risk.
- Overdue amounts payable to Tillsonburg Hydro for the distribution or retail of electricity.

- Electrical disturbance propagation caused by Customer equipment that is not corrected in a timely fashion.

- Any other conditions identified in this Conditions of Service document.

Tillsonburg Hydro may disconnect the supply of electricity to a Customer without notice in accordance with a court order, or for emergency, safety, or system reliability reasons. The remainder of this section describes in more detail various disconnection circumstances.

2.2.1 Collection of Arrears

Bills are sent to the Customer a minimum of 16 days prior to the due date. Immediately following the last date for net payment, steps shall be taken to collect the full amount of the bill. If the bill is still unpaid twenty one days after the last date for net payment, the service may be disconnected and not reconnected until satisfactory payment arrangements have been made, including an adequate charge for the cost of reconnecting.

No Customer shall be disconnected without first having been issued a final notice advising the Customer of the disconnection date. If a Customer does not pay the bill after the final notice has been issued and the disconnection date as indicated has passed, Tillsonburg Hydro may limit or cut off the supply of power.

All costs of collecting from the Customer may be collected including but not limited to interest and any legal costs, etc. Interest is charged to a Customer at a monthly rate of 1.5% compounded daily beginning the first day after a due date.

Such discontinuance of service does not relieve the Customer of the liability for arrears or minimum bills for the balance of the term of contract nor shall Tillsonburg Hydro be liable for any damage on the Customer's premises resulting from such discontinuance of service.

2.2.2 Disconnection On Order Of Inspection Department

The Electrical Safety Authority has the power under the Electricity Act, 1998 to order any utility to disconnect a service. The regulations pertaining to service discontinuance are contained in the Ontario Electrical Safety Code, 22nd Edition, 1998, Page 32, 2-018, Defects.

2.2.3 Disconnect and Reconnect Of Private Substations for Maintenance

2.2.3.1 Introduction

Customers normally perform substation maintenance annually on the transformers and switchgear contained within the confines of their private substation. When this occurs there are a number of procedures that should be followed before this maintenance can be completed.

2.2.3.2 Procedure

The steps to be followed by owners or electrical contractors are outlined below:

i) The owner or electrical contractor will contact a Tillsonburg Hydro representative at (519) 842-9200 ext. 225 or 227 to arrange a date and time for the disconnection and reconnection of the high voltage connections for the substation. Tillsonburg Hydro normally requires at

least three (3) working days advanced notice to schedule the disconnection and reconnection of the substation.

ii) The owner or electrical contractor will supply Tillsonburg Hydro with a purchase order number and a billing address.

iii) It is the responsibility of the owner or electrical contractor to contact the Electrical Safety Authority and complete an "Application for Inspection".

It should be noted that Tillsonburg Hydro is unable to reconnect the supply power until connection authorization has been received from the Electrical Safety Authority. In order to improve the inspection efficiency, the Electrical Safety Authority has an "advanced connection authorization" program available to qualified contractors. In this case the contractor shall provide the Electrical Safety Authority with at least two working days advanced notification of scheduled work. Provided that a permit has been issued for the work, the Inspection department will issue an advanced connection authorization to Tillsonburg Hydro. The Inspection Department will perform the actual inspection following reconnection of the substation.

iv) All substation disconnections and reconnections for maintenance are performed under a time and material basis. If the work is carried out during normal working hours (07:30 to 16:00) Monday to Friday except holidays, regular time will apply, any hours worked outside normal working hours will be billed at premium time.

The Electrical Safety Authority establishes the fee schedule for Electrical Inspections. Note that this fee schedule is revised annually.

v) If the electrical contractor does not require Tillsonburg Hydro to disconnect the high voltage connections but only requires the T1-L switch for isolation, the contractor may open this switch provided that they use approved safety procedures and contact Tillsonburg Hydro at 842-9200 ext. 227 before operating the switch. The operation of the switch by the electrical contractor is permissible because the switch is normally part of the private substation.

vi) In the event that Tillsonburg Hydro is unable to perform scheduled work due to inclement weather, distribution system emergencies or similar, Tillsonburg Hydro foreperson or authorized person will contact the owner or electrical contractor to reschedule the work.

If a maintenance job is scheduled to be completed during premium time and the owner or electrical contractor cancels the job within 2 hours of the start time, two hours at the applicable premium rate will be billed to the job.

2.2.4 Disconnection & Reconnection of Residential Meters and Service Cables

Cut and reconnect

Subject to annual review

See Appendix “A”

2.2.5 Electrical Disturbances

Customers must ensure that their equipment does not cause any disturbances such as harmonics and spikes that may interfere with the operation of adjacent Customer equipment. Examples of equipment, which may cause disturbances, include large motors, welders and variable speed drives.

If an undesirable system disturbance is being caused by the Customer's equipment, the Customer will be required to cease operation of the equipment until satisfactory remedial action has been taken. If the Customer does not take such action within a reasonable time, then Tillsonburg Hydro may disconnect the supply of power to the Customer.

When the supply of power is disconnected because of electrical disturbances, inspection is required before reconnection. It shall be the responsibility of the Customer requiring the reconnection to arrange for the inspection and the payment of fees.

Tillsonburg Hydro also reserves the right and has an obligation to disconnect a Customer's private line or equipment if it has caused or is likely to cause because of its condition, a disturbance or outage on Tillsonburg Hydro system. It is the Customer's responsibility to maintain their privately owned equipment to industry accepted standards to ensure that outages affecting other Tillsonburg Hydro Customers do not occur due to lack of maintenance.

2.2.6 Energy Diversion

If Tillsonburg Hydro should find that energy diversion, fraud or abuse is taking place at a Customer's location, Tillsonburg Hydro may disconnect the supply of power to the Customer.

When the supply of power is disconnected because of energy diversion, fraud or abuse, inspection is required before reconnection. It shall be the responsibility of the Customer requiring the reconnection to arrange for the inspection and the payment of fees.

2.2.7 Hazardous Conditions

If Tillsonburg Hydro should discover hazardous wiring or conditions that would put the life or safety of the general public or Tillsonburg Hydro employees in jeopardy, the Customer will be notified of the condition and will be required to remedy the hazard. If the Customer does not take such action within a reasonable time, then Tillsonburg Hydro may disconnect the supply of power to the Customer.

When the supply of power is disconnected because of an electrical hazard, inspection is required before reconnection. It shall be the responsibility of the Customer requiring the reconnection to arrange for the inspection and the payment of fees.

2.2.8 Reconnection after Six Months

Where a service has been disconnected by Tillsonburg Hydro for non-payment of rates or due to a change of occupancy of the premises, for a period of six months or longer, Rule 2-012 of the Ontario Electrical Safety Code requires a re-inspection by the Electrical Safety Authority. It shall be the responsibility of the party requiring the reconnection to arrange for the inspection and the payment of fees.

2.2.9 Disconnection of Overlapped Services

Tillsonburg Hydro reserves the right to disconnect a service in situations where 2 services have been permitted to be overlapped should the overlap period exceed 15 days. (See Section 2.1.4.1).

2.2.10 Demolition Requirements

Anyone requesting a building demolition must first obtain a Town of Tillsonburg Demolition Permit Application. The Town of Tillsonburg will request Tillsonburg Hydro to confirm the disconnection and removal of all hydro services and equipment. To avoid delays, the Applicant must provide the following information to Tillsonburg Customer Service Centre Office at (519-842-9200) correct demolition address, all Tillsonburg Hydro accounts and meter numbers associated with the property, the Customer's name and phone number, and the list of equipment to be removed.

2.2.11 House Moving

If the loaded height of a house or building that is going to be moved is over 4.42 metres (14.5 feet), application must be made to Tillsonburg Hydro before the building can be moved on Town of Tillsonburg streets.

The mover is required to complete an application at the Town of Tillsonburg Customer Service Centre: 10 Lisgar Ave, Tillsonburg Ontario N4G 5A5 and provide this application to Tillsonburg Hydro. Following an on-site visit to view the building and the proposed route of the move, the Hydro Department will provide the mover with an estimated cost based on the loaded height of the building, the distance and the route that will be taken. The mover must guarantee the height of the building at the time of making the deposit.

Tillsonburg Hydro will disconnect or raise overhead wires during the move and the mover will be required to pay the actual costs incurred.

2.3 Conveyance of Electricity

2.3.1 Limitations on the Guaranty of Supply

Tillsonburg Hydro will endeavour to use reasonable diligence in providing a regular and uninterrupted supply but does not guarantee a constant supply or the maintenance of unvaried frequency or voltage and will not be liable in damages to the Customer by reason of any failure in respect thereof.

Customers requiring a higher degree of security than that of normal supply are responsible to provide their own back-up or standby facilities. Customers may require special protective equipment at their premises to minimize the effect of momentary power interruptions or voltage sags.

Tillsonburg Hydro will endeavour to maintain voltage variation limits under normal operating conditions at the Customers' delivery points as specified by the latest edition of the Canadian Standards Association, CAN3-C235-87 (or latest edition).

Customers requiring a three-phase supply should install protective apparatus to avoid damage to their equipment, which may be caused by the interruption of one phase, or non-simultaneous switching of phases of the power supply by Tillsonburg Hydro.

Although it is Tillsonburg Hydro policy to minimize inconvenience to Customers, it is necessary to occasionally interrupt a Customer's supply to maintain or improve Tillsonburg Hydro system or to provide new or upgraded services to other Customers.

When practical, Tillsonburg Hydro will endeavour to notify Customers prior to interrupting the supply of power to any individual service. However, if an unsafe or hazardous condition is found to exist or if the use of electricity by a Customer's apparatus, appliances or other equipment is found to be unsafe or damaging to Tillsonburg Hydro or the public, or if service must be disconnected to assist in the safe or efficient restoration of power, or maintenance of Tillsonburg Hydro system, or in response to a shortage in supply, service may be disconnected without notice.

Tillsonburg Hydro shall have access rights to a property in accordance with Section 40 of the Electricity Act, 1998 and any successor Acts thereto.

2.3.2 Power Quality

This section should outline the guidelines and policies to which the distributor will endeavour to adhere to in conveying electricity supply, such as service voltage guidelines and outage notification processes. This section should also indicate the process the distributor uses for handling voltage disturbances and power quality testing and remedial action.

In response to a Customer power quality concern, where the utilization of electric power affects the performance of electrical equipment, an investigative analysis will be performed to identify the underlying cause. Depending on the circumstances, this may include review of relevant power interruption data, trend analysis, and/or use of diagnostic measurement tools.

Upon determination of the cause resulting in power quality concern, where it is deemed a system delivery issue and where industry standards are not met, Tillsonburg Hydro Inc. will recommend and/or take appropriate mitigation measures. Tillsonburg Hydro Inc. will endeavour to control harmonics generated by its own system where these are found to be detrimental to the Customers. If Tillsonburg Hydro Inc. is unable to correct the problem due to the impact on other Customers, then it is not obligated to make the corrections. Appropriate industry standards (such as IEC or IEEE standards) will be used as a guideline. If the problem lies on the Customer side of the system, Tillsonburg Hydro Inc. may seek reimbursement from the Customer for the costs incurred in its investigation.

If an undesirable system disturbance is being caused by the Customers equipment, the Customer will be required to cease operation of the equipment until satisfactory remedial action has been taken. If the Customer does not take such action within reasonable time, the Customer's supply of power may be disconnected.

If Tillsonburg Hydro Inc. determines that Consumer's equipment may be the source causing unacceptable harmonics, voltage flicker or voltage level on Tillsonburg Hydro Inc.'s distribution system; the Consumer shall assist Tillsonburg Hydro Inc. in its investigation by providing required equipment information, relevant data and necessary access for monitoring the equipment.

All electrical and mechanical equipment used by the Customer shall be subject to the reasonable approval of Tillsonburg Hydro Inc. When Customers plan to install large motors over 500hp, they must contact the Tillsonburg Hydro Inc. to ensure the existing or new services are sized correctly and that the distribution system can supply the required starting current. If customers have

equipment or install equipment that results in poor power factor (less than 90%), a power factor penalty will be applied and it is the Customer's responsibility to install equipment to correct or improve power factor.

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2.3.3 Electrical Disturbances

Tillsonburg Hydro shall not be held liable for the failure to maintain supply voltages within standard levels due to Force Majeure as defined in Section 2.3.5 of these Conditions of Service.

Voltage fluctuations and other disturbances can cause flickering lights and other serious difficulties for Customers connected to Tillsonburg Hydro distribution system. Customers must ensure that their equipment does not cause disturbances such as harmonics or spikes that might interfere with the operation of adjacent Customer equipment. Equipment that may cause disturbances includes large motors, welders, variable speed drives, etc. In planning the installation of such equipment, the Customer must consult with Tillsonburg Hydro.

> In general, larger motors will require reduced voltage starting equipment to prevent electrical disturbances. The largest motors permitted to be started across the line are as follows:
>
> 120/240 volts - 3 H.P.
>
> 120/208Y volts - 5 H.P.
>
> 347/600Y volts - 25 H.P.

Under certain conditions where the service entrance equipment rating is low in comparison to the motor starting inrush current, if lamp flicker becomes objectionable at an adjacent Customer's premises, reduced voltage starting equipment will be required on motors smaller than those specified above.

Customers having non-linear load shall not be connected to Tillsonburg Hydro distribution system unless power quality is maintained by implementing proper corrective measures such as installing filters, and/or grounding. Further, to ensure the distribution system is not adversely affected, installed power electronics equipment must comply with IEEE Standard 519-1992. The limit on individual harmonic distortion is 3%, while the limit on total harmonic distortion is 5%.

Customers, who may require an uninterrupted source of power supply or a supply completely free from fluctuation and disturbance, must provide their own power conditioning equipment for these purposes.

Where more than one metered service connection is provided to a single land parcel in order to provide different supply requirements to separate buildings, and there is not electrical tie between the service connections, each connection will be treated as a separate Customer for billing purposes. Where multiple feeds have been provided to a single land parcel because of limitations in Tillsonburg Hydro supply capacity, or where multiple feeds have been provided for security purposes and there is an electrical connection between the feeds, all of the metered connections will be aggregated together and treated as one Customer for billing purposes. Existing Customers who have different supply or billing arrangements will be permitted to maintain their existing arrangement until a material change is required in one or more of the service connections.

2.3.4 Standard Voltage Offerings

Tillsonburg Hydro distributes electrical power through 27.6 kV and 4.16 kV primary distribution systems. All supply feeders are arranged to run radial with open points between interconnections where practical. These feeders supply distribution transformers either directly or through 4.16 kV step-down sub-distribution systems.

The supply of electricity at primary voltage levels will primarily be at 27.6 kV depending on the proximity of the Customer's premises to the nearest distribution facility. For connection of a Customer at 4.16 kV, Tillsonburg Hydro will carry out a special study to justify the investment as in many areas the 4.16 kV distribution facilities are being phased out. The cost of this study may be charged to the Customer.

Tillsonburg Hydro standard secondary supply voltages are as follows:

- 120/240 volt, single phase, 3 wire
- 120/208Y volt, three phase, 4 wire
- 347/600Y volt, three phase, 4 wire

Not all secondary voltages are available at all locations. For example, some areas only have single phase power available and other areas such as industrial subdivisions may have a standardized 347/600Y volt secondary bus. In all cases Customers are required to consult with Tillsonburg Hydro to determine what secondary voltages are available.

Tillsonburg Hydro also has the following primary voltages in some but not all parts of its service territory:

- 2.4/4.16Y kV, three phase, 4 wire
- 16.0/27.6Y kV, three phase, 4 wire

As stated above, not all of these voltages are available in all areas of Tillsonburg Hydro service territory. Customers are required to consult with Tillsonburg Hydro to determine what voltages are available and to discuss their service requirements.

Customers requiring different voltages than those available in their area will be required to provide their own step down or step up transformation equipment.

In general, only one service will be permitted per Customer at one voltage, i.e., the Customer must supply their own transformation if other voltages higher or lower than the service voltage are

required for any portion of their operation. Under normal circumstances, only a single service through a single point of entry will be provided for each land parcel. If a Customer has more than one building on a single land parcel, it will be the Customer's responsibility to sub-feed the additional building(s) from the single point of supply. Exceptions may be made for commercial and industrial properties with multiple, separate buildings with different supply requirements. **N.B.** Customers must make application to Tillsonburg Hydro to determine if more than one service to a property will be permitted.

Where more than one metered service connection is provided to a single land parcel in order to provide different supply requirements to separate buildings, and there is no electrical tie between the service connections, each connection will be treated as a separate Customer for billing purposes. Where multiple feeds have been provided to a single land parcel because of limitations in Tillsonburg Hydro supply capacity, or where multiple feeds have been provided for security purposes and there is an electrical connection between the feeds, all of the metered connections will be aggregated together and treated as one Customer for billing purposes. Existing Customers who have different supply or billing arrangements will be permitted to maintain their existing arrangement until a material change is required in one or more of the service connections.

2.3.5 Voltage Guidelines

Tillsonburg Hydro maintains service voltage at the Customer's service entrance within the guidelines of C.S.A. Standard CAN3-C235-87 (or latest edition) which allows variations from nominal voltage of:

5% for Normal Operating Conditions

8% for Extreme Operating Conditions

Where voltages lie outside the indicated limits for Normal Operating Conditions but within the indicated limits for Extreme Operating Conditions, improvement or corrective action should be taken on a planned and programmed basis. Where voltages lie outside indicated limits for Extreme Operating Conditions, improvements or corrective action should be taken on an emergency basis. The urgency of such actions will depend on many factors such as the location and nature of load or circuit involved the extent to which limits are exceeded with respect to voltage levels, the expected duration of the emergency, etc.

Tillsonburg Hydro will practice reasonable diligence in maintaining voltage levels, but is not responsible for variations in voltage from external forces such as operating contingencies, exceptionally high loads or low voltage supply from Tillsonburg Hydro Transmitter or Host Distributor. Tillsonburg Hydro shall not be liable for any delay or failure in the performance of any of its obligations under this Conditions of Service due to any events or causes beyond the reasonable control of Tillsonburg Hydro, including without limitation, severe weather, flood, fire, lightning, other forces of nature, acts of animals, epidemic, quarantine restriction, war, sabotage, terrorist activity, act of a public enemy, earthquake, insurrection, riot, civil disturbance, strike, restraint by court order or public authority, or action or non-action by or inability to obtain authorization or approval from any governmental authority or any combination of these causes. (”Force Majeure")

2.3.6 Backup Generators

Customers with portable or permanently connected generation capability used for emergency back-up shall comply with all applicable criteria of the Ontario Electrical Safety Code. In particular, the Customer shall ensure that their emergency generation does not operate in parallel with Tillsonburg Hydro system without a proper interface protection and does not adversely affect Tillsonburg Hydro distribution system.

Customers with permanently connected emergency generation equipment shall notify Tillsonburg Hydro regarding the presence of such equipment.

2.3.7 Electric Metering Details & Requirements

2.4 Tariffs and Charges

2.4.1 Service Connections and Miscellaneous Charges

Tillsonburg Hydro policy is to develop and set average Customer charges at a level to permit full recovery of the allowable connection charges described in the " OEB Distribution System Code ".

Where fixed rate average connection charges do not apply, Customers will be charged on a time and material basis to fully recover the allowable cost.

2.4.1.1 Customers Switching to a Retailer

There are no physical service connection differences between Standard Service Supply (SSS) Customers and third party retailers' Customers. Both Customer energy supplies are delivered through the local Distributor with the same distribution requirements. Therefore all service connection requirements applicable to the SSS Customers are applicable to third party retailers' Customers.

2.4.1.2 Payment of Connection Charges and Supply Deposits

Where connection charges or deposits apply, an irrevocable (standby) Letter of Credit or Letter of Guarantee from a chartered bank, trust company or credit union is acceptable in lieu of a cash deposit. Purchase orders in lieu of a cash payment will be accepted from the Town of Tillsonburg only.

2.4.2 Energy Supply

2.4.2.1 Standard Service Supply (SSS)

All existing Tillsonburg Hydro Customers are Standard Service Supply (SSS) Customers until Tillsonburg Hydro is informed of their switch to a Retail Electricity Supplier. The Service Transfer Request (STR) must be made by the Customer or the Customer's authorized retailer.

2.4.2.2 Retailer Supply

Customers transferring from Standard Service Supply (SSS) to a retailer must comply with the Service Transfer Request (STR) requirements outlined in Sections 10.5 through 10.5.6 of the Retail Settlement Code.

All requests shall be submitted as Electronic files and transmitted through Tillsonburg Hydro EBT system. Service Transfer Requests (STR) must contain information as set out in Section 10.3 of the Retail Settlement Code.

If the information is incomplete, Tillsonburg Hydro will notify the retailer or Customer about the specific deficiencies and await a reply before proceeding to process the transfer.

2.4.2.3 Wheeling of Energy

All Customers considering delivery of electricity through Tillsonburg Hydro distribution system are required to contact Tillsonburg Hydro for technical requirements and applicable tariffs.

2.4.3 Deposits

This section should outline any deposit and prudential requirements the distributor has established for providing a Customer with distribution services, supply through standard service supply or through a retailer per the rules and regulations laid out in the Retail Settlement Code.

Definitions:

- "**Good payment history**" means a customer is deemed to have a good payment history unless, the customer has received more than one disconnection notice from Tillsonburg Hydro Inc., more than one cheque given to Tillsonburg Hydro Inc. by the customer has been returned for insufficient funds, more than one pre-authorized payment to Tillsonburg Hydro Inc. has been returned for insufficient funds or a disconnect/collect trip has occurred in one year in the case of a residential customer, in the previous 5 years in the case of a non-residential customer in a <50 kW demand rate class or in the previous 7 years in the case of a non-residential customer in any other rate class. The time period that makes up the good payment history must be the most recent period of time and some of the time period must have occurred in the previous 24 months.

- "**Standard Supply Service**" means customers have not chosen to sign a contract with a licensed retailer and Tillsonburg Hydro, as required by the OEB, will provide the commodity (electricity) at wholesale market prices.

Tillsonburg Hydro Inc. may require a security deposit for service based on each meter connection connected to Tillsonburg Hydro Inc.'s distribution system unless the customer has a 'Good payment history'.

Any one of the following forms of payment of a security deposit will be accepted by Tillsonburg Hydro Inc.:

1. Cash, cheque or debit, which may be paid in equal instalments, over at least four months or a shorter time period should the customer so choose.

2. An automatically renewing, irrevocable letter of credit, in a form satisfactory to Tillsonburg Hydro Inc. from a Bank for a non-residential customer.

The maximum amount of a security deposit that Tillsonburg Hydro Inc. may require a customer to pay is calculated as 2.5 times the estimated bill based on the customer's estimate or average monthly load with Tillsonburg Hydro Inc. for the most recent 12 consecutive months within the past two years.

Where a non-residential customer in any rate class other than a <50 kW demand rate class has a credit rating from a recognized credit rating agency, the maximum amount of a security deposit which Tillsonburg Hydro Inc. may require the non-residential customer to pay shall be reduced in accordance with by the following:

Credit Rating	**Allowable Reduction in Security**
AAA – and above or equivalents	100%
AA-,AA,AA+ or equivalent	95%
A-, From A, A+ to below A or equivalent	85%
BBB-, From BBB, BBB+ to below A or equivalent	75%
Below BBB- or equivalent	0%

Tillsonburg Hydro Inc. shall not require a security deposit where a customer provides a letter from another hydro or gas distributor in Canada confirming a good payment history with that distributor for the most recent relevant time period where some of the time period which makes up the good payment history has occurred in the previous 24 months; or a customer, other than a customer in a > 5000 kW demand rate class, provides a satisfactory credit check made at the customer's expense.

Tillsonburg Hydro Inc. may in its discretion reduce the amount of a security deposit that it requires a customer to pay for any reason including where the customer pays under an interim payment arrangement and where the customer makes pre-authorized payments.

Tillsonburg Hydro Inc. will review every customer's security deposit at least once in a calendar year to determine whether the entire amount of the security deposit is to be returned to the customer as the customer is now in a position that it would be exempt from paying a security deposit because of "Good payment history" or whether the amount of security deposit is to be adjusted based on a re-calculation of the maximum amount of the security deposit.

A customer may, no earlier than 12 months after the payment of a security deposit or the making of a prior demand of a review, beginning on February 1, 2005, demand in writing that Tillsonburg Hydro Inc. undertake a review to determine whether the entire amount of the security deposit is to be returned to the customer as the customer is now in a position that would be exempt from paying a security deposit or whether the amount of the security deposit is to be adjusted based on a re-calculation of the maximum amount of the security deposit.

Where Tillsonburg Hydro Inc. determines in conducting a review that some or all of the security deposit is to be returned to the customer, it shall promptly return this amount to the customer by crediting the customer's account. Where the maximum amount of the security deposit is to be adjusted upward, the distributor may require the customer to pay this additional amount at the same time as that customer's next regular bill comes due.

For customers in a >5000 kW demand rate class where the customer is now in a position that would exempt it from paying a security deposit, Tillsonburg Hydro Inc. is only required to return 50% of their security deposit credited to their account.

Tillsonburg Hydro Inc. shall promptly return any security deposit received from the customer upon closure of the customer's account, subject to the right to use the security deposit to set off another amounts owing by the customer. The security deposit shall be returned within six weeks of closure of an account.

Services that require a deposit will not be connected unless the deposit has been received and/ or Tillsonburg Hydro Inc. has agreed to acceptable arrangements for payment of such a deposit.

It is the Customer's responsibilities to notify Tillsonburg Hydro Inc. when they assume responsibility for utility services and provide the deposit if applicable. Tillsonburg Hydro Inc. will initiate the necessary action to collect the deposit if the customer does not comply.

If a service has been disconnected for non-payment of account and the customer has a deposit with Tillsonburg Hydro Inc., upon request of a reconnection, the amount of the security deposit will

be reviewed and increased if necessary. The customer must pay this additional deposit before the service will be reconnected.

If a service has been disconnected for non-payment of account and a deposit with Tillsonburg Hydro Inc. does not exist, a deposit will be required prior to reconnection.

Tillsonburg Hydro Inc. may establish additional deposit requirements where a diversion of power by a particular customer or at a specific location, has been confirmed.

Interest shall accrue monthly on security deposits made by way of cash, cheque or debit commencing on receipt of the total required deposit. The interest rate shall be at the Prime Business Rate as published on the Bank of Canada website less 2 percent, updated quarterly. The interest accrued shall be paid out at least every 12 months or on return or application of the security deposit or closure of the account, whichever comes first, and may be paid by crediting the customer's account.

Tillsonburg Hydro Inc. will apply a security deposit to the final bill prior to the change in service where a customer changes from Standard Supply Service to a competitive retailer that uses retailer-consolidate billing or a customer changes billing options from distributor-consolidating billing to split billing or retailer-consolidating billing. Any remaining amount will be promptly returned to the customer. Tillsonburg Hydro Inc. will not pay any portion of a customer's security deposit to a competitive retailer. Tillsonburg Hydro Inc. may retain a portion of the security deposit amount where a change is made from distributor-consolidated billing to split billing and which reflects the non-payment risk associated with the new billing option.

2.4.4 Billing

This section should outline the billing methods and billing cycles the distributor has established to provide a Customer with distribution services, supply through standard service supply or through a retailer as per the rules and regulations laid out in the Retail Settlement Code.

Tillsonburg Hydro Inc. renders bills to its Customers on a monthly basis. Bills for the use of electrical energy may be based on either a metered rate or flat rate, as determined by Tillsonburg Hydro Inc.

The Customer may dispute charges shown on the Customer's bill or other matters by contacting and advising Tillsonburg Hydro Inc. of the reasons for the dispute. Tillsonburg Hydro Inc. will promptly investigate all disputes and advise the Customer of the results.

Use of Estimates

For billing periods where a meter reading is not available, Tillsonburg Hydro Inc. will estimate usage in order to determine billing quantities. The estimate is based on historical usage for the Customer or premise or on a pre-determined quantity if there is no historical usage information available.

The minimum requirement for an actual meter reading will be at least once every 3 months. Failure of customers to comply could result in suspension of service until actual reads are obtained.

2.4.5 Payments and Late Payment Interest Charges

This section should outline payment methods that the distributor has established to provide the Customer with distribution services, supply through standard service supply or through a retailer as per the rules and regulations laid out in the Retail Settlement Code.

Bills are rendered for distribution services and electrical energy used by the Customer. Bills are payable in full by the due date. An interest charge will apply on the outstanding balance of each account at a rate approved by the Regulator (OEB). It will be assessed at the time each bill is issued. For current amounts (due by the most recent due date) a charge will apply from the due date to the billing date or the payment date whichever is earlier. If there are arrears prior to the current bill, a charge will apply from the last billing date to the current billing date or payment date which ever is earlier. Partial payments will apply to the oldest arrears first.

Outstanding bills are subject to the collection process and may ultimately lead to the service being disconnected. Service will be restored once satisfactory payment has been made. Disconnection of service does not relieve the Customer of the liability for arrears.

Tillsonburg Hydro Inc. shall not be liable for any damage on the Customer's premises resulting from such disconnection of services. A reconnection charge will apply where the service has been disconnected due to non-payment.

The customer will be required to pay additional charges for the processing of non-sufficient fund (N.S.F.) cheques.

Customers will pay special charges and deposits, on request, which may arise from a variety of conditions such as:

- Deposit, as a guarantee of payment of bills, Customers may be required to pay a deposit to Tillsonburg Hydro Inc.

- Transfer charge. A change of occupancy charge will apply to all accounts taken over by a new customer.

- Collection Charge. It is sometimes necessary, for the customer's convenience, for Tillsonburg Hydro Inc. employee or agent to visit a Customer's premises to collect payment for an account. There will be a charge for this service.

- Reconnection Charge. A consumer disconnected for non-payment shall be required to pay a reconnection charge.

2.4.5.1 Customer Information

The Conditions of Service shall describe the prevision of information with respect to chapter 11 of the Retail Settlement Code. This specifies the rights of consumers and retailers to access current and historical usage information and related data and the obligations of distributors in providing access to such information. The Condition of Service should include reference to include information subject to privacy regulations and load profile information.

Any processes for handling requests for information outside of the requirements of the Retail Settlement Code should be described in this section.

The rights of consumers and retailers to access current and historical usage information and related data and the obligations of Tillsonburg Hydro Inc. in providing access to such information is outlined in the Retail Settlement Code.

A third party who is not a Retailer may request historical usage information with the written authorization of the Customer to provide their historical usage information.

Tillsonburg Hydro Inc. will provide information appropriate for operational purposes that has been aggregated sufficiently, such that an individual's Customer information cannot reasonably be identified, at no charge to another distributor, a transmitter, the IMO or the OEB. Tillsonburg Hydro Inc. may charge a fee that has been approved by the OEB for all other request for aggregated information.

At the request of a Customer, Tillsonburg Hydro Inc. will provide a list of retailers who have Service Agreements in effect within its distribution service area. The list will inform the Customer that an alternative retailer does not have to be chosen in order to ensure that the Customer receives electricity and the terms of service that are available under Standard Supply Service.

Upon receiving an inquiry from a Customer connected to its distribution system. Tillsonburg Hydro Inc. will either respond to the inquiry if it deals with its own distribution services of provide the Customer with contact information for the entity responsible for the item of inquiry, in accordance the Retail Settlement Code.

An embedded distributor that receives electricity from Tillsonburg Hydro Inc. shall provide load forecasts or any other information related to the embedded distributor's system load to Tillsonburg Hydro Inc. as determined and required by Tillsonburg Hydro Inc. A distributor shall not require any information from another Distributor unless it is required for the safe and reliable operation or either Distributor's distribution system or to meet a Distributor's license obligations.

2.4.5 Customer Class Definition and Application of Rates

All Customers are to be classified according to the policies and guidelines of the Ontario Energy Board Electricity Distribution Handbook. The specific application of these policies and guidelines within the Tillsonburg Hydro service territory are outlined in this section.

The Ontario Energy Board approves all retail distribution and retail transmission rates for each retail Customer class. Refer to Section 2.4.7 for reference to the current approved rates.

2.4.5.1 Annual Rate Class Review

To ensure fairness and uniform application of rates, it is necessary to confirm that all Customers continue to be properly classified. To ensure that, Tillsonburg Hydro will conduct a periodic review of its Customer base to determine changes to customer specific rate classifications. Tillsonburg Hydro will conduct a review for all customers based on the Customer's consumption during a predefined annual 12-month consumption period. The annual 12-month consumption period will normally be deemed to be between the Customer's first meter reading date occurring in October of each year through to the end meter reading date in October of the next year, unless otherwise specified. Normally, a Customer rate reclassification review will occur in November of each year with the first change being made after January 1st of the new billing year.

Interim reviews of a Customer's rate classification can be made at any time at either Tillsonburg Hydro discretion or upon request by the customer. An interim review would be based on the immediately proceeding months, up to but no greater than a 12-month period. If an annual or interim review requires a Customer to be moved into a different rate class, Tillsonburg Hydro will notify the Customer of the rate reclassification a minimum of one bill period before the reclassification is being made. Rate reclassifications apply only to future charges; neither Tillsonburg Hydro nor the Customer can charge or recover monies for payments made during the 12-month period preceding a review and rate reclassification.

2.4.5.2 Temporary Services

Customers will be classified into the temporary service classification whenever their billing period will be less then 12 months of consecutive service. The consecutive service period is defined as the time between when the electric service becomes activated by a Customer for billing to the time the service becomes deactivated and the billing to the Customer ceases. Initial Customer rate classification will be determined by using the best available criteria from use of either forecasted consumption data, historical consumption data derived from typical/similar Customer use when available or through the use of the Application of Rates and Charges, outlined in Chapter 9 of the OEB Rate handbook. For determining the appropriate customer rate class for temporary service Customers, the evaluation process will use less than 12-month consumption averages for determining the appropriate rate class to be applied.

There are two major sets of categories under which Tillsonburg Hydro must classify its Customers and apply rates. These categories are distribution services and transmission services. The distribution services relate to the actual distribution system that Tillsonburg Hydro utilizes to provide services directly within the service territory. The transmission services are related to the infrastructure of both the transmission system and provincial electric market operations to provide service to the Tillsonburg Hydro service territory.

For each major category a definition of Customer classes and rate applications are required.

2.4.5.3 Retail Distribution Rates

2.4.5.3.1 Residential – Energy Metered and General Service < 50 kW – Energy Metered

All non demand customers without interval meters will be deemed to be Residential – Energy Metered and General Service < 50 kW – Energy Metered. This rate class will include all residential customers and general service customers with either a 12-month average annual consumption period demand of less than 50 kW per month or projected average demand of less than 50 kW per month for new Customers.

Any of the above class of Customers that install an interval meter will be deemed to be on the same retail distribution rate schedule and rate application as this Customer rate class. The service charge will be applied on a per (electric service) connection basis.

Multi-unit residential establishments such as apartment buildings supplied through one service (bulk meter) shall be classified as general service; however Tillsonburg Hydro may apply residential rates to apartment buildings with six or less units. Such application must be undertaken consistently within its service area.

Where electricity service is provided to combine residential and business (including agricultural) usage and the wiring does not provide for separate metering, the classification shall be at the discretion of the utility and should be based on such considerations as the estimated predominate consumption.

2.4.5.3.2 Sentinel Lighting & Un-metered/Scattered loads

Sentinel lighting & un-metered/Scattered loads will be defined as the un-metered (Non-Streetlight) service accounts with Town of Tillsonburg. The demand kW rate will be applied on an estimated peak (connected load) demand occurring at any time of the month and the monthly service charge will be applied on a per connection basis. See Section 2.3.4 for a further discussion of billing arrangements for Customers with more than one metered service connection.

2.4.5.3.3 Street Lighting

Street Lighting will be defined as the un-metered street light service accounts with The Town of Tillsonburg. The demand kW rates will be applied on an estimated peak (connected load) demand occurring at any time of the month. The service charge will be on a per connection basis.

2.4.5.3.4 General Service - Demand Metered

This rate class will include all general service non interval-metered Customers with a 12-month average annual consumption period demand of greater than or equal to 50 kW per month or projected average demand of greater than or equal to 50 kW per month for new Customers and having an annual consumption period demand of less than 500 kW per month for existing Customers or projected average demand of less than 500 kW per month for new Customers. Customers with a 12-month annual consumption period demand of greater or equal to 1,000 kW per month are to be placed in the General Service – Interval Metered category, as per the OEB Distribution System Code (DSC) Section 5.1.3. For demand non-interval metered Customers the demand kW charge will be applied to billing demand (measured peak demand occurring at any time of the billing period). The measured demand will be adjusted for transformer losses and power factor as applicable to determine the billing demand. The billing demand will be determined

by the higher of 90% KVA or 100% kW (Power factor adjusted) and shall be adjusted for 1% transformer losses when the metering installation is deemed to be primary metered (Primary Meter = Meter on supply side of the transformer). The service charge will be applied on a per (electric service) connection basis. See Section 2.3.4 for a further discussion of billing arrangements for customers with more than one metered service connection.

Note: **OEB Distribution System Code Section 5.1.4 states the following:**

A Distributor may set a threshold level for installation of MIST meters other than that required by section 5.1.3. As long as the threshold is delineated by customer class in the distributor's Condition of Service and sets a threshold lower than that required by section 5.1.3.

Therefore, since Tillsonburg Hydro has set a threshold for mandatory interval meter limit at 500 kW all such customers will be placed in the appropriate customer class interval meter category and the appropriate rates and applications of distribution retail rates will be applied.

2.4.5.3.5 General Service - Interval Meter

This rate class will include all general service interval metered Customers with a 12-month average annual consumption period demand of greater than or equal to 50 kW per month or projected average demand of greater than or equal to 50 kW per month for new Customers and having an annual consumption period demand of less than 5,000 kW per month or projected average demand of less than 5,000 kW per month for new Customers.

The billing demand of a General Service – Interval Metered Customer shall be based on the maximum demand in kilowatts during any consecutive 15 minutes (15-Minute Clock Average) in the bill period, as recorded on an interval meter in 15-minute intervals. The measured demand shall be adjusted for transformer losses and power factor as applicable to determine the billing demand. The billing demand will be determined by the higher of 90% kVA or 100% kW (Power factor adjusted) and shall be adjusted for 1% transformer losses when the metering installation is deemed to be primary metered (Primary Meter = Meter on supply side of the transformer).

The service charge will be applied on a per (electric service) connection basis.

2.4.5.3.6 Large User > 5,000 kW - Interval Meter

Customers with a monthly peak demand averaged over 12 consecutive months equal to 5,000 kW or greater shall be classified as large user. Where forecast demands clearly establish that a customer would become a large user, the customer may be classified as a large user as soon as the maximum demand exceeds 5,000 kW. Normally, a customer's classification will be reviewed annually at the end of the calendar year.

The billing demand of a large user Customer shall be based on the maximum demand in kilowatts during any consecutive 60 minutes (Rolling 60-Minute Averages) in the bill period as recorded on an interval meter with a demand interval of either 5 or 15 minutes. The measured demand will be adjusted for transformer losses and power factor as applicable to determine the billing demand. The billing demand will be determined by the higher of 90% kVA or 100% kW (Power factor adjusted) and shall be adjusted for 1% transformer losses when the metering installation is deemed to be primary metered (Primary Meter = Meter on supply side of the transformer).

The service charge will be applied on a per (electric service) connection basis.

2.4.5.3.7 Embedded Generation

Embedded generation, co-generation or load displacement Customers have the option to reserve demand capacity on the Tillsonburg Hydro distribution system for import load through mutual agreement/contract. The Customer's contracted reserve amount shall not exceed the generator(s) nameplate capacity rating. The Customer can make a request to change the reserve amount annually 30 days prior to the anniversary date of the agreement/contract. The distribution standby rate will be applied to all monthly KWS reserved before any transformer discounts for Customer owned equipment. The transformer discount will be applied to all KWS reserved or billed when the Customer owns their own transformation.

The distribution kW rate is applied to the incremental billed demand. Incremental billed demand is equivalent to the peak monthly billed demand less the standby reserve kW.

The monthly measured peak demand will be determined by the higher of 90% KVA or 100% kW (Power factor adjusted) and shall be adjusted for 1% transformer losses when the metering installation is deemed to be primary metered (Primary Meter = Meter on supply side of the transformer).

The billed demand will be determined by the measured peak demand occurring during any time of the billing period (i.e. month). The service charge will be applied on a per (electric service) connection basis.

When gross peak demand is determined to be over an annual average of 5,000 kW per month, the billing demand will be based on the maximum demand during any consecutive 60 minutes (Rolling 60-Minute Averages) in the bill period.

When gross peak demand is determined to be less than an annual average of 5,000 kW per month, the billing demand will be based on the maximum demand during any consecutive 15 minutes (15-Minute Clock Average) in the bill period.

Gross Demand = Import plus Generation Less Export.

2.4.5.3.8 Embedded Distributor

The embedded distributor would be treated the same as the General Service – Interval Meter Customer class in the application of rates when gross peak demand is determined to be less than an annual 12-month consumption average of 5,000 kW per month or the projected average per month would be less than 5,000 kW on average for new embedded distributors.

The embedded distributor would be treated the same as the Large User – Interval Meter Customer class in the application of rates when gross peak demand is determined to be greater than or equal to an annual 12-month consumption average of 5,000 kW per month or the projected average per month would be greater than or equal to 5,000 kW on average for new embedded distributors.

2.4.5.3.9 Transformer Allowance

The transformer allowance will be applied to all kW reserved or billed when the Customer owns their own transformation.

2.4.5.3.10 Specific Service Charges

All specific service charge rates will be applied as outlined in the distribution rates schedules approved by the Ontario Energy Board.

2.4.5.4 Retail Transmission Rates

2.4.5.4.1 Residential - Energy Metered, General Service < 50 kW - Energy Metered and Un-metered Scattered Loads

All non demand Customers without interval meters will be deemed to be Residential – Energy Metered, General Service < 50 kW – Energy Metered or Un-metered Scattered Loads. This rate class will include all residential Customers and general service Customers with either a 12-month average annual consumption period demand of less than 50 kW per month or projected average demand of less than 50 kW per month for new Customers. The rates will be applied to all energy adjusted for the total loss factor set out under the Retail Settlements Code.

Any of the above class of Customers that install an interval meter will be deemed to be on the same retail transmission rate schedule and rate application as the Residential - Energy Metered and General Service < 50 kW - Energy Metered. As the number of interval metered Customers increase in these rate classes, a redefinition of the application could be made once coincident factor data is available.

2.4.5.4.2 Sentinel Lighting

Sentinel Lighting will be defined as the un-metered sentinel light service accounts with The Town of Tillsonburg and the rates will be applied on a connected load basis.

2.4.5.4.3 Street Lighting

Street Lighting will be defined as the un-metered street light service accounts with The Town of Tillsonburg and the rates will be applied on an average monthly connected load basis.

2.4.5.4.4 General Service - Demand Metered

This rate class will include all non interval-metered Customers with a 12-month average demand of equal to or greater than 50 kW or a 12-month average demand of less than 500 kW.

For demand non-interval metered Customers the retail transmission network and connection service charges will be based on their peak billed demand occurring at any time.

The measured demands for both connection and network retail transmission service charges shall be adjusted for transformer losses and power factor as applicable to determine the billing demand. The billing demand will be determined by the higher of 90% Kva or 100% kW (Power factor adjusted) and shall be adjusted for 1% transformer losses when the metering installation is deemed to be primary metered (Primary Meter = Meter on supply side of the transformer).

Note: OEB Distribution System Code Section 5.1.4 states the following:

A Distributor may set a threshold level for installation of MIST meters other than that required by section 5.1.3. As long as the threshold is delineated by Customer class in the distributor's Condition of Service and sets a threshold lower than that required by section 5.1.3.

Therefore, since Tillsonburg Hydro has set a threshold for mandatory interval meter limit at 500 kW all such Customers will be placed in the appropriate Customer class interval meter category and the appropriate rates and applications of transmission retail rates will be applied.

2.4.5.4.5 General Service - Interval Meter

This rate class will include all interval-metered Customers with an annual average calendar year monthly demand of greater than or equal to 50 kW or less than 5,000 kW.

The network and connection billing demand of a General Service – Interval Metered Customer shall be based on the maximum demand in kilowatts during any consecutive 15 minutes (15 Minute Clock Average) in the month as recorded on an interval meter. The measured demands for both connection and network retail transmission service charges shall be adjusted for transformer losses and power factor as applicable to determine the billing demand. The billing demand will be determined by the higher of 90% Kva or 100% kW (Power factor adjusted) and shall be adjusted for 1% transformer losses when the metering installation is deemed to be primary metered (Primary Meter = Meter on supply side of the transformer).

The billed demand for network retail transmission service charges will be determined by the measured peak billed demand occurring during the peak periods of 7 am to 7 pm (local time) on weekdays excluding holidays as defined by the Hydro One Networks Inc., Transmission Rates Schedule.

The billed demand for connection retail transmission service charges will be determined by the measured peak billed demand occurring during any time of the billing period (i.e. month) as defined by the Hydro One Networks Inc., Transmission Rates Schedule.

2.4.5.4.6 Large User > 5,000 kW – Interval Meter

A Customer with a monthly peak demand regardless of whether the demand occurs in the peak or off-peak transmission system periods, averaged over 12 consecutive months, is equal to 5,000 kW or greater, shall be classified as large user. Where forecast demands clearly establish that a Customer would become a large user, the Customer may be classified as a large user as soon as the maximum demand exceeds 5,000 kW. Normally a customer's classification will be reviewed annually at the end of the calendar year.

The billing demand of a large user customer shall be based on the maximum demand in kilowatts during any consecutive 60 minutes (Rolling 60-Minute Average) in the month as recorded on an interval meter with a demand interval of either 5 or 15 minutes. The measured demands for both connection and network retail transmission service charges shall be adjusted for transformer losses and power factor as applicable to determine the billing demand. The billing demand will be determined by the higher of 90% kva or 100% kW (Power factor adjusted) and shall be adjusted for 1% transformer losses when the metering installation is deemed to be primary metered (Primary Meter = Meter on supply side of the transformer).

The billed demand for network retail transmission service charges will be determined by the measured peak billed demand occurring during the peak periods of 7 am to 7 pm (local time) on weekdays excluding holidays as defined by the Hydro One Networks Inc., Transmission Rates Schedule.

The billed demand for connection retail transmission service charges will be determined by the measured peak billed demand occurring during any time of the billing period (i.e. month) as defined by the Hydro One Networks Inc., Transmission Rates Schedule.

2.4.5.4.7 Generation (Existing & New < 1MW)

Generation (Existing & New < 1 MW) rates will apply to all embedded generation Customer import/consumed energy taken from the Tillsonburg Hydro distribution system as follows:

Existing embedded generation is defined as those generators with required approvals for such generation before October 30, 1998. Embedded generation < 1 MW will be those generators installed at any time with a generation rating of 1 MW or less and have an interval meter installed on the service entrance.

Retail Network Service Charge – rates applied to the measured coincidental net energy consumed during the clock hour at time of either the higher of the transmission system peak or 85% delivery point peak between the peak time hours of 7 am to 7 pm (local time) on weekdays excluding holidays as defined by the Hydro One Networks Inc., Transmission Rates Schedule.

The billing demand will be determined by the higher of 90% kVA or 100% kW (Power factor adjusted) and shall be adjusted for 1% transformer losses when the metering installation is deemed to be primary metered (Primary Meter = Meter on supply side of the transformer).

Retail Connection Service Charge – rates applied to the measured coincidental net energy consumed during the clock hour at the time of their delivery point peak. The billing demand will be determined by the higher of 90% kVA or 100% kW (Power factor adjusted) and shall be adjusted for 1% transformer losses when the metering installation is deemed to be primary metered (Primary Meter = Meter on supply side of the transformer).

The connection import demand will be determined by the billing import demand, which will be determined by the highest of either 90% kVA or 100% kW (Power factor adjusted). Import demand shall be adjusted for 1% transformer losses when the metering installation is deemed to be primary metered (Primary Meter = Meter on supply side of the transformer).

2.4.6 Distribution Rates

The Ontario Energy Board must approve all rates and charges that Tillsonburg Hydro applies.

The following are the types of rates and charges that are approved by the OEB:

- Loss Factors
- Retail Distribution Rates
- Retail Transmission Rates
- Wholesale Market Service Rate
- Standard Supply Service Rates
- Miscellaneous Rates and Charges

2.5 Customer Information

A third party who is not a retailer may request historical usage information with the written authorization of the Customer to provide their historical usage information.

Tillsonburg Hydro will provide information appropriate for operational purposes that has been aggregated sufficiently, such that an individual's Consumer information cannot reasonably be identified, at no charge to another Distributor, the transmitter, the IMO or the OEB. Tillsonburg Hydro may charge a fee that has been approved by the OEB for all other requests for aggregated information.

At the request of a Consumer, Tillsonburg Hydro will provide a list of retailers who have Service Agreements in effect within its distribution service area. The list will inform the Consumer that an alternative retailer does not have to be chosen in order to ensure that the Consumer receives electricity and the terms of service that are available under Standard Supply Service.

Upon receiving an inquiry from a Customer connected to its distribution system, Tillsonburg Hydro will either respond to the inquiry if it deals with its own distribution services or provide the Customer with contact information for the entity responsible for the item of inquiry, in accordance with Chapter 7 of the Retail Settlement Code.

An embedded Distributor that receives electricity from Tillsonburg Hydro shall provide load forecasts or any other information related to the embedded Distributor's system load to Tillsonburg Hydro, as determined and required by Tillsonburg Hydro.

3 CUSTOMER SPECIFIC

3.1 Residential

This section is divided into three categories of residential services: single-family or single-unit homes, multi-family buildings, and subdivision developments.

3.1.1 Single-Family Residential - General

Single-family residential dwelling units will be provided with a basic connection to Tillsonburg Hydro electric system without charge. The basic connection includes the supply and installation of overhead distribution transformer capacity or an equivalent credit for transformation equipment and up to 30 metres of overhead conductor or an equivalent credit for underground services.

For the purpose of determining whether a basic connection is provided free of charge or whether a commercial service charge applies, a single family residential dwelling must be zoned residential by the Town of Tillsonburg, must be used for dwelling purposes, and must have only one electric meter. Any costs associated with modifying a service to a residential dwelling unit to add additional meters will incur General Service (Commercial) connection costs as described in Section 3.2.

Energy supplied to residential dwellings will be single phase, 3 wires, 60 Hz, having a nominal voltage of 120/240 volts, up to a maximum 200 amps per dwelling unit. Only one electrical service will be permitted per dwelling.

3.1.1.1 Early Consultation

Where a new service is required, the Customer must supply Tillsonburg Hydro with the following information well in advance of the date when the service will be required:

i) required in-service date

ii) requested service entrance capacity and voltage rating of the service entrance equipment

iii) Locations of other services such as gas, telephone, water, cable TV, underground sprinkler systems, etc.

iv) details respecting heating equipment, air conditioners and any appliances which demand a high consumption of electrical energy

v) A survey or site plan indicating the proposed location of the service entrance equipment with respect to public rights of way and lot lines.

Customers requesting disconnect or reconnect of an existing service to permit a service upgrade should refer to “Disconnection and Reconnection of Residential Service Cables” Section 2.2.4

Point of Demarcation

The Point of Demarcation for residential overhead services is at the connection point where Tillsonburg Hydro service drop connects to the Customer's anchor point and service mast weather head. Tillsonburg Hydro is responsible for the maintenance and repair of the transformer, transformer hardware and the first 30m of the overhead service wire. The Customer is responsible for the maintenance and repair of the anchor point, weather head and all points downstream of the connection splice including the meter socket base and the jaw and connection block assemblies. Tillsonburg Hydro is responsible for the maintenance and repair of the electric meter.

The Point of Demarcation for residential underground services is at the meter. Tillsonburg Hydro is responsible for the maintenance and repair of the transformer, transformer hardware, the underground secondary cable and the electric meter. The Customer is responsible for the maintenance and repair of the meter socket base, the meter jaw and connection block assemblies and all equipment downstream. The Customer is also responsible for the conduit that guides the service cable from underground to the meter base.

For Customers who have service entrances with recessed meter bases and 'Amalgamated' switches, combination panels or a similar configuration, Tillsonburg Hydro service cables enter the Customer's disconnect switch ahead of the meter. In these instances, the Customer is also responsible for the maintenance and repair of the disconnect switch or combination panel.

For Customers whose service entrance is located more than 100 metres from the right-of-way, a high voltage primary line (either overhead or underground) will be required. The Customer will be responsible to own and maintain the primary portion of the line unless they elect to pay a 20% premium on the initial cost of the primary line to transfer the ownership and future maintenance responsibilities to Tillsonburg Hydro. If the Customer is responsible to maintain the primary line, the Point of Demarcation for overhead lines is at the first pole and the Point of Demarcation for underground lines is at the primary cable riser connection. The Customer is responsible for the

maintenance and repair of all poles, primary conductors and hardware, (including regular tree trimming), primary cable terminators, cable hangers, and primary cables in addition to the equipment listed in the first two paragraphs of this section. Tillsonburg Hydro is responsible for the transformer, transformer hardware, the civil components associated with pad mounted transformers (slab, pull box, grounding), and the first 30m of overhead secondary wire. Tillsonburg Hydro will be responsible for maintaining all residential underground secondary cables.

In all cases, if a Customer requires a primary line on their property, the Customer must sign a Connection Agreement that will describe in detail which party is responsible for the maintenance of various components of the line.

3.1.1.2 Servicing Details

The Customer or the Customer's electrical contractor must contact Tillsonburg Hydro to arrange a mutually agreeable service location and supply service arrangement.

i) Overhead Services

Arrangements for a service layout for overhead service conductors may be made directly with the Hydro foreperson at (519) 688-3009, Ext. 2227.

In overhead supplied areas, Tillsonburg Hydro will install overhead service wires from its aerial circuits on the public right of way at no charge to the Customer if the distance between Tillsonburg Hydro supply point and the Customer's service entrance is not more than 30 metres. If the distance is greater than 30 metres, the Customer will incur a charge for additional material and labour. If a pole or poles and any other attachments are required on the Customer's property to support, anchor or terminate the service conductors, these shall be supplied and installed at the Customer's expense.

If the distance is greater than 100 metres, the Customer will be required to construct a primary voltage pole line on their property to support the circuit. The Customer will have a choice to both own and maintain this line or to pay a 20% premium on the initial cost of the line to transfer the ownership and future maintenance of the line to Tillsonburg Hydro as described in Section 3.1.1.2. Tillsonburg Hydro will make the connection to Tillsonburg Hydro circuits on the public right-of-way. If a transformer is required, Tillsonburg Hydro will supply the transformer and will install and maintain up to 30m of secondary service cable. The Customer will be responsible for the installation and maintenance of all poles, hardware, primary conductors (including regular tree trimming) and any secondary conductors beyond the first 30m from the transformer pole to the service entrance. The Customer will also be required to sign a Connection Agreement with Tillsonburg Hydro and connection charges will apply.

The permissible height for the service wires entering the residential dwelling is a minimum of 15 Feet above the finished ground level. Higher elevations may be required to ensure proper clearance over driveways or from windows and other obstructions.

A Customer will be responsible to supply and install all equipment for the anchoring of the service wires near the service weather head. This will include a through bolt and insulator for the service attachment.

The Customer must locate the service conduit head not further than 3 meters from the corner of the building closest to Tillsonburg Hydro supply point. The Customer's service conductors must

run from the meter socket through the service conduit riser with at least 24 inches of conductor extending from the weather head to provide for connection to the service drop with an adequate drip loop.

The location of the service point of attachment must be such that the service wires will not cross over any part of the building, additions, out buildings, awning, or any place that is not accessible by Tillsonburg Hydro employees. The point of attachment must also be accessible by ladder.

ii) Underground Services

Arrangements for service layouts for underground supply service conductors may be made directly with the Tillsonburg Hydro at (519) 688-3009, Ext. 2227.

In underground residential areas, Tillsonburg Hydro will install underground service wires for a fixed fee if the distance from the property line to the Customer's service entrance is not more than 30 metres. The fixed fee is described in Appendix A and represents the cost of the underground service less a credit for an equivalent basic overhead connection.

In areas that are supplied with overhead circuits, a Customer may request an underground service and must meet the following conditions:

a) The Customer must arrange for a service layout, obtain approval for a proposed trench layout. Tillsonburg Hydro will supply and install the secondary cable**.**

b) The Customer is responsible for digging the trench and ensuring that the backfill is free of debris (bricks, stones, etc.). If the native material is unsuitable for backfill, the Customer is responsible to install 6 inches of sand bedding and cover. The trench must be a minimum of 36 inches in depth and 6 inches in width. Tillsonburg Hydro will advise the Customer of minimum clearances required from Tillsonburg Hydro distribution equipment.

c) The Customer must provide a 50 mm (2 inch) rigid polyvinyl chloride (PVC) conduit from the base of the meter socket to at least 1 metre below finished grade. The service entrance and meter location must be located not further than 3m from the corner of the building closest to Tillsonburg Hydro supply point.

d) If a pole is required on the Customer's property to support the underground dip or if boring costs are incurred to cross a roadway, or if any other costs are required over and above the cost of an equivalent overhead connection, these will be at the Customer's expense.

e) Tillsonburg Hydro will be responsible for terminating the secondary cable at the overhead circuit and on the line side of the Customer's meter base.

f) For services greater than 30m in length an additional charge per meter will be added.

Tillsonburg Hydro will own, operate and maintain the underground secondary cable provided there is reasonable access to the underground plant. The Customer will be responsible to remove and reinstate any privately owned obstructions (landscaping, sprinklers and sprinkler piping, sheds, buildings, etc.) if required for access. To avoid open cut driveways to repair future cable faults, an appropriate electrical conduit crossing will be accepted. Under no circumstances will drainage pipe be permitted.

In the event of a fault on the Customer's underground supply or an adjacent Customer's supply, Tillsonburg Hydro reserves the right to install temporary jumper cables from either a Customer or a neighbouring Customer service to maintain power to the affected Customer until the fault is repaired. The connections are made on the line side of the meter and do not affect consumption charges.

For services larger than 200 A, single phase, Tillsonburg Hydro will supply and install parallel secondary cables. Two 50 mm (2 inch) rigid polyvinyl chloride (PVC) conduits must be supplied by the Customer as well as an indoor main disconnect switch. Tillsonburg Hydro will install the secondary cables up through the entrance conduit into the Customer-owned switch and make the connections on the line side. For services larger than 200 A, connection charges will apply.

3.1.1.3 Metering

All of the requirements for metering single family residential dwellings are discussed in sections 2.4.6.3

3.1.2 Multi-Family Residential

For the purpose of this document, multi-family residential dwellings are defined as buildings containing more than one single family dwelling unit that are either individually metered or are metered with a bulk meter and have a service entrance capacity greater than 200 amps.

Multi-family residential dwellings fall under the General Service (Commercial) classification and connection charges will apply as described in Sections 3.2 to 3.4, depending on the size of the service. Please refer to the appropriate General Service section of this document for the conditions of service that apply to multi-family residential dwellings.

3.1.3 Residential Subdivision Developments

Electrical service facilities for single family and multi-family townhouse and condominium residential developments will be installed underground consisting of mini-pad mount transformers and primary/secondary conductors. Any variation in service will require Tillsonburg Hydro review for approval Tillsonburg Hydro will provide and install the complete distribution system including services to the line side of the Customer's meter base. The entire distribution system will be operated and maintained by Tillsonburg Hydro.

The sub-divider developer must enter into a Subdivision Agreement (I-68) with Tillsonburg Hydro. This Agreement must be fully executed before construction starts.

Early consultation with Tillsonburg Hydro is essential to avoid delays in servicing this type of development. Tillsonburg Hydro requires a minimum notice of 12 weeks prior to the required in-service date. The sub-divider developer is required to provide a site servicing plan and a lot grading plan for the placement of pad mount transformers. If the area described by a Registered Plan will be developed in stages, it is important for each stage or portion of work to be given a designation that is understood and accepted by all parties.

Tillsonburg Hydro will design a subdivision electrical servicing layout and the sub-divider developer will have the opportunity to review Tillsonburg Hydro design prior to installation. **N.B.** Minor changes are permitted as long as they do not compromise Tillsonburg Hydro standards and practices.

Tillsonburg Hydro will require the sub-divider developer to authorize the installation through a "Joint Letter" process. The sub-divider developer must sign the final distribution drawings from Tillsonburg Hydro and provide grade levels for all above ground equipment to be installed.

The sub-divider developer must provide registered easements as required by Tillsonburg Hydro. For multi-family townhouse and condominium developments, a registered blanket easement will be required for the entire project site as a Condition of Service. (See Section 2.1.6).

In most case Tillsonburg Hydro will install telephone, cable TV, and street lighting cables jointly during the electrical construction installation. Tillsonburg Hydro will facilitate the coordination process but the sub-divider developer is responsible for meeting the requirements of Bell Canada, Rogers Cable, and the Town of Tillsonburg with respect to the installation of their services. Tillsonburg Hydro is not responsible for the design of any of these systems. Trenching to be supplied by others at no cost to Tillsonburg Hydro.

The sub-divider developer will be required to make a capital contribution towards the installation as described in Section 2.1.2.

For details regarding service voltage, Point of Demarcation, access and service locations see Section 3.1.1.

3.2 General Service

This section describes the Conditions of Service applicable to General Service Customers. General Service Customers are also known as Commercial Customers and this section applies to all Customers other than single family residential Customers described in Section 3.1.1.

3.2.1 Early Consultation

Early consultation with Tillsonburg Hydro is essential since it's difficult to document all of the circumstances and conditions of service that would apply to all cases. Customers should consult with Tillsonburg Hydro in the early planning stages and submit the following information.

a) Required in-service date.

b) Voltage requirements.

c) Estimated initial maximum electric demand.

d) Estimated future maximum electric demand.

e) Specific listing of the type of loads for lighting, motors, heating, air conditioning, or other.

f) Grading plan and site plan, to scale, showing the building or buildings in relation to existing or proposed property lines, and other buildings or structures such as parking garages and

loading ramps. If applicable, the plans should include vertical and horizontal views of the proposed incoming duct bank from the point of entry to the delivery point.

g) Number of suites and/or divisions within the building(s) and the areas of each.

h) Plan, to scale, of the area in which the transformer vault is to be located (if one is required), showing detail of the vault.

i) Plan, to scale, showing the electrical room and provision for the metering equipment.

j) A drawing if applicable depicting the single line riser schematic for the entire primary/secondary distribution system.

k) The Customer/Consultant will be required to provide both conventional (paper hard copy full size) and digital format drawings to Tillsonburg Hydro. Digital drawings shall be supplied as AutoCAD files (dwg format with attached data base information). The contents of the drawing files must explicitly follow layering, colour, and line-type schemes as set out by the Town of Tillsonburg GIS specifications.

3.2.2 Point of Demarcation

The Point of Demarcation for various service types is generally as follows:

3.2.2.1 Overhead Secondary Services

For overhead secondary services, the Point of Demarcation is at the connection point where Tillsonburg Hydro service drop connects to the Customer's anchor point and service mast weather head. Tillsonburg Hydro is responsible for the maintenance and repair of the transformer, transformer hardware, and the first 30m of the overhead service wire. The Customer is responsible for the maintenance and repair of the anchor point, weather-head and all points downstream of the connection splice including the meter socket base and the jaw and connection block assemblies. Tillsonburg Hydro is responsible for the maintenance and repair of the electric meter.

3.2.2.2 Underground Secondary Services

For underground secondary services fed from pad mount transformers, the Point of Demarcation is at the secondary terminals of the transformer. The Customer is responsible to maintain and repair the secondary cable terminators, secondary cables and all equipment downstream with the exception of any metering Cts. and Pts. and Tillsonburg Hydro associated metering equipment. Tillsonburg Hydro is responsible for maintaining and repairing the electric meter, the pad mount transformer and all primary cables and equipment upstream of the Point of Demarcation.

For secondary connections in Customer vaults, the Point of Demarcation is at the secondary cable terminators. The Customer is responsible to maintain and repair the secondary cable and terminators and all equipment downstream with the exception of any metering Cts. and Pts or metering equipment if it is located on the secondary side of the service. The Customer is also responsible for maintaining the structural integrity of the Customer owned vault and keeping it in a dry, non-humid and safe environment. Repairs must be made by a "competent" person as defined in the Occupational Health and Safety Act. Tillsonburg Hydro is responsible for maintaining the transformers and any primary cables and equipment upstream of the Point of Demarcation. Tillsonburg Hydro is also responsible for the metering Cts & Pts and any associated equipment.

3.2.2.3 Service Lengths Greater than 100 metres

For Customers whose service entrance is located more than 100 metres from the right-of-way, a high voltage primary line (either overhead or underground) will be required. The Customer will be responsible to own and maintain the primary portion of the line unless they elect to pay a 20% premium on the initial cost of the primary line to transfer the ownership and future maintenance responsibilities to Tillsonburg Hydro. If the Customer is responsible to maintain the primary line, the Point of Demarcation for overhead lines is at the first pole and the Point of Demarcation for underground lines is at the primary cable riser connection. The Customer is responsible for the maintenance and repair of all poles, primary conductors and hardware, (including regular tree trimming), primary cable terminators, cable hangers, and primary cables in addition to the equipment listed in the first two paragraphs of this section. Tillsonburg Hydro is responsible for the transformer, transformer hardware and the first 30m of secondary cable or wire.

In all cases, if a Customer requires a primary line on their property, the Customer must sign a Connection Agreement that will describe in detail which party is responsible for the maintenance of various components of the line. The Agreement will also describe operational requirements necessary to provide isolation and protection of personnel and plant.

3.2.2.4 Customer-Owned Substations

For Customer-owned substations, Tillsonburg Hydro supplies the Customer at high voltage and the Customer owns all high voltage equipment, transformers, and points downstream.

For overhead high voltage primary services, the Point of Demarcation is at the first pole or connection point on the Customer's property. The Customer is responsible for the maintenance and repair of all poles, primary conductors, disconnect switches, substation equipment and transformers downstream. Tillsonburg Hydro is responsible for the aerial primary conductor and any in-line disconnect switches or power fuses upstream of the first pole or connection point on the Customer's property.

For underground high voltage primary services, the Point of Demarcation is at the primary cable riser connection. The Customer is responsible for the maintenance and repair of the primary cable terminators, primary cables, substation equipment and transformers downstream of the Demarcation Point with the exception of metering Cts and Pts and associated metering equipment. Tillsonburg Hydro is responsible for the cable riser fused disconnects switch and lightning arresters and will hang the Customer's terminated cable on the riser pole. The Customer is responsible for providing the supports for hanging the cable and the U-guard protection for the first 10 feet.

Customers have an obligation to maintain their Customer-owned equipment on a regular basis. Tillsonburg Hydro reserves the right to disconnect Customer-owned equipment if they believe it poses a safety or system reliability risk.

3.2.2.5 Deviations

In cases where there is a deviation in demarcation from what is described above, a separate Connection Agreement must be signed by the Customer and Tillsonburg Hydro to define each party's responsibilities. The Agreement will also describe operational requirements necessary to provide isolation and protection of personnel and plant.

3.2.3 Short Circuit Capacity

The Customer must ensure that their service entrance equipment has an adequate circuit interrupting capability in order to demonstrate compliance with Rule 14-012, Types and Ratings of Protective and Control Devices, of the Ontario Electrical Safety Code. Tillsonburg Hydro will advise on request, the maximum short circuit current available at any specific location and will provide short circuit information at either the primary point of supply if the service is a Customer-owned substation or at the secondary bushings at the transformer supplied by Tillsonburg Hydro. Maximum short circuit levels are provided since the actual levels may change from time to time as Tillsonburg Hydro primary distribution circuits are reconfigured, capacity at supply transformer stations is increased, cogeneration facilities are connected, or as Hydro One's transmission/generation systems are modified.

3.2.4 Access and Easements

The Customer shall grant, at no cost to Tillsonburg Hydro, where requested, a registered easement to permit the installation and maintenance of service. See Section 2.1.6.

3.2.5 Servicing Details

In addition to the servicing details described in Section 3.1.1.4, the following information applies to larger general service Customers:

3.2.5.1 Overhead Secondary Services

Customers may be required to provide space for the transformer pole and transformer bank on their private property at the discretion of Tillsonburg Hydro.

Customers may at their option choose to provide their own underground secondary service cables to be fed from Tillsonburg Hydro overhead transformer bank. This is described in the following section.

3.2.5.2 Underground Secondary Services

i) Supplied from Tillsonburg Hydro Overhead System

The Customer may at their option and at their cost provide underground secondary servicing from Tillsonburg Hydro overhead system provided that:

- Service size is limited to 600 amperes, 120/208Y or 347/600Y volts.

  In special circumstances, Tillsonburg Hydro may allow the connection of an 800 ampere 347/600Y volt service - special application must be made to Tillsonburg Hydro.

- Secondary conductors are subject to approval by the Electrical Safety Authority and are limited to the numbers and maximum sizes as follows:

- For Corflex conductors, a maximum of 1 run of four 750 kcmil aluminium/copper conductors.

- For copper conductors and conduit, 1 runs of four 500 kcmil copper conductors in one 4" rigid PVC conduit. The Customer must supply conduit, weather head(s) and all mounting hardware.

- A pole may be required on the Customer's property to terminate their underground service cables. The location of the pole must be approved by Tillsonburg Hydro and the installation must pass inspection by the Electrical Safety Authority.

3.2.6 Metering

3.3 General Service (Above 50 kW)

In addition to the requirements of Section 3.2, individual services that are forecast by Tillsonburg Hydro to have a monthly average peak demand of over 50 kW, will be required to have a demand meter in addition to the kilowatt hour consumption meter.

Customers without demand meters whose yearly energy consumption exceeds 150,000 kW hrs over any 12 month period may be required to have a demand meter at the discretion of Tillsonburg Hydro.

3.4 General Service (Above 500 kW)

In addition to the requirements of Sections 3.2 and 3.3, the OEB Distribution System Code requires interval metering on all new services having a monthly average peak demand during the calendar year of over 500 kW.

3.5 Embedded Generation

All Embedded Generators must execute a Connection Agreement. The connection and operation of a Customer's embedded generator must not endanger workers or jeopardize public safety, or adversely affect or compromise equipment owned or operated by Tillsonburg Hydro, or the security, reliability, efficiency or the quality of electrical supply to other Customers connected to Tillsonburg Hydro distribution system. If damage or increased operating costs result from a connection with a generator, Tillsonburg Hydro shall be reimbursed for these costs by the generator. The Embedded Generator shall be responsible for all costs associated with Tillsonburg Hydro performing studies and developing plans for risk mitigation that are to the satisfaction of Tillsonburg Hydro.

3.5.1 General Technical Information Requirements

All Embedded Generators shall provide Tillsonburg Hydro with the following documentation to ensure that the Distribution System is adequately protected from potential damage or increased operating costs resulting from the connection of the Embedded Generation Facility:

(a) Electrical submissions signed and stamped by a licensed professional engineer; detailed single line and three line diagrams showing all electrical devices associated with the Embedded Generation Facility such as generators, isolating devices, breakers, protection relays, inverter systems, instrument transformers, lightning arresters, fuses and metering.

(b) Evidence of approval of the Electrical Safety Authority for all the Embedded Generator's owned electrical facilities.

(c) a copy of the report of the most recent re-verification of protections signed and stamped by a licensed professional engineer, and

(d) Any other documentation reasonably related to Tillsonburg Hydro obligations.

3.5.2 Interface Protection and Isolating Devices

The Embedded Generator shall provide an interface protection that minimizes the frequency and severity of disturbances on the distribution system and the impact on other Customers. The Embedded Generation facilities must also meet the technical requirements as identified in the Connection Agreement. The interface protection shall be capable of automatically isolating the Generator (s) from the distribution system in the following situations:

(a) internal faults within the Generation facility
(b) external faults in the distribution system; and
(c) Abnormal system conditions, including, but not limited to open phase and islanding, over/under voltage and over/under frequency.

The Embedded Generator shall provide, install and maintain a disconnecting device at the connection point with the distribution system for the purpose of isolating the Embedded Generation facility in case of emergency and for work protection. The disconnecting device shall:

(a) be located at or near to the Demarcation Point of connection of the Embedded Generation facility to the distribution system, and must be readily accessible;

(b) provide a visible indication of the open main current-carrying path that isolates the Embedded Generation facility from the distribution system;

(c) have a three-pole gang operated switch mechanism suitable for load break operations at rated load. (Subject to Tillsonburg Hydro prior written approval, single phase Customers may use single pole switches or openers);

(d) meet Ontario Electrical Safety Code requirements;

(e) be rated for maximum fault current available at that location on the distribution system;

(f) be lockable in the open position;

(g) be suitable for safe operation under the conditions of use; and

(h) Have an interlock, which will prevent back-feed in the event of an outage on the distribution system.

These devices must be operated at least once a year, unless specified otherwise in the Connection Agreement, and the verification report of the operation of the devices shall be retained by the Embedded Generator and shall be provided to Tillsonburg Hydro upon request.

3.5.3 Metering for Embedded Generation Facilities

Metering Installations - Installed After May, 2002

The metering shall be installed at the Demarcation Point of connection of the Embedded Generation facility to the distribution system. If this is not practical, Tillsonburg Hydro will, where appropriate, apply loss factors to the generation output in accordance with the loss factors applied for Retail settlements and billing.

The Embedded Generator shall install a Four-Quadrant Interval Meter in accordance with the Distribution System Code and Tillsonburg Hydro standard metering requirements. The Embedded Generator shall provide Tillsonburg Hydro with the technical details of the meter installation.

An Embedded Generator that may, at any time, deliver power to the distribution system shall be responsible for the ownership, installation and maintenance (using a Registered Meter Service Provider), of an approved meter. This excludes net metering Customer installations connected prior to May, 2002.

Embedded Generation Facilities That Do Not Deliver Power to the Distribution System

If the Embedded Generator does not require a generation licence from the Ontario Energy Board, Tillsonburg Hydro shall meter the Embedded Generation facility in the same manner as it meters standard Customers. Notwithstanding the foregoing, the Embedded Generator shall pay all incremental costs associated with such metering. The meters for such installations shall be one directional meters.

Metering Installations - Installed Prior to May, 2002

Where there is an existing meter installation for an Embedded Generation facility, the Embedded Generator shall take ownership of the meter installation in accordance with Tillsonburg Hydro requirements by no later than the meter seal expiry date. The Embedded Generator shall provide Tillsonburg Hydro with the technical details of the metering installations for review, if requested.

Embedded Generation facilities that receive energy e.g. for station use or back-up supply, shall be placed in the appropriate Rate class and billed for the energy consumed.

3.5.4 Transformers

Any step-up transformation equipment required to step-up the Embedded Generation facility's output voltage to the primary voltage of Tillsonburg Hydro distribution line shall be supplied, installed, owned and maintained by the Embedded Generator.

For customers connected to the distribution system that wish to install an Embedded Generation facility with a total installed generation capacity of less than 10 kW, Tillsonburg Hydro may, at its sole discretion, permit the Embedded Generation facility to be connected through Tillsonburg Hydro existing transformer. In such cases, the Embedded Generator shall be responsible for any and all damage to Tillsonburg Hydro facilities and equipment caused by the operation of the Embedded Generation facility.

3.5.5 Maintenance Schedules

The Embedded Generator must implement and adhere to a regular scheduled maintenance plan to assure both Tillsonburg Hydro and the Embedded Generator that the connection devices, protection and control systems are maintained in good working order. The provisions of the maintenance plan are to be listed in the Connection Agreement. The Embedded Generator must conduct a re-verification at least every 48 months (or as specified in the Connection Agreement) and provide a written report to Tillsonburg Hydro signed by a professional licensed engineer.

Tillsonburg Hydro in its sole discretion may request to witness the re-verification of any protections that could adversely impact the distribution system. The Embedded Generator shall pay for the

re-verification and provide Tillsonburg Hydro a copy of the report giving the results of the re-verification of the protections.

3.5.6 Reporting Requirements

All Embedded Generators over 100 KVA shall report any significant event to Tillsonburg Hydro within 5 business days. The Connection Agreement may include a list of events deemed significant and provide a standard report format.

The Embedded Generator shall keep a written log of the operation of its protections that result in the tripping of its interrupting devices. On request, the Embedded Generator must provide a copy of the log to Tillsonburg Hydro. The log shall contain, at a minimum, the following information:

(a) date and time of event/operation of protections

(b) which relay or protection feature of the relay initiating the trip

(c) Conditions and unit output at the time of the trip that may be related to the operation (e.g. Lightning, outage of feeder, etc.).

3.5.7 Capital Contribution

When Tillsonburg Hydro is required to add new Tillsonburg Hydro facilities and equipment, alter existing Tillsonburg Hydro facilities and equipment, or increase the capacity of the distribution system to connect a new Embedded Generation facility (an "Expansion"), Tillsonburg Hydro will perform an economic evaluation to determine the Embedded Generator's capital contribution for the equipment, labour and ongoing maintenance costs of the Expansion. Tillsonburg Hydro will use the discounted cash flow model described in Section 2.1.2 and assume that future revenue will be zero.

3.5.8 Compliance

All equipment of Embedded Generators connected, operating or procured before May, 2002 is deemed to be in compliance with Tillsonburg Hydro performance requirements except for the requirements of the Electrical Safety Authority and isolating device requirements identified in Section 3.5.2.

Tillsonburg Hydro may require the equipment deemed compliant above be brought into actual compliance with Tillsonburg Hydro performance requirements within a timeframe established by Tillsonburg Hydro, but not to exceed 12 months, where, at Tillsonburg Hydro sole opinion, there is:

(a) a material deterioration of the distribution system reliability resulting from the performance of the Embedded Generator's equipment; or

(b) a material negative impact on the power quality of an existing or new Customer resulting from the performance of the equipment at the Embedded Generation facility; or

(c) a material increase in Generating capacity at the site where the equipment deemed compliant is located.

3.5.9 Disconnection of Embedded Generation Facility

Tillsonburg Hydro has the right to disconnect an Embedded Generation facility from its distribution system where, where in the sole opinion of Tillsonburg Hydro, any of the following conditions exist:

(a) there is a material deterioration of the distribution system reliability resulting from the performance of the Embedded Generator's equipment;

(b) there is a material negative impact on the quality of power of an existing or a new Customer resulting from the performance of the equipment at the Embedded Generation facility;

(c) the Embedded Generator has failed to re-verify the protection and control systems every 48 months or as specified in the Connection Agreement or failed to submit the report within 30 days; or

(d) The Embedded Generator's report of the re-verification of the protection and control systems shows unacceptable deficiencies.

3.6 Embedded Market Participant

Under the "Market Rules for the Ontario Electricity Market", Chapter 2, Section 1.2.1, "No persons shall participate in the IMO - administered Markets or cause or permit electricity to be conveyed into, through or out of the IMO - controlled grid unless that person has been authorized by the IMO to do so".

All Embedded Market Participants within the service jurisdiction of Tillsonburg Hydro, once approved by the IMO, are required to inform Tillsonburg Hydro of their approved status in writing, 30 days prior to their participation in the Ontario Electricity Market.

3.7 Embedded Distributor

All Embedded Distributors within the service jurisdiction of Tillsonburg Hydro are required to inform Tillsonburg Hydro of their status in writing 30 days prior to the supply of energy from Tillsonburg Hydro. The terms and conditions applicable to the connection of an Embedded Distributor shall be included in a Connection Agreement with Tillsonburg Hydro.

3.8 Un-metered Connections

This section pertains to the conditions of service and supply of electrical energy for un-metered connections.

3.8.1 Street Lighting

The location of supply for street lighting circuits will vary and must be established through consultation with Town of Tillsonburg Engineering Department Ext.232 for each application. Underground feeds will generally be supplied from pad mount transformers, network vaults, or from an overhead system through a cable riser. Overhead systems will normally be fed by way of individual connections for each street light from the secondary spun bus, although in some circumstances, a separate street lighting circuit may be required. All underground street lighting services will require a separate disconnect switch to allow for isolation of the service without requiring the presence of Tillsonburg Hydro personnel. In most cases, overhead street lighting systems will not require disconnect switches unless required by the Electrical Safety Authority.

The service voltage for overhead street lighting connections will be 120 volts, single phase, 2 wires and the service voltage for underground street lighting feeds will be 120 volts, single phase, and 3 wires. The onus is on the installer to ensure a balanced loading between the two 120 volt legs of the supply.

Prior to the energization of a new street lighting service, Tillsonburg Hydro will require notification from the Electrical Safety Authority that the installation has been inspected and approved. The final power source connection will be made by Tillsonburg Hydro.

All street lighting services will be un-metered and energy consumption will be based on the connected wattage and the calculated hours of use using the approved methods and rates established by the OEB. For Underground Street light services fed from pad mount transformers or vaults, a connection fee will apply based on Tillsonburg Hydro approved commercial connection charge for a 100 Amp U/G 120/240 volt service. Tillsonburg Hydro personnel must be involved in the disconnection and reconnection of existing street light services fed from pad mount transformers or vaults where there is no disconnect switch.

3.8.2 Traffic Signals

The location of supply for traffic signal systems will vary and must be established for each application through consultation with Town of Tillsonburg Engineering Department Ext.232

Feeds may be from either the overhead or underground electrical systems and in all cases a disconnect switch will need to be installed and approved by the Electrical Safety Authority. All cabling used for the purpose of traffic signal installations must be installed in dedicated conduits separate from street lighting or any other secondary duct work.

The service voltage for traffic signal systems will be 120 volts, single phase, and 2 wires.

Prior to the energization of a new traffic signal service, Tillsonburg Hydro will require notification from the Electrical Safety Authority that the installation has been inspected and approved. The final power source connection will be made by Tillsonburg Hydro.

All traffic signal services will be metered and a connection fee for new traffic signal (and intersection lighting) feeds will apply based on Tillsonburg Hydro approved commercial connection charge for a 100 Amp U/G 120/240 volt service. Tillsonburg Hydro personnel must be involved in the disconnection and reconnection of existing traffic signal services fed from pad mount transformers or vaults where there is no disconnect switch accessible. A charge per trip will apply.

4 GLOSSARY OF TERMS

"Affiliate Relationships Code" means the code, approved by the Ontario Energy Board.

"Billing Demand" means the metered demand or connected load after necessary adjustments have been made for power factor, intermittent rating, transformer losses and minimum billing. A measurement in kilowatts (kW) of the maximum rate at which electricity is consumed during a billing period.

"Building" means a building, portion of a building, structure, or facility.

"Conditions of Service" means a document developed by a Distributor in accordance with subsection 2.4 of the Distribution System Code that described the operating practices and connection rules for Distributors.

"Connection" means the process of installing and activating connection assets in order to distribute electricity to a Customer.

"Connection Agreement" means an agreement entered into between the Distributor and a person connected to its distribution system that delineates the conditions of the connection and delivery of electricity to that connection.

"Connection Assets" means that portion of the distribution system used to connect the Customer to the existing main distribution system, and consists of the assets between the point of connection on a Distributor's main distribution system and the ownership Demarcation Point with that Customer.

"Connection Authorization" when concerning supply of electrical energy to an electrical installation from a supply authority, shall mean written permission by the Electrical Safety Authority to Tillsonburg Hydro or any other person or corporation, to supply electric energy to a particular electrical installation; or when concerning supply of electric energy from one part of an electrical installation to another, or from a source of electric energy other than that of Tillsonburg Hydro, shall mean permission from the inspection department to a contractor to connect a particular electrical installation or part thereof to a source of electric energy.

"Consumer" means a person who uses electricity that the person did not generate.

"Consumer's Service" shall mean all that portion of the Consumer's installation from the service box or its equivalent up to and including the point at which Tillsonburg Hydro makes connection.

"Contract" shall mean a contract for the supply of electrical service or energy.

"Contractor" shall mean any person who as principal, servant, or agent, by himself or herself or by associates, employees, servants or agents performs or engages to perform either for his or her own use and benefit or for that of another and for or without remuneration or gain any work with respect to any electrical installation or any other work to which the Ontario Electrical Code applies.

"Customer" shall mean the person or persons contracting for the supply of electric service or energy from Tillsonburg Hydro. This includes developers of residential or commercial subdivisions.

"Customer in Arrears" shall mean a Customer who owes to Tillsonburg Hydro charges or accounts for power after the due date.

"Demand" means the average value of power measured over a specified interval of time, usually expressed in kilowatts (kW).

"Demand Meter" means a meter that measures a Consumer's peak usage during a specified period of time.

"Demarcation Point or Point of Demarcation" means the physical location at which a Distributor's responsibility for operational control or ownership and maintenance of distribution equipment including connection assets ends at the Customer. The Demarcation Point for

operational control may be different then the Demarcation Point for the ownership and maintenance of equipment.

"Developer" means a Person or Persons owning property for which new or modified electrical services are to be installed.

"Disconnection" means deactivation of connection assets that result in cessation of distribution services to a Customer.

"Distribution Loss Factor" means a factor or factors by which metered loads must be multiplied such that when summed equal the total measured load at the supply point(s) to the distribution system.

"Distribution Losses" means energy losses that result from the interaction of intrinsic characteristics of the distribution network such as electrical resistance with network voltages and current flows.

"Distribution Services" means services related to the distribution of electricity and the services the Board has required Distributors to carry out, for which a charge or rate has been approved by the OEB under Section 78 of the Ontario Energy Board Act.

"Distribution System Code" means the code approved by the Ontario Energy Board.

"Distributor" means a Person who owns or operates a Distribution System.

"Electrical Safety Authority" or ESA means the Person or body designated under the Electricity Act Regulations as the Electrical Safety Authority.

"Electricity Act" means the Electricity Act 1998, SO 1998, as amended from time to time.

"Embedded Distributor" means a Distributor who is not a Wholesale Market Participant and that is provided electricity by a Host Distributor.

"Embedded Generator or Embedded Generation Facility" means a Generator whose generation facility is not directly connected to the IMO - Controlled Grid but instead is connected to a Distribution System.

"Embedded Retail Generator" means an Embedded Generator that settles through a Distributor's Retail Settlement System and is not a wholesale market participant.

"Embedded Wholesale Consumer" means a Consumer who is a Wholesale Market Participant whose facility is not directly connected to the IMO - Controlled Grid but is connected to a Distribution System.

"Embedded Wholesale Generator" means an Embedded Generator that is a Wholesale Market Participant.

"Energy Competition Act" means the Energy Competition Act, 1998, SO-1998, as amended from time to time.

"Energy Diversion" means the electricity consumption unaccounted for but that can be quantified through various measures upon review of the meter mechanism, such as unbilled meter readings, tap off load(s) before revenue meter or meter tampering.

"Enhancement" means a modification to an existing distribution system that is made for purposes of improving system operating characteristics such as reliability or power quality or for relieving system capacity constraints resulting, for example from general load growth.

"Expansion" means an addition to a distribution system in response to a request for additional Customer connections that otherwise could not be made: for example, by increasing the length of the distribution system.

"EUSA" is the Electrical and Utility Safety Authority.

"IMO" means the Independent Electricity Market Operator established under the Electricity Act.

"Inspector" shall mean any person duly appointed by the Electrical Safety Authority for the purpose of enforcing the Ontario Electrical Code.

"Load Factor" means the ratio of average demand for a designated time period (usually one month) to the maximum demand occurring in that period.

"Load Transfer" means a network supply point of one Distributor that is supplied through the distribution network of another Distributor and where this supply point is not considered a wholesale supply or bulk sale point.

"Load Transfer Customer" means a Customer that is provided distribution services through a load transfer.

"Market Rules" means the rules made under the Electricity Act.

"Measurement Canada" means the Special Operating Agency established by the Electricity and Gas Inspection Act, 1980-81-82-83, C.87.

"Meter Service Provider" means any entity that performs metering services on behalf of a Distributor.

"Meter Socket" means a mounting device for accommodating a socket type revenue meter.

"Multi-Family Residential Dwelling" means a dwelling zoned residential by the Town of Tillsonburg, used for dwelling purposes, containing more than one single family dwelling unit that are either individually metered or are metered with a bulk-meter having a service entrance capacity greater than 200 amps.

"OEB" is the Ontario Energy Board, the regulatory authority in Ontario responsible for electricity and gas.

"Ontario Energy Board Act" means the Ontario Energy Board Act, 1988, S.O. 1998, C.15, as amended from time to time.

"Permit" shall mean the official written permission of the Electrical Safety Authority, on a form provided for the purpose, authorizing work to be commenced on any electrical installation.

"Person" includes an individual, corporation, a sole proprietorship, partnership, unincorporated organization, unincorporated association, body corporate, and any other legal entity.

"Physical Distributor" with respect to a load transfer, means the Distributor that provides physical delivery of electricity to a load transfer Customer, but is not responsible for connecting and billing the load transfer Customer directly.

Point of Demarcation" See Demarcation Point.

"Retail" with respect to electricity means,

a) To sell or offer to sell electricity to a Consumer

b) To act as agent or broker for a retailer with respect to the sale or offer for sale of electricity

c) To act or offer to act as an agent or broker for a Consumer with respect to the sale or offering for sale of electricity.

"Retail Settlement Code" means the code approved by the Ontario Energy Board.

"Retailer" means a person who retails electricity.

"Secondary Service" means any service which is supplied with a nominal voltage less than 750 volts.

"Service Agreement" means the agreement that sets out the relationship between a licensed retailer and a Distributor in accordance with the provisions of Chapter 12 of the Retail Settlement Code.

"Service Area" with respect to a Distributor, means the area in which the Distributor is authorized by its licence to distribute electricity.

"Single Family Residential Dwelling" shall be a dwelling zoned residential by the Town of Tillsonburg, used for dwelling purposes, and having only one electric meter with a service entrance capacity of 200 amps or less.

"Standard Supply Service Code" means the code approved by the Ontario Energy Board.

"Supply Service" shall mean any one set of conductors run by Tillsonburg Hydro from its electrical system to a Consumer's service.

"Wholesale Market Participant" means a person that sells or purchases electricity or ancillary services through the IMO - administered markets.

"Wholesale Settlement Cost" means costs for both competitive and non-competitive electricity services billed to a Distributor by the IMO or a Host Distributor or provided by an Embedded Retail Generator or by a neighbouring Distributor.

"Wholesale Supplier" means a person who sells electricity or ancillary services through the IMO administered markets or directly to another person other than a Consumer.

5 TABLES

Table 1 Demarcation Points, Connection Fees and Disconnection Fees

The range of connections listed below may not be available in all areas due to limitations within the distribution system.

Customer Class (Service Type)	Ownership Demarcation Point	Basic Connection - includes the following connection assets	Basic Connection Fee - Subject to Annual Review	Variable Connection Fee	Customer Responsibilities and Other Charges	Service Disconnection Fee (Initiated by Customer)
Class 1 - Residential Class - Single Service for single family detached or semi-detached						
Overhead	Top of Customer's service mast	Up to 30 m OH service wire from THI supply pole inc. connections, standard revenue meter (one meter per unit) and equipment credit for transformation	No Charge - Recovered through distribution rates	Customer charged actual costs for connection assets above and beyond basic connection.	Customers requesting an UG service in an OH area will be required to pay 1 00% connection costs less the Standard Allowance for an OH service Customer responsible for all trenching, conduit, road crossings and restoration.	Temporary meter removal or re-install $60.00 Service Upgrade No charge for Cut & Reconnect - (maximum 200 amp) No Charge for permanent removal of Connection Assets
Underground	Line side of Customer's meter base	Same as Residential Class overhead	No Charge - Recovered through distribution rates	Customer charged actual costs for connection assets above and beyond basic connection	Customers requesting an UG service will be required to pay 100% connection costs less the Standard Allowance for an OH service Customer responsible for all trenching, conduit, road crossings and restoration.	Temporary meter removal or re-install $60.00 Service Upgrade No charge for Cut & Reconnect - (maximum 200 amp) No charge for permanent removal of Connection Assets
Class 2A - General Service - Less than 50 kW - Multi unit residential (Maximum 6 units)						
Overhead	Top of Customer service mast	Up to 30 m OH service wire from THI supply pole inc. connections, one standard revenue meter per unit (plus house meter if req'd) and equipment credit for pole mounted transformation	No Charge - Recovered through distribution rates as determined through economic evaluation based on averaged connection costs.	Customer charged actual costs for connection assets above and beyond basic connection.	Customers requesting an UG service will be required to pay 100% connection costs less the Std. Allowance for an OH service Customer responsible for all trenching, conduit and restoration.	Temporary meter removal or re-install $60.00 Service Upgrade (Up to max. 6 units) Cut & Reconnect service $450.00 No Charge for permanent removal of Connection Assets

Underground	Line side of Customer's meter base					
Customer Class (Service Type)	Ownership Demarcation Point	Basic Connection - includes the following connection assets	Basic Connection Fee - Subject to Annual Review	Variable Connection Fee	Customer Responsibilities and Other Charges	Service Disconnection Fee (Initiated by Customer)
Class 2B - General Service - Less than 50 kW - Commercial						
Overhead - Single Building Service	Top of Customer's service mast	Up to 30 m OH service wire from THI supply pole inc. connections, standard revenue meter and averaged cost for transformation	120/208V Up to 100A $7,108.00 200A $8,485.00 347/600V Up to 100A $8,282.00	Customer charged actual costs for connection assets above and beyond basic connection Interval meters, if requested, will be included in the variable connection fee.	Customer responsible for costs associated with additional or redesign due to changes in Customer's original request.	Temporary meter removal or re-install $60.00 Service Upgrade Customer charged applicable Basic Connection Fee (Transformer credit may apply - See Sec. 2.1.1.1 b)
Underground - Single Building Service	Point of connection at utility supply point. This could be secondary buss (UG or OH) or transformer secondary spade. Secondary service conductor supplied, installed and owned by Customer. (Subject to ESA inspection.)	Connections at utility supply point, standard revenue meter and averaged cost for transformation.	120/208V Up to 100A $6,901.00 200A $8,105.00 347/600V Up to 100A $7,975.00	Customer charged actual costs for connection assets above and beyond basic connection Interval meters, if requested, will be included in the variable connection fee.	Customer responsible for costs associated with additional or redesign due to changes in Customer's original request. Customer responsible for all trenching, conduit, secondary conductor, road crossings, restoration and all applicable permits and approvals.	Temporary meter removal and reinstall $60.00 Service Upgrade Customer charged applicable Basic Connection Fee (Transformer credit may apply - See Sec. 2.1. 1.1 b) No Charge for permanent removal of Connection Assets
Class 3A - General Service - Greater than 50 kW (50 kW - 999 kW) Commercial						
Overhead - Single Building Service (Not requiring transformers on private property)	Top of Customer's service mast	Up to 30 m OH service wire from THI supply pole inc. connections, standard revenue meter (interval meter if required) and averaged cost for transformation.	Customer charged actual costs to provide connection. Costs to include all labour, equipment, material, transformers, metering, engineering and administration charges.	100% of connection asset cost recovered through "Basic Connection Charge".	Customer responsible for costs associated with additional or redesign due to changes in Customer's original request.	Customer charged fixed, average costs associated with service upgrade, disconnection and/or removal of all connection assets up the demarcation point.

Underground - Single Building Service (Not requiring transformers on private property)	Point of connection at utility supply point. This could be secondary buss (UG or OH) or transformer secondary spade. Underground secondary service conductor owned by Customer.	Connections at utility supply point, standard revenue meter (interval meter if required) and averaged cost for transformation.	Customer charged actual costs to provide connection. Costs to include all labour, equipment, material, transformers, metering, engineering and administration charges.	100% of connection asset cost recovered through "Basic Connection Charge".	Customer responsible for costs associated with additional or redesign due to changes in Customer's original request. Customer responsible for secondary conductor from point of supply to main disconnect, all trenching, conduit, road crossings, restoration and all applicable permits and approvals.	Customer charged fixed, average costs associated with service upgrade, disconnection and/or removal of all connection assets up the demarcation point.
Customer Class (Service Type)	Ownership Demarcation Point	Basic Connection - includes the following connection assets	Basic Connection Fee - Subject to Annual Review	Variable Connection Fee	Customer Responsibilities and Other Charges	Service Disconnection Fee (Initiated by Customer)
Overhead - Single Building Service (Requiring utility owned transformers on private property)	Top of Customer's service mast (OH secondary) or Point of connection at utility supply point. This could be secondary buss (UG or OH) or transformer secondary spade. Secondary service conductor owned by Customer. (UG secondary)	Up to 30 m of 3 phase OH primary conductor and neutral wire from THI supply pole, transformer pole and transformer(s) inc. connections, standard revenue meter (interval meter if required)	Customer charged actual costs to provide connection. Costs to include all labour, equipment, material, cables, duct work as applicable, transformers, metering, engineering and administration charges.	100% of connection asset cost recovered through "Basic Connection Charge".	Customer responsible for costs associated with additional or redesign due to changes in Customer's original request. Customer responsible for UG secondary conductor from point of supply to main disconnect, all trenching, conduit, road crossings, restoration and all applicable permits and approvals.	Customer charged actual costs associated with service upgrade, disconnection and/or removal of all connection assets inc. cables, transformers and associated equipment up the demarcation point.
Underground – Single Building Service (Requiring utility owned transformers on private property)	Point of connection at utility supply point. This point of connection will be the transformer secondary spade. Underground secondary service conductor owned by Customer.	Up to 30 m of 3 phase UG primary conductor from THI supply pole, and transformer inc. connections, standard revenue meter (interval meter if required). Connection point on distribution system that lies along the Customer's connection based on original Customer request.	Customer charged actual costs to provide connection. Costs to include all labour, equipment, material, cables, duct work as applicable, transformers, metering, engineering and administration charges.	100% of connection asset cost recovered through "Basic Connection Charge".	Customer responsible for costs associated with additional or redesign due to changes in Customer's original request Customer responsible for secondary conductor from point of supply to main disconnect, all trenching, conduit, road crossings, restoration and all applicable permits and approvals.	Customer charged actual costs associated with service upgrade, disconnection and/or removal of all connection assets inc. cables, transformers and associated equipment up the demarcation point.
Class 3B - General Service - Greater than 50 kW Multi-unit Residential (more than 6 units) and Subdivisions						

Overhead or Underground - Multi-unit residential housing development (No transformers required on private property)	Top ofCustomer's service mast (OH secondary) or Point of connection at utility supply point. This could be secondary buss (UG or OH) or transformer Secondary spade. Secondary service conductor owned by Customer. (UG secondary)	Not Applicable	Economic Evaluation completed to determine connection fees	Economic Evaluation completed to determine connection fees	Connection Agreement required. Developer to provide security as required by THI.	Customer charged actual costs associated with service upgrade, disconnection and/or removal of all connection assets inc. cables, transformers and associated equipment up the demarcation point.
Customer Class (Service Type)	Ownership Demarcation Point	Basic Connection - includes the following connection assets	Basic Connection Fee - Subject to Annual Review	Variable Connection Fee	Customer Responsibilities and Other Charges	Service Disconnection Fee (Initiated by Customer)
Overhead or Underground - Multi-unit residential housing development (Requiring utility owned transformers on private property)	Top of Customer's service mast (OH secondary) or Point of connection at utility supply point. This could be secondary buss (UG or OH) or transformer Secondary spade. Secondary service conductor owned by Customer. (UG secondary)	Not Applicable	Economic Evaluation completed to determine connection fees	Economic Evaluation completed to determine connection fees	Connection Agreement required. Developer to provide security as required by THI.	Customer charged actual costs associated with service upgrade, disconnection and/or removal of all connection assets inc. cables, transformers and associated equipment up the demarcation point.
Residential Subdivision Development	Line side of Customer's meter base (UG). Top of Customer's service mast (OH)	Not Applicable	Economic Evaluation completed to determine connection fees	Economic Evaluation completed to determine connection fees	Electrical Distribution System Servicing Agreement required. Developer to provide security as required by THI.	Not Applicable
Class 4 - General Service - 1000 kW and Above (Including Large User)						

Overhead or Underground Supply to Customer Owned Substation or Customer Owned Transformers	First point of attachment on private property for OH primary line (Customer owned pole or structure within 30m of property line) Load side of utility owned switchgear or primary junction for UG supply.	Connection point on distribution system that lies along the Customer's building. Overhead or underground primary conductors (3 phase and neutral), connection to distribution system. Interval revenue metering at secondary voltage. Design of connection based on original Customer request.	Customer charged actual costs to provide connection. Costs to include all labour, equipment, material, engineering and administration charges. The cost of Primary Metering, if required, will be included in the Basic Connection Fee.	100% of connection asset cost recovered through "Basic Connection Charge".	Customer responsible for costs associated with additional or redesign due to changes in Customer initial request; inspection and related feeder switching and scheduling	One annual power interruption to facilitate station maintenance at no charge, provided work is completed during THI normal working hours. All other interruptions the Customer is charged actual costs associated with service upgrade, disconnection and/or removal of all connection assets up the demarcation point including related switching and scheduling.

Table 2 Meter Sockets

Self Contained Socket Metering

Voltage	Phase	Wire	Meter Socket (See description below)	Maximum Service Switch Size Rating in Amperes
120/240	1	3	A	200
208/120	2	3	B	200
208/120	3	4	C	200
600/347	3	4	C	200

** Used only where grounded supply is not available.

Meter Socket Descriptions

A - 4 Jaw socket type square - Standard Square Base - 100A overhead and 60A Off Splitter

, - 200A Jumbo Type - 200A Overhead and All Underground

B - 5 Jaw socket type with the "5" jaw at the 9 o'clock position c/w #12 white wire from "5" jaw to an insulated neutral block in the meter base.

C - 7 Jaw meter base with the "7" jaw at the 6 o'clock position c/w #12 white wire from "7" jaw to an insulated neutral block in the meter base.

Notes:

1. A list of approved meter sockets is available upon request.
2. Meter sockets shall be mounted so that the midpoint of the meter is set at 68" from finished grade or floor level. Meter base location shall be determined by Tillsonburg Hydro Inc.
3. Where the supply is from a 4-wire 600/347-volt system, metering shall be 4-wire. Where the Customer does not require a neutral, a full size neutral conductor sized in accordance with Table 17 of the Electrical Safety Code must be provided to all meter cabinets or sockets. The neutral conductor is to be terminated in the socket (or cabinet) on an insulated neutral block in accordance with the Ontario Electrical Safety Code.
4. Three phase meter bases shall be mounted on the load side of the main switch.

Table 3 Meter Cabinets

Meter Cabinets

Voltage	Phase	Wire	Main Switch Size in Amperes	Meter Cabinets (See description below)
120/240	1	3	400**	A
208/120	3	4	Over 200 - 800	B
600/347			Over 800	A (Instrument transformers in switchgear or primary metered installation)
600*	3	3	Over 200 – 800	B
			Over 800	A (Instrument transformers in switchgear or primary metered installation)

* Use only where grounded 4 wires supply not available.
** If the meter base is remote from the cabinet, a "self-shorting" meter base shall be used.

Meter Cabinet Descriptions

A - 30" X 30" X 12" complete with removable 26" X 26" back plate. B - 48" X 48" X 12" complete with removable 44" X 44" back plate.

Notes:

1. Meter cabinets shall be fabricated with a minimum #16 gauge steel
2. Cabinets shall have side-hinged doors opening at the center and be equipped with a three-point latching device and complete with a provision for padlocking.
3. The cabinet shall be mounted a maximum distance of 78" from the floor to the top of the cabinet and a minimum of 24" from the floor to the bottom of the cabinet.
4. Where two or more circuits are used in one meter cabinet, Tillsonburg Hydro Inc. will issue specific metering requirements.
5. Normally the current transformers will be installed in the meter cabinet and the

   Customer's contractor shall supply and install connectors to terminate the conductors at the current transformers. The neutral must be connected to an isolated neutral block within the meter cabinet for 600/347-volt services.
6. For installations where the current transformers are remote from the meter cabinet a 30" X 30" X 12" meter cabinet may be used. The Customer is responsible to supply and install an 11/4" conduit to connect the two locations. The length of this conduit shall not exceed 150 ft.
7. Outdoor meter cabinets may be permitted and must be approved by Tillsonburg Hydro Inc. If approved, only "outdoor type" waterproof cabinets shall be used.

Table 4 Meter Centers (Section)

Meter centers may be used for installations of 750 volts or less provided they meet the following specifications:

1. Side-hinged doors or panels shall be installed over all sections of the switchboard where Tillsonburg Hydro Inc. may be required to work, such as unmetered sections and those sections containing breakers, switches and meter mounting devices. Hinged doors or panels shall have provisions for sealing or padlocking in the closed position. Where bolts are used, they shall be of a captive knurled type. The hinged covers over breakers or switches shall be constructed so the covers cannot be opened when sealed or padlocked.

2. Breakers or switch handles shall have provisions for sealing or padlocking in the "off[1] position.

3. Meter mounting devices shall be wired/connected on the load side of the breakers or switches. (Cold metering)

4. Each combination meter socket and breaker panel shall have adequate space for permanent Customer identification with respect to street address and/or unit number.

5. The center of the finished floor. The center of the top row of meter sockets shall not be more than 72" from the finished floor.

6. The distance between horizontally or vertically adjacent meter socket rims shall not be less than 6".

7. The meter mounting socket and sealing ring shall be acceptable to Tillsonburg Hydro Inc.

8. Where a neutral is required, the meter-mounting device shall have a pre-wired

   Ungrounded neutral connection to the 5th or 7th terminal. The connection, if not made directly to the neutral buss, shall be not less than #12 AWG copper.

Table 5 **Primary Metering**

The following is provided only as a guideline regarding primary metered installations.

Tillsonburg Hydro Inc. will provide specific requirements and specifications for each individual

Installation.

1. Primary metering installations will be specified by Tillsonburg Hydro Inc. and dealt with on an individual basis.

2. The equipment may be a fully contained metering tank or individual current and potential transformers and all other necessary equipment.

3. The primary metering PTs and CTs and the metering cabinet can be mounted at various locations indoors or outdoors depending on the application.

4. The Customer's contractor must provide a 30" L X 30" W X 12" D lockable metering cabinet with removable back plate.

5. Outdoor cabinets must be water proof in design and acceptable to Tillsonburg Hydro Inc.

6. The Customer's contractor must supply a 1-1/4" conduit to connect the primary PTs and CTs terminal box to the metering cabinet. The two locations and the length of this conduit cannot exceed 150 feet.

7. Primary metering locations require interval metering. Since the Utility reads interval meter remotely via telephone line, the Utility requires telephone line access to the meter. The customer must provide dedicated phone line for the meter phone line and locate it inside the metering cabinet.

6 REFERENCES

1. Economic Evaluation Model for Distribution System Expansion

Refer to Appendix B of the Distribution System Code: "Methodology and Assumptions for an Economic Evaluation"

2. Sample Standard Connection Agreement

Refer to Appendix D of the Distribution System Code: "Information in a Connection Agreement with Customer"

3. Sample Operations Agreement between the Distributor and an Embedded Generator

Refer to Appendix E of the Distribution System Code: "Information in a Connection Agreement with a Generator"

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Appendix "A"
To The Rate Order Arising from Decision
EB-2007-0860
Tillsonburg Hydro Inc.

April 17, 2008

Tillsonburg Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2008
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0860

APPLICATION

- The application of these rates and charges shall be in accordance with the License of the Distributor and any Codes, Guidelines or Orders 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 License or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2008 for all charges incurred by customers on or after that date.
RETAIL SERVICE CHARGES – May 1, 2008 for all charges incurred by retailers or customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2008 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification applies to an account in one of three categories of residential services: single-family or single-unit homes, multi-family buildings, and subdivision developments. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

General Service Less Than 50 kW
This classification applies to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

General Service 50 to 499 kW
This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 500 kW. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

General Service 500 to 4,999 kW
This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 500 kW but less than 5,000 kW. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

Unmetered Scattered Load
This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

Sentinel Lighting
This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in Tillsonburg Hydro's Conditions of Service.

Street Lighting
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 Tillsonburg Hydro's Conditions of Service.

Tillsonburg Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2008
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0860

MONTHLY RATES AND CHARGES

Residential		
Service Charge		$ 11.65
Distribution Volumetric Rate	$/kWh	0.0159
Retail Transmission Rate – Network Service Rate	$/kWh	0.0045
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)		$ 0.25
General Service Less Than 50 kW		
Service Charge		$ 25.03
Distribution Volumetric Rate	$/kWh	0.0100
Retail Transmission Rate – Network Service Rate	$/kWh	0.0041
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)		$ 0.25
General Service 50 to 499 kW		
Service Charge		$ 111.76
Distribution Volumetric Rate	$/kW	0.8315
Retail Transmission Rate – Network Service Rate	$/kW	1.5822
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5008
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)		$ 0.25
General Service 500 to 4,999 kW		
Service Charge		$ 1,158.42
Distribution Volumetric Rate	$/kW	0.4773
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.0773
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.0442
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)		$ 0.25
Unmetered Scattered Load		
Service Charge (per connection)		$ 12.38
Distribution Volumetric Rate	$/kWh	0.0100
Retail Transmission Rate – Network Service Rate	$/kWh	0.0041
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)		$ 0.25

Tillsonburg Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2008
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0860

Sentinel Lighting

Service Charge (per connection)		$ 1.18
Distribution Volumetric Rate	$/kW	7.3155
Retail Transmission Rate – Network Service Rate	$/kW	1.3027
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2357
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)		$ 0.25

Street Lighting

Service Charge (per customer)		$ 1,336.76
Distribution Volumetric Rate	$/kW	4.4791
Retail Transmission Rate – Network Service Rate	$/kW	1.2993
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2324
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)		$ 0.25

Specific Service Charges

Customer Administration		
Returned Cheque (plus bank charges)		$ 15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)		$ 30.00
Special Meter Reads		$ 30.00
Non-Payment of Account		
Late Payment - per month %		1.50
Late Payment - per annum %		19.56
Collection of account charge – no disconnection		$ 30.00
Disconnect/Reconnect Charge - at Meter - During Regular Hours		$ 65.00
Disconnect/Reconnect Charge - at Meter - After Regular Hours		$ 185.00
Disconnect/Reconnect Charge at Pole – During Regular Hours		$ 185.00
Install/Remove Load Control Device – After Regular Hours		$ 185.00
Service Call – After Regular Hours		$ 165.00
Specific Charge for Access to the Power Poles – per pole/year		$ 22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy %		(1.00)

Tillsonburg Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2008
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0860

Retail Service Charges (if applicable)

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

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

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0422
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0317
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Changes in Conditions of Services

THI's Conditions of Service were amended April 22, 2008 to incorporate the authorized distribution rates that took effect May 1, 2008.

List of Witnesses and their Curriculum Vitae

List of Witnesses

- B. Drinkwater
- D. Eddington, C.A.
- J. Gott, C.A.
- R. Jacob
- S. Lund, P.Eng.

Their Curriculum Vitae are provided at E1/T2/S9/AttA-E, respectively.

Bryan Drinkwater

Trottier Drive
Tillsonburg, Ontario, N4G 5P9
Res: 519-842-4037 E-mail: bdrinkwater@tillsonburg.ca
Business: 519-688-3009, extension 2225

BUSINESS EXPERIENCE

TOWN OF TILLSONBURG – Tillsonburg, Ontario **1999 – Present**
Operation Utility/ Manager

Report to Operations Director / General Manager of Hydro Inc. Responsible for day to day operations and budgeting of Hydro and Water departments. Member of Western District EDA. Instrumental in helping to achieve market opening, Hydro deregulation and on-going OEB regulation.

TILLSONBURG PUBLIC UTILITIES COMMISSION – Tillsonburg, Ontario
1975 – 1999
Water Foreman and Operator

Reports to the Operations/Utility Manager, responsible for all aspects of water distribution including operating maintenance and capital budgeting. Ensure the safe and reliable distribution of water for the Town of Tillsonburg.

EDUCATION

MOE Certified Class Three Water Operator
Certified JHSC Member

Direct in Charge Operator, 2000-2006

DARRELL EDDINGTON, C.A.

268 Centre Street
Ingersoll, Ontario, N5C1X6
Res: 519-485-2503 E-mail: Darrell_Eddington@sympatico.ca
Business: 519-842-6428, extension 3251

BUSINESS EXPERIENCE

TOWN OF TILLSONBURG – Tillsonburg, Ontario **2003 – Present**
Director of Finance, Treasurer, Town of Tillsonburg and Tillsonburg Hydro Inc.

Reports to the Chief Administrative Officer for the Town of Tillsonburg. Manages the finances for the Town and Tillsonburg Hydro Inc. including responsibility for all regulatory reporting, banking, budgets, asset management, analyses, general ledger, taxation, payroll, human resources, health and safety, accounts receivable, accounts payable and insurance.

EDUCATION

Institute of Chartered Accountants of Ontario, Chartered Accountant, 1982

Bachelor of Commerce, McMaster University, Hamilton, Ontario, 1979

W. JOHN GOTT, C.A.

11 Otter View Drive
Otterville, Ontario, N0J 1R0
Res: 519-879-9731 E-mail: JohnGott@nor-del.com
Business: 519-842-6428, extension 3229

BUSINESS EXPERIENCE

TOWN OF TILLSONBURG – Tillsonburg, Ontario **2000 – Present**
Finance Regulatory Affairs Manager

Reports to the Director of Finance/Treasurer for the Town of Tillsonburg and Tillsonburg Hydro Inc. Ensures Director of Finance is current on all fiscal and financial management issues. Preparation of reports required required by the Ontario Energy Board and the Independent Electricity System Operator for maintenance of electricity distribution license; Electricity Distribution Rate Applications; Participates in the annual budget process; Updates and performs maintenance on the financial system; Preparation and analysis of year end working papers and financial statements; Participates in service agreements management.

VINE AND PARTNERS, LLP – Hamilton, Ontario **1995 - 2000**
Assurance Services Manager

Co-ordination of assurance engagements, including audits, reviews, compilations, interaction with clients, confirmation calls and client bookkeeping in various industries, supervision of associate staff, provision of on-going performance evaluations, build and facilitate teamwork and ensure Quality Control standards met.

EDUCATION

Institute of Chartered Accountants of Ontario, Chartered Accountant, 1998

Bachelor of Accounting with Honours, Brock University, St. Catharines, Ontario, 1995

RICK JACOB

3 Woodside Drive
Tillsonburg, Ontario, N4G 5P9
Res: 519-842-2345 E-mail: rjacob@tillsonburg.ca
Business: 519-688-3009, extension 2239

BUSINESS EXPERIENCE

TOWN OF TILLSONBURG – Tillsonburg, Ontario **1977 – Present**
Instrumentation Technologist, Town of Tillsonburg and Tillsonburg Hydro Inc.

Reports to the Operations/Utility Manager, responsible for all aspects of metering including meter reverification, MV90, maintain and install single phase and three phase installations, meter read variance lists and other customer service work as required. Provide fiber optic, information technology and instrumentation support for Tillsonburg Hydro. Daily retrieval and translation of remotely interrogated interval meters.

EDUCATION

AMEU Journeyman Meterman, 1982

Electronics Technician, Fanshawe College, London, Ontario, 1976

Steven T. Lund, P.Eng.

22 Woodland Crescent
Tillsonburg, Ontario, N4G 5R5
Res: 519-688-9838 E-mail: slund@tillsonburg.ca
Business: 519-842-6428, extension 3228

BUSINESS EXPERIENCE

Tillsonburg Hydro Inc. – Tillsonburg, Ontario **2000 – Present**
General Manager

Responsible for reporting to the Tillsonburg Hydro Inc. board of directors as General Manager. Responsible for overseeing the $18 million operations and capital budget for THI through Master Service Agreement with the Town of Tillsonburg. Main objective of Hydro business plan include voltage conversion work to reduce costs and replacing aging infrastructure to ensure safe and reliable distribution of electricity within the Town of Tillsonburg, Tillsonburg TS capacity review with Hydro One, construction of M8 distribution feeder to supply Van Norman Industrial park to allow for industrial and residential growth in this area. Oversaw smooth and successful transition of Electricity Restructuring Act (1998) from Tillsonburg PUC to Tillsonburg Hydro Inc. with help of key management and electrical staff. Serves as Secretary and a member for Western District EDA.

Town of Tillsonburg, Ontario **1999 – Present**
Director of Operations

Reports to the CAO for the Town of Tillsonburg and attends Council Meetings. Responsible for overseeing the $20 million operations and capital budget for Operations Services for the Town of Tillsonburg including Hydro Distribution, Water Distribution, Sanitary Collection, Engineering, Public Works, Building Services, Fleet Services operations for the Town of Tillsonburg.

City of Owen Sound, Ontario **1989 – 1999**
Deputy City Engineer/ Manager of Public Works

Reported to the City Engineer for the City of Owen Sound and attended Council Meetings as required and committee meetings. Responsible for overseeing the operations and capital budget for Engineering and Public Works for the City of Owen Sound of Tillsonburg including Water Distribution, Sanitary Collection and Treatment, Engineering, Public Works, Traffic, Parking and Transit, Fleet Services operations for the

City of Owen Sound. Performed capital project management and engineering for the Owen Sound PUC for water distribution system.

EDUCATION

Licensed Professional Engineer, Province of Ontario, 1988.

B.Sc. University of Waterloo, 1985.

Budget Directives (Capital and Operating) and Guidelines

THI's statement of 2009 budget assumptions is provided E1/T2/S10/AttA.

Tillsonburg Hydro Inc.
2008 Financial Plan
List of Major Assumptions
As at February 28, 2008
(As Approved by the Board of Directors)

REVENUES:

- Growth in residential consumption based on net average growth in the last three years
- No growth in residential power revenues.
- Decrease in general service power revenues, assumes Ottawa Fibre will not resume operations in 2008.
- Cost of power the same as 2007.
- Streetlighting customer will be with a retailer for the entire year
- Wholesale power revenue – no significant changes.
- Distribution service revenues, Q1: Based on 2007 Q1 plus 0.9% May 1, 2007 rate increase, less revenue earned from a customer that ceased operations . Q2 – Q4: Based on 2007, plus 0.5%, assumed approval of 2008 Rate application as filed.
- Retail service revenue – same average number of customers signed up with a retailer in 2008.
- Assumed same level of late payment charges/collection history.
- Other fees – same level of activity.
- Interest revenue assumed prime rate will remain constant 5.75% throughout 2008, and that cash on hand will be comparable to 2007. No deferral/variance account interest in 2008.
- Non-utility activities – same level of Ontario Power Authority programs as 2007, plus SPEC recovery

EXPENSES:

- Operating and Maintenance – Operations Regulatory Affairs Manager and an additional linesperson will be hired in May 2008.
- Billing and Collecting – initial one-time cost to set-up a new CIS billing system will be recovered in the 2009 rate application. Thus, deferred on the balance sheet.
- Community Relations – Assumes no conservation and demand activities beyond participation in OPA programs.
- General administration expenses – incremental cost of 2009 Rate application will be recovered in the 2009 rate application. Thus, deferred on the balance sheet. No staff increases.
- Depreciation – based on projected 2007 expenditures and proposed 2008 capital program. Impact of 2007 and 2008 EEM contributions not reflected.
- Interest - customer deposits and IESO letter of credit comparable to 2007, with no significant deemed interest on deferral/variance accounts or other charges.
- Income Tax PILS – based on 2007 tax rates, 18.62% on first $400,000, excess at 27.62%

Economic Assumptions Used

When preparing its 2009 budget THI assumed that the economic conditions of the previous period would continue into the 2009TY.

Specifically, THI assumed that:

- Residential customers would increase by 1.4%;
- the 2008 price of electricity would apply; and
- energy deliveries would be at approximately the same absolute level.

THI did not make explicit assumptions with respect to inflation or employment growth or with respect to the economic well being of the automotive parts fabrication and manufacturing sector.

Changes in Methodology

THI does not propose any changes to its budgeting methodology or practices for the 2009TY.

Finance

2006 Financial Statements

THI's audited 2006 Financial Statements is provided at E1/T3/S1/AttA.

Please note that THI restated its 2006 financial results in its 2007 Financial Statements.

TILLSONBURG HYDRO INC.

FINANCIAL STATEMENTS
DECEMBER 31, 2006

MILLARD, ROUSE AND ROSEBRUGH LLP
CHARTERED ACCOUNTANTS

24 HARVEY STREET
TILLSONBURG, ONTARIO

AUDITORS' REPORT

To the Shareholder of Tillsonburg Hydro Inc.

We have audited the balance sheet of Tillsonburg Hydro Inc. as at December 31, 2006 and the statements of operations, retained earnings (deficit) and cash flow for the year then ended. These financial statements are the responsibility of 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, 2006 and the results of its operations and cash flow for the year then ended in accordance with Canadian generally accepted accounting principles.

Millard Rouse & Rosebrugh

CHARTERED ACCOUNTANTS

April 4, 2007
Tillsonburg, Ontario

OUR REPORTS AND CERTIFICATES ARE ISSUED ON THE UNDERSTANDING THAT UNLESS THEY ARE REPRODUCED IN THEIR ENTIRETY, ANY SUMMARIES THEREOF, EXCERPTS THEREFROM OR REFERENCES THERETO SHALL BE SUBMITTED TO US FOR OUR APPROVAL

TILLSONBURG HYDRO INC.
2006 FINANCIAL STATEMENTS

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TILLSONBURG HYDRO INC.
BALANCE SHEET
AS AT DECEMBER 31, 2006

ASSETS	2006 $	2005 $
CURRENT ASSETS		
Bank	**365,823**	408,235
Accounts Receivable	**3,401,082**	2,818,911
Prepaid Expenses	**26,696**	38,134
Inventory	**387,308**	318,170
Due from Related Parties (Note 8)	**----**	294,115
	4,180,909	3,877,565
PROPERTY, PLANT AND EQUIPMENT (Note 4)		
Cost	**12,239,072**	11,590,954
Accumulated Depreciation	**(6,683,875)**	(6,336,046)
	5,555,197	5,254,908
OTHER ASSETS		
Regulatory Assets (Note 5)	**555,656**	554,350
	10,291,762	9,686,823
LIABILITIES AND SHAREHOLDER EQUITY		
CURRENT LIABILITIES		
Accounts Payable and Accrued Liabilities	**2,095,777**	2,002,097
Income Taxes Payable	**98,886**	36,031
Customer Deposits (Current Portion)	**61,862**	70,436
Deposits in Aid of Construction	**114,575**	81,522
Due to Related Parties (Note 8)	**132,099**	----
	2,503,199	2,190,086
LONG TERM LIABILITIES		
Customer Deposits	**96,778**	96,778
SHAREHOLDER EQUITY		
Share Capital (Note 6)	**6,992,565**	6,992,565
Contributed Capital	**1,190,387**	1,190,387
Retained Earnings (Deficit)	**(491,167)**	(782,993)
	7,691,785	7,399,959
	10,291,762	9,686,823

Approved on behalf of the Board:

The accompanying notes are an integral part of these financial statements.

TILLSONBURG HYDRO INC.
STATEMENT OF RETAINED EARNINGS (DEFICIT)
FOR THE YEAR ENDED DECEMBER 31, 2006

	2006 $	2005 $
BALANCE - Beginning of the Year	**(782,993)**	(833,472)
Net Income for the Year	**291,826**	50,479
BALANCE - End of the Year	**(491,167)**	(782,993)

The accompanying notes are an integral part of these financial statements.

TILLSONBURG HYDRO INC.
STATEMENT OF OPERATIONS
FOR THE YEAR ENDED DECEMBER 31, 2006

	Budget 2006 $	Actual 2006 $	Actual 2005 $
POWER REVENUE			
General Service	11,081,770	**10,414,351**	11,495,406
Residential Service	2,231,900	**2,392,799**	2,429,787
Street Lighting	77,000	**89,994**	81,777
Wholesale and Transmission Charges	3,440,000	**3,418,725**	3,906,281
	16,830,670	**16,315,869**	17,913,251
COST OF POWER	16,830,670	**16,315,869**	17,913,251
GROSS MARGIN ON POWER	----	**----**	----
DISTRIBUTION REVENUE			
Distribution Service	2,132,932	**2,320,224**	1,731,176
Retail Service	10,500	**15,559**	10,778
Other	50,000	**134,126**	115,567
	2,193,432	**2,469,909**	1,857,521
TOTAL REVENUE	2,193,432	**2,469,909**	1,857,521
EXPENSES			
Operating and Maintenance	841,672	**841,672**	671,784
Billing and Collecting	365,360	**377,485**	331,029
Community Relations	10,747	**25,863**	----
General Administration	376,326	**376,326**	366,844
Depreciation	400,855	**409,940**	384,320
Interest and Finance Charges	26,000	**9,882**	15,099
	2,020,960	**2,041,168**	1,769,076
NET INCOME BEFORE UNDERNOTED ITEMS	172,472	**428,741**	88,445
(GAIN) LOSS ON DISPOSAL OF CAPITAL ASSETS	----	**22,115**	----
INCOME AND CAPITAL TAXES (Note 7)	40,000	**114,800**	37,966
NET INCOME (LOSS) FOR THE YEAR	132,472	**291,826**	50,479

The accompanying notes are an integral part of these financial statements.

TILLSONBURG HYDRO INC.
STATEMENT OF CASH FLOW
FOR THE YEAR ENDED DECEMBER 31, 2006

	2006 $	2005 $
CASH PROVIDED BY (USED IN) OPERATIONS		
Net Income for the Year	**291,826**	50,479
Items not Requiring an Outlay of Cash:		
Depreciation	**409,940**	384,320
Loss on Disposal of Capital Assets	**22,115**	----
	723,881	434,799
Changes in Working Capital Amounts other than Cash:		
Accounts Receivable	**(582,171)**	567,100
Prepaid Expenses	**11,438**	(35,845)
Inventory	**(69,138)**	(23,213)
Due from Related Parties	**426,214**	(392,550)
Accounts Payable and Accrued Liabilities	**93,680**	(3,024)
Income Taxes Payable	**62,855**	29,143
Customer Deposits	**(8,574)**	18,549
Deposits in Aid of Construction	**33,053**	(6,133)
	691,238	588,826
CASH PROVIDED BY (USED IN) INVESTING ACTIVITIES		
Contributions in Aid of Construction	**275,633**	167,882
Additions to Property, Plant and Equipment	**(996,413)**	(757,445)
Cost of Disposal of Capital Assets	**(11,564)**	----
	(732,344)	(589,563)
CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES		
Regulatory Assets	**(1,306)**	7,320
NET INCREASE (DECREASE) IN CASH FOR THE YEAR	**(42,412)**	6,583
BANK - Beginning of the Year	**408,235**	401,652
BANK - End of the Year	**365,823**	408,235

The accompanying notes are an integral part of these financial statements.

TILLSONBURG HYDRO INC.
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2006

1. ACCOUNTING POLICIES

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles as amended by principles specifically prescribed by the Ontario Energy Board for rate regulated businesses in the "Accounting Procedures Handbook for Electric Distribution Utilities".

a) Basis of Accounting

These financial statements have been prepared using the accrual basis of accounting. The accrual basis of accounting recognizes revenue as it becomes available and measurable. Expenses are recognized as they are incurred and measurable as a result of the receipt of goods or services and the creation of a legal obligation to pay.

b) Inventory

Inventory consists of repair parts, supplies and material held for future capital expansion and maintenance activities and is valued at the lower of cost and replacement value. Cost is determined using weighted averages.

c) Property, Plant and Equipment and Depreciation

Property, plant and equipment is valued at acquisition cost less accumulated depreciation. Depreciation is provided on the straight line basis using the following rates, which are designed to reflect the approximate economic life of each class of asset:

Substation Equipment	25 Years
Distribution Lines and Transformers	25 Years
Distribution Meters	25 Years

d) Revenue Recognition

Service revenue is recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading to the end of the year. Estimated customer usage from the last billing date to the end of the year, is included in revenue.

e) Deposits in Aid of Construction

Deposits in Aid Construction are required contributions received from outside sources used to finance additions to property, plant and equipment. These deposits are deferred until expended on the intended capital project. Amounts expended are transferred to a contra-asset account and amortized at an equivalent rate to that used for the depreciation of the related property, plant and equipment. Unspent amounts are refunded.

TILLSONBURG HYDRO INC.
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2006

1. ACCOUNTING POLICIES - Continued

f) Payments in Lieu of Corporate Income Taxes

The company provides for payments in lieu of corporate income taxes using the taxes payable method. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Tillsonburg Hydro Inc.

g) Regulatory Policies

Tillsonburg Hydro Inc. has adopted the following policies, as prescribed by the Ontario Energy Board (OEB) for rate-regulated enterprises. The policies have resulted in accounting treatments differing from Canadian generally accepted accounting principles for enterprises operating on a non-rate-regulated environment:

1. Various regulatory costs have been deferred in accordance with criteria set out in the OEB's Accounting Procedures handbook. In the absence of such regulation, their costs would have been expensed when incurred under Canadian GAAP.

2. The company had deferred certain retail settlement variance amounts under the provisions of Article 490 in the OEB's Accounting Procedures handbook.

3. The company provides for payments in lieu of corporate income taxes relating to its regulated business using the taxes payable method as directed by the OEB.

h) Use of Estimates

The preparation of periodic financial statements sometimes requires management to make certain estimates and assumptions that affect reported amounts. In these instances, since precise determination is dependent on future events, actual results could differ from those estimates.

2. RATE SETTING AND INDUSTRY REGULATION

The Ontario Energy Board Act (1998) (the Act) gave the Ontario Energy Board (OEB) increased powers and responsibilities to regulate the electricity industry on Ontario. These powers and responsibilities include the ability to approve or fix rates for the transmission and distribution of electricity, the ability to provide continued rate protection for rural and remote electricity consumers and the responsibility for ensuring the distribution companies fulfill obligations to connect and service customers.

The Act provides for a competitive market in the sale of electricity in addition to the regulation of the monopoly electricity delivery system in Ontario.

TILLSONBURG HYDRO INC.
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2006

2. RATE SETTING AND INDUSTRY REGULATION - Continued

The OEB has regulatory authority over the electricity delivery sector. The Act sets out the Board's powers to issue a distribution license, which must be obtained by any person owning or operating a distribution system under the Act. The Act allows the Board to prescribe license requirements and conditions to electricity distributors, which they include such considerations as specified accounting records, regulatory accounting principles, separation of accounts for separate businesses and filing requirements for rate setting purposes.

With the commencement of the open market, the company purchases electricity from the Independent Electricity System Operator (IESO), at spot market rates and charges its customers unbundled rates. The unbundled rates include the actual cost of generation and transmission of electricity and an approved rate for electricity distribution. The cost of generation, transmission and other charges such as connection and debt retirement are collected by Tillsonburg Hydro Inc. and remitted to the IESO. The company retains the distribution charge on the customer hydro invoices. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. The company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the company has recorded regulatory liabilities, which represent amounts for expenses incurred in different periods than would be the case had the company been unregulated. Specific regulatory assets and liabilities are disclosed in Note 5.

The company's approved rate for distribution includes components for the recovery of approved transition costs and estimated payments in lieu of corporate income taxes.

3. ELECTRICITY PRICES AND CREDITS TO CUSTOMERS

On November 11, 2002 legislation was introduced to reduce electricity prices for families, small businesses and farmers, while increasing Ontario's supply of electricity and encouraging conservation and alternative energy. The price of electricity to certain customers was frozen at 4.3 cents per kilowatt-hour.

Effective April 1, 2004 the 4.3 cent price cap was replaced with the rates of 4.7 cents on the first 750 kilowatt hours per month and 5.5 cents on the remaining consumption. An adjustment to the transmission and distribution rates also occurred at that time.

Effective April 1, 2005 the price cap was adjusted to the rates of 5.0 cents on the first 750 kilowatt hours per month and 5.8 cents on the remaining consumption. An adjustment to the transmission and distribution rates also occurred at that time.

Effective August 1, 2005 an adjustment to the distribution rates occurred.

TILLSONBURG HYDRO INC.
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2006

3. ELECTRICITY PRICES AND CREDITS TO CUSTOMERS - Continued

Under new regulation issued in October 2005, Regulated Price Plan customers received a one-time credit reflecting a lower cost of power than the fixed community price between April 1, 2004 and March 31, 2005. The application of the one-time credit did not result in any adjustment to net income in the current or previously reported periods.

Effective November 1, 2005 the price cap for residential customers was adjusted to the rates of 5.0 cents on the first 1,000 kilowatt hours per month and 5.8 cents on the remaining consumption.

Effective May 1, 2006 the price cap was adjusted to the rates of 5.8 cents on the first 600 kilowatt hours per month and 6.7 cents on the remaining consumption. An adjustment to the transmission and distribution rates also occurred at that time.

Effective November 1, 2006 the price cap for residential customers was adjusted to the rates of 5.5 cents on the first 1,000 kilowatt hours per month and 6.4 cents on the remaining consumption.

4. PROPERTY, PLANT AND EQUIPMENT

	Cost $	Accumulated Depreciation $	Net 2006 $	Net 2005 $
Substation Land	11,520	----	**11,520**	11,520
Substation Equipment	533,602	(409,998)	**123,604**	144,151
Distribution System	13,214,465	(6,417,470)	**6,796,995**	6,255,833
	13,759,587	(6,827,468)	**6,932,119**	6,411,504
Contributions in Aid of Construction	(1,520,515)	143,593	**(1,376,922)**	(1,156,596)
	12,239,072	(6,683,875)	**5,555,197**	5,254,908

TILLSONBURG HYDRO INC.
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2006

5. REGULATORY ASSETS AND LIABILITIES

The following expenses (recoveries) may be considered by the Ontario Energy Board in future rate applications and accordingly have been deferred until such time as direction is provided by the OEB.

Likewise, the difference between the utility's purchased cost of power based on time of use and the amounts billed to non-time of use customers is required to be deferred. The disposition of these amounts is expected to be reflected in future rate adjustments.

	2006 $	2005 $
Qualifying Transition Costs	**520,770**	499,883
Pre-Market Opening Variance	**136,498**	130,554
Retail Settlement Variances	**80,069**	(153,429)
Recovery of Regulatory Assets	**(108,069)**	121,697
OEB Cost Assessment	**24,594**	19,677
Conservation and Demand Management	**(85,220)**	(126,696)
Deferred PIL's	**(57,362)**	6,472
One-Time Wholesale Market Service Charges	**24,941**	23,800
Miscellaneous Deferrals	**33,927**	32,392
Smart Meters	**(14,492)**	----
	555,656	554,350

Transition costs represent the incremental recoverable costs of preparing for the open electricity market.

Qualifying transition costs are subject to OEB approval of unamortized balances as at December 31, 2006 and future direction from the OEB for further write downs.

The pre-market opening energy variance and the retail settlement variance accounts represent differences between charges billed to customers using the Ontario Energy Board approved fixed reference price and the actual costs billed to Tillsonburg Hydro Inc. by the IESO.

The deferred payment in lieu of taxes represents the accumulated difference in the approved estimate of taxes to be paid and the actual taxes paid. The estimates were approved by the OEB and are now being recovered as part of the company's rate base. The true up has been recorded as part of deferred payments in lieu of taxes and charged to income.

TILLSONBURG HYDRO INC.
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2006

5. REGULATORY ASSETS AND LIABILITIES - Continued

On December 9, 2004, the OEB issued its decision on the Phase II recovery of various regulatory deferral accounts incurred prior to December 31, 2003, plus related interest. As a result of the OEB's decision, the proportion of our regulatory assets subject to potential OEB disallowance has been significantly reduced. However, regulatory asset amounts included in approved accounts that were recognized after December 31, 2003 have not yet been reviewed by the OEB. The company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Conservation and demand management includes costs of conservation and demand management activities and investments outlined in the company's Conservation and Demand Management Plan. This also includes amounts the company collects in rates for its third tranche or final installment of MARR (market adjusted revenue requirement), over the approved collection period between March 1, 2005 and February 28, 2006.

Starting in 2006, rates included an amount to fund a smart meter conversion program. The amount the company collects in rates is deferred to offset the costs of the conversion program.

6. SHARE CAPITAL

	2006 $	2005 $
Authorized:		
Unlimited Common Shares		
Unlimited Class A Shares - non-voting, non-cumulative, redeemable		
Issued:		
1 common share	**6,992,565**	6,992,565

7. PAYMENTS IN LIEU OF INCOME AND CAPITAL TAXES

As a regulated Lines Distribution Corporation, Tillsonburg Hydro is required to remit payments in lieu of income taxes and capital taxes, as follows:

	2006 $	2005 $
Income Taxes	**122,000**	34,184
Capital Taxes	**(7,200)**	3,782
	114,800	37,966

TILLSONBURG HYDRO INC.
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2006

8. RELATED PARTY TRANSACTIONS

Banking and accounting activities are administered by the Town of Tillsonburg on behalf of Tillsonburg Hydro Inc. Amounts due from related parties represent the net working capital position between the Town and the corporation.

9. PRUDENTIAL SUPPORT

Tillsonburg Hydro Inc. has posted a letter of credit with the Independent Electricity System Operator (IESO) in the amount of $1,266,441 (2005 - $1,266,441). The IESO is responsible for ensuring that prudential support is posted by all market participants to satisfy their prudential support obligation and, therefore, mitigate the impact of an event of default by a market participant on the rest of the market.

In turn, Tillsonburg Hydro Inc. has received prudential support from retailers in the amount of $22,875 cash (2005 - $21,881 cash and a $55,000 letter of credit).

10. LITIGATION AND CONTINGENT LIABILITIES

Class actions were commenced against the Consumers Gas Company in 1994 and against Toronto Hydro in 1998. Both actions claimed restitution for unjust enrichment arising from the late payment penalties levied on overdue utility bills by the defendant utilities.

On April 24, 2004, the Supreme Court of Canada rendered its judgment regarding defenses raised by Consumers Gas. With respect to the unjust enrichment claim, the Court held that the rate orders of the Ontario Energy Board contravened the Criminal Code, which is Federal legislation and this is paramount to Provincial legislation and the Ontario Energy Board Act. The Court also ruled that an order for repayment of monies collected would not occur before the issuance of the statement of claim in 1994. The full impact to Tillsonburg Hydro Inc. is not yet known with certainty and the magnitude of any restitution cannot be accurately estimated. However, the Board of Directors of Tillsonburg Hydro Inc. felt it was prudent to make an allowance of $75,000 (2005 - $75,000).

The class action against Toronto Hydro is now proceeding and is being defended by the Electric Distributors Association legal counsel.

Finance

2007 Financial Statements

THI's audited 2007 Financial Statements is provided at E1/T3/S2/AttA.

TILLSONBURG HYDRO INC.

FINANCIAL STATEMENTS

DECEMBER 31, 2007

SCRIMGEOUR & COMPANY
CHARTERED ACCOUNTANT

AUDITOR'S REPORT

To the Shareholder and Board of Directors:

I have audited the statement of financial position of the Tillsonburg Hydro Inc. as at December 31, 2007 and the statements of operations, retained earnings and changes in financial position for the year then ended. These financial statements are the responsibility of the Corporation's management. My responsibility is to express an opinion on these financial statements based on my audit.

I conducted my audit in accordance with generally accepted auditing standards. Those standards require that I 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 my opinion, these financial statements present fairly, in all material respects, the financial position of the Tillsonburg Hydro Inc. as at December 31, 2007 and the results of its operations and changes in financial position for the year then ended in accordance with Canadian generally accepted accounting principles.

May 8, 2008
August 6, 2008 (note 12)
London, Canada

Scrimgeour · Company
LICENSED PUBLIC ACCOUNTANT

Suite 950, 495 Richmond Street London, Ontario N6A 5A9 • Phone: 519-672-6811 Fax: 519-672-9757

TILLSONBURG HYDRO INC.
STATEMENT OF FINANCIAL POSITION
DECEMBER 31, 2007
(with comparative balances as at December 31, 2006)

	2007	2006 (note 12)
ASSETS		
Current		
Cash and short term investments	$ 847,463	$ 365,823
Accounts receivable	2,904,951	3,401,082
Due from related parties (note 8)	357,748	
Income taxes receivable	56,142	
Inventory	361,777	387,308
Prepaid expenses	30,042	26,696
	4,558,123	4,180,909
Capital - (note 4)		
Cost	13,042,205	12,239,072
Less accumulated amortization	7,124,294	6,683,875
	5,917,911	5,555,197
Other assets		
Regulatory assets (note 5) (note 12)		387,417
Total assets	**$ 10,476,034**	**$ 10,123,523**
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable and accrued liabilities	$ 1,948,282	$ 2,095,777
Income taxes payable (note 12)		40,744
Customer deposits	85,363	61,862
Deposits in aid of construction	190,625	114,575
Due to related parties (note 8)		132,099
	2,224,270	2,445,057
Long term		
Customer deposits	96,778	96,778
Other liabilities		
Regulatory liabilities (note 5) (note 12)	186,169	
Total liabilities	**2,507,217**	**2,541,835**
Shareholder's Equity		
Common shares (note 6)	6,992,565	6,992,565
Contributed capital	1,190,387	1,190,387
Accumulated net earnings (deficit) - Statement 2	(214,135)	(601,264)
	7,968,817	7,581,688
Total liabilities and shareholder's equity	**$ 10,476,034**	**$ 10,123,523**

On behalf of the Board: _____ _____

The accompanying notes are an integral part of this financial statement.

TILLSONBURG HYDRO INC.
STATEMENT OF RETAINED EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2007
(with comparative balances for the year ended December 31, 2006)

	2007	2006 (note 12)
Accumulated net earnings (deficit), beginning of year	**$ (601,264)**	**$ (782,993)**
Net earnings for the year - Statement 3 (note 12)	387,129	181,729
Accumulated net earnings (deficit), end of year	**$ (214,135)**	**$ (601,264)**

The accompanying notes are an integral part of this financial statement.

TILLSONBURG HYDRO INC.
STATEMENT OF OPERATIONS
FOR THE YEAR ENDED DECEMBER 31, 2007
(with comparative balances for the year ended December 31, 2006)

	Budget 2007	Actual 2007	Actual 2006 (note 12)
Power service			
Residential	$ 11,909,698	$ 11,060,636	$ 10,414,351
General	2,392,900	2,352,279	2,392,799
Streetlighting	90,000	17,861	89,994
Wholesale and transmission charges	3,863,502	3,539,321	3,418,725
	18,256,100	16,970,097	16,315,869
Cost of power	18,256,100	16,970,097	16,315,869
Gross margin on power			
Distribution revenue			
Distribution service	2,467,829	2,503,740	2,320,224
Retail service	15,800	16,751	15,559
Other	124,200	133,406	134,126
	2,607,829	2,653,897	2,469,909
Expenditures			
Operating and maintenance	826,141	796,141	841,672
Billing and collecting	387,106	394,759	377,485
Community relations	85,220	6,458	25,863
General administration	422,912	422,912	376,326
Amortization (note 1)	410,000	440,419	409,940
Interest and finance charges	10,000	19,023	9,882
	2,141,379	2,079,712	2,041,168
Net operating revenue (loss)	**466,450**	**574,185**	**428,741**
Loss on disposal of assets			22,115
Prior period adjustment (note 12)			110,097
Provision for corporate taxes (note 7)	129,000	187,056	114,800
Net earnings for the year	**$ 337,450**	**$ 387,129**	**$ 181,729**

The accompanying notes are an integral part of this financial statement.

TILLSONBURG HYDRO INC.
STATEMENT OF CHANGES IN FINANCIAL POSITION
FOR THE YEAR ENDED DECEMBER 31, 2007
(with comparative balances for the year ended December 31, 2006)

	2007	2006 (note 12)
Operating activities		
Net earnings (loss) for the period (Statement 3)	$ 387,129	$ 181,729
Charges (credits) not involving cash		
Amortization	440,419	409,940
Loss on disposal of capital assets		22,115
Net change in non-cash working capital balances related to operations (A)	(116,361)	(90,785)
	711,187	522,999
Investing activities		
Contributions in aid of construction	138,385	275,633
Capital asset acquisitions (net of dispositions)	(941,518)	(1,007,977)
	(803,133)	(732,344)
Financing activities		
Regulatory assets	573,586	166,933
	573,586	166,933
Change in cash during the year	481,640	(42,412)
Cash, beginning of year	365,823	408,235
Cash, end of year	**$ 847,463**	**$ 365,823**

(A) Consists of changes in accounts receivable, inventory, prepaid expenses, customer deposits, due from (to) related parties and accounts payable and accrued liabilities.

The accompanying notes are an integral part of this financial statement.

TILLSONBURG HYDRO INC.
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2007

Tillsonburg Hydro Inc. was incorporated in Ontario on October 26, 2000 to distribute electrical power in accordance with Section 144 of the Electricity Act, 1998.

1. Significant accounting policies

The Corporation's financial statements have been prepared in accordance with Canadian accepted accounting principles as amended by principles specifically prescribed by the Ontario Energy board for rate regulated businesses in the "Accounting Procedures Handbook for Electric Distribution Utilities".

Basis of Accounting

These financial statements have been prepared using the accrual basis of accounting. The accrual basis of accounting recognizes revenue as it becomes available and measurable. Expenses are recognized as they are incurred and measurable as a result of the receipt of goods or services and the creation of a legal obligation to pay.

Accounts receivable

Accounts receivable are shown net of an allowance for doubtful accounts of $26,462 (2006 - $55,744).

Inventories

Inventory consists of repair parts, supplies and material held for future capital expansion and maintenance activities and is valued at the lower of cost and replacement value. Cost is determined using weighted averages.

Capital assets and amortization

Capital assets included property, plant and equipment. These assets are valued at acquisition cost less accumulated amortization. Amortization is provided on the straight line basis using the following rates, which are designed to reflect the approximate economic life of each class of asset:

Substation equipment	25 years
Distribution lines and transformers	25 years
Distribution meters	25 years

Revenue Recognition

Service revenue is recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading to the end of the year. Estimated customer usage from the last billing date to the end of the year, is included in revenue.

1. Significant accounting policies continued

Deposit in aid of construction

Deposits in aid of construction are required contributions received from outside sources used to finance additions to property, plant and equipment. These deposits are deferred until expended on the intended capital project. Amounts expended are transferred to a contra-asset account and amortized at an equivalent rate to that used for the depreciation of the related property, plant and equipment. Unspent amounts are refunded.

Payment in lieu of corporate income taxes

The company provides for payments in lieu of corporate income taxes using the taxes payable method. Under the taxes payable method, no provisions are made for the future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Tillsonburg Hydro Inc.

Regulatory policies

Tillsonburg Hydro Inc. has adopted the following policies, as prescribed by the Ontario Energy Board (OEB) for rate-regulated enterprises. The policies have resulted in accounting treatments differing from Canadian generally accepted accounting principles (GAAP) for enterprises operating on a non-regulated environment:

1. Various regulatory costs have been deferred in accordance with criteria set out in the OEB's Accounting Procedures handbook. In the absence of such regulation, their costs would have been expensed when incurred under Canadian GAAP.

2. The company has deferred certain retail settlement variance amounts under the provisions of Article 490 in the OEB's Accounting Procedures handbook.

3. The company provides for payments in lieu of corporate income taxes relating to its regulated business using the taxes payable method as directed by the OEB.

Use of estimates

The preparation of periodic financial statements sometimes requires management to make certain estimates and assumptions that affect reported amounts. In these instances, since precise determination is dependent on future events, actual results could differ from those estimates.

2. Rate setting and industry regulation

The Ontario Energy Board Act (1998) (the Act) gave the Ontario Energy Board (OEB) increased powers and responsibilities to regulate the electricity industry on Ontario. These powers and responsibilities include the ability to approve or fix rates for the transmission and distribution of electricity, the ability to provide continued rate protection for rural and remote electricity consumers and the responsibility for ensuring the distribution companies fulfil obligations to connect and service customers.

The Act provides for a competitive market in the sale of electricity in addition to the regulation of the monopoly electricity delivery system in Ontario.

The OEB has regulatory authority over the electricity delivery sector. The Act sets out the Board's powers to issue a distribution license, which must be obtained by any person owning or operating a distribution system under the Act. The Act allows the Board to prescribe license requirements and conditions to electricity distributors, which they include such considerations as specified accounting records, regulatory accounting principles, separation of accounts for separate businesses and filing requirements for rate setting purposes.

With the commencement of the open market, the company purchases electricity from the Independent Electricity System Operator (IESO), at spot market rates and charges its customers unbundled rates. The unbundled rates include the actual cost of generation and transmission of electricity and an approved rate for electricity distribution. The cost of generation, transmission and other charges such as connection and debt retirement are collected by Tillsonburg Hydro Inc. and remitted to the IESO. The company retains the distribution charge on the customer hydro invoices. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. The company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered on future rates. In addition, the company has recorded regulatory liabilities, which will represent amounts for expenses incurred in different periods than would be the case had the company been unregulated. Specific regulatory assets and liabilities are disclosed in note 5.

The company's approved rate for distribution includes components for the recovery of approved transition costs and estimated payments in lieu of corporate income taxes.

3. Electricity prices and credits to customers

On November 11, 2002 legislation was introduced to reduce electricity prices for families, small businesses and farmers, while increasing Ontario's supply of electricity and encouraging conservation and alternative energy. Customers that are eligible for the Regulated Price Plan (RPP) receive a fixed price of 4.3 cents per kilowatt-hour.

Effective April 1, 2004 the RPP rate was increased to 4.7 cents on the first 750 kilowatt-hours (Tier 1) per month and 5.5 cents on the remaining consumption (Tier 2). An adjustment to the transmission and distribution rates also occurred at that time.

Effective April 1, 2005 the RPP rates for Tier 1 and Tier 2 were adjusted to the rates of 5.0 cents and 5.8 cents respectively. An adjustment to the transmission and distribution rates also occurred at that time.

Effective August 1, 2005 and adjustment to the distribution rates occurred.

Under the new regulation issued in October 2005, RPP customers received a one-time credit reflecting a lower cost of power than the fixed price between April 1, 2004 and March 31, 2005. The application of the one-time credit did not result in any adjustment to net income in the current or previously reported periods.

Effective November 1, 2005 the RPP Tier 1 for residential customers was increased to the first 1,000 kilowatt hours per month, non-residential customers Tier 1 remained at the first 750 kilowatt hours per month.

Effective May 1, 2006 the RPP rates were adjusted for Tier 1 and Tier 2 to 5.8 cents and 6.7 cents respectively. And, Tier 1 for residential customers was decreased to the first 600 kilowatt hours per month, and non-residential customers Tier 1 remained unchanged. An adjustment to the transmission and distribution rates also occurred at that time.

Effective November 1, 2006 the RPP rates were adjusted for Tier 1 and Tier 2 to 5.5 cents and 6.4 respectively. And, Tier 1 for residential customers was increased to the the first 1,000 kilowatt hours per month, and non-residential customers Tier 1 remained unchanged.

Effective May 1, 2007 the RPP rates were adjusted for Tier 1 and Tier 2 to 5.3 cents and 6.2 cents respectively. And, Tier 1 for residential customers was decreased to the first 600 kilowatt hours per month, and non-residential customers Tier 1 remained unchanged. An adjustment to the transmission and distribution rates also occurred at that time.

Effective November 1, 2007 the RPP rates were adjusted for Tier 1 and Tier 2 to 5.0 cents and 5.9 cents respectively. And, Tier 1 for residential customers was increased to the first 1,000 kilowatt hours per month, and non-residential customers Tier 1 remained unchanged.

4. Capital assets

The value of property, plant and equipment as at year end are as follows:

	Cost	Accumulated Amortization	Net 2007	Net 2006
Substation land	$ 11,520	$	$ 11,520	$ 11,520
Substation equipment	533,602	(419,994)	113,608	123,604
Distribution system	14,155,983	(6,911,481)	7,244,502	6,796,995
	14,701,105	(7,331,475)	7,369,630	6,932,119
Contributions in aid of construction	(1,658,900)	207,181	(1,451,719)	(1,376,922)
	$13,042,205	$(7,124,294)	$ 5,917,911	$ 5,555,197

5. Regulatory assets and liabilities

The following expenses (recoveries) may be considered by the Ontario Energy Board in future rate applications and accordingly have been deferred until such time as direction is provided by the OEB.

Likewise, the difference between the utility's purchased cost of power based on time of use and the amounts billed to non-time of use customers is required to be deferred. The disposition of these amounts is expected to be reflected in future rate adjustments. See note 12 for a change in these balances as a result of an audit by the Ontario Energy Board.

	2007	2006
Deferred costs:		
Qualifying transition costs	$	$ 378,568
Pre-market opening variance		123,880
OEB cost assessment	18,950	4,895
OMERS cost	67,022	67,022
Deferred PILs	(61,535)	(58,905)
Miscellaneous deferrals	14,199	33,927
Conservation and demand management		(85,220)
Smart meters	(34,979)	(14,624)
	3,657	449,543
Retail service variance accounts:		
Retail settlement variances	(1,034,803)	22,414
One-time wholesale market services charges	156	24,941
	(1,034,647)	47,355
Recovery of regulatory assets	844,821	(109,481)
Total regulatory (liabilities) assets	$ (186,169)	$ 387,417

Transition costs represent the incremental recoverable costs of preparing for the open electricity market.

5. Regulatory assets and liabilities continued

Qualifying transition costs are subject to OEB approval of unamortized balances as at December 31, 2007 and future direction from the OEB for further write downs.

The pre-market opening energy variance and the retail settlement variance accounts represent differences between charges billed to customers using the Ontario Energy Board approved fixed reference price and the actual costs billed to Tillsonburg Hydro Inc. by the IESO.

The deferred payment in lieu of taxes represents the accumulated difference in the approved estimate of taxes to be paid and the actual taxes paid. The estimates were approved by the OEB and are now being recovered as part of the company's rate base. The true up has been recorded as part of deferred payments in lieu of taxes and charged to income.

On December 9, 2004, the OEB issued it's decision on the Phase II recovery of various regulatory deferral accounts incurred prior to December 31, 2003, plus related interest. As a result of the OEB's decision, the proportion of our regulatory assets subject to potential OEB disallowance has been significantly reduced. However, regulatory asset amounts included in approved accounts that were recognized after December 31, 2003 have not yet been reviewed by the OEB. The company continually assesses the likelihood of recovery of each of it's regulatory assets and liabilities into the setting of future rates. If, at some future date, the company judges that it is no longer probable that the OEB will include a regulatory asset of liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Conservation and demand management includes costs of conservation and demand management activities and investments outlined in the company's Conservation and Demand Management Plan. This also includes amounts the company collects in rates for its third tranche or final installment of MARR (market adjusted revenue requirement), over the approved collection period between March 1, 2005 and February 28, 2006.

Starting in 2006, rates included an amount to fund a smart meter conversion program. The amount the company collects in rates is deferred to offset the costs of the conversion program.

6. Share capital

The share capital of the Corporation consists of the following:

Authorized
- Unlimited common shares
- Unlimited number of Class A shares - non-voting, non-cumulative redeemable

	2007	2006
Issued		
- 1 voting common share	$ 6,992,565	$ 6,992,565

7. Payments in lieu of income and capital taxes

As a regulated Lines Distribution Corporation, Tillsonburg Hydro Inc. is required to remit payments in lieu of income taxes and capital taxes, as follows:

	2007	2006
Income taxes - current	$ 174,000	$ 122,000
Income taxes - prior year's adjustment	13,056	
Capital taxes - prior year's adjustment		(7,200)
	$ 187,056	$ 114,800

Payments in lieu of income taxes are calculated on the net operating revenues, adjusted for timing differences arising on differences between amortization of capital assets for tax purposes. The applicable rates for the year ending December 31, 2007 are 18.62% combined federal and provincial rates on the first $400,000, 36.12% on the next $100,000 and 40.37% on the excess over $500,000.

8. Related party transactions

Banking and accounting activities are administered by the Town of Tillsonburg on behalf of Tillsonburg Hydro Inc. Amounts due from related parties represent the net working capital position between the Town and the Corporation. A Master Service Agreement governs the financial relationship between the Corporation and the Town of Tillsonburg. These financial statements reflect this Agreement.

9. Prudential support

Tillsonburg Hydro Inc. has posted a letter of credit with the Independent Electricity System Operator (IESO) in the amount of $ 956,406 (2006 $1,266,441). The IESO is responsible for ensuring that prudential support is posted by all market participants to satisfy their prudential support and obligation and, therefore, mitigate the impact of an event of default by a market participant on the rest of the market.

In turn, Tillsonburg Hydro Inc. has received prudential support from retailers in the amount of $ 23,824 (2006 - $ 22,875).

10. Litigation and contingent liabilities

Class actions were commenced against the Consumers Gas Company in 1994 and against Toronto Hydro as the proposed representative defendant for all Ontario Municipal Electric Utilities in 1998. Both actions claimed restitution for unjust enrichment arising from the late payment penalties levied on overdue utility bills by the defendant nullities.

On April 24, 2004, the Supreme Court of Canada rendered it's judgment regarding defences raised by Consumers Gas. With respect to the unjust enrichment claim, the Court held that the rate orders of the Ontario Energy Board contravened the Criminal Code, which is Federal legislation and this is paramount to Provincial legislation and the Ontario Energy Board Act. This Court also ruled that an order for repayment of monies collected would not occur before the issuance of the statement of claim in 1994. The full impact to Tillsonburg Hydro Inc. is not yet known with certainty and the magnitude of any restitution cannot be accurately estimated. However, the Board of Directors of Tillsonburg Hydro Inc. felt it was prudent to make an allowance of $ 75,000 (2006 - $ 75,000).

The Electric Distributors Association and Toronto Hydro have jointly engaged legal counsel to represent the interests of the LDCs in the class action litigation.

11. Comparative balances

The comparative balances were reported on by the Corporation's former auditors.

12. Prior period adjustment

Subsequent to the completion and issuance of the 2007 audited financial statements, the Ontario Energy Board audited the Corporation's deferral and variance accounts. Resulting from this review, to properly adhere to regulatory decisions, the 2006 deferral and variance asset accounts were decreased by $168,239 and taxes payable were decreased by $58,142. This resulted in a reduction of the net earnings and accumulated net earnings for 2006 of $110,097.

Pro Forma Statements (2008)

THI's pro forma 2008 financial statements will be filed at a later date as E1/T3/S3/AttA.

Cost of Power Projections

Consistent with the Board's guidance, as set out in its Minimum Filing Requirements, THI has relied on Navigant Consulting's forecast of the cost of power for the 2009TY of 5.45 cents/kWh. THI has relied on its currently authorized Retail Transmission Service Rates and other currently authorized rates (eg., Debt Retirement Charge). THI's projected 2009TY cost of power is provided at E1/T3/S4/AttA.

THI notes that Navigant Consulting's forecast is prepared in support of the Board's duties to establish the Regulated Rate Plan commodity prices. To the extent that THI's customers load profile and composition differs from that of RPP customers THI's actual Cost of Power will differ from the forecast.

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C2 Pass-through Charges

Electricity (Commodity)	**Customer**	**Revenue**	**Expense**	**2008**	*rate ($/kWh):*	**$0.05450**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**
kWh	Residential	4006	4705	53,153,199		2,896,849
kWh	General Service < 50 kW	4035	4705	25,923,660		1,412,839
kWh	General Service >50 kW, <500 kW	4035	4705	38,311,464		2,087,975
kWh	General Service >500 kW, <5,000 kW	4035	4705	110,874,923		6,042,683
kWh	Sentinel Lighting	4030	4705	77,063		4,200
kWh	Street Lighting	4025	4705	1,376,103		74,998
kWh	Unmetered Scattered Load	4035	4705	510,499		27,822
kWh	General Service >500 kW, <1,500 kW	4035	4705			
kWh	General Service >1,500 kW	4035	4705			
	TOTAL			**230,226,912**		**12,547,367**

Transmission - Network	**Customer**	**Revenue**	**Expense**	**2008**		
	Class Name	**USA #**	**USA #**	**Volume**	**Rate**	**Amount**
kWh	Residential	4066	4714	53,153,199	$0.0045	239,189
kWh	General Service < 50 kW	4066	4714	25,923,660	$0.0041	106,287
kW	General Service >50 kW, <500 kW	4066	4714	108,082	$1.5822	171,007
kW	General Service >500 kW, <5,000 kW	4066	4714	231,714	$2.0773	481,339
kW	Sentinel Lighting	4066	4714	205	$1.3027	267
kW	Street Lighting	4066	4714	3,783	$1.2993	4,915
kWh	Unmetered Scattered Load	4066	4714	510,499	$0.0041	2,093
kW	General Service >500 kW, <1,500 kW	4066	4714			
kW	General Service >1,500 kW	4066	4714			
	TOTAL			**79,931,142**		**1,005,098**

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C2 Pass-through Charges

Volumes from sheet C1, Account #s from sheet Y4

Electricity (Commodity)	**Customer**	**2009**	*rate ($/kWh):*	**$0.05450**
	Class Name	**Volume**		**Amount**
kWh	Residential	52,051,100		2,836,785
kWh	General Service < 50 kW	25,386,149		1,383,545
kWh	General Service >50 kW, <500 kW	37,517,100		2,044,682
kWh	General Service >500 kW, <5,000 kW			
kWh	Sentinel Lighting	77,063		4,200
kWh	Street Lighting	1,376,103		74,998
kWh	Unmetered Scattered Load	528,845		28,822
kWh	General Service >500 kW, <1,500 kW	35,106,370		1,913,297
kWh	General Service >1,500 kW	76,059,225		4,145,228
	TOTAL	**228,101,955**		**12,431,557**
Transmission - Network	**Customer**	**2009**		
	Class Name	**Volume**	**Rate**	**Amount**
kWh	Residential	52,051,100	$0.0045	234,230
kWh	General Service < 50 kW	25,386,149	$0.0041	104,083
kW	General Service >50 kW, <500 kW	106,725	$1.5822	168,860
kW	General Service >500 kW, <5,000 kW		$2.0773	
kW	Sentinel Lighting		$1.3027	
kW	Street Lighting	3,783	$1.2993	4,915
kWh	Unmetered Scattered Load	528,845	$0.0041	2,168
kW	General Service >500 kW, <1,500 kW	72,828	$2.0773	151,286
kW	General Service >1,500 kW	156,866	$2.0773	325,857
	TOTAL	**78,306,295**		**991,400**

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C2 Pass-through Charges

Transmission - Connection	Customer Class Name	Revenue USA #	Expense USA #	2008 Volume	2008 Rate	2008 Amount
kWh	Residential	4068	4716	53,153,199	$0.0043	228,559
kWh	General Service < 50 kW	4068	4716	25,923,660	$0.0039	101,102
kW	General Service >50 kW, <500 kW	4068	4716	108,082	$1.5008	162,209
kW	General Service >500 kW, <5,000 kW	4068	4716	231,714	$2.0442	473,670
kW	Sentinel Lighting	4068	4716	205	$1.2357	253
kW	Street Lighting	4068	4716	3,783	$1.2324	4,662
kWh	Unmetered Scattered Load	4068	4716	510,499	$0.0039	1,991
kW	General Service >500 kW, <1,500 kW	4068	4716			
kW	General Service >1,500 kW	4068	4716			
	TOTAL			**79,931,142**		**972,446**

Wholesale Market Service	Customer Class Name	Revenue USA #	Expense USA #	2008 Volume	*rate ($/kWh):*	**$0.00520** Amount
kWh	Residential	4062	4708	53,153,199		276,397
kWh	General Service < 50 kW	4062	4708	25,923,660		134,803
kWh	General Service >50 kW, <500 kW	4062	4708	38,311,464		199,220
kWh	General Service >500 kW, <5,000 kW	4062	4708	110,874,923		576,550
kWh	Sentinel Lighting	4062	4708	77,063		401
kWh	Street Lighting	4062	4708	1,376,103		7,156
kWh	Unmetered Scattered Load	4062	4708	510,499		2,655
kWh	General Service >500 kW, <1,500 kW	4062	4708			
kWh	General Service >1,500 kW	4062	4708			
	TOTAL			**230,226,912**		**1,197,180**

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C2 Pass-through Charges

Volumes from sheet C1, Account #s from sheet Y4

Transmission - Connection	**Customer**	**2009**		
	Class Name	**Volume**	**Rate**	**Amount**
kWh	Residential	52,051,100	$0.0043	223,820
kWh	General Service < 50 kW	25,386,149	$0.0039	99,006
kW	General Service >50 kW, <500 kW	106,725	$1.5008	160,173
kW	General Service >500 kW, <5,000 kW		$2.0442	
kW	Sentinel Lighting		$1.2357	
kW	Street Lighting	3,783	$1.2324	4,662
kWh	Unmetered Scattered Load	528,845	$0.0039	2,062
kW	General Service >500 kW, <1,500 kW	72,828	$2.0442	148,875
kW	General Service >1,500 kW	156,866	$2.0442	320,665
	TOTAL	**78,306,295**		**959,263**
Wholesale Market Service	**Customer**	**2009**	*rate ($/kWh):*	**$0.00520**
	Class Name	**Volume**		**Amount**
kWh	Residential	52,051,100		270,666
kWh	General Service < 50 kW	25,386,149		132,008
kWh	General Service >50 kW, <500 kW	37,517,100		195,089
kWh	General Service >500 kW, <5,000 kW			
kWh	Sentinel Lighting	77,063		401
kWh	Street Lighting	1,376,103		7,156
kWh	Unmetered Scattered Load	528,845		2,750
kWh	General Service >500 kW, <1,500 kW	35,106,370		182,553
kWh	General Service >1,500 kW	76,059,225		395,508
	TOTAL	**228,101,955**		**1,186,130**

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C2 Pass-through Charges

Rural Rate Protection	**Customer**	**Revenue**	**Expense**	**2008**	*rate ($/kWh):*	**$0.00100**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**
kWh	Residential	4062	4730	50,682,203		50,682
kWh	General Service < 50 kW	4062	4730	24,970,085		24,970
kWh	General Service >50 kW, <500 kW	4062	4730	36,902,217		36,902
kWh	General Service >500 kW, <5,000 kW	4062	4730	106,796,506		106,797
kWh	Sentinel Lighting	4062	4730	73,943		74
kWh	Street Lighting	4062	4730	1,310,738		1,311
kWh	Unmetered Scattered Load	4062	4730	472,835		473
kWh	General Service >500 kW, <1,500 kW	4062	4730			
kWh	General Service >1,500 kW	4062	4730			
	TOTAL			**221,208,527**		**221,209**
Debt Retirement Charge	**Customer**	**Revenue**	**Expense**	**2008**	*rate ($/kWh):*	**$0.00700**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**
	TOTAL					
Low Voltage Charges	**Customer**	**Revenue**	**Expense**	**2008**		
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**
	TOTAL (Input amount)	4075	4750			
GRAND TOTAL						**15,943,298**

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C2 Pass-through Charges

Volumes from sheet C1, Account #s from sheet Y4

Rural Rate Protection		**Customer**	**2009**	*rate ($/kWh):*	**$0.00100**
		Class Name	**Volume**		**Amount**
	kWh	Residential	52,051,100		52,051
	kWh	General Service < 50 kW	25,386,149		25,386
	kWh	General Service >50 kW, <500 kW	37,517,100		37,517
	kWh	General Service >500 kW, <5,000 kW			
	kWh	Sentinel Lighting	77,063		77
	kWh	Street Lighting	1,376,103		1,376
	kWh	Unmetered Scattered Load	528,845		529
	kWh	General Service >500 kW, <1,500 kW	35,106,370		35,106
	kWh	General Service >1,500 kW	76,059,225		76,059
		TOTAL	**228,101,955**		**228,102**
Debt Retirement Charge		**Customer**	**2009**	*rate ($/kWh):*	**$0.00700**
		Class Name	**Volume**		**Amount**
		TOTAL			
Low Voltage Charges		**Customer**	**2009**		
		Class Name	**Volume**		**Amount**
		TOTAL (Input amount)			
GRAND TOTAL					**15,796,452**

Reconciliation between Financial Statements and Financial Results Filed

THI's financial statements match its filed financial results and accordingly no reconciliation is provided.

Proposed Accounting Treatment for long lived assets

THI's accounting policies adhere to Generally Accepted Accounting Procedures and to the Canadian Institute of Chartered Accountants Handbook.

THI's long lived assets consist of its Physical Distribution Plant assets. These assets are accounted for at historic costs that are determined based on:

- directly incurred costs to acquire and make useful the individual components;
- directly incurred labour costs determined based on the Town's time sheet records; and
- appropriate allocation of overheads and indirect costs that are determined based on the Town's time sheet records;

THI uses pooled asset accounting procedures for indistinguishable assets and asset specific accounting procedures for identifiable assets.

THI relies on the straight line depreciation methodology to determine annual depreciation expense.

Compliance with the Uniform System of Accounts

THI complies with the Board's Uniform System of Accounts ("USoA").

THI's General Ledger accounts are mapped to the appropriate USoA account and appropriate reconciliations are conducted.

Consistent with the USoA, THI reports the amounts paid to the Town of Tillsonburg pursuant to the Master Service Agreement as expenses of the period. THI is aware that these sums support the Town's direct costs of the period of the Town's employees who provide service to THI and contribute to:

- the Town's interest payments and financing charges associated with the assets THI employs; and
- the Town's depreciation expense associated with the assets THI employs.

Accounting Orders

The Board has not issued any unique accounting orders to THI. THI applies the generically authorized accounting orders and concepts authorized from time to time by the Board (eg., Smart Meter deferral accounting, CDM costs incurred through 3rd Tranche authorization, costs incurred as a result of contracting with the OPA for the provision of CDM).

THI has not sought and does not seek any specific accounting orders.

Annual Report

THI does not issue Annual Reports; accordingly, none is provided.

Prospectus, information and recent share issue update

THI has not issued and does not propose to issue in the 2009TY any prospecti, information or share issue updates. As is documented at E1/T2/S5 THI has issued 1 share to the Town of Tillsonburg who has 100% control over THI.

Extraordinary Events

Extraordinary Circumstances

THI's extraordinary circumstances since 2005 include:

- Applying for and being granted an order to charge revised distribution rates to overcome financial issues in 2005;
- Experiencing a short term attachment of a large customer from late in 2006 until early in 2007;
- Implementing a succession plan to address the anticipated retirement of 2 or more key technical staff members in the immediate future.

The Board authorized changes to THI's distribution rates effective August 1, 2005 in response to an application filed with Minister of Energy approval. Those changed distribution rates improved THI's financial well being such that THI was able to undertake many deferred OM&A and capital programs and supported THI's ability to provide distribution services to the inhabitants of the Town of Tillsonburg and at an appropriate level of quality.

THI experienced the short term attachment of a large customer from late in 2006 until early in 2007. This is documented in the evidence on distribution revenues and in the Load Forecast Report (E3/T2/S1/AttA). At this time, while the customer is hopeful that it will reopen, there is no certainty that this will occur. The customer manufactures a product used in new home construction and its primary market is the United States, which is experiencing a housing supply/demand imbalance.

THI is also taking steps to address the anticipated retirement of 2 or more key staff members in the next 5 years. THI successfully recruited two apprentice linesmen in August 2008. This is discussed in greater detail in Exhibit 4.

THI has not experienced any events in the past 5 years that would be disclosed on the financial statements as an unusual claim on Net Income or as a contingent liability or gain.

Rate Base

Overview

THI forecasts that its 2009TY average rate base will amount to $8,947k and consist of:

- $6,262k m of Physical Distribution Plant assets, net of Accumulated Depreciation and Contributions in Aid of Construction ("CiAC"); and
- $2,685k of Working Cash Allowance.

The purpose of this evidence is to describe:

- THI's existing physical distribution system
- THI's proposed reclassification of assets previously recorded in Uniform System of Accounts ("USoA") account 1715 to USoA accounts 1835 and 1845;
- THI's capital budget for the 2009TY and its long range capital spending plans;
- THI's Contribution in Aid of Construction ("CiAC") policies and practices;
- THI's Accumulated Depreciation, and the associated policies;
- THI's asset accounting policies;
- THI's application of the Board's methodology for determining the Working Cash Allowance ; and
- The reasons for year over year changes in gross assets, accumulated depreciation and computed working cash allowance.

THI forecasts that its 2009TY closing Rate Base values will consist of:

Gross Property, Plant, Equipment	16,661k
Accumulated Depreciation	8,099k
Contributions in Aid of Construction	2,272k
Average Physical Distribution Plant	6,290k
Working Cash Allowance	2,685k
Rate Base 2009TY	8,975k

THI's Physical Plant and Equipment ("PPE") consists of distribution stations, municipal stations, conductor, conduit, poles, transformers, services and meters. THI's PPE does not include computers (hardware and software), telecommunications gear, vehicles, buildings; these assets

are owned by the Town of Tillsonburg and, under the Master Service Agreement ("MSA") between the Town of Tillsonburg and THI, are made available to THI for its use in providing distribution service to the inhabitants of the Town of Tillsonburg. The Town of Tillsonburg retains ownership of all assets that are not specifically and directly required to distribute electricity.

THI proposes to invest $866k in its distribution system in the 2009 TY. $349k will support the continuation of the Voltage Conversion program and $517k will support the connection of 104 new residential customers. THI has assumed that developers will render CiAC in the amount of $310k and, as a result, THI's net investment for new customer connections will amount to $207k. THI will take service through four different feeders emanating from HONI's Tillsonburg TS; they are considered adequate in light of the anticipated peak demand forecast for the 2009TY. The Town of Tillsonburg will replace it's CIS that is utilized by THI late in 2008 so that Time of Use commodity rates and Smart Meters can be accommodated. However, THI does not need to budget capital for this investment since the capital costs of this investment will be paid by the Town of Tillsonburg and recovered through payments made pursuant to the MSA; this is discussed in greater detail in Exhibit 4.

The Town procures all the materials required under the capital budget according to its procurement policies (the Town's procurement policy is provided at E2/T1/S1/AttA) to ensure open and competitive processes and prudently incurred costs.

The 2009TY Rate Base is $502k greater than that of the 2008BY and $729k greater than THI's 2006 EDR rate base as determined using 2004 historic test year data. THI's rate base has increased 9% since 2004 or 1.8% per year on average. The increase in distribution system assets is driven by:

- the connection of approximately 475 new residential customers;
- continued investment in the system to support the ongoing provision of distribution services to all existing and new customers in a safe and reliable manner, while maintaining an appropriate level of quality; and
- changes in the level of Working Cash Allowance.

The Town of Tillsonburg recently hired an Asset Management Technologist who, among other things, is responsible for completing an Asset Condition Assessment of THI's distribution system. THI has a long standing practice of conducting regular inspections of the distribution system and has relied on this information as a proxy for asset condition data.

THI capital asset accounting policies adhere to Canadian GAAP and to the Canadian CICA and have not changed since incorporation.

THI applies the Board's economic evaluation, as set out in the Board's Distribution System Code, to estimate the Contributions in Aid of Construction of all system expansions.

THI estimated the 2009TY Working Cash Allowance using the Board's 2006 EDR methodology, specifically by computing 15% of the sum of the 2009TY Cost of Power and controllable costs.

THI's Distribution System

Distribution Plant is used to redeliver energy and power from Hydro One's transmission system to the inhabitants of the Town of Tillsonburg and chiefly consists of:

- Distribution Stations;
- Conductor;
- Poles, towers and conduit;
- Transformers;
- Services; and
- Meters.

THI's physical distribution plant includes:

- 151 km of circuit km of line, that is characterized as:
    - 102 km of overhead line and 49 km of underground line; or
    - 88 km of 3 phase line and 63 km of single phase line;
- 853 transformers
    - 3 Municipal Stations; and

- 850 distribution transformers.

A schematic of THI's distribution system is provided at E1/T2/S3/AttA.

These assets are deployed over a licensed service area that is 22 km^2 or 9 mi^2 and provide redelivery of energy and power to approximately 6,600 end users during 2007. These customers collectively caused a peak day load of 48.4 MW or 56.9 MVA in the summer of 2007 and consumed 223 GWh of energy in all of 2007.

THI takes delivery of power and energy from Hydro One Networks Inc. (HONI) at the Tillsonburg Transmission Station ("TS") which has 8 feeders. THI presently has exclusive use of three of these feeders and will commission the fourth feeder by the 4th quarter of the 2008BY. The maximum delivery capacity of the three feeders that are currently relied on is approximately 50 MVA, individually their maximum permitted long range loading is approximately 20MVA. When the fourth feeder enters into service THI will rebalance the loads on all feeders to provide appropriate reliability, redundancy and to minimize line losses.

HONI delivers power to THI at 27.6 kV. THI further transforms the 27.6 kV supply:

- to distribution voltages at its distribution transformers; or
- to 4.16 kV at its 3 Municipal Stations ("MS") and then to distribution voltages.

THI proposes to reclassify the conductors feeding into its three MSs; presently, they are recorded in USoA account 1715 and THI proposes to reclassify them to USoA accounts 1835 and 1845. This reclassification will not affect the value of the proposed rate base.

Three of THI's General Service ("GS") 50 – 499 kW and all of its GS 500 – 4,999 kW customers own their transformers. Four of these customers take delivery at voltages greater than 750V.

THI's conductors, poles and conduit consist of two different systems – one being a legacy system and the other the renewed system. The legacy distribution system operates at 4.16 kV, is typically situated along rear lot lines and serves the established central core of the Town of Tillsonburg. The renewed distribution system operates at 27.6 kV, is typically situated in public

road allowance and serves the large commercial and industrial customers situated in south Tillsonburg as well as the newer developed areas of the Town that surround the central core area.

THI owns and operates approximately 6,600 meters, of differing types and vintages. Consistent with provincial government policy THI is preparing to deploy Smart Meters throughout its licensed service area. Over 400 Smart Meters have been installed to date on a pilot project basis in a designated area of the Town of Tillsonburg and were funded by 3rd Tranche CDM. Presently, all newly attaching residential customers in the pilot project area are provided with a Smart Meter that is operated in a manner consistent with conventional electro-mechanical meters. All newly attaching residential customers in other areas of the Town are provided with a conventional electro-mechanical meter. THI's GS 500 – 4,999 kW customers are all equipped with interval meters that satisfy the requirements of the Retail Settlement Code. Approximately 10 of THI's GS 50 – 499 kW customers' demand exceed 200 kW and are equipped with meters with IT functionality. The remaining members of the GS 50 – 499 kW customer class and all of the GS < 50 kW customer class are equipped with conventional meters. THI owns and is responsible for all the Potential Transformers and Current Transformers and other gear required for metering purposes.

THI's distribution physical plant assets have an average remaining life of approximately 13 years. The system is appropriately maintained so that the physical plant assets will achieve their design service life. A key element of this maintenance program is monthly inspections of all THI's Municipal Stations and appropriate scheduling of regular and preventative maintenance activities. These inspections are also relied on to identify any assets that must or should be removed from service in order to maintain secure and reliable supply.

THI's physical assets are confined to the distribution plant required to receive and deliver power and energy in a safe and reliable manner to the inhabitants of the Town of Tillsonburg. THI does not own, operate or have any responsibility for fleet, IT, telecommunications, office and related assets and infrastructure. These assets are owned by the Town of Tillsonburg and are made available to THI pursuant to a Master Service Agreement ("MSA"), it is provided at

E1/T2/S1/AttA. This ownership arrangement was implemented upon the dissolution of Tillsonburg Public Utilities Commission and the formation of THI. It is consistent with the Town's practice of requiring a corporate entity or Town department to retain ownership of only those assets having unique application; as a result, THI owns those assets that are dedicated to the provision of electricity distribution service.

Under the terms of the 2008 MSA, THI has the use of Town owned assets such as:

- Vehicles, that include appropriately equipped boom and bucket trucks and service vehicles;
- Information Technology and telecommunications assets;
- Appropriate materials, tools etc.; and
- Buildings and other facilities (eg., garage, warehouse).

It is important to recognize that THI's capital is understated versus that of other electricity distributors who own such assets. From an accounting perspective, THI 'rents' these assets from the Town.

THI's asset accounting policies adhere to Canadian Generally Accepted Accounting Principles and are described in the notes to the 2007 Financial Statements (E1/T3/S2/AttA). Briefly, THI uses historic cost accounting and records asset acquisition costs and appropriately capitalized costs (eg., labour, materials, burdens). Direct labour, fleet and materials costs are assigned to projects and accounts based on a time sheet system. Engineering, Administration and Management costs are burdened at 14%, 6% and 5% respectively. THI uses pooled asset accounting for all assets other than Municipal Stations, which are accounted for as specific assets.

THI applies the Board's economic evaluation to all system expansions. The calculation relies on THI's actual capital structure rather than its hypothetical capital structure that is used for rate making purposes. THI seeks the maximum amount of CiAC from each project that is determined to be uneconomic at existing rates. CiAC as recorded as an offset to the gross value of all distribution assets and is appropriately amortized.

Additions to Rate Base

THI seeks Board approval to include the capital assets that will be commissioned in the 2009TY in its Board authorized 2009TY rate base:

Capital Investment

THI invests in its distribution system to:

- Attach new customers;
- Renew its existing infrastructure; and
- Implement provincial energy policy (eg., Smart Metering, CDM).

Capital Budgeting Methodology

THI prepares a capital budget for each project it intends to undertake. The capital budget is based on THI's knowledge of the work to be performed, the type and amount of resources required to undertake and complete the work in a safe and efficient manner. Engineering, Administration and Fleet costs are estimated using long standing burden rates.

Capital Budget – New Customers

In the 2009TY THI forecasts that it will invest $517k to attach 104 new residential customers who are expected to render CiAC in the amount of $310k and as a result, THI's net investment is expected to amount to $207k. The capital budget is provided in the table below.

Capital Budget - Customer Additions	
	2009TY
TS	0
Land	0
DS	0
Poles, Towers and Fixtures	86,480
Overhead Conductors & Devices	110,309
Underground Conduit	34,221
Underground Conductors & Devices	90,246
Line Transformers	129,954
Services	54,681
Distribution Meters	10,962
Contributions & Grants - Credit	-309,652
Total	207,200

THI will perform all required activities consistent with its Conditions of Service and with the Distribution System Code. Where appropriate, THI will make an Offer to Connect that sets out the services that THI will provide and if a CiAC is sought. No large load customers are forecast to connect to THI's distribution system in the 2009TY.

THI has attached new customers in every year since its formation. Customer attachments for the period 2004-2009 are provided in the table below.

Customer Additions

	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Projected	2009 Forecast
Residential	89	82	109	113	102	104

In order to attach a new residential customer THI must evaluate the existing infrastructure's capability of servicing the new customer(s) as well as identify the connection assets that must be put into place. Expansions to add new residential subdivisions typically rely on underground infrastructure, including conduit and conductor, adequate transformation, Protection and Control/Grounding gear, meters, connection conductor – all of which must be co-ordinated with

the overall civil infrastructure of the development. These costs are included in the economic evaluation that is conducted for all expansion projects and impact the computed CiAC. In-fill residential customers typically do not give rise to a system expansion and are simply connected to the existing distribution system.

THI prepares an Offer to Connect for those customers who trigger a system expansion and a CiAC, consistent with the requirements of the DSC. The Offer to Connect sets out the activities that THI is responsible for, the choices available to the customer and the consequences – both financial and legal – to the customer.

The 2009TY capital budget for customer attachments and connections is considered representative of the typical investment for the future assuming materials prices do not change materially. THI has assumed that a similar level of CiAC will be required from developers in the 2009TY as is projected to be required in the 2008BY. This is because THI expects that its newly connecting customers will continue to be senior citizens who have relatively low electricity consumption and frequently reside elsewhere for extended periods.

Capital Budget - Voltage Conversion program

THI forecasts that it will invest $349k in the 2009TY through the Voltage Conversion program that renews its existing distribution system infrastructure so that existing customers continue to receive safe, reliable distribution service of an appropriate level of quality as well as benefits such as reduced system losses. The Voltage Conversion capital budget is provided in the table below.

Capital Budget - Voltage Conversion Program	
	2009TY
TS	0
Land	0
DS	0
Poles, Towers and Fixtures	73,284
Overhead Conductors & Devices	72,455
Underground Conduit	0
Underground Conductors & Devices	5,629
Line Transformers	157,354
Services	40,160
Distribution Meters	0
Contributions & Grants – Credit	0
Total	348,882

The Voltage Conversion program was first implemented on a systematic basis in 2000 and will require several more years to complete. Under this program THI's legacy distribution system is replaced with assets operating at 27.6 kV and situated on public road allowance. The Voltage Conversion program provides the following benefits to THI's customers:

- Modernizing the distribution infrastructure;
- Eliminating obsolete or unsupported technologies and devices;
- Replacing devices that have reached or exceeded their designed service life;
- Implementing assets consistent with current safety standards;
- Improving accessibility by relocating assets from rear lot lines to public road allowance; and
- Reducing distribution system losses.

Under this program THI is replacing its legacy assets that operate at 4.16 kV 'delta' configuration with infrastructure that operates at 27.6 kV 'wye' configuration. Simultaneous with the replacement of these assets, THI rebalances the loading on the lines and optimizes the system (eg., to minimize distribution system losses). This program will modernize THI's distribution infrastructure, reduce losses and remove obsolete assets from service through

annual phases. The service area that is to be dealt with under the voltage conversion program each year is identified by considering:

- System performance;
- Outages and their causes;
- Asset Management issues including vintage and condition of assets by area; and
- THI's knowledge of future developments and expected changes in loading by area.

The need for the voltage conversion project was identified by Elecsar Engineering Ltd. and is documented in the May 19, 2000 report. Elecsar conducted an operational audit of THI's system, as it existed in spring 2000, and determined that the distribution system was well maintained and operated in an efficient manner. Elecsar's operational audit identified the following concerns and opportunities:

- Overloading of THI's Municipal Stations;
- Consistent protection documentation and an overall need to clearly document all assets (eg., size ratings of fuses) and their current status (eg., whether switches are normally open);
- a need to test all devices used in the field;
- a need for new neutrals, rather than continuing to lightly load the existing neutral;
- the potential for large ground fault currents that, in the worst case, posed a public safety risk;
- a need to either rebalance the system or improve grounding;
- the need to match lighting arrestors to the distribution system, so that new equipment is not over-stressed;
- overhead distribution system assets situated at the rear of properties;
- Reliance on gear that is or is approaching technological obsolescence (eg., certain oil filled breakers);
- The need for improved public signage on high voltage gear;
- Observed line losses were greater than average.

The Voltage Conversion program is implemented in a manner that allows THI to achieve lower distribution system losses and other benefits. An inspection of THI's system schematic (E1/T2/S3/AttA) shows that those areas served by legacy assets have assets located on the rear of the property's lot. This arrangement presents two reliability issues:

- THI has limited ability to control vegetation on private property; and
- THI cannot restore service as quickly if assets are situated at the rear of the property due to equipment access considerations.

To overcome these concerns THI complements the implementation of the Voltage Conversion program with the relocation of distribution system assets to public road allowances. This action is expected to lower the cost of THI's vegetation management program and to improve its reliability performance.

The Voltage Conversion program also presents an opportunity to eliminate obsolete gear and equipment. THI recognizes that as more distributors modernize their distribution assets and it will become increasingly difficult to source replacement parts for its legacy 4.16kV system. A 4.16 kV distribution system is becoming obsolete in south western Ontario as LDCs convert to higher operating voltages, such as 27.6 kV. As a result there is a well established pool of experienced staff familiar with the technical requirements, operations and maintenance of the newer systems. THI will benefit from being able to participate in a larger labour market of appropriately skilled operations and technical staff. Finally, there is a concern that lack of access to replacement parts could result in unsatisfactorily long outages to some of THI's customers. Replacing the legacy system with more commonly used assets and more modern systems is expected to realize benefits to THI's customers.

Another benefit of replacing legacy assets is that THI's system will be upgraded to current standards (eg., grounding standards). Like all capital systems, distribution assets have been improved over time (eg., for safety, reliability). THI's voltage conversion program presents an opportunity to deploy assets that meet or exceed current standards with respect to safety and reliability.

Through the Voltage Conversion program THI also has an opportunity to update its system records. This activity is being undertaken by the Town's recently hired Asset Management Technologist, in conjunction with his other responsibilities (eg., to conduct an Asset Condition Assessment, to assist in populating the Town's GPS). This presents advantages to customers since it allows THI to document and inventory its assets, assess their condition to develop an appropriate asset management maintenance and replacement program. These activities will ensure long term system reliability. This information will also be useful when implementing a computerized feeder design and operation program that will deal with balances and minimize line losses.

~~o~~One of the key benefits of the Voltage Conversion program is reduced distribution system losses. This will benefit all customers in the short term as distribution losses are treated as a pass through. THI's customers have already benefitted from an improvement in its loss factor; the Board approved 2003 loss factor was 5.01% which was reduced to 4.22% in 2006. THI proposes to further reduce its loss factor to 3.88% in the 2009TY. The loss factor will continue to improve as MSs are removed from service; MS 3 is expected to be removed from service in 2010 or 2011.

THI will continue to monitor and evaluate its distribution system. The Town recently hired an Asset Management Technologist whose duties include gathering information to assess the inventory of the distribution system, populating the Town's GPS with distribution system information and conducting a distribution system condition assessment. All these activities and tasks are undertaken in support of THI's overall capital replacement program that will ensure a fully functioning, safe and reliable distribution system through appropriate system maintenance and rehabilitation.

Implementing Government Policy

Consistent with provincial government policy THI is preparing to deploy Smart Meters throughout its licensed service area. THI will deploy Smart Meters in the 2009TY to certain newly attaching customers; these meters were previously acquired under THI's 3rd Tranche

CDM plan. THI will incur costs in the 2009TY related to preparation for the implementation of time of use commodity prices.

THI's 2006 Smart Meter Implementation Plan was previously filed with the Board. THI has amended that plan such that rather than deploying Smart Meters over 4 years it now plans to install Smart Meters throughout the service area as soon as possible over the next two to three year. The Town of Tillsonburg, who procures all of THI's assets, participated in the London Hydro Smart Meter RfP; its results will provide more reliable pricing information. Consistent with the Board's accounting direction, THI will defer its Smart Meter capital spending.

Through its Third Tranche funding, THI acquired approximately 500 Smart Meters. Over 400 of these meters were deployed throughout a designated pilot project area and as of October 2005 all newly attaching residential customers in the designated area are also provided with a Smart Meter. All new residential customers outside the pilot area receive electromechanical meters. THI maintains and operates Smart Meters through its OM&A budget and reads and operates them in the same manner as are residential electromechanical meters. These Smart Meters were procured from Elster and do not exceed the government's Minimum Specifications. THI has recorded these meters in USoA account 1860, consistent with the Board's treatment of 3rd Tranche capital investment.

THI has the expertise and knowledge to successfully implement and maintain smart metering system as defined by the Ministry of Energy. THI will prudently incur costs when implementing smart metering. However, THI continues to be concerned over the adequacy of the Smart Meter Rate Adder ("SMRA"). Elsewhere in this application THI will seek Board authorization to increase the 2009TY SMRA to $1.00/metered-customer/month.

THI's largest customers whose demand exceeds 200 kW all have interval meters. All other customers, specifically GS < 50 kW and smaller GS 50 – 500 kW, will be either Smart Metered or interval metered by the end of 2010.

Like many other distributors, THI will need to make changes to its billing practices and to the business systems relied on to issue accurate bills on a timely basis in preparation for the implementation of time of use commodity rates and to continue to be in compliance with the governing regulatory instruments. The replacement of the Town's Customer Information System is discussed in greater detail in Exhibit 4.

THI plans to continue to participate in OPA provided or sponsored Conservation and Demand Management ("CDM") programs in the 2009 TY. THI accounts for these costs and revenues as non-distribution adjustments. Consistent with the OEB's policy, THI will maintain its financial records so that its CDM capital spending is separate and distinct from the costs recovered through regulated rates. As a result, THI does not propose to include any capital spending in the 2009TY that will be recovered through distribution rates for these activities.

Capital Spending Plans post 2009TY

THI expects to incur costs to attach approximately 100 new residential customers a year and to continue to implement the Voltage Conversion program. The forecast 2009TY costs of attaching 104 residential customers are expected to be representative of the costs incurred in periods after the 2009TY.

The cost of the voltage conversion program is expected to vary from year to year, depending on the complexity of the phase or projects to be implemented and in light of other capital funding requirements. When the current phase of the Voltage Conversion project is complete THI will evaluate its two remaining MSs on factors such as:

- Loading;
- Reliability;
- Technical performance;
- Overall condition;
- Vintage and availability of parts.

This evaluation will identify the MS to be removed from service next and identify the portions of the system to be renewed under the Voltage Conversion program.

THI's Contribution in Aid of Construction policies and practices

THI completes an Economic Feasibility test of all system expansion projects to determine whether a Contribution in Aid of Construction ("CiAC") will be required from the subject customers. THI uses the economic feasibility model prepared by the Municipal Electric Association (now the Electricity Distributors Association). THI runs the Economic Evaluation using its actual capital structure (100% equity), its average consumption/customer (approximately 750 kWh/month for residential customers) and, where applicable, average demand/customer. THI also uses its Board authorized distribution rates, the Board determined Allowed Return on Equity and prevailing tax rates. THI estimates the capital costs of each project uniquely and relies on its historic average OM&A/customer.

THI's long standing policy is to require that developers render the CiAC identified by the economic feasibility model. THI adheres to the requirements of the Distribution System Code when running the Economic Evaluation, making an Offer to Connect, recovering the CiAC and administering deposits.

For the purposes of forecasting the 2009TY Rate Base, THI has used the average CiAC/customer of 2007. This forecast is considered reasonable since the 2008 rate increase is expected to be offset by lower consumption. THI's service area is attracting senior citizens who typically reside in smaller than average homes, are less electricity intensive and often do not reside in THI's services area during the winter months. THI does not have detailed knowledge of either the costs of the expansions that will be constructed in the 2009TY or of new customer load parameters.

THI's Accumulated Depreciation and associated policies

THI's Opening Accumulated Depreciation is assumed to be the Closing Accumulated Depreciation of the previous period. The depreciation expense of the period is added to the Opening Accumulated Depreciation to determine the Closing Accumulated Depreciation.

THI's asset accounting policies

THI's accounting policies are described in Note 1 to the audited financial statements (E1/T3/S2/AttA). Briefly, THI adheres to Canadian GAAP and appropriately capitalizes all eligible costs. THI uses a time sheet system to identify the period costs and indirect costs eligible for capitalization.

Working Cash Allowance

THI proposes that its 2009TY Working Cash Allowance be $2,685k. This amount was determined by applying the Board authorized 15% factor to the sum of:

- the forecast 2009TY Cost of Power, being $15,796k; and
- the forecast 2009TY Controllable Costs, being 2,103k.

Variance Analysis

THI computes the variance between the budgeted and actual costs of each capital project. Significant cost variances for Voltage Conversion capital projects are typically due to unforeseen conditions of underground assets (eg., such that more extensive 'day lighting' of buried assets is required due to congestion with other utilities, if conduit or duct banks must be replaced, if contract labour and equipment is required to augment THI's resources). Cost variances for Customer Attachment capital projects are typically due to unforeseen requirements for contract labour and equipment.

2009TY versus 2008BY

THI's year over year changes in rate base are provided at E2/T1/S3/AttA.

THI's 2009TY rate base is $502k or 5.9% greater than the 2008BY rate base.

THI's 2009TY average PPE portion of rate base is approximately $463k or 8% greater than that of 2008BY. This is due to the averaging of the respective period opening balances and closing balances. The 2009TY period opening balances are $872k greater than the 2008BY opening balances because of gross capital spending of $866k. The 2009 closing period balance includes $812k of combined CiAC and depreciation expense and differs from the 2008BY closing balance by $54k.

The 2009TY Voltage Conversion project capital spending is less than that of the 2008BY. The capital spending on customer additions is comparable.

The 2009TY Working Cash Allowance is $39k or 1.5% greater than that of 2008BY. The increase is the net effect of the expected increase in the THI's period expenses less the forecast reduction in the Cost of Power.

2008BY versus 2007AY

The 2008BY rate base is $264k or 3.2% greater than the 2007AY rate base.

THI's 2008BY average PPE rate base is $407k or 7.5% greater than the 2007AY average PPE rate base. This is due to the combined effect of the following changes to the opening and closing balances:

- THI's capital spending to attach new customers $511k
- THI's Voltage Conversion program capital spending $583k
- Contributions in Aid of Construction $304k
- Depreciation Expense $473k

The Voltage Conversion program capital spending reflects the costs of the specific projects implemented in that year.

The 2008BY Working Cash Allowance is $143k less than that of the 2007AY. The reduction is the net effect of a projected reduction in the cost of power of $1,027k and $75k increase in controllable costs. The net reduction amounts to $952k, 15% of which is $143k.

2007AY versus 2006AY

The 2007AY rate base is $153k or 1.9% greater than that of the 2006AY.

The 2007AY PPE portion of rate base is $54k greater than the 2006AY PPE. This variance is also attributed to the voltage conversion program activities undertaken in these years. A list of the project specific variances is provided at E2/T1/S1/AttB.

The 2007AY Working Cash Allowance is $99K or 3.7% greater than that of 2006AY. This is the result of a $654k increase in the cost of power and a $6k increase in controllable costs. The overall increase amounts to $660k, of which 15% is $99k.

CORPORATION OF THE

TOWN OF TILLSONBURG

BY-LAW NO. 3140

BEING A BY-LAW TO ADOPT A POLICY ON PROCUREMENT

WHEREAS the Municipal Act, S.O. 2001 requires a municipality to have a procurement policy;

AND WHEREAS the Council of the Town Of Tillsonburg recognizes the need for a clear and concise set of policies concerning procurement;

THEREFORE THE COUNCIL OF THE CORPORATION OF THE TOWN OF TILLSONBURG ENACTS AS FOLLOWS:

1. **THAT** effective upon passage the Policy on Procurement attached hereto as Schedule "A" and forming part of this By-law is hereby adopted as the policies and procedures for procurement for the Town of Tillsonburg.

2. **THAT** this Procurement Policy By-law may be amended from time to time as directed and deemed necessary by the Council of the Corporation of the Town of Tillsonburg.

3. **THAT** any procurement or purchasing policies previously adopted are hereby repealed;

4. **AND THAT** this by-law shall come into full force and effect upon final passing.

READ A FIRST, SECOND AND THIRD TIME AND FINALLY PASSED THIS 13th DAY OF DECEMBER, 2004.

_____ _____

MAYOR **CLERK**

Schedule “A” to By-Law 3140
Procurement Policy

OBJECTIVES

1. This procurement policy outlines the procedures to be followed in order to help achieve the best value for time and money when purchasing or contracting for goods and services for the Town of Tillsonburg.

2. The guiding principal is that procurement decisions will be made using a competitive process that is objective, open, transparent and equitable.

3. This procurement policy will promote and maintain the integrity of the purchasing process and protect Council, vendors and staff involved in the process by providing clear direction and accountabilities.

RESPONSIBILTIES

4. The Department Head, the Treasurer and the CAO are responsible for ensuring that the procedures of the Purchasing Policy are adhered to.

5. This purchasing policy may be overridden by Council if Council, in its’ sole discretion, determines it to be appropriate and in the best interests of the Town.

PROCEDURES

6. Prior to the approval of the current year’s business plan and budget, a department may incur normal operating expenditures.

7. Council approval of the current budget shall be sufficient authority for departments to proceed with the procurement of materials, supplies and contractors, subject to the procedures and limitations contained herein.

8. All purchasing shall be conducted by the Department Head or his/her designate in accordance with the policies and procedures established herein.

9. Purchases of a small value, i.e. under $100, may be made by a Department Head or his/her designate via a petty cash fund.

10. A Department Head or his/her designate shall initiate a purchase, using a purchase order where applicable, in the following manner:

    a. For purchases up to $1,000.00, comparison pricing should be done where practical.

    b. For purchases between $1,000.00 and $5,000.00, three (3) verbal quotations shall be obtained where possible. The supplier shall be selected consistent with the standard terms and conditions as determined by the Finance Department.

    c. For purchases between $5,000.00 and $25,000.00, three (3) informal, written quotations shall be obtained where possible. The supplier shall be selected consistent with the standard terms and conditions as determined by the Finance Department. All purchases of new equipment, tools and/or chemicals must meet Health and Safety regulatory compliance.

    d. Annually, collective purchases where the anticipated volume on a Town wide basis is above $25,000 (for example stationery and supplies) will be tendered and reported to Council.

    e. For purchases greater than $25,000.00, a Department Head or his/her designate shall, at his/her sole discretion, select one of the following procedures to gather quotation information:

        i) formal invitation to quote/request for quotation/request for proposal OR
        ii) sealed tenders.

The quotations or tenders shall be submitted by the Department Head or his/her designate to Council upon receipt along with a recommendation for supplier.

f. Notwithstanding the forgoing, Council may, by resolution, direct the method of obtaining quotation information.

g. Resolutions approving budget amendments, capital expenditures or special appropriations shall contain the purpose of the expenditure, cost estimates or expenditure limitation, a cost/benefit analysis if applicable, and the appropriate fund. All staff reports recommending such resolutions shall contain the CAO’s endorsement.

h. All purchases of new equipment, tools and/or chemicals must meet Health and Safety regulatory compliance and should involve a Joint Health and Safety Committee Representative.

EXCEPTIONS

11. Where an emergency occurs that, in the opinion of the Department Head or his/her designate, constitutes immediate danger to health, safety, life or property, or requires the immediate procurement of goods and services, the Department Head or his/her designate may purchase such goods or services through the open market upon consultation with the CAO and Mayor. As soon as practical following the emergency, a full written report shall be submitted to the CAO for review and immediate submission to Council.

12. A tendering process may not be required where the goods or services are proprietary, where there is only one supplier that can meet the Town’s needs within a reasonable distance or where the cost of changing suppliers for a product or service already in place is deemed to be exorbitant. Upon staff recommendations, Council shall, in its’ sole discretion, determine whether a tender process may be forgone for these reasons.

13. Notwithstanding the provisions of this policy, the following expenditures may be made without following the formal purchasing procedures detailed herein:

    a. petty cash items;
    b. training and education including:
        i) conferences
        ii) courses
        iii) memberships
        iv) seminars
        v) staff development
        vi) subscriptions

    subject to the provision that CAO approval be received;
    c. mileage, travel and accommodation;
    d. employer expenses including:
        i) payroll
        ii) payroll deduction remittances
        iii) insurance premiums
        iv) group benefits
        v) pension remittances;
    e. utilities;
    f. maintenance and support for existing computer hardware and software previously presented to Council subject to all new hardware and software purchases meeting the limitations contained herein must be presented to Council;
    g. other professional and special services including:
        i) legal costs for general issues;
        ii) planning consultant for general issues;
        iii) engineering consultants for general issues.

GOALS

14. Objectivity
Quotations and tenders shall be solicited, reviewed and selected in an unbiased atmosphere.

Staff and Council members involved with the solicitation, review and selection process for any particular bid shall not submit their own, personal bid for consideration. Further, should a bid be submitted from an immediate family member (parent, spouse, same-sex partner or any child) of the staff or Council member involved with the process, it should be disclosed to Council in the final recommendation report.

Personal preferences shall not be given priority unless the bid submitted demonstrates that it is the lowest priced, compliant bid.

15. Equity
The terms of selection shall be detailed in the procurement documents and shall be applied equally to all bidders. Tenders and Requests for Proposals shall be advertised locally as well as in daily papers that are deemed appropriate by the department head involved. Invitations to bid may be extended rather than by a general advertisement if staff is of the opinion that there are a limited number of appropriate suppliers that can meet the Town’s needs at that time. No action shall be undertaken by staff or Council that would give any bidder an unfair advantage. This does not require, however, that the Town change existing conditions to ensure that conversion costs from the incumbent to another supplier are ignored in an evaluation.

16. Openness and Transparency
The Town’s specifications and the terms of selection shall be clearly defined in each invitation or tender document. The decision for the successful bidder shall be based solely on the specifications requirements as documented and the bidder’s documents..

17. Accountability
The CAO shall maintain accountability on behalf of Council during each process. Informal contact with staff or Council members not specified as official contacts in the tender/request for proposal documents shall be considered unethical and may threaten the validity of that supplier’s bid or even the process as a whole.

Sealed quotations, tenders or proposals, marked with the time and date of receipt, shall be maintained in a locked tender box until the time specified in the procurement documents.

If the lowest bidder’s price is higher than the Town’s budget, this will be brought to Council’s attention at the time of the final recommendation report and Council, in its’ sole discretion, will decide whether to proceed or to investigate alternatives.

18. Risk Management
Suppliers will be required to provide proof of insurance along with a WSIB clearance certificate (or municipal waiver, if applicable) for all contracts. Insurance requirements will be detailed in the procurement documentation and must be adhered to throughout the term of the contract.

Performance bonds may be required and will be disclosed during the bidding process. These bonds will be held by the Town until end-of-contract indicators are in place (ie. final clearance certificates are issued) at which time they will be released.

EVALUATION

19. Effectiveness
The Town shall endeavour to define its’ needs in a clear and simple format to minimize the occurrence of amendments to bidding documents or changes to contracts once in place. A listing of all changes required shall be maintained with the contract documents for review.

An analysis of whether ratepayers’ needs are being met in a satisfactory manner shall be performed throughout the term of a contract and changes or difficulties encountered shall be documented and considered upon renewal or re-tendering for those particular services

or goods. This analysis shall involve on-going monitoring of service or product quality and a compilation of ratepayer complaints and resolutions.

Further, prior to contract renewal or re-tendering, performance criteria will be defined and an evaluation of these criteria shall be made by the department head directly involved with the contract and shall be formally reported to Council. Poor performance on the part of the supplier/contractor may preclude future contracts being awarded.

In the event that there are no successful bidders, the procurement documents shall be reviewed immediately by the department head and the CAO. The review shall include contacting persons or businesses that took out tender documents but did not submit or were not successful. This review shall determine if there was an error on the part of the Town in drawing up the documents, setting unreasonable requirements or anything else that prevented the successful completion of the procurement process.

20. Review

This policy shall be reviewed every five (5) years at a minimum. An evaluation of the goals set out and the level of achieving those goals shall be made by staff and reported to Council. If significant problems are discovered, priorities have changed or the current policy has become unmanageable, changes must be reported to and proposed for Council’s consideration.

Further, procurement procedures will be reviewed at the same time to determine if the procedures outlined in this policy are being followed and whether they are supporting the goals of the policy. Variations in practice from the desired procedures should be evaluated to determine the underlying reasons for the changes and reported to Council.

Rate Base Summary Table

THI's 2009TY average base is summarized in the tables below.

TOTAL RATE BASE		
		2009
Net Fixed Assets in Service:	*(3)*	
Opening Balance	6,234,879	
Closing Balance	6,289,357	
Average Balance		6,262,118
Working Capital Allowance		2,684,962
TOTAL RATE BASE		8,947,080

The table presented below provides the proposed 2009TY closing values on a USoA account basis.

Asset Class	Gross Value	Accumulated Depreciation	Net Book Value
1805-Land	11,520	0	11,520
1820-Distribution Station Equipment - Normally Primary below 50 kV	400,152	-329,067	71,085
1830-Poles, Towers and Fixtures	4,656,693	-2,791,738	
1835-Overhead Conductors and Devices	1,532,431	-332,614	1,864,954
1840-Underground Conduit	3,367,114	-2,230,799	1,199,817
1845-Underground Conductors and Devices	1,233,349	-233,136	1,136,315
1850-Line Transformers	3,857,360	-1,844,334	1,000,212
1855-Services	863,062	-131,722	2,013,026
1860-Meters	738,978	-586,483	152,495
1995-Contributions and Grants - Credit	-2,272,249	380,840	144,938
Total	14,388,411	-8,099,054	6,289,357

A continuity presentation of THI's rate base is provided at E2/T1/S2/AttA.

Appendix 2-2

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Projection	2009 Projection
Net Capital Assets in Service:					
Opening Balance		5,254,908	5,421,756	5,362,909	6,234,879
Ending Balance		5,421,756	5,362,909	6,234,879	6,289,357
Average Balance	5,663,915	5,338,332	5,392,332	5,798,894	6,262,118
Working Capital Allowance *(see below)*	2,554,131	2,689,502	2,788,555	2,645,809	2,684,962
Total Rate Base	**8,218,046**	**8,027,834**	**8,180,887**	**8,444,703**	**8,947,080**
Expenses for Working Capital					
Eligible Distribution Expenses:					
3500-Distribution Expenses - Operation	403,209	659,328	616,632	681,845	871,060
3550-Distribution Expenses - Maintenance	145,599	182,352	179,508	162,754	186,092
3650-Billing and Collecting	327,045	377,483	394,768	426,108	543,447
3700-Community Relations		25,863	6,458		
3800-Administrative and General Expenses	466,193	376,320	422,904	424,719	502,694
3950-Taxes Other Than Income Taxes	2,679	-7,200			
Total Eligible Distribution Expenses	1,344,725	1,614,146	1,620,270	1,695,427	2,103,292
3350-Power Supply Expenses	15,682,815	16,315,870	16,970,098	15,943,298	15,796,452
Total Expenses for Working Capital	17,027,540	17,930,016	18,590,368	17,638,725	17,899,744
Working Capital factor	15.0%	15.0%	15.0%	15.0%	15.0%
Working Capital Allowance	**2,554,131**	**2,689,502**	**2,788,555**	**2,645,809**	**2,684,962**

Appendix 2-1

* Asset retirements and other changes	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other *	Amortization	
1610-Miscellaneous Intangible Plant					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1805-Land					
Gross Assets	11,520				11,520
Accumulated Amortization					
Net Book Value	11,520				11,520
1806-Land Rights					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1808-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1810-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1815-Transformer Station Equipment - Normally Primary above 50 kV					
Gross Assets	48,314		-48,314		
Accumulated Amortization	-108,115		-2,666	-1,333	-112,114
Net Book Value	-59,800		-50,980	-1,333	-112,114
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	82,808		317,344		400,152
Accumulated Amortization	-337,984		48,765	-8,664	-297,884
Net Book Value	-255,176		366,109	-8,664	102,269
1825-Storage Battery Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1830-Poles, Towers and Fixtures					
Gross Assets	2,366,139	157,469	1,565,421		4,089,029

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** Asset retirements and other changes*	2006 EDR	Variance to 2006 Actual			2006
	Approved	Additions	Ret./Other *	Amortization	Balance
Accumulated Amortization	-1,868,162		-278,987	-148,490	-2,295,639
Net Book Value	497,978	157,469	1,286,434	-148,490	1,793,390
1835-Overhead Conductors and Devices					
Gross Assets	449,285	243,543	224,765		917,593
Accumulated Amortization	-27,999		-41,747	-31,833	-101,579
Net Book Value	421,286	243,543	183,018	-31,833	816,015
1840-Underground Conduit					
Gross Assets	2,085,225	41,111	1,147,240		3,273,575
Accumulated Amortization	-1,503,420		-234,309	-120,140	-1,857,870
Net Book Value	581,805	41,111	912,931	-120,140	1,415,706
1845-Underground Conductors and Devices					
Gross Assets	360,926	156,327	233,448		750,700
Accumulated Amortization	-16,952		-36,467	-26,901	-80,320
Net Book Value	343,974	156,327	196,981	-26,901	670,380
1850-Line Transformers					
Gross Assets	1,424,099	210,875	1,408,984		3,043,958
Accumulated Amortization	-1,278,261		-150,172	-88,655	-1,517,088
Net Book Value	145,839	210,875	1,258,812	-88,655	1,526,870
1855-Services					
Gross Assets	233,818	88,856	132,182		454,856
Accumulated Amortization	-16,905		-22,134	-16,417	-55,456
Net Book Value	216,913	88,856	110,048	-16,417	399,400
1860-Meters					
Gross Assets	381,146	98,233	205,375		684,753
Accumulated Amortization	-438,660		-48,039	-22,814	-509,512
Net Book Value	-57,515	98,233	157,336	-22,814	175,241
1905-Land					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1906-Land Rights					
Gross Assets					
Accumulated Amortization					
Net Book Value					

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** Asset retirements and other changes*	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other *	Amortization	
1908-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1910-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1920-Computer Equipment - Hardware					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1925-Computer Software					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1930-Transportation Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1935-Stores Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1940-Tools, Shop and Garage Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1945-Measurement and Testing Equipment					
Gross Assets					

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** Asset retirements and other changes*	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other *	Amortization	
Accumulated Amortization					
Net Book Value					
1950-Power Operated Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1955-Communication Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1960-Miscellaneous Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1965-Water Heater Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1970-Load Management Controls - Customer Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1975-Load Management Controls - Utility Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1980-System Supervisory Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1985-Sentinel Lighting Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					

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** Asset retirements and other changes*	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other *	Amortization	
1990-Other Tangible Property					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1995-Contributions and Grants - Credit					
Gross Assets	-538,500	-275,633	-706,382		-1,520,515
Accumulated Amortization	31,694				31,694
Net Book Value	-506,806	-275,633	-706,382		-1,488,821
2005-Property Under Capital Leases					
Gross Assets					
Accumulated Amortization			56,592	55,308	111,899
Net Book Value			56,592	55,308	111,899
TOTAL					
Gross Assets	**6,904,780**	**720,779**	**4,480,063**		**12,105,623**
Accumulated Amortization	**-5,564,763**		**-709,164**	**-409,940**	**-6,683,867**
Net Book Value	**1,340,018**	**720,779**	**3,770,898**	**-409,940**	**5,421,756**

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* Asset retirements and other changes	2006 Balance	2007 Changes			2007 Balance
		Additions	Ret./Other *	Amortization	
1610-Miscellaneous Intangible Plant					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1805-Land					
Gross Assets	11,520				11,520
Accumulated Amortization					
Net Book Value	11,520				11,520
1806-Land Rights					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1808-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1810-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1815-Transformer Station Equipment - Normally Primary above 50 kV					
Gross Assets					
Accumulated Amortization	-112,114			-1,333	-113,447
Net Book Value	-112,114			-1,333	-113,447
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	400,152				400,152
Accumulated Amortization	-297,884		-586	-9,619	-308,088
Net Book Value	102,269		-586	-9,619	92,064
1825-Storage Battery Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1830-Poles, Towers and Fixtures					
Gross Assets	4,089,029	83,470	0		4,172,500

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* Asset retirements and other changes	2006 Balance	2007 Changes			2007 Balance
		Additions	Ret./Other *	Amortization	
Accumulated Amortization	-2,295,639		-123,511	-154,729	-2,573,878
Net Book Value	1,793,390	83,470	-123,511	-154,729	1,598,621
1835-Overhead Conductors and Devices					
Gross Assets	917,593	120,077			1,037,671
Accumulated Amortization	-101,579		78,712	-40,644	-63,511
Net Book Value	816,015	120,077	78,712	-40,644	974,160
1840-Underground Conduit					
Gross Assets	3,273,575	25,491	0		3,299,066
Accumulated Amortization	-1,857,870		-95,526	-122,185	-2,075,581
Net Book Value	1,415,706	25,491	-95,526	-122,185	1,223,486
1845-Underground Conductors and Devices					
Gross Assets	750,700	226,069			976,769
Accumulated Amortization	-80,320		54,762	-33,252	-58,809
Net Book Value	670,380	226,069	54,762	-33,252	917,960
1850-Line Transformers					
Gross Assets	3,043,958	275,235			3,319,194
Accumulated Amortization	-1,517,088		-82,022	-97,515	-1,696,625
Net Book Value	1,526,870	275,235	-82,022	-97,515	1,622,569
1855-Services					
Gross Assets	454,856	178,748			633,604
Accumulated Amortization	-55,456		2,277	-20,147	-73,326
Net Book Value	399,400	178,748	2,277	-20,147	560,278
1860-Meters					
Gross Assets	684,753	32,427	0		717,180
Accumulated Amortization	-509,512		-25,248	-25,170	-559,930
Net Book Value	175,241	32,427	-25,248	-25,170	157,250
1905-Land					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1906-Land Rights					
Gross Assets					
Accumulated Amortization					
Net Book Value					

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** Asset retirements and other changes*	2006	2007 Changes			2007
	Balance	Additions	Ret./Other *	Amortization	Balance
1908-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1910-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1920-Computer Equipment - Hardware					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1925-Computer Software					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1930-Transportation Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1935-Stores Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1940-Tools, Shop and Garage Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1945-Measurement and Testing Equipment					
Gross Assets					

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** Asset retirements and other changes*	2006	2007 Changes			2007
	Balance	Additions	Ret./Other *	Amortization	Balance
Accumulated Amortization					
Net Book Value					
1950-Power Operated Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1955-Communication Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1960-Miscellaneous Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1965-Water Heater Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1970-Load Management Controls - Customer Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1975-Load Management Controls - Utility Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1980-System Supervisory Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1985-Sentinel Lighting Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					

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** Asset retirements and other changes*	2006	2007 Changes			2007
	Balance	Additions	Ret./Other *	Amortization	Balance
1990-Other Tangible Property					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1995-Contributions and Grants - Credit					
Gross Assets	-1,520,515	-138,385			-1,658,900
Accumulated Amortization	31,694				31,694
Net Book Value	-1,488,821	-138,385			-1,627,206
2005-Property Under Capital Leases					
Gross Assets					
Accumulated Amortization	111,899		-409,389	63,588	-233,901
Net Book Value	111,899		-409,389	63,588	-233,901
TOTAL					
Gross Assets	**12,105,623**	**803,133**	**0**		**12,908,756**
Accumulated Amortization	**-6,683,867**		**-600,530**	**-441,004**	**-7,725,401**
Net Book Value	**5,421,756**	**803,133**	**-600,530**	**-441,004**	**5,183,354**

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* Asset retirements and other changes	2007 Balance	2008 Changes			2008 Balance
		Additions	Ret./Other *	Amortization	
1610-Miscellaneous Intangible Plant					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1805-Land					
Gross Assets	11,520				11,520
Accumulated Amortization					
Net Book Value	11,520				11,520
1806-Land Rights					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1808-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1810-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1815-Transformer Station Equipment - Normally Primary above 50 kV					
Gross Assets					
Accumulated Amortization	-113,447			-1,333	-114,780
Net Book Value	-113,447			-1,333	-114,780
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	400,152				400,152
Accumulated Amortization	-308,088			-9,250	-317,338
Net Book Value	92,064			-9,250	82,814
1825-Storage Battery Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1830-Poles, Towers and Fixtures					
Gross Assets	4,172,500	324,429			4,496,929

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* Asset retirements and other changes	2007 Balance	2008 Changes			2008 Balance
		Additions	Ret./Other *	Amortization	
Accumulated Amortization	-2,573,878			-165,536	-2,739,414
Net Book Value	1,598,621	324,429		-165,536	1,757,515
1835-Overhead Conductors and Devices					
Gross Assets	1,037,671	232,288	79,709		1,349,667
Accumulated Amortization	-63,511			-50,798	-114,309
Net Book Value	974,160	232,288	79,709	-50,798	1,235,358
1840-Underground Conduit					
Gross Assets	3,299,066	33,827			3,332,893
Accumulated Amortization	-2,075,581			-124,570	-2,200,151
Net Book Value	1,223,486	33,827		-124,570	1,132,742
1845-Underground Conductors and Devices					
Gross Assets	976,769	106,964	53,741		1,137,474
Accumulated Amortization	-58,809			-39,898	-98,707
Net Book Value	917,960	106,964	53,741	-39,898	1,038,767
1850-Line Transformers					
Gross Assets	3,319,194	250,859			3,570,052
Accumulated Amortization	-1,696,625			-109,022	-1,805,647
Net Book Value	1,622,569	250,859		-109,022	1,764,406
1855-Services					
Gross Assets	633,604	134,618			768,221
Accumulated Amortization	-73,326			-25,570	-98,896
Net Book Value	560,278	134,618		-25,570	669,325
1860-Meters					
Gross Assets	717,180	10,836			728,016
Accumulated Amortization	-559,930			-25,644	-585,573
Net Book Value	157,250	10,836		-25,644	142,442
1905-Land					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1906-Land Rights					
Gross Assets					
Accumulated Amortization					
Net Book Value					

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* Asset retirements and other changes	2007 Balance	2008 Changes			2008 Balance
		Additions	Ret./Other *	Amortization	
1908-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1910-Leasehold Improvements					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1920-Computer Equipment - Hardware					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1925-Computer Software					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1930-Transportation Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1935-Stores Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1940-Tools, Shop and Garage Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1945-Measurement and Testing Equipment					
Gross Assets					

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** Asset retirements and other changes*	2007 Balance	2008 Changes			2008 Balance
		Additions	Ret./Other *	Amortization	
Accumulated Amortization					
Net Book Value					
1950-Power Operated Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1955-Communication Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1960-Miscellaneous Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1965-Water Heater Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1970-Load Management Controls - Customer Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1975-Load Management Controls - Utility Premises					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1980-System Supervisory Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1985-Sentinel Lighting Rental Units					
Gross Assets					
Accumulated Amortization					
Net Book Value					

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** Asset retirements and other changes*	2007	2008 Changes			2008
	Balance	Additions	Ret./Other *	Amortization	Balance
1990-Other Tangible Property					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1995-Contributions and Grants - Credit					
Gross Assets	-1,658,900	-303,697			-1,962,597
Accumulated Amortization	31,694				31,694
Net Book Value	-1,627,206	-303,697			-1,930,903
2005-Property Under Capital Leases					
Gross Assets					
Accumulated Amortization	-233,901			79,042	-154,859
Net Book Value	-233,901			79,042	-154,859
TOTAL					
Gross Assets	**12,908,756**	**790,123**	**133,450**		**13,832,329**
Accumulated Amortization	**-7,725,401**			**-472,579**	**-8,197,980**
Net Book Value	**5,183,354**	**790,123**	**133,450**	**-472,579**	**5,634,348**

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** Asset retirements and other changes*	2008	2009 Changes		
	Balance	Additions	Ret./Other *	Amortization
1610-Miscellaneous Intangible Plant				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1805-Land				
Gross Assets	11,520			
Accumulated Amortization				
Net Book Value	11,520			
1806-Land Rights				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1808-Buildings and Fixtures				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1810-Leasehold Improvements				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1815-Transformer Station Equipment - Normally Primary above 50 kV				
Gross Assets				
Accumulated Amortization	-114,780		114,780	
Net Book Value	-114,780		114,780	
1820-Distribution Station Equipment - Normally Primary below 50 kV				
Gross Assets	400,152			
Accumulated Amortization	-317,338			-12,684
Net Book Value	82,814			-12,684
1825-Storage Battery Equipment				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1830-Poles, Towers and Fixtures				
Gross Assets	4,496,929	159,764		

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* Asset retirements and other changes	2008 Balance	2009 Changes		
		Additions	Ret./Other *	Amortization
Accumulated Amortization	-2,739,414			-175,220
Net Book Value	1,757,515	159,764		-175,220
1835-Overhead Conductors and Devices				
Gross Assets	1,349,667	182,764		
Accumulated Amortization	-114,309		-79,709	-59,099
Net Book Value	1,235,358	182,764	-79,709	-59,099
1840-Underground Conduit				
Gross Assets	3,332,893	34,221		
Accumulated Amortization	-2,200,151			-125,931
Net Book Value	1,132,742	34,221		-125,931
1845-Underground Conductors and Devices				
Gross Assets	1,137,474	95,875		
Accumulated Amortization	-98,707		-35,071	-43,954
Net Book Value	1,038,767	95,875	-35,071	-43,954
1850-Line Transformers				
Gross Assets	3,570,052	287,308		
Accumulated Amortization	-1,805,647			-119,785
Net Book Value	1,764,406	287,308		-119,785
1855-Services				
Gross Assets	768,221	94,841		
Accumulated Amortization	-98,896			-30,160
Net Book Value	669,325	94,841		-30,160
1860-Meters				
Gross Assets	728,016	10,962		
Accumulated Amortization	-585,573			-26,080
Net Book Value	142,442	10,962		-26,080
1905-Land				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1906-Land Rights				
Gross Assets				
Accumulated Amortization				
Net Book Value				

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** Asset retirements and other changes*	2008	2009 Changes		
	Balance	Additions	Ret./Other *	Amortization
1908-Buildings and Fixtures				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1910-Leasehold Improvements				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1915-Office Furniture and Equipment				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1920-Computer Equipment - Hardware				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1925-Computer Software				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1930-Transportation Equipment				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1935-Stores Equipment				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1940-Tools, Shop and Garage Equipment				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1945-Measurement and Testing Equipment				
Gross Assets				

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** Asset retirements and other changes*	2008	2009 Changes		
	Balance	Additions	Ret./Other *	Amortization
Accumulated Amortization				
Net Book Value				
1950-Power Operated Equipment				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1955-Communication Equipment				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1960-Miscellaneous Equipment				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1965-Water Heater Rental Units				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1970-Load Management Controls - Customer Premises				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1975-Load Management Controls - Utility Premises				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1980-System Supervisory Equipment				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1985-Sentinel Lighting Rental Units				
Gross Assets				
Accumulated Amortization				
Net Book Value				

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** Asset retirements and other changes*	2008	2009 Changes		
	Balance	Additions	Ret./Other *	Amortization
1990-Other Tangible Property				
Gross Assets				
Accumulated Amortization				
Net Book Value				
1995-Contributions and Grants - Credit				
Gross Assets	-1,962,597	-309,652		
Accumulated Amortization	31,694			
Net Book Value	-1,930,903	-309,652		
2005-Property Under Capital Leases				
Gross Assets				
Accumulated Amortization	-154,859			91,309
Net Book Value	-154,859			91,309
TOTAL				
Gross Assets	**13,832,329**	**556,082**		
Accumulated Amortization	**-8,197,980**			**-501,604**
Net Book Value	**5,634,348**	**556,082**		**-501,604**

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** Asset retirements and other changes*	**2009 Balance**
1610-Miscellaneous Intangible Plant	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1805-Land	
Gross Assets	11,520
Accumulated Amortization	
Net Book Value	11,520
1806-Land Rights	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1808-Buildings and Fixtures	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1810-Leasehold Improvements	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1815-Transformer Station Equipment - Normally Primary above 50 kV	
Gross Assets	
Accumulated Amortization	0
Net Book Value	0
1820-Distribution Station Equipment - Normally Primary below 50 kV	
Gross Assets	400,152
Accumulated Amortization	-330,022
Net Book Value	70,131
1825-Storage Battery Equipment	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1830-Poles, Towers and Fixtures	
Gross Assets	4,656,693

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Appendix 2-1

** Asset retirements and other changes*	**2009 Balance**
Accumulated Amortization	-2,914,634
Net Book Value	1,742,059
1835-Overhead Conductors and Devices	
Gross Assets	1,532,431
Accumulated Amortization	-253,118
Net Book Value	1,279,313
1840-Underground Conduit	
Gross Assets	3,367,114
Accumulated Amortization	-2,326,082
Net Book Value	1,041,032
1845-Underground Conductors and Devices	
Gross Assets	1,233,349
Accumulated Amortization	-177,733
Net Book Value	1,055,616
1850-Line Transformers	
Gross Assets	3,857,360
Accumulated Amortization	-1,925,432
Net Book Value	1,931,929
1855-Services	
Gross Assets	863,062
Accumulated Amortization	-129,056
Net Book Value	734,006
1860-Meters	
Gross Assets	738,978
Accumulated Amortization	-611,653
Net Book Value	127,325
1905-Land	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1906-Land Rights	
Gross Assets	
Accumulated Amortization	
Net Book Value	

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Appendix 2-1

** Asset retirements and other changes*	**2009 Balance**
1908-Buildings and Fixtures	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1910-Leasehold Improvements	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1915-Office Furniture and Equipment	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1920-Computer Equipment - Hardware	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1925-Computer Software	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1930-Transportation Equipment	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1935-Stores Equipment	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1940-Tools, Shop and Garage Equipment	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1945-Measurement and Testing Equipment	
Gross Assets	

Appendix 2-1

** Asset retirements and other changes*	**2009 Balance**
Accumulated Amortization	
Net Book Value	
1950-Power Operated Equipment	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1955-Communication Equipment	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1960-Miscellaneous Equipment	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1965-Water Heater Rental Units	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1970-Load Management Controls - Customer Premises	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1975-Load Management Controls - Utility Premises	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1980-System Supervisory Equipment	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1985-Sentinel Lighting Rental Units	
Gross Assets	
Accumulated Amortization	
Net Book Value	

Appendix 2-1

** Asset retirements and other changes*	**2009 Balance**
1990-Other Tangible Property	
Gross Assets	
Accumulated Amortization	
Net Book Value	
1995-Contributions and Grants - Credit	
Gross Assets	-2,272,249
Accumulated Amortization	31,694
Net Book Value	-2,240,555
2005-Property Under Capital Leases	
Gross Assets	
Accumulated Amortization	-63,550
Net Book Value	-63,550
TOTAL	
Gross Assets	**14,388,411**
Accumulated Amortization	**-8,699,584**
Net Book Value	**5,688,827**

Variance Analysis on Rate Base Table

THI's year over year changes in rate base are presented at E2/T1/S3/AttA.

Attachment 1

Variances in excess of $623,488 are shown in bold

	2009 Projection	2008 Projection	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	6,234,879	5,362,909	**871,970**	**16.3%**
Ending Balance	6,289,357	6,234,879	54,479	0.9%
Average Balance	6,262,118	5,798,894	463,224	8.0%
Working Capital Allowance *(see below)*	2,684,962	2,645,809	39,153	1.5%
Total Rate Base	**8,947,080**	**8,444,703**	**502,377**	**5.9%**

Expenses for Working Capital

Variances in excess of $21,680 are shown in bold

Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	871,060	681,845	**189,215**	**27.8%**
3550-Distribution Expenses - Maintenance	186,092	162,754	**23,337**	**14.3%**
3650-Billing and Collecting	543,447	426,108	**117,339**	**27.5%**
3700-Community Relations				
3800-Administrative and General Expenses	502,694	424,719	**77,975**	**18.4%**
3950-Taxes Other Than Income Taxes				
Total Eligible Distribution Expenses	2,103,292	1,695,427	**407,866**	**24.1%**
3350-Power Supply Expenses	15,796,452	15,943,298	**-146,846**	**(0.9%)**
Total Expenses for Working Capital	17,899,744	17,638,725	**261,020**	**1.5%**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**2,684,962**	**2,645,809**	**39,153**	**1.5%**

Attachment 1

Variances in excess of $536,291 are shown in bold

	2008 Projection	2007 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	5,362,909	5,421,756	-58,847	(1.1%)
Ending Balance	6,234,879	5,362,909	**871,970**	**16.3%**
Average Balance	5,798,894	5,392,332	406,562	7.5%
Working Capital Allowance *(see below)*	2,645,809	2,788,555	-142,746	(5.1%)
Total Rate Base	**8,444,703**	**8,180,887**	**263,815**	**3.2%**

Expenses for Working Capital

Variances in excess of $20,613 are shown in bold

Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	681,845	616,632	**65,213**	**10.6%**
3550-Distribution Expenses - Maintenance	162,754	179,508	-16,754	(9.3%)
3650-Billing and Collecting	426,108	394,768	**31,340**	**7.9%**
3700-Community Relations		6,458	-6,458	(100.0%)
3800-Administrative and General Expenses	424,719	422,904	1,815	0.4%
3950-Taxes Other Than Income Taxes				
Total Eligible Distribution Expenses	1,695,427	1,620,270	**75,156**	**4.6%**
3350-Power Supply Expenses	15,943,298	16,970,098	**-1,026,799**	**(6.1%)**
Total Expenses for Working Capital	17,638,725	18,590,368	**-951,643**	**(5.1%)**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**2,645,809**	**2,788,555**	**-142,746**	**(5.1%)**

Attachment 1

Variances in excess of $542,176 are shown in bold

	2007 Actual	2006 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	5,421,756	5,254,908	166,848	3.2%
Ending Balance	5,362,909	5,421,756	-58,847	(1.1%)
Average Balance	5,392,332	5,338,332	54,000	1.0%
Working Capital Allowance *(see below)*	2,788,555	2,689,502	99,053	3.7%
Total Rate Base	**8,180,887**	**8,027,834**	**153,053**	**1.9%**

Expenses for Working Capital

Variances in excess of $20,241 are shown in bold

Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	616,632	659,328	**-42,696**	**(6.5%)**
3550-Distribution Expenses - Maintenance	179,508	182,352	-2,844	(1.6%)
3650-Billing and Collecting	394,768	377,483	17,286	4.6%
3700-Community Relations	6,458	25,863	-19,405	(75.0%)
3800-Administrative and General Expenses	422,904	376,320	**46,584**	**12.4%**
3950-Taxes Other Than Income Taxes		-7,200	7,200	100.0%
Total Eligible Distribution Expenses	1,620,270	1,614,146	6,124	0.4%
3350-Power Supply Expenses	16,970,098	16,315,870	**654,228**	**4.0%**
Total Expenses for Working Capital	18,590,368	17,930,016	**660,352**	**3.7%**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	2,788,555	2,689,502	**99,053**	**3.7%**

Attachment 1

Variances in excess of $566,392 are shown in bold

	2006 Actual	2006 EDR Approved		Var $	Var %
Net Capital Assets in Service:					
Opening Balance	5,254,908				
Ending Balance	5,421,756				
Average Balance	5,338,332	5,663,915		**-325,583**	**(5.7%)**
Working Capital Allowance *(see below)*	2,689,502	2,554,131		**135,371**	**5.3%**
Total Rate Base	**8,027,834**	**8,218,046**		**-190,212**	**(2.3%)**

Expenses for Working Capital

Variances in excess of $16,406 are shown in bold

Eligible Distribution Expenses:					
3500-Distribution Expenses - Operation	659,328	403,209		**256,119**	**63.5%**
3550-Distribution Expenses - Maintenance	182,352	145,599		**36,753**	**25.2%**
3650-Billing and Collecting	377,483	327,045		**50,438**	**15.4%**
3700-Community Relations	25,863			**25,863**	
3800-Administrative and General Expenses	376,320	466,193		**-89,873**	**(19.3%)**
3950-Taxes Other Than Income Taxes	-7,200	2,679		-9,879	(368.8%)
Total Eligible Distribution Expenses	1,614,146	1,344,725		**269,421**	**20.0%**
3350-Power Supply Expenses	16,315,870	15,682,815		**633,054**	**4.0%**
Total Expenses for Working Capital	17,930,016	17,027,540		**902,475**	**5.3%**
Working Capital factor	15.0%	15.0%			
Working Capital Allowance	**2,689,502**	**2,554,131**		**135,371**	**5.3%**

- **Fixed Asset Continuity Statements**

Detailed information on THI's fixed assets is provided as a continuity statement at E2/T2/S1/AttA and at E2/T2/S1/AttB.

A discussion of year over year changes is provided at E2/T1/S1/p17-19.

Historical Board Approved 2006 EDR to 2006HY

THI's 2006 EDR Board approved net physical plant rate base amounted to $5,664k and is $326k greater than the net physical plant rate base of 2006. The reduction in rate base is due to the combined effect of:

- capital spending in the period $1,666k
- depreciation expense in the period of $1,160k
- CiAC $1,013k

2006HY to 2007HY

THI's 2007HY net physical plant was $54k greater than 2006HY. This variance is also attributed to the voltage conversion program activities undertaken in these years. A list of the 2007 project specific variances is provided at E2/T1/S1/AttB.

The 2007AY Working Cash Allowance is $99K or 3.7% greater than that of 2006AY. This is the result of a $654k increase in the cost of power and a $6k increase in controllable costs. The overall increase amounts to $660k, of which 15% is $99k.

2007HY to 2008BY

The 2008BY rate base is $264k greater than the 2007AY rate base. This increase is due to gross capital investment in the 2008BY of $1,094k that is partially offset by $777k of combined depreciation expense and CiAC. The Working Cash Allowance portion of Rate Base decreased by $143k because of changes in the Cost of Power

2008BY to 2009TY

The 2009TY rate base is $502k greater than the 2008BY rate base. This is due to continuing investment in PPE infrastructure, although at a lower level than that of 2008BY. These investment levels are partially offset by depreciation expense and CiAC that in total will amount to $812k. THI's working cash allowance increased by $39k due to the net impact of a $147k decrease in the cost of power and a $408k increase in THI's period costs to operate and maintain the distribution system and to administer the business.

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B1 Gross Capital Assets

Gross Capital Asset Account	2006 EDR Approved	Variance to 2006 Actual			2006 Actual Ending Balance
		Additions	Retirements / Other	Ending Balance	
1610-Miscellaneous Intangible Plant					
1805-Land	11,520			11,520	11,520
1806-Land Rights					
1808-Buildings and Fixtures					
1810-Leasehold Improvements					
1815-Transformer Station Equipment - Normally Primary above 50 kV	48,314		-48,314		
1820-Distribution Station Equipment - Normally Primary below 50 kV	82,808		317,344	400,152	400,152
1825-Storage Battery Equipment					
1830-Poles, Towers and Fixtures	2,366,139	157,469	1,565,421	4,089,029	4,089,029
1835-Overhead Conductors and Devices	449,285	243,543	224,765	917,593	917,593
1840-Underground Conduit	2,085,225	41,111	1,147,240	3,273,575	3,273,575
1845-Underground Conductors and Devices	360,926	156,327	233,448	750,700	750,700
1850-Line Transformers	1,424,099	210,875	1,408,984	3,043,958	3,043,958
1855-Services	233,818	88,856	132,182	454,856	454,856
1860-Meters	381,146	98,233	205,375	684,753	684,753
1905-Land					
1906-Land Rights					
1908-Buildings and Fixtures					
1910-Leasehold Improvements					
1915-Office Furniture and Equipment					
1920-Computer Equipment - Hardware					
1925-Computer Software					
1930-Transportation Equipment					
1935-Stores Equipment					
1940-Tools, Shop and Garage Equipment					
1945-Measurement and Testing Equipment					
1950-Power Operated Equipment					
1955-Communication Equipment					
1960-Miscellaneous Equipment					
1965-Water Heater Rental Units					
1970-Load Management Controls - Customer Premises					
1975-Load Management Controls - Utility Premises					
1980-System Supervisory Equipment					
1985-Sentinel Lighting Rental Units					
1990-Other Tangible Property					
1995-Contributions and Grants - Credit	-538,500	-275,633	-706,382	-1,520,515	-1,520,515
2005-Property Under Capital Leases					
TOTAL	**6,904,780**	**720,779**	**4,480,063**	**12,105,623**	**12,105,623**

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B1 Gross Capital Assets

Gross Capital Asset Account	2007 Actual Additions	2007 Actual Retirements / Other	2007 Actual Ending Balance	2007 Actual Ending Balance	Additions
1610-Miscellaneous Intangible Plant					
1805-Land			11,520	11,520	
1806-Land Rights					
1808-Buildings and Fixtures					
1810-Leasehold Improvements					
1815-Transformer Station Equipment - Normally Primary above 50 kV					
1820-Distribution Station Equipment - Normally Primary below 50 kV			400,152	400,152	
1825-Storage Battery Equipment					
1830-Poles, Towers and Fixtures	83,470	0	4,172,500	4,172,500	324,429
1835-Overhead Conductors and Devices	120,077		1,037,671	1,037,671	232,288
1840-Underground Conduit	25,491	0	3,299,066	3,299,066	33,827
1845-Underground Conductors and Devices	226,069		976,769	976,769	106,964
1850-Line Transformers	275,235		3,319,194	3,319,194	250,859
1855-Services	178,748		633,604	633,604	134,618
1860-Meters	32,427	0	717,180	717,180	10,836
1905-Land					
1906-Land Rights					
1908-Buildings and Fixtures					
1910-Leasehold Improvements					
1915-Office Furniture and Equipment					
1920-Computer Equipment - Hardware					
1925-Computer Software					
1930-Transportation Equipment					
1935-Stores Equipment					
1940-Tools, Shop and Garage Equipment					
1945-Measurement and Testing Equipment					
1950-Power Operated Equipment					
1955-Communication Equipment					
1960-Miscellaneous Equipment					
1965-Water Heater Rental Units					
1970-Load Management Controls - Customer Premises					
1975-Load Management Controls - Utility Premises					
1980-System Supervisory Equipment					
1985-Sentinel Lighting Rental Units					
1990-Other Tangible Property					
1995-Contributions and Grants - Credit	-138,385		-1,658,900	-1,658,900	-303,697
2005-Property Under Capital Leases					
TOTAL	**803,133**	**0**	**12,908,756**	**12,908,756**	**790,123**

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B1 Gross Capital Assets

Gross Capital Asset Account	2008 Projection Retirements / Other	2008 Projection Ending Balance	2008 Projection Ending Balance	2009 Projection Additions	2009 Projection Retirements / Other
1610-Miscellaneous Intangible Plant					
1805-Land		11,520	11,520		
1806-Land Rights					
1808-Buildings and Fixtures					
1810-Leasehold Improvements					
1815-Transformer Station Equipment - Normally Primary above 50 kV					
1820-Distribution Station Equipment - Normally Primary below 50 kV		400,152	400,152		
1825-Storage Battery Equipment					
1830-Poles, Towers and Fixtures		4,496,929	4,496,929	159,764	
1835-Overhead Conductors and Devices	79,709	1,349,667	1,349,667	182,764	
1840-Underground Conduit		3,332,893	3,332,893	34,221	
1845-Underground Conductors and Devices	53,741	1,137,474	1,137,474	95,875	
1850-Line Transformers		3,570,052	3,570,052	287,308	
1855-Services		768,221	768,221	94,841	
1860-Meters		728,016	728,016	10,962	
1905-Land					
1906-Land Rights					
1908-Buildings and Fixtures					
1910-Leasehold Improvements					
1915-Office Furniture and Equipment					
1920-Computer Equipment - Hardware					
1925-Computer Software					
1930-Transportation Equipment					
1935-Stores Equipment					
1940-Tools, Shop and Garage Equipment					
1945-Measurement and Testing Equipment					
1950-Power Operated Equipment					
1955-Communication Equipment					
1960-Miscellaneous Equipment					
1965-Water Heater Rental Units					
1970-Load Management Controls - Customer Premises					
1975-Load Management Controls - Utility Premises					
1980-System Supervisory Equipment					
1985-Sentinel Lighting Rental Units					
1990-Other Tangible Property					
1995-Contributions and Grants - Credit		-1,962,597	-1,962,597	-309,652	
2005-Property Under Capital Leases					
TOTAL	**133,450**	**13,832,329**	**13,832,329**	**556,082**	

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B1 Gross Capital Assets

Gross Capital Asset Account	Ending Balance
1610-Miscellaneous Intangible Plant	
1805-Land	11,520
1806-Land Rights	
1808-Buildings and Fixtures	
1810-Leasehold Improvements	
1815-Transformer Station Equipment - Normally Primary above 50 kV	
1820-Distribution Station Equipment - Normally Primary below 50 kV	400,152
1825-Storage Battery Equipment	
1830-Poles, Towers and Fixtures	4,656,693
1835-Overhead Conductors and Devices	1,532,431
1840-Underground Conduit	3,367,114
1845-Underground Conductors and Devices	1,233,349
1850-Line Transformers	3,857,360
1855-Services	863,062
1860-Meters	738,978
1905-Land	
1906-Land Rights	
1908-Buildings and Fixtures	
1910-Leasehold Improvements	
1915-Office Furniture and Equipment	
1920-Computer Equipment - Hardware	
1925-Computer Software	
1930-Transportation Equipment	
1935-Stores Equipment	
1940-Tools, Shop and Garage Equipment	
1945-Measurement and Testing Equipment	
1950-Power Operated Equipment	
1955-Communication Equipment	
1960-Miscellaneous Equipment	
1965-Water Heater Rental Units	
1970-Load Management Controls - Customer Premises	
1975-Load Management Controls - Utility Premises	
1980-System Supervisory Equipment	
1985-Sentinel Lighting Rental Units	
1990-Other Tangible Property	
1995-Contributions and Grants - Credit	-2,272,249
2005-Property Under Capital Leases	
TOTAL	**14,388,411**

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B3 Net Capital Asset Balances

Account Description	2006 EDR Approved - Ending Balances			2006 Actual - Ending Balances			2007 Actual - Ending Ba	
	Gross Assets	Accumulated Amortization	Net Book Value	Gross Assets	Accumulated Amortization	Net Book Value	Gross Assets	Accumulated Amortization
1610-Miscellaneous Intangible Plant								
1805-Land	11,520		11,520	11,520		11,520	11,520	
1806-Land Rights								
1808-Buildings and Fixtures								
1810-Leasehold Improvements								
1815-Transformer Station Equipment - Normally Primary above 50 kV	48,314	-108,115	-59,800		-112,114	-112,114		-113,447
1820-Distribution Station Equipment - Normally Primary below 50 kV	82,808	-337,984	-255,176	400,152	-297,884	102,269	400,152	-307,134
1825-Storage Battery Equipment								
1830-Poles, Towers and Fixtures	2,366,139	-1,868,162	497,978	4,089,029	-2,295,639	1,793,390	4,172,500	-2,450,982
1835-Overhead Conductors and Devices	449,285	-27,999	421,286	917,593	-101,579	816,015	1,037,671	-143,007
1840-Underground Conduit	2,085,225	-1,503,420	581,805	3,273,575	-1,857,870	1,415,706	3,299,066	-1,980,297
1845-Underground Conductors and Devices	360,926	-16,952	343,974	750,700	-80,320	670,380	976,769	-114,213
1850-Line Transformers	1,424,099	-1,278,261	145,839	3,043,958	-1,517,088	1,526,870	3,319,194	-1,615,527
1855-Services	233,818	-16,905	216,913	454,856	-55,456	399,400	633,604	-75,992
1860-Meters	381,146	-438,660	-57,515	684,753	-509,512	175,241	717,180	-534,760
1905-Land								
1906-Land Rights								
1908-Buildings and Fixtures								
1910-Leasehold Improvements								
1915-Office Furniture and Equipment								
1920-Computer Equipment - Hardware								
1925-Computer Software								
1930-Transportation Equipment								
1935-Stores Equipment								
1940-Tools, Shop and Garage Equipment								
1945-Measurement and Testing Equipment								
1950-Power Operated Equipment								
1955-Communication Equipment								
1960-Miscellaneous Equipment								
1965-Water Heater Rental Units								
1970-Load Management Controls - Customer Premises								
1975-Load Management Controls - Utility Premises								
1980-System Supervisory Equipment								
1985-Sentinel Lighting Rental Units								
1990-Other Tangible Property								
1995-Contributions and Grants - Credit	-538,500	31,694	-506,806	-1,520,515	143,593	-1,376,922	-1,658,900	-210,488
2005-Property Under Capital Leases								
TOTAL	**6,904,780**	**-5,564,763**	**1,340,018**	**12,105,623**	**-6,683,867**	**5,421,756**	**12,908,756**	**-7,545,847**

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B3 Net Capital Asset Balances

Amounts from sheets B1 and B2

Account Description	alances	2008 Projection - Ending Balances			2009 Projection - Ending Balances		
	Net Book Value	Gross Assets	Accumulated Amortization	Net Book Value	Gross Assets	Accumulated Amortization	Net Book Value
1610-Miscellaneous Intangible Plant							
1805-Land	11,520	11,520		11,520	11,520		11,520
1806-Land Rights							
1808-Buildings and Fixtures							
1810-Leasehold Improvements							
1815-Transformer Station Equipment - Normally Primary above 50 kV	-113,447		-114,780	-114,780		0	0
1820-Distribution Station Equipment - Normally Primary below 50 kV	93,019	400,152	-316,384	83,769	400,152	-329,067	71,085
1825-Storage Battery Equipment							
1830-Poles, Towers and Fixtures	1,721,517	4,496,929	-2,616,518	1,880,410	4,656,693	-2,791,738	1,864,954
1835-Overhead Conductors and Devices	894,664	1,349,667	-193,805	1,155,862	1,532,431	-332,614	1,199,817
1840-Underground Conduit	1,318,769	3,332,893	-2,104,868	1,228,025	3,367,114	-2,230,799	1,136,315
1845-Underground Conductors and Devices	862,556	1,137,474	-154,111	983,363	1,233,349	-233,136	1,000,212
1850-Line Transformers	1,703,667	3,570,052	-1,724,549	1,845,503	3,857,360	-1,844,334	2,013,026
1855-Services	557,612	768,221	-101,562	666,659	863,062	-131,722	731,340
1860-Meters	182,420	728,016	-560,404	167,612	738,978	-586,483	152,495
1905-Land							
1906-Land Rights							
1908-Buildings and Fixtures							
1910-Leasehold Improvements							
1915-Office Furniture and Equipment							
1920-Computer Equipment - Hardware							
1925-Computer Software							
1930-Transportation Equipment							
1935-Stores Equipment							
1940-Tools, Shop and Garage Equipment							
1945-Measurement and Testing Equipment							
1950-Power Operated Equipment							
1955-Communication Equipment							
1960-Miscellaneous Equipment							
1965-Water Heater Rental Units							
1970-Load Management Controls - Customer Premises							
1975-Load Management Controls - Utility Premises							
1980-System Supervisory Equipment							
1985-Sentinel Lighting Rental Units							
1990-Other Tangible Property							
1995-Contributions and Grants - Credit	-1,869,388	-1,962,597	289,530	-1,673,066	-2,272,249	380,840	-1,891,409
2005-Property Under Capital Leases							
TOTAL	**5,362,909**	**13,832,329**	**-7,597,450**	**6,234,879**	**14,388,411**	**-8,099,054**	**6,289,357**

- **Gross Assets Table**

A detailed presentation of THI's gross assets is provided at E2/T2/S1/AttA.

- **Materiality/Variance Analysis on Gross Assets**

Detailed information on THI's Rate Base year over year changes is provided at E2/T1/S2/AttA and E2/T1/S2/AttA1.

- **Accumulated Depreciation Table**

Detailed information on THI's accumulated depreciation is provided at E2/T2/S4/AttA.

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B2 Amortization of Capital Assets

Capital Asset Account	2006 EDR Approved	Variance to 2006 Actual			2006 Actual Ending Balance	Amortization Expense
		Amortization Expense	Retirements / Other	Ending Balance		
1610-Miscellaneous Intangible Plant						
1805-Land						
1806-Land Rights						
1808-Buildings and Fixtures						
1810-Leasehold Improvements						
1815-Transformer Station Equipment - Normally Primary above 50 kV	-108,115	-1,333	-2,666	-112,114	-112,114	-1,333
1820-Distribution Station Equipment - Normally Primary below 50 kV	-337,984	-8,664	48,765	-297,884	-297,884	-9,619
1825-Storage Battery Equipment						
1830-Poles, Towers and Fixtures	-1,868,162	-148,490	-278,987	-2,295,639	-2,295,639	-154,729
1835-Overhead Conductors and Devices	-27,999	-31,833	-41,747	-101,579	-101,579	-40,644
1840-Underground Conduit	-1,503,420	-120,140	-234,309	-1,857,870	-1,857,870	-122,185
1845-Underground Conductors and Devices	-16,952	-26,901	-36,467	-80,320	-80,320	-33,252
1850-Line Transformers	-1,278,261	-88,655	-150,172	-1,517,088	-1,517,088	-97,515
1855-Services	-16,905	-16,417	-22,134	-55,456	-55,456	-20,147
1860-Meters	-438,660	-22,814	-48,039	-509,512	-509,512	-25,170
1905-Land						
1906-Land Rights						
1908-Buildings and Fixtures						
1910-Leasehold Improvements						
1915-Office Furniture and Equipment						
1920-Computer Equipment - Hardware						
1925-Computer Software						
1930-Transportation Equipment						
1935-Stores Equipment						
1940-Tools, Shop and Garage Equipment						
1945-Measurement and Testing Equipment						
1950-Power Operated Equipment						
1955-Communication Equipment						
1960-Miscellaneous Equipment						
1965-Water Heater Rental Units						
1970-Load Management Controls - Customer Premises						
1975-Load Management Controls - Utility Premises						
1980-System Supervisory Equipment						
1985-Sentinel Lighting Rental Units						
1990-Other Tangible Property						
1995-Contributions and Grants - Credit	31,694	55,308	56,592	143,593	143593.3832	63,588
2005-Property Under Capital Leases						
TOTAL	**-5,564,763**	**-409,940**	**-709,164**	**-6,683,867**	**-6683867.02**	**-441004.032**
Accumulated Amortization on Balance Sheet	-5,521,092	1.1600-Accumulated Amortization		-6,683,875	1.1600-Accumulated Amortization	
Amortization Expense Adjustment	-43671			8		
Amortization Expense	**5,521,092**	**409,940**	**709,164**	**6,683,875**	**6,683,867**	**441,004**

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B2 Amortization of Capital Assets

Capital Asset Account	2007 Actual Retirements / Other	2007 Actual Ending Balance	2007 Actual Ending Balance	2008 Projection Amortization Expense	2008 Projection Retirements / Other	2008 Projection Ending Balance
1610-Miscellaneous Intangible Plant						
1805-Land						
1806-Land Rights						
1808-Buildings and Fixtures						
1810-Leasehold Improvements						
1815-Transformer Station Equipment - Normally Primary above 50 kV		-113,447	-113,447	-1,333		-114,780
1820-Distribution Station Equipment - Normally Primary below 50 kV	-586	-307,134	-307,134	-9,250		-316,384
1825-Storage Battery Equipment						
1830-Poles, Towers and Fixtures	-123,511	-2,450,982	-2,450,982	-165,536		-2,616,518
1835-Overhead Conductors and Devices	78,712	-143,007	-143,007	-50,798		-193,805
1840-Underground Conduit	-95,526	-1,980,297	-1,980,297	-124,570		-2,104,868
1845-Underground Conductors and Devices	54,762	-114,213	-114,213	-39,898		-154,111
1850-Line Transformers	-82,022	-1,615,527	-1,615,527	-109,022		-1,724,549
1855-Services	2,277	-75,992	-75,992	-25,570		-101,562
1860-Meters	-25,248	-534,760	-534,760	-25,644		-560,404
1905-Land						
1906-Land Rights						
1908-Buildings and Fixtures						
1910-Leasehold Improvements						
1915-Office Furniture and Equipment						
1920-Computer Equipment - Hardware						
1925-Computer Software						
1930-Transportation Equipment						
1935-Stores Equipment						
1940-Tools, Shop and Garage Equipment						
1945-Measurement and Testing Equipment						
1950-Power Operated Equipment						
1955-Communication Equipment						
1960-Miscellaneous Equipment						
1965-Water Heater Rental Units						
1970-Load Management Controls - Customer Premises						
1975-Load Management Controls - Utility Premises						
1980-System Supervisory Equipment						
1985-Sentinel Lighting Rental Units						
1990-Other Tangible Property						
1995-Contributions and Grants - Credit	-409,389	-210,488	-210,488	79,042		289,530
2005-Property Under Capital Leases						
TOTAL	**-600,530**	**-7,545,847**	**-7,545,847**	**-472,579**		**-7,597,450**
Accumulated Amortization on Balance Sheet			-7,124,294	1.1600-Accumulated Amortization		
Amortization Expense Adjustment			-577			
Amortization Expense			**7,545,270**	**472,579**		

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B2 Amortization of Capital Assets

Capital Asset Account	2008 Projection Ending Balance	2009 Projection Amortization Expense	2009 Projection Retirements / Other	2009 Projection Ending Balance
1610-Miscellaneous Intangible Plant				
1805-Land				
1806-Land Rights				
1808-Buildings and Fixtures				
1810-Leasehold Improvements				
1815-Transformer Station Equipment - Normally Primary above 50 kV	-114,780		114,780	0
1820-Distribution Station Equipment - Normally Primary below 50 kV	-316,384	-12,684		-329,067
1825-Storage Battery Equipment				
1830-Poles, Towers and Fixtures	-2,616,518	-175,220		-2,791,738
1835-Overhead Conductors and Devices	-193,805	-59,099	-79,709	-332,614
1840-Underground Conduit	-2,104,868	-125,931		-2,230,799
1845-Underground Conductors and Devices	-154,111	-43,954	-35,071	-233,136
1850-Line Transformers	-1,724,549	-119,785		-1,844,334
1855-Services	-101,562	-30,160		-131,722
1860-Meters	-560,404	-26,080		-586,483
1905-Land				
1906-Land Rights				
1908-Buildings and Fixtures				
1910-Leasehold Improvements				
1915-Office Furniture and Equipment				
1920-Computer Equipment - Hardware				
1925-Computer Software				
1930-Transportation Equipment				
1935-Stores Equipment				
1940-Tools, Shop and Garage Equipment				
1945-Measurement and Testing Equipment				
1950-Power Operated Equipment				
1955-Communication Equipment				
1960-Miscellaneous Equipment				
1965-Water Heater Rental Units				
1970-Load Management Controls - Customer Premises				
1975-Load Management Controls - Utility Premises				
1980-System Supervisory Equipment				
1985-Sentinel Lighting Rental Units				
1990-Other Tangible Property				
1995-Contributions and Grants - Credit	289,530	91,309		380,840
2005-Property Under Capital Leases				
TOTAL	**-7,597,450**	**-501,604**		**-8,099,054**
Accumulated Amortization on Balance Sheet				
Amortization Expense Adjustment			-472,579	
Amortization Expense		**501,604**		

- **Materiality Analysis on Accumulated Depreciation - WIP**

THI's accumulated depreciation is presented at E2/T2/S4/AttA. The year over year changes in accumulated depreciation are due to the application of the Board approved depreciation rates to THI's gross assets.

- **Capital Plan by Project**

THI's capital plan is documented at E2/T1/S1/p7-15. Further information on THI's THI's 2008 and 2009 Voltage Conversion capital project plans are provided at E2/T3/S1/AttA and E2/T3/S1/AttB respectively.

THI - 2008 Capital Budget

Project			USoA Account Code					
			1830	1835	1845	1850	1855	
Lincoln St.	Labour	6400	14855	10610		6366	10610	
	Fleet	2489	7793	5559		3326	5559	
	Materials	18310	26409	26409		66020	13204	
	Other	11250	525	525		525	525	
		38449	49582	43103		76237	29898	
Fox Alley Conversion	Labour	101052	5069	3620		2897	2897	
	Fleet	45549	2293	1638		1310	1310	
	Materials	24146	9140	5484		18281	3656	
	Other	60778	263	263		263	263	
		231525	16765	11005	0	22751	8126	
Hi Way #3 Conversion	Labour	13474	740	1854		926	185	
	Fleet	8614	420	1050		525	105	
	Materials	38617	3982	2986		11948	995	
	Other	23878						
		84583	5142	5890		13399	1285	
Fox Alley South	Labour	19638	740	1852	740	3708	371	
	Fleet	9088	424	1062	424	2126	212	
	Materials	20289		9018		27056		
	Other	12744		525		525		
		61759	1164	12457	1164	33415	583	
Fox Alley Joseph's Block	Labour	12632	269		1078	1078	269	
	Fleet	6454	155		615	615		
	Materials	52506	127		2587	9071		
	Other	20744	79		184	788		
		92336	630	0	4464	11552	269	
New Line M-8	Labour	13137	21673	17936	1818	14975	14332	
	Fleet	4397	11085	9309	1039	7902	7186	
	Materials	41412	39658	43897	2587	132376	17855	
	Other	15326	867	1313	184	2101	788	
		74272	73283	72455	5628	157354	40161	
Total	Labour	166333	43346	35872	3636	29950	28664	0
	Fleet	76591	22170	18618	2078	15804	14372	
	Materials	195280	79316	87794	5174	264752	35710	
	Other	144720	1734	2626	368	4202	1576	
Grand Total		582924	146566	144910	11256	314708	80322	

THI - 2009 Capital Budget

Project			USoA Account Code				
			1830	1835	1845	1850	1855
Coon Alley	Labour	42441	14855	10610		6366	10610
	Fleet	22237	7793	5559		3326	5559
	Materials	132042	26409	26409		66020	13204
	Other	2100	525	525		525	525
		198820	49582	43103		76237	29898
Edgewodd	Labour	14483	5069	3620		2897	2897
	Fleet	6551	2293	1638		1310	1310
	Materials	36561	9140	5484		18281	3656
	Other	1052	263	263		263	263
		58647	16765	11005	0	22751	8126
Washingto	Labour	3705	740	1854		926	185
	Fleet	2100	420	1050		525	105
	Materials	19911	3982	2986		11948	995
	Other	0					
		25716	5142	5890		13399	1285
Wolfe St.	Labour	7411	740	1852	740	3708	371
	Fleet	4248	424	1062	424	2126	212
	Materials	36074		9018		27056	
	Other	1050		525		525	
		48783	1164	12457	1164	33415	583
Concession	Labour	2694	269		1078	1078	269
	Fleet	1385	155		615	615	
	Materials	11785	127		2587	9071	
	Other	1051	79		184	788	
		16915	630	0	4464	11552	269
Total	Labour	70734	21673	17936	1818	14975	14332
	Fleet	36521	11085	9309	1039	7902	7186
	Materials	236373	39658	43897	2587	132376	17855
	Other	5253	867	1313	184	2101	788
Grand Total		**348881**	**73283**	**72455**	**5628**	**157354**	**40161**

Summary of Asset Additions

THI's asset additions are driven by its Voltage Conversion program and because it attached new customers. The gross capital spending attributable to customer additions and to the Voltage Conversion program is provided in the tables below.

2008BY Capital Additions

			Projected 2008
	Customer Additions	Volt Conversion	Total
TS	0		
Land	0		
DS	0		
Poles, Towers and Fixtures	85,483	238946	324,429
Overhead Conductors & Devices	109,038	123250	232,288
Underground Conduit	33,827		33,827
Underground Conductors & Devices	89,206	17758	106,964
Line Transformers	128,457	122402	250,859
Services	54,051	80567	134,618
Distribution Meters	10,836		10,836
Capital Investment	510,897	582923	1,093,820
Contributions & Grants - Credit	-303,697	0	-303,697
Total	207,200	582,923	790,123

2009TY Capital Additions

	Budget 2009		
	Customer Additions	Voltage Conversion	Total
TS			
Land			
DS			
Poles, Towers and Fixtures	86,480	73,284	159,764
Overhead Conductors & Devices	110,309	72,455	182,764
Underground Conduit	34,221		34,221
Underground Conductors & Devices	90,246	5,629	95,875
Line Transformers	129,954	157,354	287,308
Services	54,681	40,160	94,841
Distribution Meters	10,962		10,962
Capital Investment	516,852	348,882	865,734
Contributions & Grants - Credit	-309,652	0	-309,652
Total	207,200	348,882	556,082

Summary of Asset Retirements

THI proposes to retire a portion of its existing stock of electro mechanical meters in 2009 and the remainder in 2010. These assets will be removed from the financial statements in the year of removal, consistent with GAAP. Consistent with the Board's current accounting direction they will not be removed from rate base.

THI anticipates that it will remove Municipal Station 3 from service no earlier than 2010 and that it may occur as late as 2012.

- **Leave to Construct (under Section 92)**

In the 2009TY THI does not anticipate seeking leave of the Board under section 92 of *The Ontario Energy Board Act, 1998*.

- **Fixed Assets and Associated Depreciation Rates**

THI relies on a 4% depreciation rate or a 25 year depreciable life for all distribution assets. This is consistent with the Board's policy as provided in the 2000 EDR Handbook.

- **Materiality Analysis on Capital Additions**

THI proposes a materiality criterion of 10%, consistent with the Board's Minimum Filing Requirements. Under this criterion, none of THI's capital additions result in material increases. Detailed information on the year over year changes is provided at E2/T1/S2/AttA and E2/T1/S2/AttA1.

- **System Expansions**

THI expands its distribution system each year in order to attach new customers. In the 2009TY THI expects to invest $517k of gross capital investment or $207k on a net of Contribution in Aid of Construction ("CiAC") basis to connect 104 new residential customers.

THI completes an Economic Feasibility test of all system expansion projects to determine whether a CiAC will be required from the subject customers. THI uses the economic feasibility model prepared by the Municipal Electric Association (now the Electricity Distributors Association). THI runs the Economic Evaluation using its actual capital structure (100% equity), its average consumption/customer and, where applicable, average demand/customer. THI also uses its Board authorized distribution rates, the Board determined Allowed Return on Equity and prevailing tax rates. THI estimates the capital costs of each project uniquely based on its average OM&A/customer.

THI's long standing policy is to require that developers render the CiAC identified by the economic feasibility model. THI adheres to the requirements of the Distribution System Code when running the Economic Evaluation, making an Offer to Connect, recovering the CiAC and administering deposits.

For the purposes of forecasting the 2009TY Rate Base, THI has used the average CiAC/customer of 2007. This forecast is considered reasonable since the 2008 rate increase is offset by lower consumption. THI's service area is attracting senior citizens who typically reside in smaller than average homes, are less electricity intensive that younger consumers and often do not reside in THI's services area during the winter months. As of this writing, THI does not have detailed knowledge of either the costs of the expansions that will be constructed in the 2009TY or of the customer composition and their consumption or load parameters.

THI's 2008BY and 2009TY annual capital spending on system expansions is provided at Ex2/T3/S2/p1-2.

- **Capitalization Policy**

THI's capitalization policy is consistent with Canadian GAAP and with the requirements if the CICA. It is described in Note 1 to THI's audited financial statements (E1/T3/S2/AttA). Briefly, THI appropriately capitalizes all eligible costs. THI uses a time sheet system to identify the period costs and indirect costs eligible for capitalization.

- **Summary of 2008 Working Capital Allowance**

THI proposes a 2009TY Working Cash Allowance of $2,685k.

This amount was determined by applying the Board authorized 15% factor to the sum of:

- the forecast 2009TY Cost of Power, being $15,796k; and
- the forecast 2009TY Controllable costs, being 2,103k.

Working Capital Allowance

		2009TY
Eligible Distribution Expenses:		871,060
3500-Distribution Expenses - Operation		874,451
3550-Distribution Expenses - Maintenance		186,092
3650-Billing and Collecting		
3700-Community Relations		502,694
3800-Administrative and General Expenses		537,694
3950-Taxes Other Than Income Taxes		
Total Eligible Distribution Expenses		2,103,292
3350-Power Supply Expenses		15,796,452
Total Expenses for Working Capital		17,899,744
Working Capital Allowance	15.0%	2,684,962

- **Working Capital Allowance calculations by accounts**

THI's derivation of its 2009TY working cash allowance based on account specific balances is provided in the table below.

Working Capital Allowance

	2009		Amount Eligible
Eligible Distribution Expenses: *(1)*			
3500-Distribution Expenses - Operation	871,060		130,659
3550-Distribution Expenses - Maintenance	186,092		27,914
3650-Billing and Collecting	543,447		81,517
3700-Community Relations			
3800-Administrative and General Expenses	502,694		75,404
3950-Taxes Other Than Income Taxes			
Total Eligible Distribution Expenses	2,103,292		315,494
3350-Power Supply Expenses	15,796,452		2,369,468
Total Expenses for Working Capital	17,899,744		2,684,962

Distribution Revenue

Overview of Distribution Revenue

THI forecasts that it will recover:

- $2,437k in revenues from regulated distribution rates, being the difference between the gross revenues of $2,575k and transformer allowance of $138k;
- $101k of revenues from other Regulated Rates and Charges;
- $28k of interest income;

In total THI forecasts that it will recover $2,566k in regulated revenues in the 2009TY by applying its currently authorized rates and other charges.

The sources of this revenue are described in Table 1 below.

Table 1 – Sources of 2009TY revenue

Total Net Revenues	2,566,138
Revenues Recovered Through Distribution Rates	
Total Gross Revenues	2,575,538
Transformer Allowance	-138,278
Sub-total Net Revenues	2,437,260
Other Revenues	
Other Regulated Charges	
Rent	29,390
Late Payment Charges	12,300
Specific Service Charges	28,335
Retailer Charges	9,123
SSS Administration Charges	21,730
Sub-total	100,878
Interest	28,000

Revenues recovered through Distribution Rates exclude $21k recovered through THI's authorized Smart Meter Rate Adder. This amount will be recorded in USoA account 1555.

THI's total annual revenues by source for the period 2006 to 2009 are set out in Table 2 below.

Table 2 – Annual Revenues 2006-2009 (all amounts in $)

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Estimated	2009 Weather Normalized
Revenues From Distribution Rates and Specific Service Charges	1,545,119	2,335,785	2,520,493	2,444,677	2,468,113
Other Operating Revenues	21,545	69,072	92,406	68,945	70,025
Other Income			3		
Investment Income	34,818	65,054	41,000	28,000	28,000
Total	1,610,482	2,472,911	2,653,896	2,541,622	2,566,138

THI has presented the evidence on Revenues by relying on its existing customer classes or its proposed customer classes as is appropriate or to facilitate trend and variance analysis. The proposed customer class changes will be discussed in greater detail in Exhibits 8 and 9. THI has relied on the currently authorized rates to estimate the revenues that will be recovered from the proposed changed customer classes and has combined or partitioned the charge parameter data discussed in this evidence appropriately.

Summary of Distribution Revenue Table

THI forecasts that it will recover $2,566k of distribution revenue in the 2009TY by applying its currently authorized rates and charges. A discussion of the charge parameter forecast is provided at E3/T2/S2 and of the volumes supporting the Specific Service Charge revenue is provided at E3/T3/S1. Table 1 below provides the amounts recovered through regulated distribution rates and through Specific Service Charges.

Revenues Recovered Through Distribution Rates	
Total Gross Revenues	2,575,538
Transformer Allowance	-138,278
Total Net Distribution Rates Revenues	2,437,260
Total Other Regulated Revenues	128,878
Total	2,566,138

- **Calculations of Distribution Revenue Table**

The derivation of THI's revenues recovered through distribution rates is provided at E3/T1/S3/AttA. A continuity analysis of revenues is provided at E3/T1/S3/AttB.

The derivation of THI's revenues recovered through Specific Service Charges is provided at E3/T1/S3/AttC.

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C4 Revenue from Current Distribution Charges

Rates from sheet C3; Volumes from sheet C1

Customer Class Name	2008 PROJECTED DISTRIBUTION REVENUE AT EXISTING RATES							
	Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Rate	per	Volume	Variable Charge Revenue	TOTAL
Residential	$11.3900	5,892	805,319	$0.0159	kWh	50,682,203	805,847	1,611,166
General Service < 50 kW	$24.7700	640	190,234	$0.0100	kWh	24,970,085	249,701	439,934
General Service >50 kW, <500 kW	$111.5000	72	96,336	$0.8315	kW	108,082	89,870	186,206
General Service >500 kW, <5,000 kW	$1,158.1600	12	166,775	$0.4773	kW	231,714	110,597	277,372
Sentinel Lighting	$1.1800	79	1,119	$7.3155	kW	205	1,500	2,618
Street Lighting	$1,336.7600	1	16,041	$4.4791	kW	3,783	16,944	32,986
Unmetered Scattered Load	$12.3800	19	2,823	$0.0100	kWh	472,835	4,728	7,551
General Service >500 kW, <1,500 kW	$1,158.1600			$0.4773	kW			
General Service >1,500 kW	$1,158.1600			$0.4773	kW			
Gross Revenue (before Transformer Allowances)			1,278,646				1,279,187	2,557,833
Transformer Allowances				($0.6000)	kW	232,484	-139,490	-139,490
Total Revenue			**1,278,646**				**1,139,697**	**2,418,342**
Less: Pass-through amount embedded in distribution rates *								
DISTRIBUTION REVENUE			**1,278,646**				**1,139,697**	**2,418,342**

Customer Class Name	2009 PROJECTED DISTRIBUTION REVENUE AT EXISTING RATES							
	Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Rate	per	Volume	Variable Charge Revenue	TOTAL
Residential	$11.3900	5,996	819,533	$0.0159	kWh	50,519,778	803,264	1,622,798
General Service < 50 kW	$24.7700	637	189,342	$0.0100	kWh	24,890,062	248,901	438,242
General Service >50 kW, <500 kW	$111.5000	72	96,336	$0.8315	kW	106,725	88,742	185,078
General Service >500 kW, <5,000 kW	$1,158.1600			$0.4773	kW			
Sentinel Lighting	$1.1800			$7.3155	kW			
Street Lighting	$1,336.7600	1	16,041	$4.4791	kW	3,783	16,944	32,986
Unmetered Scattered Load	$12.3800	98	14,559	$0.0100	kWh	546,778	5,468	20,027
General Service >500 kW, <1,500 kW	$1,158.1600	8	111,183	$0.4773	kW	72,828	34,761	145,944
General Service >1,500 kW	$1,158.1600	4	55,592	$0.4773	kW	156,866	74,872	130,464
Gross Revenue (before Transformer Allowances)			1,302,586				1,272,952	2,575,538
Transformer Allowances				($0.6000)	kW	230,464	-138,278	-138,278
Total Revenue			**1,302,586**				**1,134,673**	**2,437,260**
Less: Pass-through amount embedded in distribution rates *								
DISTRIBUTION REVENUE			**1,302,586**				**1,134,673**	**2,437,260**

** per revenue amounts on sheet C2 e.g. Low Voltage*

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C4 Revenue from Current Distribution Charges

Rates from sheet C3; Volumes from sheet C1

Customer Class Name	PROJECTED REVENUE FROM DISTRIBUTION CHARGES AT EXISTING RATES					
	2008 Fixed %	2008 Variable %	2008 Total %	2009 Fixed %	2009 Variable %	2009 Total %
Residential	49.98%	50.02%	62.99%	50.50%	49.50%	63.01%
General Service < 50 kW	43.24%	56.76%	17.20%	43.20%	56.80%	17.02%
General Service >50 kW, <500 kW	51.74%	48.26%	7.28%	52.05%	47.95%	7.19%
General Service >500 kW, <5,000 kV	60.13%	39.87%	10.84%			
Sentinel Lighting	42.72%	57.28%	0.10%			
Street Lighting	48.63%	51.37%	1.29%	48.63%	51.37%	1.28%
Unmetered Scattered Load	37.38%	62.62%	0.30%	72.70%	27.30%	0.78%
General Service >500 kW, <1,500 kV				76.18%	23.82%	5.67%
General Service >1,500 kW				42.61%	57.39%	5.07%
TOTAL	**52.87%**	**47.13%**	**100.00%**	**53.44%**	**46.56%**	**100.00%**

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C4 Revenue from Current Distribution Charges

Rates from sheet C3; Volumes from sheet C1

	2009 PROCEEDS FROM CURRENT MONTHLY SERVICE (FIXED) RATES					
Customer Class Name	**Distribution**	**Smart Meters**				**TOTAL**
Residential	819,533	18,708				838,241
General Service < 50 kW	189,342	1,987				191,329
General Service >50 kW, <500 kW	96,336	225				96,561
General Service >500 kW, <5,000 kV						
Sentinel Lighting						
Street Lighting	16,041					16,041
Unmetered Scattered Load	14,559					14,559
General Service >500 kW, <1,500 kV	111,183	25				111,208
General Service >1,500 kW	55,592	12				55,604
TOTAL	**1,302,586**	**20,957**				**1,323,543**

	2009 PROCEEDS FROM CURRENT VARIABLE RATES					
Customer Class Name	**Distribution**					**TOTAL**
Residential	803,264					803,264
General Service < 50 kW	248,901					248,901
General Service >50 kW, <500 kW	88,742					88,742
General Service >500 kW, <5,000 kV						
Sentinel Lighting						
Street Lighting	16,944					16,944
Unmetered Scattered Load	5,468					5,468
General Service >500 kW, <1,500 kV	34,761					34,761
General Service >1,500 kW	74,872					74,872
TOTAL	**1,272,952**					**1,272,952**

Appendix 1-2

Account Grouping	2006 EDR Approved	2006 Actual	2007 Actual	2008 Projection	2009 @ existing rates	2009 @ new dist. rates
3000-Sales of Electricity	15,661,269	16,315,870	16,970,095	15,943,298	15,796,452	15,796,452
3050-Revenues From Services - Distribution	1,545,119	2,335,785	2,520,493	2,444,677	2,468,113	3,214,905
3100-Other Operating Revenues	21,545	69,072	92,406	68,945	70,025	70,025
3150-Other Income & Deductions			3			
3200-Investment Income	34,818	65,054	41,000	28,000	28,000	28,000
3350-Power Supply Expenses	-15,682,815	-16,315,870	-16,970,098	-15,943,298	-15,796,452	-15,796,452
Net Revenues	1,579,935	2,469,910	2,653,899	2,541,622	2,566,138	3,312,930

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C8 Other Service Revenues

Service	USA #	2006 EDR Approved Volume	2006 EDR Approved Rate	2006 EDR Approved Revenue	2006 Actual Volume	2006 Actual Rate	2006 Actual Revenue	Volume
Standard Supply Service -- Administrative Charge	4080	65,192	$0.25	16,298	59,208	$0.25	14,802	58,716
Arrears Certificate	4084							
Statement of Account	4084							
Pulling post-dated cheques	4084							
Duplicate invoices for previous billing	4084							
Request for other billing information	4084							
Easement Letter	4084							
Income tax letter	4084							
Notification Charge	4084							
Account history	4235							
Credit reference/credit check (plus credit agency costs)	4235							
Returned Cheque charge (plus bank charges)	4235	102	$15.00	1,530	105	$15.00	1,575	107
Charge to certify cheque	4235							
Legal letter charge	4084							
Account set up charge / change of occupancy charge	4235	808	$30.00	24,240	836	$30.00	25,080	852
Special Meter reads	4235	6	$30.00	180	6	$30.00	180	6
Meter dispute charge plus Measurement Canada fees (if meter found cor	4235							
Late Payment - per month	4225	493,400	1.50%	7,401	460,667	1.50%	6,910	772,853
Collection of account charge – no disconnection	4225		$30.00			$30.00		
Collection of account charge – no disconnection – after regular hours	4225							
Disconnect/Reconnect at meter – during regular hours	4235		$65.00			$65.00		
Disconnect/Reconnect at meter – after regular hours	4235		$185.00			$185.00		
Disconnect/Reconnect at pole – during regular hours	4235		$185.00			$185.00		
Disconnect/Reconnect at pole – after regular hours	4235							
Install / remove load control device – during regular hours	4235		$185.00					
Install / remove load control device – after regular hours	4235		$185.00			$185.00		
Service call – customer-owned equipment	4235							
Service call – after regular hours	4235		$165.00			$165.00		
Temporary service install and remove – overhead – no transformer	4235							
Temporary service install and remove – underground – no transformer	4235							
Temporary service install and remove – overhead – with transformer	4235							
Specific Charge for Access to the Power Poles – per pole/year	4210	1,081	$22.35	24,160	1,028	$22.35	22,976	1,315
Administrative Billing Charge	4235							
Transformer Allowance for Ownership - per kW of billing demand/month	4080		$0.60			$0.60		
Retailer Service Agreement -- standard charge	4082		$100.00		8	$100.00	800	8
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	36	$20.00	720	30	$20.00	600	96
Retailer Service Agreement -- monthly variable charge (per customer)	4082	3,561	$0.50	1,781	4,701	$0.50	2,351	4,794
Distributor-Consolidated Billing -- monthly charge (per customer)	4082	3,406	$0.30	1,022	4,552	$0.30	1,366	4,642
Retailer-Consolidated Billing -- monthly credit (per customer)	4082		($0.30)			($0.30)		
Service Transaction Request -- request fee (per request)	4084	248	$0.25	62	2,348	$0.25	587	2,457
Service Transaction Request -- processing fee (per processed request)	4084		$0.50		628	$0.50	314	657
Interval Meter Load Management Tool	4235							
TOTAL				**77,394**			**77,540**	

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C8 Other Service Revenues

		2007 Actual		2008 Projection			2009 Projection (existi	
Service	**USA #**	**Rate**	**Revenue**	**Volume**	**Rate**	**Revenue**	**Volume**	**Rate**
Standard Supply Service -- Administrative Charge	4080	$0.25	14,679	74,796	$0.25	18,699	86,920	$0.25
Arrears Certificate	4084							
Statement of Account	4084							
Pulling post-dated cheques	4084							
Duplicate invoices for previous billing	4084							
Request for other billing information	4084							
Easement Letter	4084							
Income tax letter	4084							
Notification Charge	4084							
Account history	4235							
Credit reference/credit check (plus credit agency costs)	4235							
Returned Cheque charge (plus bank charges)	4235	$15.00	1,605	109	$15.00	1,635	111	$15.00
Charge to certify cheque	4235							
Legal letter charge	4084							
Account set up charge / change of occupancy charge	4235	$30.00	25,560	868	$30.00	26,040	883	$30.00
Special Meter reads	4235	$30.00	180	6	$30.00	180	6	$30.00
Meter dispute charge plus Measurement Canada fees (if meter found cor	4235							
Late Payment - per month	4225	1.50%	11,593	780,000	1.50%	11,700	820,000	1.50%
Collection of account charge – no disconnection	4225	$30.00			$30.00			$30.00
Collection of account charge – no disconnection – after regular hours	4225							
Disconnect/Reconnect at meter – during regular hours	4235	$65.00			$65.00			$65.00
Disconnect/Reconnect at meter – after regular hours	4235	$185.00			$185.00			$185.00
Disconnect/Reconnect at pole – during regular hours	4235	$185.00			$185.00			$185.00
Disconnect/Reconnect at pole – after regular hours	4235							
Install / remove load control device – during regular hours	4235							
Install / remove load control device – after regular hours	4235	$185.00			$185.00			$185.00
Service call – customer-owned equipment	4235							
Service call – after regular hours	4235	$165.00			$165.00			$165.00
Temporary service install and remove – overhead – no transformer	4235							
Temporary service install and remove – underground – no transformer	4235							
Temporary service install and remove – overhead – with transformer	4235							
Specific Charge for Access to the Power Poles – per pole/year	4210	$22.35	29,390	1,315	$22.35	29,390	1,315	$22.35
Administrative Billing Charge	4235							
Transformer Allowance for Ownership - per kW of billing demand/month	4080	$0.60			$0.60			$0.60
Retailer Service Agreement -- standard charge	4082	$100.00	800	8	$100.00	800	12	$100.00
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	$20.00	1,920	96	$20.00	1,920	144	$20.00
Retailer Service Agreement -- monthly variable charge (per customer)	4082	$0.50	2,397	4,852	$0.50	2,426	4,938	$0.50
Distributor-Consolidated Billing -- monthly charge (per customer)	4082	$0.30	1,393	4,699	$0.30	1,410	4,782	$0.30
Retailer-Consolidated Billing -- monthly credit (per customer)	4082	($0.30)			($0.30)			($0.30)
Service Transaction Request -- request fee (per request)	4084	$0.25	614	2,814	$0.25	704	2,970	$0.25
Service Transaction Request -- processing fee (per processed request)	4084	$0.50	329	752	$0.50	376	794	$0.50
Interval Meter Load Management Tool	4235							
TOTAL			**90,459**			**95,279**		

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C8 Other Service Revenues

USA Account #s per sheet Y6

		ng rates)	2009 Projection (proposed rates)		
Service	**USA #**	**Revenue**	**Volume**	**Rate**	**Revenue**
Standard Supply Service -- Administrative Charge	4080	21,730	86,920	$0.25	21,730
Arrears Certificate	4084				
Statement of Account	4084				
Pulling post-dated cheques	4084				
Duplicate invoices for previous billing	4084				
Request for other billing information	4084				
Easement Letter	4084				
Income tax letter	4084				
Notification Charge	4084				
Account history	4235				
Credit reference/credit check (plus credit agency costs)	4235				
Returned Cheque charge (plus bank charges)	4235	1,665	111	$15.00	1,665
Charge to certify cheque	4235				
Legal letter charge	4084				
Account set up charge / change of occupancy charge	4235	26,490	883	$30.00	26,490
Special Meter reads	4235	180	6	$30.00	180
Meter dispute charge plus Measurement Canada fees (if meter found cor	4235				
Late Payment - per month	4225	12,300	820,000	1.50%	12,300
Collection of account charge – no disconnection	4225			$30.00	
Collection of account charge – no disconnection – after regular hours	4225				
Disconnect/Reconnect at meter – during regular hours	4235			$65.00	
Disconnect/Reconnect at meter – after regular hours	4235			$185.00	
Disconnect/Reconnect at pole – during regular hours	4235			$185.00	
Disconnect/Reconnect at pole – after regular hours	4235				
Install / remove load control device – during regular hours	4235				
Install / remove load control device – after regular hours	4235			$185.00	
Service call – customer-owned equipment	4235				
Service call – after regular hours	4235			$165.00	
Temporary service install and remove – overhead – no transformer	4235				
Temporary service install and remove – underground – no transformer	4235				
Temporary service install and remove – overhead – with transformer	4235				
Specific Charge for Access to the Power Poles – per pole/year	4210	29,390	1,315	$22.35	29,390
Administrative Billing Charge	4235				
Transformer Allowance for Ownership - per kW of billing demand/month	4080			$0.60	
Retailer Service Agreement -- standard charge	4082	1,200	12	$100.00	1,200
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	2,880	144	$20.00	2,880
Retailer Service Agreement -- monthly variable charge (per customer)	4082	2,469	4,938	$0.50	2,469
Distributor-Consolidated Billing -- monthly charge (per customer)	4082	1,435	4,782	$0.30	1,435
Retailer-Consolidated Billing -- monthly credit (per customer)	4082			($0.30)	
Service Transaction Request -- request fee (per request)	4084	743	2,970	$0.25	743
Service Transaction Request -- processing fee (per processed request)	4084	397	794	$0.50	397
Interval Meter Load Management Tool	4235				
TOTAL		**100,878**			**100,878**

- **Variance Analysis on Distribution Revenue**

THI's year over year changes in revenue are provided at E3/T1/S4/AttA. Changes between 2008BY revenues and 2009TY revenues are primarily due to volume changes.

E3/T1/S4/AttB provides a variance analysis of THI's revenue. The variances show:

- For the residential customer class
- Fixed Charge revenue varies principally because of price variances or due to changes in the level of rates authorized by the Board;
- Variable Charge revenue varies principally because of price variances or due to changes in the level of rates authorized by the Board.

- For the General Service <50 kW customer class
- Fixed Charge revenue varies principally because of changes in the number of customers;
- Variable Charge revenue varies principally because of price variances or due to changes in the level of rates authorized by the Board.

- For the General Service >50 kW, <499 kW customer class
- Fixed Charge revenue varies principally because of price variances or due to changes in the level of rates authorized by the Board;
- Variable Charge revenue varies principally because of price variances or due to changes in the level of rates authorized by the Board.

- For the General Service >500 kW, <4,999 kW customer class
- Fixed Charge revenue varies principally because of price variances or due to changes in the level of rates authorized by the Board;
- Variable Charge revenue varies principally because of price variances or due to changes in the level of rates authorized by the Board.

- The revenue variances in the Unmetered Scattered Load, Street Lighting and Sentinel Lighting customer classes are not material.

Appendix 1-3

Account Grouping	2009 @ new dist. rates	2009 @ existing rates	Var $	Var %	
3000-Sales of Electricity	15,796,452	15,796,452			
3050-Revenues From Services - Distribution	3,214,905	2,468,113	**746,792**	**30.3%**	New Revenue Requirement
3100-Other Operating Revenues	70,025	70,025			
3150-Other Income & Deductions					
3200-Investment Income	28,000	28,000			
3350-Power Supply Expenses	-15,796,452	-15,796,452			
Net Revenues	3,312,930	2,566,138	**746,792**	**29.1%**	New Revenue Requirement

Appendix 1-3

Account Grouping	2009 @ existing rates	2008 Projection	Var $	Var %
3000-Sales of Electricity	15,796,452	15,943,298	**-146,846**	**(0.9%)**
3050-Revenues From Services - Distribution	2,468,113	2,444,677	**23,436**	**1.0%**
3100-Other Operating Revenues	70,025	68,945	1,080	1.6%
3150-Other Income & Deductions				
3200-Investment Income	28,000	28,000		
3350-Power Supply Expenses	-15,796,452	-15,943,298	**146,846**	**0.9%**
Net Revenues	2,566,138	2,541,622	**24,516**	**1.0%**

Appendix 1-3

Account Grouping	2008 Projection	2007 Actual	Var $	Var %
3000-Sales of Electricity	15,943,298	16,970,095	**-1,026,796**	**(6.1%)**
3050-Revenues From Services - Distribution	2,444,677	2,520,493	**-75,817**	**(3.0%)**
3100-Other Operating Revenues	68,945	92,406	**-23,460**	**(25.4%)**
3150-Other Income & Deductions		3	-3	(100.0%)
3200-Investment Income	28,000	41,000	-13,000	(31.7%)
3350-Power Supply Expenses	-15,943,298	-16,970,098	**1,026,799**	**6.1%**
Net Revenues	2,541,622	2,653,899	**-112,277**	**(4.2%)**

Appendix 1-3

Account Grouping	2007 Actual	2006 Actual		Var $	Var %
3000-Sales of Electricity	16,970,095	16,315,870		**654,225**	**4.0%**
3050-Revenues From Services - Distribution	2,520,493	2,335,785		**184,709**	**7.9%**
3100-Other Operating Revenues	92,406	69,072		**23,334**	**33.8%**
3150-Other Income & Deductions	3			**3**	
3200-Investment Income	41,000	65,054		**-24,054**	**(37.0%)**
3350-Power Supply Expenses	-16,970,098	-16,315,870		**-654,228**	**(4.0%)**
Net Revenues	2,653,899	2,469,910	##	**183,989**	**7.4%**

Appendix 1-3

Account Grouping	2006 Actual	2006 EDR Approved	Var $	Var %
3000-Sales of Electricity	16,315,870	15,661,269	**654,601**	**4.2%**
3050-Revenues From Services - Distribution	2,335,785	1,545,119	**790,666**	**51.2%**
3100-Other Operating Revenues	69,072	21,545	**47,527**	**220.6%**
3150-Other Income & Deductions				
3200-Investment Income	65,054	34,818	**30,236**	**86.8%**
3350-Power Supply Expenses	-16,315,870	-15,682,815	**-633,054**	**(4.0%)**
Net Revenues	2,469,910	1,579,935	**889,975**	**56.3%**

- **Weather Normalization Forecasting Methodology**

THI retained Elenchus Research Associates Inc. ("ERA") to prepare a load forecast for the 2008BY and 2009TY. ERA's report is provided at E3/T2/S1/AttA.

ERA reviewed THI's charge parameter data for the period 2003-2007. The data for the period 2003 – 2007 was normalized for changes to customer classes, changes in customer class composition due to periodic customer reclassifications and for an event confined to the GS 500 – 4,999 kW customer class (note: this is discussed in greater detail at E3/T2/S1/AttA/p10). ERA analyzed THI's customer normalized data and concluded that the loads of the GS 500 kW – 4,999 kW, Street Lighting, Sentinel Lighting and Unmetered Scattered Load customer classes were not weather sensitive. The loads for all other customer classes were determined to be weather sensitive.

Energy and demand are principally driven by weather, economic activity and calendarization (i.e., depending on whether a specific day is falls on weekend or is a statutory holiday).

ERA parameterized THI's normal weather scenario using the 10 most recent years of Heating Degree Days ("HDD") and Cooling Degree Days ("CDD") observations recorded at Hamilton International Airport ("HIA"). HIA is situated on top of the Niagara escarpment and is considered to experience weather patterns similar to those experienced in Tillsonburg. It also has a complete and accurate weather data set. Alternate sites for weather data include London, Windsor, Wiarton and Pearson International Airport. These sites were not relied on due to concerns over either the completeness of the weather data set or the distance to Tillsonburg.

Using the weather data collected at HIA, THI will experience 3,779 Heating Degree Days and 300 Cooling Degree Days in a weather normal year.

ERA estimated the following log linear regression equation for THI's weather sensitive customer classes:

$kWh_{\text{Weather Sensitive}} = 15.02 + 0.00037 * HDD + 0.00263 * CDD + 0.01551 * \#\text{ peak days} + 0.00242 * employ$

Diagnostic statistics of the above equation and a plot of the fitted curve versus the normalized data are provided at page 6 of ERA's report (E3/T2/S1/AttA).

Medium Term Weather Normalized Distribution System Load Forecast
2008 to 2009

Prepared for

Tillsonburg Hydro Inc.

August 14, 2008

1 INTRODUCTION

This document outlines the results and methodology used to derive the weather normal load forecast prepared for use in Tillsonburg Hydro Inc.'s (THI's) rebasing rate application for 2009 rates. A weather normal load forecast for applicable load was developed for the bridge year (2008) and test year (2009) and weather normalized historical consumption was also derived.

Short-term variation in electricity consumption is heavily influenced by three main factors – weather (e.g. heating and cooling), which is by far the most dominant effect for most systems; economic factors (increases or decreases in economic activity leads to changes in employment, industrial and commercial activity, building and population change); and timing factors (non-holiday weekdays when businesses are typically operating). We have incorporated variables to account for all of these factors in considering THI's load and correcting for weather anomalies.

The forecast for Tillsonburg Hydro Inc. is based on monthly data provided for the Distribution System from January 2003 to December 2007. Monthly data for 2002 was also provided; however, it was excluded due to data anomalies.[1] A significant portion of THI's load comes from a small group of large users in the GS 500-4999 kW class. In 2007, this class had 12 customers and accounted for almost 50 per cent of energy consumption. On the other hand, the residential class with about 5,800 customers, accounted for about 21 per cent of energy in 2007 and the GS<50 kW class accounted for about 11% of energy. Large user classes typically have usage patterns that are not particularly sensitive to weather. They tend to have flat load and sometimes have divergent consumption trends from residential and smaller general service customers (e.g., shut-downs in July and December/January that reduce consumption in what are otherwise peak periods for weather sensitive load). This is the case for the GS 500-4999 kW class in Tillsonburg.

[1] For example, negative losses in some months. This may be due to issues such as allocating unbilled and billing periods.

There are several ways to deal with this issue when trying to determine weather normal consumption. One method is to analyse each weather sensitive class separately (i.e, residential, GS<50, etc.). While this would have been the preferred approach, data issues such as unintuitive monthly movements in consumption, precluded this solution. There may be several reasons for the data issues. Tillsonburg is a small LDC. Without customer diversity, allocation of unbilled energy and billing cycle issues can significantly affect monthly class consumption. This undermines the ability to match monthly consumption with monthly weather patterns.

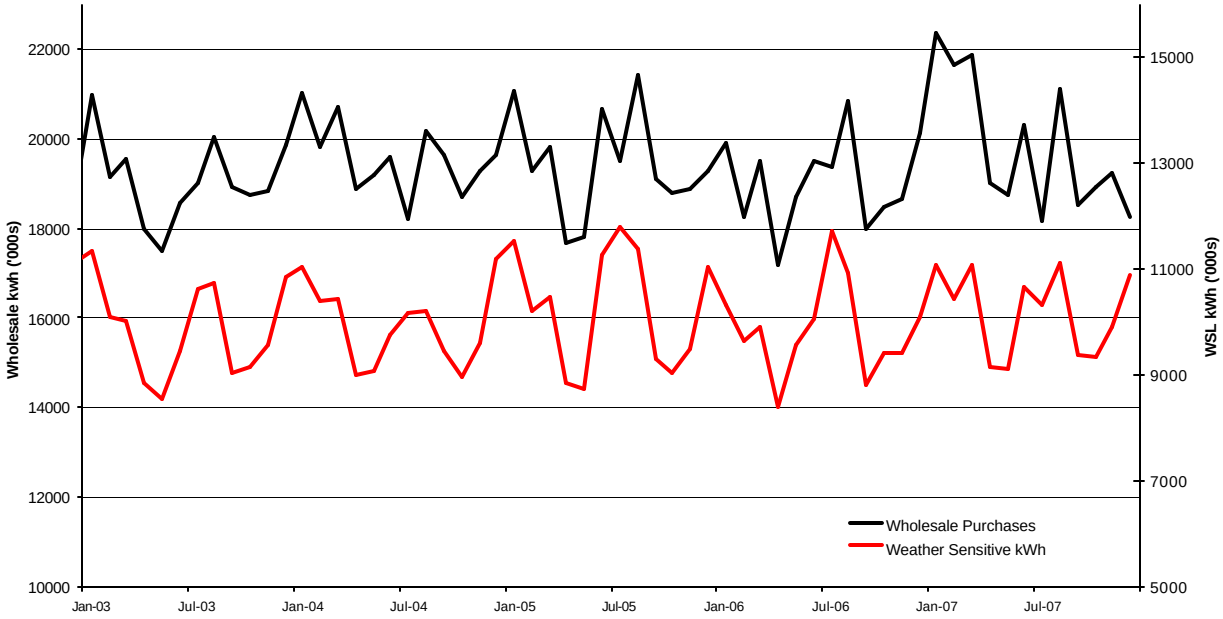
Monthly wholesale purchases represents the most accurate monthly measurement of LDC consumption. However, since upwards of 50 per cent of this volume is non-weather sensitive, much of it actually counter-cyclical due to plant shut-downs in July, the weather effects of the remaining consumption is washed out. The solution adopted for this is to calculate "weather-sensitive purchases" by removing non-sensitive load (GS 500-4999 kW as well as street lighting, sentinel lighting and USL) from monthly wholesale purchases. Since the large users are interval metered, the remaining "weather sensitive load" should retain an accurate reflection of monthly consumption.

2 ENERGY FORECAST USING WHOLESALE KWH DELIVERIES

The following chart (*Chart 1*) displays monthly wholesale purchases and calculated weather sensitive load[2] (WSL kWh) from January 2003 to December 2007.

[2] Monthly kWh purchases less monthly kWh from GS 500-4999 kW class, lighting, and USL.

Chart 1
Tillsonburg Wholesale Purchases and Weather Sensitive Load



In order to determine the relationship between observed weather and energy consumption, monthly weather observations describing the extent of heating or cooling required within the month are necessary. Environment Canada publishes monthly observations on heating degree days (HDD) and cooling degree days (CDD) for selected weather stations across Canada. Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18°C. Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18°C. For Tillsonburg, we have used monthly HDD and CDD as reported at Hamilton Airport.

In order to measure the change in economic activity, a data series must be chosen which represents, as much as possible, regional economic activity. We have used the monthly employment levels for London CMA, as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM series v2067636).

Finally, we have used the number of non-holiday weekdays in the month to account for peak day consumption. We have included New Year's Day, Good Friday, Easter Monday, Victoria Day, Canada Day, August Civic Holiday (Simcoe Day), Labour Day,

Thanksgiving Day, Christmas and Boxing Day. From 2008, we have included the Ontario Family Day holiday in February, but we have not included Remembrance Day in November. The historical data for monthly employment and peak days are displayed in *Table 1* below.

Table 1
Monthly Peak Days

	2003	2004	2005	2006	2007
January	21	21	20	21	22
February	20	20	20	20	20
March	21	23	21	23	22
April	20	20	21	18	19
May	21	20	21	22	22
June	21	22	22	22	21
July	22	21	20	20	22
August	20	21	22	22	22
September	21	21	21	20	19
October	22	20	20	21	22
November	20	22	22	22	22
December	21	21	20	19	19
	Employment (000s) – London Census Metropolitan Area				
January	229.3	240.4	241.5	238.2	248.6
February	226.6	240.1	242.4	237.8	247.7
March	226.5	240.4	241.5	237.5	245.2
April	226.5	240.8	242.2	241.1	243.5
May	229.0	239.6	243.4	246.6	242.9
June	232.6	244.8	246.1	249.8	244.1
July	236.0	250.1	248.3	248.2	248.7
August	237.9	252.6	248.3	244.8	251.4
September	238.3	247.4	246.2	244.9	253.9
October	238.6	241.9	242.8	247.3	252.9
November	240.1	239.9	239.8	249.5	249.9
December	240.0	241.6	238.5	250.1	246.5
Ann % chg	***2.9%***	***4.2%***	***0.0%***	***0.5%***	***1.3%***

Using this data, the following log-linear regression equation describing the relationship between monthly actual weather sensitive energy consumption and the explanatory variables was estimated:

Table 2

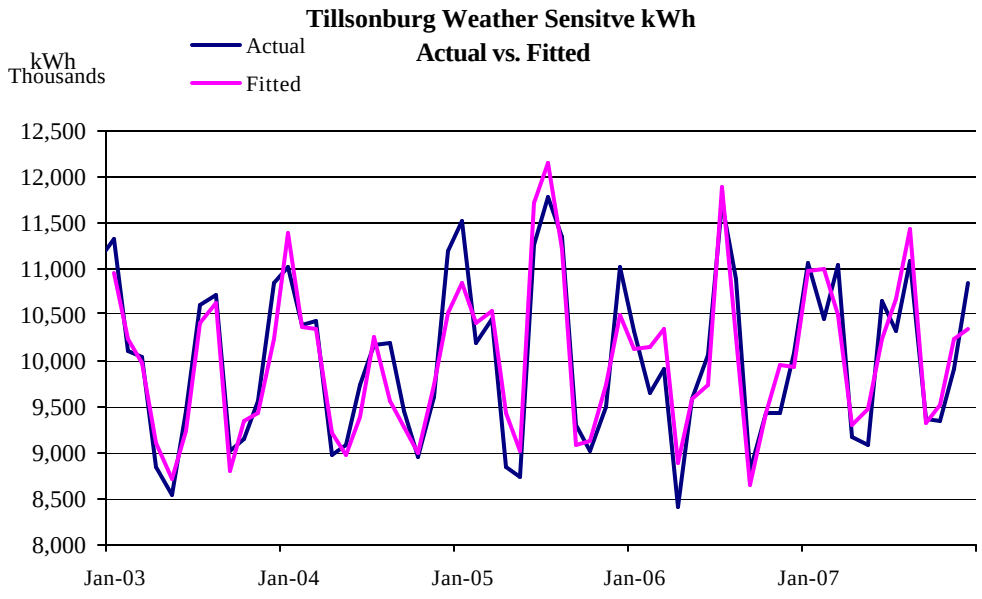
OLS estimates using the 60 observations 2003:01-2007:12
Dependent variable: ln(WSL_kWh)

Unadjusted R^2 = 0.854432
Adjusted R^2 = 0.843845
F-statistic (4, 55) = 80.7074 (p-value < 0.00001)
Durbin-Watson statistic = 1.8976

Variable	*Coefficient*	*t-statistic*	*p-value*
const	15.0204	73.1891	<0.00001
HDD	0.000373061	15.3132	<0.00001
CDD	0.00263362	16.2433	<0.00001
Peakdays	0.0155119	3.5811	0.00072
Employ	0.00242165	3.1807	0.00241

Fitted vs. actual observations are plotted in the chart below:

Chart 2



Annual estimates are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 0.74% with the largest absolute error on an annual estimate at 1.01%.

Table 3 – Actual vs. Predicted

Year	*Actual WSL kWh*	*Predicted kWh*	*Error*
2003	118,215,283	117,022,411	*-1.01%*
2004	119,205,428	117,996,147	*-1.01%*
2005	122,975,978	123,796,482	*0.67%*
2006	118,248,822	118,857,953	*0.52%*
2007	122,350,428	122,982,707	*0.52%*
	Mean Absolute Percentage Error		***0.74%***

2.1 WEATHER NORMALIZATION AND FORECASTED KWH

It is not possible to accurately forecast weather for months or years in advance. Therefore, one can only base future weather expectations on what has happened in the past. Individual years may experience unusual spells of weather (unusually cold winter, unusually warm summer, etc.). However, over time, these unusual spells "average" out. While there may be trends over several years (e.g., warmer winters for example), using several years of data rather than one particular year filters out the extremes of any particular year. For Tillsonburg, the 10 year average from 1998 to 2007 has been adopted as the appropriate definition of weather normal. Other definitions also exist. Environment Canada publishes 30 year "Climate Normal" data based on observations from 1971 to 2000. The OEB has considered yet others (for example, a five-year rolling average used to predict heating degree days for bridge year and test year in the case of Natural Resource Gas Limited (RP-2004-0167)). Our view is that a ten-year average based on the most recent ten calendar years available is a reasonable compromise that likely reflects the "average" weather experienced in recent years. Others have also adopted this definition (for example, Toronto Hydro Electric System Limited in EB-2005-0421 and EB-2007-0680).

Presented below is a table outlining the 10-year and 30-year average monthly HDD and CDD for Hamilton International Airport.

Table 4 – 30-yr and 10-yr HDD and CDD, Hamilton Int'l Airport

	1971-2000 30yr normal		1998-2007 10yr normal	
	HDD	**CDD**	**HDD**	**CDD**
Jan	742.9	0.0	711.4	0.0
Feb	654.5	0.0	620.4	0.0
Mar	567	0.0	549.3	0.0
Apr	353.4	1.1	336.9	0.8
May	169.7	12.2	162.5	13.8
Jun	45.1	46.0	40.0	64.0
Jul	8.1	93.5	6.0	104.4
Aug	16.5	73.2	9.6	83.6
Sep	98.1	22.7	67.5	30.6
Oct	275.7	0.9	253.9	3.0
Nov	441.1	0.0	405.3	0.0
Dec	640.2	0.0	616.4	0.0
Annual	**4,012.2**	**249.6**	**3,779.1**	**300.2**

Forecasts for Ontario's employment outlook for 2008 and 2009 are available from four Canadian Chartered Banks at time of writing. Their forecasts are summarized below.

Table 5 - Employment Forecast – Ontario
(figures in annual percentage change)

	BMO *(Winter 2008)*	RBC *(April 2008)*	Scotia *(May 5, 2008)*	TD *(April 16,2008)*	avg
2008	0.7	0.9	1.2	1.0	0.9
2009	0.7	1.0	0.8	0.4	0.7

Incorporating the forecast economic variables, monthly peak days, and 10-yr weather normal heating and cooling degree days, the following weather corrected consumption and forecast values are calculated:

Table 6 - Weather Corrected WSL kWh, Tillsonburg Hydro

			10-yr (1998-2007)	
Year	Actual WSL kWh	%chg	Weather Normal	%chg
2003	118,215,283		117,181,435	
2004	119,205,428	0.8%	120,372,509	2.7%
2005	122,975,978	3.2%	120,019,616	-0.3%
2006	118,248,822	-3.8%	120,398,733	0.3%
2007	122,350,428	3.5%	121,718,517	1.1%
2008F			122,180,935	0.4%
2009F			122,560,194	0.3%

3 CLASS SPECIFIC WEATHER NORMALIZATION AND CONSUMPTION FORECASTS

The following table (*Table 7*) presents class specific weather normal historic and forecast values for those classes that have weather sensitive load. Historic class specific kWh consumption is allocated based on each class' share in WSL kWh, exclusive of distribution losses. Forecast class values are allocated based on the class share for 2007.

Table 7 - Weather Corrected Class Specific Consumption, Tillsonburg Hydro

			10-yr (1998-2007)
Year	Actual residential kWh	*Share%*	Weather Normal
2003	49,451,899	41.8%	49,019,419
2004	48,498,330	40.7%	48,973,153
2005	52,839,258	43.0%	51,568,994
2006	50,348,412	42.6%	51,263,809
2007	51,071,709	41.7%	50,807,936
2008F			**51,000,959**
2009F			**51,159,269**
Year	Actual GS<50 kWh	*Share%*	Weather Normal
2003	25,726,330	21.8%	25,501,341
2004	26,490,574	22.2%	26,749,930
2005	26,529,300	21.6%	25,891,531
2006	24,804,580	21.0%	25,255,558
2007	25,161,987	20.6%	25,032,031
2008F		21.8%	**25,127,130**
2009F		22.2%	**25,205,126**
Year	Actual GS 50-499 kWh	*Share%*	Weather Normal
2003	32,276,163	27.3%	31,993,893
2004	32,928,322	27.6%	33,250,707
2005	34,219,741	27.8%	33,397,093
2006	34,517,444	29.2%	35,145,014
2007	37,185,820	30.4%	36,993,764
2008F			**37,134,306**
2009F			**37,249,574**

Actual, normalized and forecast kW for the weather sensitive GS 50-499 class are summarized in *Table 8* below. Historical normalized values are calculated based on the

annual ratio of class kW to class kWh. Forecast kW is based on the class kW to class kWh ratio in 2007.

Table 8 – GS 50-499 Class kW (Actual, Normalized, and Forecast)

Year	Actual kW	Class kW/kWh ratio	Normalized kW	% change
2003	102,787	0.0032	101,888	
2004	113,601	0.0034	114,713	12.6%
2005	111,395	0.0033	108,717	-5.2%
2006	104,325	0.0030	106,222	-2.3%
2007	109,409	0.0029	108,844	2.5%
2008F			**109,257**	0.4%
2009F			**109,596**	0.3%

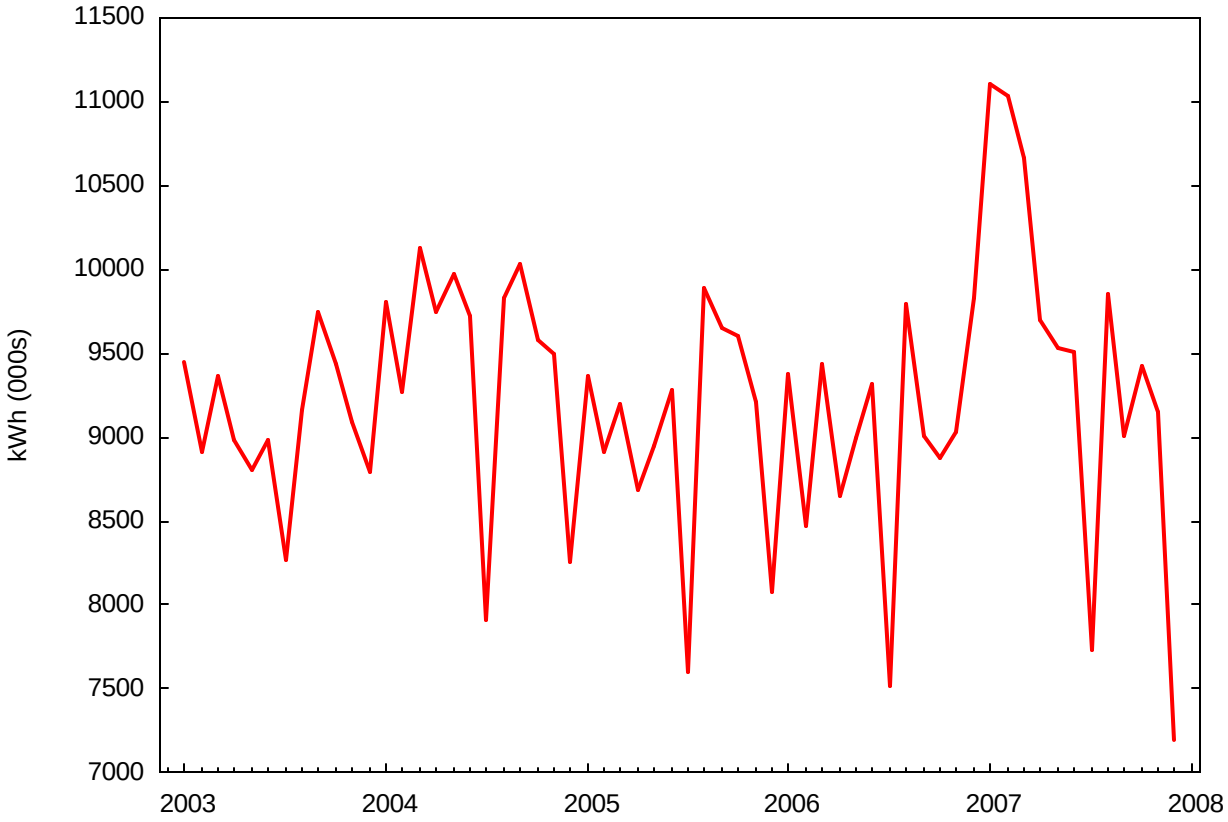
The table below (*Table 9*) presents actual and forecast kWh and kW (where applicable) for the non-weather sensitive classes of GS 500-4999 kW, Street Lighting, Sentinel Lighting and Unmetered Scattered Load (USL).

The GS 500-4999 kW class is forecast based on the trend in employment outlook. However, in late 2006 and early 2007, the class experienced a significant but transient increase in consumption from late November 2006 through to March/April of 2007. This was associated with the full start-up of a customer that had been on-line since 2006. After operating at full capacity (24 hours per day) for a number of months, the facility was closed due to soft market conditions. This customer continues to be connected but with no production. This resulted in class consumption in 2007 being 7,380,000 kWh and 19,900 kW greater than consumption at average levels since shutdown. Annual class consumption in 2007 has been adjusted downwards by these amounts to reflect this. Class consumption is then adjusted by the trend forecast for employment, growing annually at 0.9% and 0.7% respectively, for 2008 and 2009. *Chart 3* below shows historical kWh consumption in the class.

The kW forecast for these classes is based on the 2006 kW/kWh ratio multiplied the forecast kWh in the class.[3]

[3] GS 500-4999 kW class uses the 2006 ratio to correct for the large customer that operated for only a portion of 2007.

Chart 3: Tillsonburg Hydro GS 500-4999 Class kWh Consumption



The kWh and kW forecast for street lighting, sentinel lighting and USL is held constant at 2007 levels, as no growth in any of these classes is anticipated.

The results are summarized in the table below.

Table 9

GS 500-4999 kW, Lighting & USL Historic and Trend Forecast Consumption

	GS 500-4999 kW				*Street Lighting*			
Year	kWh	%	kW	%	kWh	%	kW	%
2003	108,991,266		225,457		1,272,899		3,704	
2004	113,754,268	4.4%	230,731	2.3%	1,280,056	0.6%	3,777	2.0%
2005	108,418,488	-4.7%	224,380	-2.8%	1,298,589	1.4%	3,778	0.0%
2006	108,303,756	-0.1%	236,055	5.2%	1,304,938	0.5%	3,778	0.0%
2007	113,889,596	5.2%	255,372	8.2%	1,310,738	0.4%	3,783	0.1%
2008F	**107,468,182**	-5.6%	**234,234**	-8.3%	**1,310,738**	0.0%	**3,783**	0.0%
2009F	**108,220,459**	0.7%	**235,873**	0.7%	**1,310,738**	0.0%	**3,783**	0.0%

Sentinel Lighting					*USL*	
Year	kWh	%	kW	%	kWh	%
2003	68,661		190		411,126	
2004	77,195	12.4%	216	13.8%	410,135	-0.2%
2005	74,010	-4.1%	205	-4.9%	438,575	6.9%
2006	73,943	-0.1%	205	-0.1%	449,644	2.5%
2007	73,943	0.0%	205	0.0%	472,835	5.2%
2008F	**73,943**	0.0%	**205**	0.0%	**472,835**	0.0%
2009F	**73,943**	0.0%	**205**	0.0%	**472,835**	0.0%

Table 10 below presents the results for class specific historic actual and historic normalized (2007) kWh and kW (where applicable), and normalized forecast values for bridge year (2008) and test year (2009).

Table 10 – Load Forecast (Historical, Bridge and Test Years).

	2007 Actual	2007 Normalized	2008f Normalized	2009f Normalized
Residential (kWh)	51,071,709	50,807,936	**51,000,959**	**51,159,269**
GS<50 (kWh)	25,161,987	25,032,031	**25,127,130**	**25,205,126**
GS 50-499 (kWh)	37,185,820	36,993,764	**37,134,306**	**37,249,574**
(kW)	109,409	108,844	**109,257**	**109,596**
GS 500-4999 (kWh)	113,889,596	113,889,596	**107,468,182**	**108,220,459**
(kW)	255,372	255,372	**234,234**	**235,873**
Street Lights (kWh)	1,310,738	1,310,738	**1,310,738**	**1,310,738**
(kW)	3,783	3,783	**3,783**	**3,783**
Sentinel Lights (kWh)	73,943	73,943	**73,943**	**73,943**
(kW)	205	205	**205**	**205**
USL (kWh)	472,835	472,835	**472,835**	**472,835**
Total Retail kWh	229,166,628	228,580,843	**222,588,092**	**223,691,945**

Historic customer figures on an average annual basis are presented in *Table 11* below. *Table 11* also provides forecasted for the number of customers in each rate class for 2008 and 2009. Residential and GS<50 are forecast based on the average growth from 2003 to 2007. No growth is expected in any of the other classes.

Table 11 – Average Annual Customer Connections – Tillsonburg Hydro

	Residential	%chg	GS<50	%chg	GS50-499	%chg	GS500-4999	USL
2003	5,397		656		68		11	17
2004	5,486	1.6%	658	0.3%	72	5.7%	11	18
2005	5,568	1.5%	654	-0.6%	73	0.3%	11	18
2006	5,677	2.0%	648	-0.9%	72	-0.7%	12	19
2007	5,790	2.0%	643	-0.8%	72	-0.2%	12	19
2008f	**5,892**	**1.8%**	**640**	**-0.5%**	**72**	**0.0%**	**12**	**19**
2009f	**5,996**	**1.8%**	**637**	**-0.5%**	**72**	**0.0%**	**12**	**19**

	Street lights	%chg	Sentinel	%chg
2003	2,441		75	
2004	2,441	0.0%	83	10.2%
2005	2,434	-0.3%	79	-4.2%
2006	2,353	-3.3%	79	-0.1%
2007	2,372	0.8%	79	0.0%
2008f	**2,372**		**79**	
2009f	**2,372**		**79**	

Explanation of Causes and Assumptions for the Volume Forecast

Revenue Forecasting Methodology

Prior to the subject rate rebasing application THI forecast its prospective revenues recovered through authorized rates and charges using historical data - specifically using the number of customers, delivered kWh and demand data of the previous period, applied at currently authorized rates.

For the purposes of the subject application, THI has adopted a 2 step approach to revenue forecasting. The first step consists of using econometric techniques to forecast THI's charge parameters. The second step adjusts the econometric forecast for anticipated exogenous factors, specifically Conservation and Demand Management, embedded generation and economic conditions. The proposed charge parameters for the 2009TY are set out in the table 1 below.

Table 1 – 2009TY Charge Parameters

Customer Class	# of Customers	Energy (kWh)	Demand (kW)
Residential	5,996	50,519,778	
General Service <50 kW	637	24,890,062	
General Service >50 kW, <500 kW	72	36,783,954	106,725
General Service >500 to 4999 kW	10	106,867,703	229,694
General Service >500 kW, <1,500 kW (1)	8	33,649,353	72,828
General Service >1,500 kW (1)	4	73,218,353	156,866
Street Lighting	1	1,310,738	3,783
Unmetered Scattered Load (2)	98	546,778	
TOTAL	6,814	220,919,014	340,406

(1) These proposed classes will replace GS 500-4,999 kW

(2) Includes Sentinel Lighting

The Econometric Forecast

As is discussed at E3/T2/S1, THI retained Elenchus Research Associates Inc. ("ERA") to prepare a load forecast for the 2008BY and 2009TY.

ERA's load forecast has been prepared using econometric techniques. Because these techniques cannot incorporate anticipated trends THI proposes to make adjustments for anticipated exogenous factors.

Adjustments for Exogenous Factors

In the second step of THI's load forecasting process, the output of the econometric load forecast was adjusted for anticipated exogenous factors by analyzing:

- Embedded generation;
- Conservation and Demand Management ("CDM"); and
- Economics.

ERA's econometric analysis relied on historic data for the period 2003-2007. As a result, this data does not reflect:

- the impact on electricity consumption or demand attributable to recent economic events, specifically the economic slowdown underway in the United States;
- local consumer response to the Conservation Bureau's offering of CDM programs; or
- local area embedded generation.

No adjustment was made because of Embedded Generation or due to economic events. Adjustments were made to the energy and demand forecasts that are consistent with the OPA's CDM forecasts for south western Ontario in the 2009TY.

CDM Adjustments

THI's CDM programs created 1.8 GWh of annual energy savings, or approximately 0.8% of its total energy deliveries. The majority of these savings, 1.2 GWh, are attributable to the residential customer class and the remainder is attributable to THI's distribution system improvements. On a per customer basis, the 3rd tranche CDM programs have resulted in savings of 200 kWh/customer/year. These programs have also achieved a 6,000 kW reduction in demand in that period. THI's CDM reports for 2005, 2006 and 2007 are provided at E3/T2/S2/AttA-C.

THI's data shows that it's residential and GS < 50 kW customers have reduced their annual electricity consumption by approximately 2.5% and 1% respectively in both the 2005-06 and 2006-07 periods.

The OPA's documented assumptions of the energy and demand throughput for 2008-2017 and of the attainable CDM results for that period are provided at E3/T2/S2/AttD and E3/T2/S2/AttE. These documents show that the OPA is projecting that in 2009 its CDM programs will reduce energy throughput by approximately 1.25% and reduce demand by approximately 2.6%. It is clear that the OPA will continue to develop and bring to market CDM programs geared to achieving or exceeding these results. For THI in particular, the OPA's programs will engage its non-residential customer classes for the first time ever in broad scale CDM offerings.

ERA's econometric forecast of throughput for the 2009TY for the following customer classes has been reduced by 1.25%:

- residential;
- GS<50 kW;
- GS 50-499 kW; and
- GS 500 – 4,999 kW.

These adjustments are considered conservative because:

- THI's residential customers have achieved energy reductions of 2.5% in past years and the OPA is expected to offer several new CDM programs targeted to the residential customer class;
- The GS<50 kW customer class achieved a 1% reduction in energy consumed per customer in 2006 and 2007 and is expected to participate in OPA CDM programs targeted to them;
- The GS 50-499 kW and GS 500 – 4,999 kW customer classes are expected to participate in OPA CDM programs that will be geared to them and offered on a first time ever basis and to achieve the OPA's estimated 1.25% overall reduction in energy throughput.

For similar reasons ERA's econometric forecast of demand for the 2009TY for the customer classes named above has been reduced by 2.6%.

The resulting CDM adjusted kWh forecast is provided in the table 2 below.

Table 2 – THI 2009TY CDM adjusted load forecast

Customer Class	# of Customers	Energy (kWh)	Demand (kW)
Residential	5,996	50,519,778	
General Service <50 kW	637	24,890,062	
General Service >50 kW, <500 kW	72	36,783,954	106,725
General Service >500 to 4999 kW	10	106,867,703	229,694
General Service >500 kW, <1,500 kW (1)	8	33,649,353	72,828
General Service >1,500 kW (1)	4	73,218,353	156,866
Street Lighting	1	1,310,738	3,783
Unmetered Scattered Load (2)	98	546,778	
TOTAL	6,814	220,919,014	340,406

(1) These proposed classes will replace GS 500-4,999 kW

(2) Includes Sentinel Lighting

Adjustment for Economic Conditions

THI's GS 500- 4,999 kW customer class has 12 members. Eight of them are engaged in the manufacturing or fabrication of automotive parts and include the 4 largest members of the class. These 8 customers account for 83% of the class' consumption. THI believes that there is a significant downside risk with respect to the load forecast of these customers because of the economic slowdown currently underway in the United States, specifically:

- impact on the overall demand for automobiles; and
- consumer's shifting preference in favour of fuel efficient vehicles.

THI recognizes that if its automotive supply customers do not experience any reduction in the demand for the products they manufacture or fabricate that they can expect to retool their assembly or fabrication lines and hence be 'down' versus their normal operations. To date there is no discernable change in the billed kWh and kW for the customers in this class; this has been determined by reviewing the January to June 2008 data against the January to June 2007 data. THI has not adjusted this class' load forecast for the 2009TY and will continue to monitor its year over year energy and demand levels.

THI's 2009TY throughput forecast for rate making purposes is provided in table 2 above.

Community or Economic Development Plan(s)

The County of Oxford's projections of number of new residences and employment growth in the Town of Tillsonburg for 2008-17 is provided at E3/T2/S2/AttF.

Introduction

Energyshop.com was engaged by 32 Local Distribution Companies (LDCs), across the province of Ontario, to design, deliver and track a fall coupon campaign with retailer Canadian Tire. Throughout the late summer and early fall billing periods, Tillsonburg Hydro Inc. (THI) provided their customers with a bill insert containing valuable energy-savings coupons to help them save on their electricity bill.

THI customers had until December 31, 2005 to redeem their point of purchase coupons at any local Canadian Tire outlet. Upon redemption, Canadian Tire sent the coupon to a redemption house, who then sorted by utility and product.

As part of this effort, SeeLine Group Inc. (SLG) was asked to undertake a Total Resource Costs (TRC) test assessment of the 2005 Lighten Your Electricity Bill Program as delivered by Energyshop.com. Using many of the technology cost and savings estimates outlined in the

Ontario Energy Board's TRC Guide, program results were screened using SLG's SeeToolTM TRC Calculator. The number of participant and program cost data provided by Energyshop.com.

THI also implemented a Smart Meter Pilot program in response to the Government of Ontario's initiative to install 800,000 smart electricity meters by December 31, 2007. The pilot program involved the installation of 384 smart meters in the fall of 2005.

This report includes a summary of assumptions and results from the TRC screening. Appendix A and B provides the detailed information on program assumptions.

Lessons Learned

We believe that the '2005 Lighten Your Electricity Bill' program was a huge success in Tillsonburg. Initially it was estimated that there would be a 3% response rate in the coupon program. Tillsonburg was amount the highest with a 17% response. In this respect, we have decided to participate in OPA's Education and Incentive Program for 2006.

Conclusion

Programs and incentives for power factor correction and energy audits are in place for 2006. With the installation of Smart Meters in late fall of 2005, we are only now receiving a web presentment for the customers in the pilot. An educational session will be held within the next 2 months.

Tillsonburg Hydro Inc.

Bryan Drinkwater
Operations Manager

Appendix A - Evaluation of the CDM Plan

	Total	Residential	Commercial	Institutional	Industrial	Agricultural	LDC System	Smart Meter Pilot	Other 2	Other 3	Other 4
Net TRC value ($):		$60,332									
Benefit to cost ratio:		6.72									
Number of participants or units delivered:		1184									
Total KWh to be saved over the lifecycle of the plan (kWh):		1,670,162									
Total in year kWh saved (kWh):		119,897									
Total peak demand saved (kW):		11.56									
Total kWh saved as a percentage of total kWh delivered (%):		0.05									
Peak kW saved as a percentage of LDC peak kW load (%):		0.03									
Gross in year C&DM expenditures ($):		$6,749									
Expenditures per KWh saved ($/kWh):*		$0.004									
*Expenditures per KW saved ($/kW)**:*		$584									

Utility discount rate (%):	7.63

*Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate energy savings.
**Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate capacity savings.

Appendix B - Discussion of the Program

(complete this section for each program)

A. **Name of the Program:** 2005 Lighten Your Electricity Bill

Description of the program (including intent, design, delivery, partnerships and evaluation):

In partnership with Energyshop.com and 32 LDCs , across Ontario, to design, deliver and track a fall coupon campaign with retailer Canadian Tire. The intent is to increase public awareness of energy conservation and demand management in Ontario and contribute to the overall development of an energy conservation culture in Ontario, as well, to help acheive energy conservation and demand management results for our 2005 program year.

Measure(s):

	Measure 1	Measure 2 (if applicable)	Measure 3 (if applicable)
Base case technology:	Incandescent lighting	Incandescent lighting	Non Programmable Thermostat
Efficient technology:	Compact Fluorescent Bulbs	LED Christmas Lighting	Programmable Thermostat
Number of participants or units delive	519	448	83
Measure life (years):	4	30	18

B. **TRC Results:**

TRC Benefits ($):	*$*	*70,883.00*
TRC Costs ($):		
Utility program cost (less incentives):	$	1,323.00
Participant cost:	$	9,228.00
Total TRC costs:	$	10,551.00
Net TRC (in year CDN $):	$	60,332.00
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	$	6.72

C. **Results:** (one or more category may apply)

Conservation Programs:

Demand savings (kW):	*Summer*	11.56	
	Winter	30.58	
		lifecycle	*in year*
Energy saved (kWh):		*1,670,162*	119,897
Other resources saved :			
Natural Gas (m3):			
Other (specify):			

Demand Management Programs:

Controlled load (kW)	
Energy shifted On-peak to Mid-peak (kWh):	
Energy shifted On-peak to Off-peak (kWh):	
Energy shifted Mid-peak to Off-peak (kWh):	

Demand Response Programs:

Dispatchable load (kW):	
Peak hours dispatched in year (hours):	

Power Factor Correction Programs:

Amount of KVar installed (KVar):	
Distribution system power factor at begining of year (%):	
Distribution system power factor at end of year (%):	

Line Loss Reduction Programs:

Peak load savings (kW):		
	lifecycle	*in year*
Energy savngs (kWh):		

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):	
Energy generated (kWh):	
Peak energy generated (kWh):	
Fuel type:	

Other Programs (specify):

Metric (specify):	

D. **Program Costs*:**

Utility direct costs ($):	*Incremental capital:*	$	-
	Incremental O&M:	$	1,322.46
	Incentive:	$	5,334.00
	Total:	$	6,656.46
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		
Participant costs ($):	*Incremental equipment:*	$	9,228.00
	Incremental O&M:		
	Total:	$	9,228.00

E. Comments:

SLG used many of the technology savings identified by the OEB in its Total Resource Guide. For those technologies without defined savings, every effort was made to develop reasonable assumptions, defensible under the OEB guidelines.

*Please refer to the TRC Guide for the treatment of equipment cost in the TRC Test.

2005 Lighten Your Electricity Bill program cont…

Measure(s):

	Measure 1	Measure 2
Base case technology:	No Timers	No Ceiling Fan
Efficient technology:	Indoor/Outdoor/AC Timers	Ceiling Fan
Number of participants or u	90	44
Measure life (years):	20	20

TILLSONBURG HYDRO INC.

RP-2004-0203\EB-2005-0192

2006 Annual Report CDM Third Tranche Funding

Content:

1. **Introduction**
2. **Evaluation of the CDM Plan**
3. **Discussions of Programs**
4. **Lessons Learned**
5. **Conclusion**

1. Introduction:

Because of the success with the 2005 fall coupon campaign, in 2006, Tillsonburg Hydro again participated in the spring and fall coupon program this time in partnership with the OPA. This along with the seasonal light exchange program helped to promote a conservation culture within its service area. Two other programs were also completed in the year as will be discussed.

2. Evaluation of our CDM Plan

Continuing with the delivery of our CDM Plan to the residential sector in 2006, Tillsonburg Hydro also implemented the System Optimization portion to not only reduce line losses to our system but also reduce a percentage of our overall peak load. Evaluation of the smart meter program is still on going.

3. Discussion of Programs

- **The spring and fall 'Every Kilowatt Counts' coupon program was again a great success in Tillsonburg. Tillsonburg Hydro participated in partnership with the OPA to deliver the word of conservation through coupon redemption of energy efficient technology.**

- **The Seasonal Light Exchange program was delivered because of the tremendous response to the coupon redemption in the EKC program. It involved bringing in an older incandescent string of lights and receiving a LED string right at the Tillsonburg Customer Service Center. Even though there was a short advertisement period of this program there were approximately 600 strings exchanged.**

- **Energy audit funds were not highly promoted this year, however, funds were made available to a company to conduct one. Substantial opportunities were found to exist in reducing the plants energy and utility costs. A follow-up has yet to be made in response to there recommendations.**

- **System Optimization was accomplished through the decommissioning of two old substations operating at 4,160 volts. This showed a direct reduction on the system peak with energy savings of approximately 570,000 kWh every year.**

4. Lessons Learned

The spring and fall EKC coupon program continues to be very successful in the Tillsonburg area and statistics resulting from it led us to believe the that our seasonal light exchange would also be a hit. As more and more people become attuned to this type of program, a conservation culture will continue to grow in the future.
Although efforts in programs such as coupon redemption and technology exchanges add significantly to conservation, distribution system optimization directly contributes to the reduction of system peaks and energy going forward.

5. Conclusion

It is Tillsonburg Hydro's intention to continue offering these successful programs through partnerships and customer education to help drive the Province's initiative to produce a culture of conservation.

Sincerely,

Bryan Drinkwater
Operations Manager
Tillsonburg Hydro Inc.

Appendix A - Evaluation of the CDM Plan

Highlighted boxes are to be completed manually, white boxes are linked to Appendix C and will be brought forward automatically.

	[5] Cumulative Totals Life-to-date	Total for 2006	Residential	Commercial	Institutional	Industrial	Agricultural	LDC System	[4] Smart Meters	Other #1	Other #2
Net TRC value ($):	*$ 431,919*	**$ 371,587**	**$ 451,194**	**$ -**	**$ -**	**$ (5,000)**	**$ -**	**$ (74,607)**		**$ -**	**$ -**
Benefit to cost ratio:	*3.99*	3.97	10.91	0.00	0.00	0.00	0.00	0.00		0.00	0.00
Number of participants or units delivered:	*19,441*	*18,257*	18,255			1		1			
Lifecycle (kWh) Savings:	*27,185,579*	25,515,417	8,328,297	0	0	0	0	17,187,120		0	0
Report Year Total kWh saved (kWh):	*1,911,616*	1,791,719	1,218,815	0	0	0	0	572,904		0	0
Total peak demand saved (kW):	*636.72*	313	255	0	0	0	0	57		0	0
Total kWh saved as a percentage of total kWh delivered (%):	*0.41%*	0.71%	2.02%	0.00%	0.00%	0.00%	0.00%	0.25%			
Peak kW saved as a percentage of LDC peak kW load (%):		0.08%	0.07%	0.00%	0.00%	0.00%	0.00%	0.02%			
[1] *Report Year Gross C&DM expenditures ($):*	*$ 157,598*	$ 150,849	$ 11,129	$ -	$ -	$ 5,000	$ -	$ 74,607	$ 60,113	$ -	$ -
[2] *Expenditures per KWh saved ($/kWh):*	$ 0.01	$ 0.01	$ 0.00	$ -	$ -	$ -	$ -	$ 0.00		$ -	$ -
[3] *Expenditures per KW saved ($/kW):*	$ 247.51	$ 482.59	$ 43.59	$ -	$ -	$ -	$ -	$ 1,302.04		$ -	$ -

Utility discount rate (%):	7.63

[1] Expenditures are reported on accrual basis.
[2] Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate energy savings
[3] Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate capacity savings.
[4] Please report spending related to 3rd tranche of MARR funding only. TRC calculations are not required for Smart Meters. Only actual expenditures for the year need to be reported.
[5] Includes total for the reporting year, plus prior year, if any (for example, 2006 CDM Annual report for third tranche will include 2005 and 2004 numbers, if any.

Appendix B - Discussion of the Program

(complete this Appendix for each program)

A. **Name of the Program:** Seasonal Light Exchange

Description of the program (including intent, design, delivery, partnerships and evaluation):

An event which handed out 612 Seasonal LED Light strings, to Tillsonburg residents, in a one for one exchange to retire older technology. This translates to an annual savings of 16,937 kWh. The program showed a lot of interest and it is likely we'll run it again in 2007.

Measure(s):

	Measure 1	Measure 2 (if applicable)	Measure 3 (if applicable)
Base case technology:	Incandescent lighting		
Efficient technology:	LED Christmas Lighting		
Number of participants or units delivered for reporting year:	612		
Measure life (years):	30		
Number of Participants or units delivered life to date	612		

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	*$ 30,663.00*	30663
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	*$ 11,128.75*	11128.75
Incremental Measure Costs (Equipment Costs)		
Total TRC costs:	$ 11,128.75	11128.75
Net TRC (in year CDN $):	$ 19,534.25	$ 19,534.25
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	$ 2.76	2.76

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*	0		
	Winter	7.56		

	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	*508113*	16937	508113	
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

	lifecycle	in year	
Peak load savings (kW):			
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		
	Incremental O&M:	$ 11,128.75	
	Incentive:		
	Total:	$ 11,128.75	
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

(complete this Appendix for each program)

A. **Name of the Program:** 2006 Spring EKC coupon program

Description of the program (including intent, design, delivery, partnerships and evaluation):

To provide customer incentives for energy efficient technologies. This program was in partnership with the OPA.

Measure(s):

	Measure 1	Measure 2	Measure 3	Measure 4
Base case technology:				
Efficient technology:	CFLs	Timers	Programmable Thermostats	Fans
Number of participants or units delivered for reporting year:	1556	57	18	28
Measure life (years):	4	20	18	20
Number of Participants or units delivered life to date				

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	$ 48,104.00	0
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ -	0
Incremental Measure Costs (Equipment Costs)	$ 5,475.00	
Total TRC costs:	$ 5,475.00	0
Net TRC (in year CDN $):	$ 42,629.00	$ -
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	$ 8.79	#DIV/0!

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*	1.17		
	Winter	0		

	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	*904536*	162151	0	
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):		
	lifecycle	*in year*
Energy savings (kWh):		

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		
	Incremental O&M:	$ -	
	Incentive:		
	Total:	$ -	
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit b

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made

Appendix B - Discussion of the Program

(complete this Appendix for each program)

A. **Name of the Program:** 2006 Fall EKC coupon program

Description of the program (including intent, design, delivery, partnerships and evaluation):

To provide customer incentives for energy efficient technologies. This program was in partnership with the OPA.

Measure(s):

	Measure 1	Measure 2	Measure 3	Measure 4	Measure 5	Measure 6
Base case technology:	Incandescent	5w Incandescent	Incandescent Mini Lights			
Efficient technology:	CFLs	LED Christmas Lights	LED Christmas Lights	pStats	Dimmers	Motion Sensor
Number of participants or units delivered for reporting year:	9724	1521	1521	77	21	8
Measure life (years):	4	30	30	18	10	20
Number of Participants or units delivered life to date	9724	1521	1521	77	21	88

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	$ 417,935.00	0
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ -	0
Incremental Measure Costs (Equipment Costs)	$ 26,104.00	
Total TRC costs:	$ 26,104.00	0
Net TRC (in year CDN $):	$ 391,831.00	$ -
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	$ 16.01	#DIV/0!

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*	7.92		
	Winter	246.55		

	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	6915648	1039727	6915648	1039727
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):		
	lifecycle	*in year*
Energy savings (kWh):		

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D.	**Actual Program Costs:**		**Reporting Year**	**Cumulative Life to Date**
	Utility direct costs ($):	*Incremental capital:*		
		Incremental O&M:	$ -	
		Incentive:		
		Total:	$ -	
	Utility indirect costs ($):	*Incremental capital:*		
		Incremental O&M:		
		Total:		

E. Assumptions & Comments:

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit b

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made

Appendix B - Discussion of the Program

(complete this Appendix for each program)

A. **Name of the Program:** System Opimization

Description of the program (including intent, design, delivery, partnerships and evaluation):

· System Optimization was accomplished through the decommissioning of two old substations operating at 4,160 volts. This showed a direct reduction on the system peak with energy savings of approximately 570,000 kWh every year.

Measure(s):

	Measure 1	Measure 2 (if applicable)	Measure 3 (if applicable)
Base case technology:			
Efficient technology:	Removal of substation		
Number of participants or units delivered for reporting year:	2		
Measure life (years):	30		
Number of Participants or units delivered life to date			

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	$ -	0
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ 74,606.83	0
Incremental Measure Costs (Equipment Costs)		
Total TRC costs:	$ 74,606.83	0
Net TRC (in year CDN $):	-$ 74,606.83	$ -
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	$ -	#DIV/0!

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*	0	
	Winter	0	

	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	*0*	0	0	
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):		57.3	
	lifecycle	*in year*	
Energy savings (kWh):	17,187,120	572,904	

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		
	Incremental O&M:	$ 74,606.83	$ 74,606.83
	Incentive:		
	Total:	$ 74,606.83	$ 74,606.83
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit b

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made

Appendix B - Discussion of the Program

(complete this Appendix for each program)

A. **Name of the Program:** Smart Meter Initiatives

Description of the program (including intent, design, delivery, partnerships and evaluation):

Smart Meter pilot program to monitor and access technology available.

Measure(s):

	Measure 1	Measure 2 (if applicable)	Measure 3 (if applicable)
Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:	1		
Measure life (years):			
Number of Participants or units delivered life to date	1		

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	$ -	0
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ 60,112.95	60112.95
Incremental Measure Costs (Equipment Costs)		
Total TRC costs:	$ 60,112.95	60112.95
Net TRC (in year CDN $):	-$ 60,112.95	-$ 60,112.95
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	$ -	0.00

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*	0	
	Winter	0	

	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	*0*	0	0	
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

	lifecycle	in year	
Peak load savings (kW):			
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*	$ 54,693.95	$ 54,693.95
	Incremental O&M:	$ 5,418.99	$ 5,418.99
	Incentive:		
	Total:	$ 60,112.94	$ 60,112.94
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit b

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made

Appendix B - Discussion of the Program

(complete this Appendix for each program)

A. **Name of the Program:** Energy Audit Program

Description of the program (including intent, design, delivery, partnerships and evaluation):

· Energy audit funds were not highly promoted this year, however, funds were made available to a company to conduct one. Substantial opportunities were found to exist in reducing the plants energy and utility costs. A follow-up has yet to be made in response to there recommendations.

Measure(s):

	Measure 1	Measure 2 (if applicable)	Measure 3 (if applicable)
Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:	1		
Measure life (years):			
Number of Participants or units delivered life to date	1		

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	$ -	0
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ 5,000.00	0
Incremental Measure Costs (Equipment Costs)		
Total TRC costs:	$ 5,000.00	0
Net TRC (in year CDN $):	-$ 5,000.00	$ -
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	$ -	#DIV/0!

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*	0	
	Winter	0	

	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	*0*	0	0	
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

	lifecycle	in year	
Peak load savings (kW):			
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*	$ -	$ -
	Incremental O&M:	$ 5,000.00	$ 5,000.00
	Incentive:		
	Total:	$ 5,000.00	$ 5,000.00
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

Customer to provide follow-up of any implementations to recommendations.

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit b

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made

Appendix C - Program and Portfolio Totals

Report Year: 2006

1. Residential Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Seasonal Light Exchange	$ 30,663	$ 11,129	$ 19,534	2.76	16,937	508,113	8	$ 11,129
2006 Spring EKC Coupon	$ 48,104	$ 5,475	$ 42,629	8.79	162,151	904,536	1	$ -
2006 Fall EKC Coupon	$ 417,935	$ 28,904	$ 389,031	14.46	1,039,727	6,915,648	247	$ -
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Residential**	$ 496,702	$ 45,508	$ 451,194	10.91	1,218,815	8,328,297	255	$ 11,129
Residential Indirect Costs not attributable to any specific program →								
Total Residential TRC Costs		$ 45,508						
****Totals TRC - Residential**	**$ 496,702**	**$ 45,508**	**$ 451,194**	**10.91**				

2. Commercial Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Name of Program A			$ -	0.00				
Name of Program B			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Commercial**	$ -	$ -	$ -	0.00	0	0	0	$ -

Commercial Indirect Costs not attributable to any specific program →				
Total TRC Costs		$ -		
****Totals TRC - Commercial**	**$ -**	**$ -**	**$ -**	**0.00**

3. Institutional Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Name of Program A			$ -	0.00				
Name of Program B			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Institutional**	$ -	$ -	$ -	0.00	0	0	0	$ -
Institutional Indirect Costs not attributable to any specific program →								
Total TRC Costs		$ -						
****Totals TRC - Institutional**	**$ -**	**$ -**	**$ -**	**0.00**				

4. Industrial Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Energy Audit		$ 5,000	-$ 5,000	0.00				$ 5,000
Name of Program C			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				

Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Industrial**	$ -	$ 5,000	-$ 5,000	0.00	0	0	0	$ 5,000
Industrial Indirect Costs not attributable to any specific program	→							
Total TRC Costs		$ 5,000						
****Totals TRC - Industrial**	**$ -**	**$ 5,000**	**-$ 5,000**	**0.00**				

5. Agricultural Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Name of Program A			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Agricultural**	$ -	$ -	$ -	0.00	0	0	0	$ -
Agricultural Indirect Costs not attributable to any specific program	→							
Total TRC Costs		$ -						
****Totals TRC - Agricultural**	**$ -**	**$ -**	**$ -**	**0.00**				

6. LDC System Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
System Optimization		$ 74,607	-$ 74,607	0.00	572,904	17,187,120	57	$ 74,607
Name of Program B			$ -	0.00				

Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program C			$ -	0.00				
***Totals App. B - LDC System**	$ -	$ 74,607	-$ 74,607	0.00	572,904	17,187,120	57	$ 74,607
LDC System Indirect Costs not attributable to any specific program →								
Total TRC Costs		$ 74,607						
****Totals TRC - LDC System**	**$ -**	**$ 74,607**	**-$ 74,607**	**0.00**				

7. Smart Meters Program

Only spending information that was authorized under the 3rd tranche of MARR is required to be reported for Smart Meters.

Report Year Gross C&DM Expenditures ($) →	60,113

8. Other #1 Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Name of Program A			$ -	0.00				
Name of Program B			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Other #1**	$ -	$ -	$ -	0.00	0	0	0	$ -
Other #1 Indirect Costs not attributable to any specific program →								
Total TRC Costs		$ -						
****Totals TRC - Other #1**	**$ -**	**$ -**	**$ -**	**0.00**				

9. Other #2 Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Name of Program A			$ -	0.00				
Name of Program B			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Other #2**	$ -	$ -	$ -	0.00	0	0	0	$ -
Other #2 Indirect Costs not attributable to any specific program →								
Total TRC Costs		$ -						
****Totals TRC - Other #2**	**$ -**	**$ -**	**$ -**	**0.00**				

LDC's CDM PORTFOLIO TOTALS

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
***TOTALS FOR ALL APPENDIX B**	$ 496,702	$ 125,115	$ 371,587	3.97	$ 1,791,719	$ 25,515,417	$ 313	$ 150,849
*Any **other** Indirect Costs not attributable to any specific program* →								
TOTAL ALL LDC COSTS		$ 125,115						
****LDC' PORTFOLIO TRC**	$ 496,702	$ 125,115	$ 371,587	3.97				

* The savings and spending information from this row is to be carried forward to Appendix A.

** The TRC information from this row is to be carried forward to Appendix A.

TILLSONBURG HYDRO INC.

RP-2004-0203\EB-2005-0192

2007 Annual Report CDM Third Tranche Funding

Content:

1. **Introduction**
2. **Evaluation of the CDM Plan**
3. **Discussions of Programs**
4. **Lessons Learned**
5. **Conclusion**

1. Introduction:

Tillsonburg Hydro Inc. is pleased to submit this third annual CDM report. Tillsonburg Hydro's Conservation and Demand Management programs and spending in 2007 all relate to the "third traunche" programs as were approved by the OEB in March of 2005. The approved total budget of $247,903 is represented in these programs. The total amount of actual spending in 2007 was $85,220 bringing the total life to date spending to $247,903. All third traunche spending was completed in 2007.

2. Evaluation of our CDM Plan

Continuing with the delivery of our CDM Plan to the residential sector in 2007 involving partnerships with the OPA , Tillsonburg Hydro also implemented the System Optimization portion to not only reduce line losses to our system but also reduce a percentage of our overall peak load.

3. Discussion of Programs

- **System Optimization was accomplished through the decommissioning of two old substations operating at 4,160 volts. This showed a direct reduction on the system peak with energy savings of approximately 570,000 kWh every year.**

- **Funding for a residential solar energy system was provided to a contractor to promote the awareness of green energy with the idea to lessen Tillsonburg Hydro's demand growth going forward.**

4. Lessons Learned

Conservation continues to grow in the Tillsonburg area as seen through the partnership programs Tillsonburg Hydro incorporated again this year.

Although efforts in programs such as the Summer Savings program, The Great Refrigerator Roundup and ERIP add significantly to conservation, distribution system optimization directly contributes to the reduction of system peaks and energy going forward. This can be seen in Tillsonburg Hydro's continued reduction in line losses.

5. Conclusion

It is Tillsonburg Hydro's intention to continue offering these successful programs through partnerships and customer education to help drive the Province's initiative to produce a culture of conservation. Also through our programs we have reinforced the efficiency of our system. Spending of $85,220 in 2007 and life to date spending of $247,902 represents 100% of our CDM amount.

Sincerely,

Bryan Drinkwater
Operations Manager
Tillsonburg Hydro Inc.

Appendix A - Evaluation of the CDM Plan

Highlighted boxes are to be completed manually, white boxes are linked to Appendix C and will be brought forward automatically.

	[5] Cumulative Totals Life-to-date	Total for 2007	Residential	Commercial	Institutional	Industrial	Agricultural	LDC System	[4] Smart Meters	Other #1	Other #2
Net TRC value ($):	*$ 348,594*	**-$ 83,325**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (78,762)**		**$ (4,562)**	**$ -**
Benefit to cost ratio:		0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00
Number of participants or units delivered:	*19,441*										
Lifecycle (kWh) Savings:	*44,372,699*	17,187,120	0	0	0	0	0	17,187,120		0	0
Report Year Total kWh saved (kWh):	*2,484,520*	572,904	0	0	0	0	0	572,904		0	0
Total peak demand saved (kW):	*694.02*	57	0	0	0	0	0	57		0	0
Total kWh saved as a percentage of total kWh delivered (%):	*1.04%*	0.24%	0.00%	0.00%	0.00%	0.00%	0.00%	0.24%		0.00%	0.00%
Peak kW saved as a percentage of LDC peak kW load (%):		0.12%	0.00%	0.00%	0.00%	0.00%	0.00%	0.12%		0.00%	0.00%
[1] *Report Year Gross C&DM expenditures ($):*	*$ 247,902*	$ 85,220	$ -	$ -	$ -	$ -	$ -	$ 78,762	$ 1,895	$ 4,562	$ -
[2] *Expenditures per KWh saved ($/kWh):*	$ 0.01	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ 0.00		$ -	$ -
[3] *Expenditures per KW saved ($/kW):*	$ 357.20	$ 1,487.25	$ -	$ -	$ -	$ -	$ -	$ 1,374.56		$ -	$ -

Utility discount rate (%):	7.63

[1] Expenditures are reported on accrual basis.
[2] Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate energy savings.
[3] Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate capacity savings.
[4] Please report spending related to 3rd tranche of MARR funding only. TRC calculations are not required for Smart Meters. Only actual expenditures for the year need to be reported.
[5] Includes total for the reporting year, plus prior year, if any (for example, 2007 CDM Annual report for third tranche will include 2006, 2005 and 2004 numbers, if any.

Appendix B - Discussion of the Program

(complete this Appendix for each program)

A. **Name of the Program:** Smart Meter Initiatives

Description of the program (including intent, design, delivery, partnerships and evaluation):

Measure(s):

	Measure 1	Measure 2 (if applicable)	Measure 3 (if applicable)
Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:			
Measure life (years):			
Number of Participants or units delivered life to date			

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*		
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ 1,895.47	64,440.43
Incremental Measure Costs (Equipment Costs)		
Total TRC costs:	$ 1,895.47	64,440.43
Net TRC (in year CDN $):		
Benefit to Cost Ratio (TRC Benefits/TRC Costs):		

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*		
	Winter		

	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):				
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

	lifecycle	in year	
Peak load savings (kW):			
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*	$ 1,895.47	$ 64,440.43
	Incremental O&M:		
	Incentive:		
	Total:	$ 1,895.47	$ 64,440.43
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

(complete this Appendix for each program)

A. **Name of the Program:** System Opimization

Description of the program (including intent, design, delivery, partnerships and evaluation):

· System Optimization was accomplished through the decommissioning of two old substations operating at 4,160 volts. This showed a direct reduction on the system peak with energy savings of approximately 570,000 kWh every year.

Measure(s):

	Measure 1	Measure 2 (if applicable)	Measure 3 (if applicable)
Base case technology:			
Efficient technology:	Removal of substation		
Number of participants or units delivered for reporting year:	2		
Measure life (years):	30		
Number of Participants or units delivered life to date			

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	$ -	0
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ 78,762.17	153,369
Incremental Measure Costs (Equipment Costs)		
Total TRC costs:	$ 78,762.17	153,369
Net TRC (in year CDN $):	-$ 78,762.17	-$ 153,369.00
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	$ -	0.00

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*	0		
	Winter	0		
	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	*0*	0	0	
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):		57.3	
	lifecycle	*in year*	
Energy savings (kWh):	17,187,120	572,904	

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		
	Incremental O&M:	$ 78,762.17	$ 153,369.00
	Incentive:		
	Total:	$ 78,762.17	$ 153,369.00
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit b

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made

Appendix B - Discussion of the Program

(complete this Appendix for each program)

A. **Name of the Program:** Solar Energy System

Description of the program (including intent, design, delivery, partnerships and evaluation):

Funding provided for a residential solar project. Mainly to provide an awareness to alternate energy.

Measure(s):

	Measure 1	Measure 2 (if applicable)	Measure 3 (if applicable)
Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:	1		
Measure life (years):	25		
Number of Participants or units delivered life to date			

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	$ -	0
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ -	0
Incremental Measure Costs (Equipment Costs)	$ 4,562.36	4562.36
Total TRC costs:	$ 4,562.36	4,562
Net TRC (in year CDN $):	-$ 4,562.36	-$ 4,562.36
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	$ -	0.00

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*	0			
	Winter	0			
	lifecycle		*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	*0*		0	0	
Other resources saved :					
Natural Gas (m3):					
Other (specify):					

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

	lifecycle	in year	
Peak load savings (kW):			
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Incentive:	$ 4,562.36	$ 4,562.36
	Total:	$ 4,562.36	$ 4,562.36
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit b

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made

Appendix C - Program and Portfolio Totals

Report Year: 2007

1. Residential Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Name of Program A			$ -	0.00				
Name of Program B			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Residential**	$ -	$ -	$ -	0.00	0	0	0	$ -
Residential Indirect Costs not attributable to any specific program →								
Total Residential TRC Costs		$ -						
****Totals TRC - Residential**	**$ -**	**$ -**	**$ -**	**0.00**				

2. Commercial Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Name of Program A			$ -	0.00				
Name of Program B			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Commercial**	$ -	$ -	$ -	0.00	0	0	0	$ -

Commercial Indirect Costs not attributable to any specific program →				
Total TRC Costs		$ -		
****Totals TRC - Commercial**	**$ -**	**$ -**	**$ -**	**0.00**

3. Institutional Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Name of Program A			$ -	0.00				
Name of Program B			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Institutional**	$ -	$ -	$ -	0.00	0	0	0	$ -
Institutional Indirect Costs not attributable to any specific program →								
Total TRC Costs		$ -						
****Totals TRC - Institutional**	**$ -**	**$ -**	**$ -**	**0.00**				

4. Industrial Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Name of Program A			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				

Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Industrial**	$ -	$ -	$ -	0.00	0	0	0	$ -
Industrial Indirect Costs not attributable to any specific program	→							
Total TRC Costs		$ -						
****Totals TRC - Industrial**	**$ -**	**$ -**	**$ -**	**0.00**				

5. Agricultural Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Name of Program A			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Agricultural**	$ -	$ -	$ -	0.00	0	0	0	$ -
Agricultural Indirect Costs not attributable to any specific program	→							
Total TRC Costs		$ -						
****Totals TRC - Agricultural**	**$ -**	**$ -**	**$ -**	**0.00**				

6. LDC System Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
System Optimization		$ 78,762	-$ 78,762	0.00	572,904	17,187,120	57	$ 78,762
Name of Program B			$ -	0.00				

Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program C			$ -	0.00				
***Totals App. B - LDC System**	$ -	$ 78,762	-$ 78,762	0.00	572,904	17,187,120	57	$ 78,762
LDC System Indirect Costs not attributable to any specific program →								
Total TRC Costs		$ 78,762						
****Totals TRC - LDC System**	**$ -**	**$ 78,762**	**-$ 78,762**	**0.00**				

7. Smart Meters Program

Only spending information that was authorized under the 3rd tranche of MARR is required to be reported for Smart Meters.

Report Year Gross C&DM Expenditures ($) →	1,895

8. Other #1 Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Solar Energy System		$ 4,562	-$ 4,562	0.00				$ 4,562
Name of Program B			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Other #1**	$ -	$ 4,562	-$ 4,562	0.00	0	0	0	$ 4,562
Other #1 Indirect Costs not attributable to any specific program →								
Total TRC Costs		$ 4,562						
****Totals TRC - Other #1**	**$ -**	**$ 4,562**	**-$ 4,562**	**0.00**				

9. Other #2 Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Name of Prigram A			$ -	0.00				
Name of Program B			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Other #2**	$ -	$ -	$ -	0.00	0	0	0	$ -
Other #2 Indirect Costs not attributable to any specific program →								
Total TRC Costs		$ -						
****Totals TRC - Other #2**	**$ -**	**$ -**	**$ -**	**0.00**				

LDC's CDM PORTFOLIO TOTALS

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
***TOTALS FOR ALL APPENDIX B**	$ -	$ 83,325	-$ 83,325	0.00	$ 572,904	$ 17,187,120	$ 57	$ 85,220
*Any **other** Indirect Costs not attributable to any specific program* →								
TOTAL ALL LDC COSTS		$ 83,325						
****LDC' PORTFOLIO TRC**	$ -	$ 83,325	-$ 83,325	0.00				

* The savings and spending information from this row is to be carried forward to Appendix A.

** The TRC information from this row is to be carried forward to Appendix A.

IPSP REFERENCE FORECAST - ASSUMPTIONS AND RESULTS

1.0 FORECAST DETAILS

1.1 Annual tables

Annual values for the period 2007 to 2027 are presented in Tables 1 through 13.

Section 2.0 provides information at the provincial level and includes the IPSP reference forecast, the extreme weather scenario, the high and low scenarios as well as the natural conservation numbers imbedded in the reference forecast.

Section 3.0 provides sectoral and end-use detail.

Section 4.0 provides results on a regional basis.

1.2 Regional and scenario assumptions

Additionally, section 5.0 provides details regarding the mapping of Census Divisions onto the IESO electrical zones.

Section 0 provides the critical driver assumptions for the low and high scenarios.

2.0 PROVINCIAL FORECASTS

Table 1: IPSP Reference Peak (MW) and Energy (TWh) Forecasts

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Peak (MW)	26282	26515	26749	26986	27205	27426	27648	27873	28099	28457	28820
Energy (TWh)	157	158	159	159	161	162	163	164	165	168	169

	2020	2021	2022	2023	2024	2025	2026	2027
Peak (MW)	29936	30444	30960	31485	32020	32563	33115	33677
Energy (TWh)	176	178	181	184	187	189	192	195

Source: OPA Forecast is at the generator and is weather normal.

Assumes the base year is 2005 (25823 MW, 155 TWh).

Table 2: IPSP Extreme Weather Peak Forecast (MW)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Peak (MW)	28012	28236	28459	28692	28902	29114	29329	29545	29760	30122	30485	30853	31226

	2020	2021	2022	2023	2024	2025	2026	2027
Peak (MW)	31604	32120	32646	33181	33725	34278	34837	35413

Source: OPA

Forecast is at the generator and is weather normal.

Table 3: IPSP Forecast Growth Scenarios – "Low"

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Peak (MW)	26153	26320	26488	26656	26701	26746	26791	26836	26881	27003	27127	27251	27375
Energy (TWh)	156	157	157	158	158	159	158	158	159	160	160	161	161

	2020	2021	2022	2023	2024	2025	2026	2027
Peak (MW)	27500	27718	27938	28159	28382	28607	28834	29062
Energy (TWh)	162	163	164	165	167	167	168	170

Source: OPA

Table 4: IPSP Forecast Growth Scenarios – "High"

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Peak (MW)	26376	26657	26941	27228	27585	27946	28312	28683	29059	29625	30201	30789	31389
Energy (TWh)	157	159	160	161	163	165	166	168	170	174	177	180	183

	2020	2021	2022	2023	2024	2025	2026	2027
Peak (MW)	32000	32815	33651	34508	35388	36289	37214	38162
Energy (TWh)	187	191	196	200	206	210	215	221

Source: OPA

Table 5: Natural Efficiency Incorporated in the Reference Forecast - Based from 2004

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Peak (MW)	-	113	354	600	853	1113	1379	1537	1714	1911	2130	2375	2439	2504	2572
Energy (TWh)	-	1	2	4	5	7	8	9	10	11	12	14	14	15	15

	2019	2020	2021	2022	2023	2024	2025	2026	2027
Peak (MW)	2641	2711	2768	2825	2884	2944	3005	3067	3131
Energy (TWh)	15	16	16	16	17	17	17	18	18

Source: M.K. Jaccard and Associates

Note that natural conservation is calculated based on a specified year. In this case it is with respect to the base year underlying the CDM directives.

3.0 IPSP REFERENCE FORECAST – END USE AND SECTORAL DETAIL

Table 6: IPSP Reference Forecast by end use – Coincident Peak Demand (MW): Residential

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Residential	**7875**	**8056**	**8242**	**8430**	**8462**	**8493**	**8525**	**8557**	**8588**	**8654**	**8720**
Space Heating SFD	0	0	0	0	0	0	0	0	0	0	0
Space Heating AP/AT	0	0	0	0	0	0	0	0	0	0	0
Room AC	424	428	430	433	436	438	440	442	444	451	457
Central AC	4033	4163	4296	4432	4444	4454	4462	4469	4474	4502	4531
Furnace Fan	731	729	726	723	720	717	713	710	706	702	698
Lighting	236	236	236	237	238	240	241	242	244	250	256
Refrigeration	353	346	339	332	325	318	311	304	297	290	282
Freezer	173	172	171	170	169	168	168	167	166	165	164
Water Heating	430	429	427	426	404	382	362	342	324	325	327
Dish Washer	37	39	41	43	45	47	50	52	54	56	58
Clothes Washer / Dryer	403	413	423	433	435	437	438	439	440	443	445
Miscellaneous	1056	1103	1151	1201	1246	1293	1340	1389	1439	1471	1502

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Residential	**8786**	**8853**	**8921**	**9048**	**9178**	**9309**	**9442**	**9577**	**9714**	**9853**
Space Heating SFD	0	0	0	0	0	0	0	0	0	0
Space Heating AP/AT	0	0	0	0	0	0	0	0	0	0
Room AC	463	470	476	483	489	496	503	510	517	524
Central AC	4559	4586	4614	4678	4743	4808	4875	4942	5010	5079
Furnace Fan	695	691	687	696	705	714	723	732	741	750
Lighting	262	268	275	281	287	294	300	307	313	320
Refrigeration	275	268	262	263	265	267	269	271	273	275
Freezer	163	162	161	160	159	158	157	157	156	155
Water Heating	328	329	331	334	337	341	344	348	351	355
Dish Washer	60	62	64	66	68	70	71	73	75	77
Clothes Washer / Dryer	447	449	450	455	459	464	468	473	477	482
Miscellaneous	1535	1568	1601	1633	1665	1698	1732	1766	1801	1836

Source: OPA

Forecast is at the generator and is weather normal.

Table 7: IPSP Reference Forecast by end use – Coincident Peak Demand (MW): Commercial/Institutional

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Commercial/Institutional	**12232**	**12285**	**12336**	**12387**	**12515**	**12643**	**12773**	**12905**	**13037**	**13225**	**13416**
Space Heating	34	36	38	40	42	44	46	48	51	53	55
Space Cooling	6799	6798	6797	6795	6855	6916	6977	7038	7100	7192	7285
Ventilation	880	883	885	888	898	908	918	929	939	954	969
Lighting	2893	2925	2958	2990	3027	3064	3101	3139	3177	3216	3255
Electric Auxiliary	1513	1531	1548	1566	1586	1607	1628	1649	1670	1706	1744
Water Heating	114	112	110	108	106	105	103	102	100	104	107

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Commercial/Institutional	**13609**	**13805**	**14003**	**14234**	**14469**	**14707**	**14950**	**15196**	**15446**	**15700**
Space Heating	58	60	63	65	67	70	73	75	78	81
Space Cooling	7380	7475	7571	7689	7808	7929	8052	8176	8301	8429
Ventilation	984	1000	1015	1034	1054	1073	1093	1113	1134	1154
Lighting	3295	3335	3376	3415	3454	3494	3535	3575	3616	3657
Electric Auxiliary	1781	1820	1859	1907	1956	2006	2057	2109	2163	2217
Water Heating	111	115	119	124	130	135	141	148	154	161

Source: OPA

Forecast is at the generator and is weather normal.

Table 8: IPSP Reference Forecast by end use – Coincident Peak Demand (MW): Industrial

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Industrial	**6175**	**6173**	**6171**	**6169**	**6228**	**6289**	**6350**	**6412**	**6474**	**6578**	**6684**
Process Machine Drive	3593	3606	3619	3631	3665	3699	3733	3768	3803	3859	3915
Electrochemical Processes	257	260	262	265	267	269	271	273	275	276	278
Steam Production	0	0	0	0	0	0	0	0	0	0	0
Heat Production	1190	1168	1147	1126	1134	1141	1149	1157	1165	1191	1217
HVAC	669	673	676	679	690	702	714	726	739	755	771
Lighting	466	467	468	468	473	478	482	487	492	498	503

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Industrial	**6792**	**6901**	**7012**	**7161**	**7313**	**7469**	**7627**	**7789**	**7955**	**8124**
Process Machine Drive	3972	4030	4089	4150	4211	4273	4336	4398	4460	4523
Electrochemical Processes	279	281	282	284	286	287	289	291	292	294
Steam Production	0	0	0	0	0	0	0	0	0	0
Heat Production	1244	1271	1299	1358	1420	1485	1553	1623	1696	1772
HVAC	787	804	821	840	859	879	898	918	939	960
Lighting	509	515	521	529	537	544	552	560	567	575

Source: OPA

Forecast is at the generator and is weather normal.

Table 9: IPSP Reference Forecast by end use – Energy Demand (TWh): Residential

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Residential	**52**	**53**	**53**	**54**	**54**	**54**	**54**	**55**	**55**	**56**	**56**
Space Heating SFD	4.1	4.1	4.1	4.0	4.0	4.0	3.9	3.9	3.9	3.9	3.8
Space Heating AP/AT	5.0	4.9	4.9	4.9	4.9	4.9	4.8	4.8	4.8	4.8	4.8
Room AC	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Central AC	3.1	3.2	3.3	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.5
Furnace Fan	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.1
Lighting	9.0	9.0	9.0	9.0	9.1	9.1	9.1	9.2	9.2	9.4	9.6
Refrigeration	3.9	3.8	3.8	3.7	3.7	3.6	3.5	3.5	3.4	3.4	3.3
Freezer	1.7	1.7	1.7	1.7	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Water Heating	6.0	6.0	6.0	6.0	5.7	5.5	5.3	5.1	4.9	4.9	4.9
Dish Washer	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.8	0.8	0.8
Clothes Washer / Dryer	4.0	4.1	4.1	4.2	4.2	4.3	4.3	4.3	4.3	4.3	4.3
Miscellaneous	13.5	14.0	14.4	14.8	15.3	15.8	16.2	16.6	17.1	17.5	17.7

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Residential	**56**	**57**	**57**	**58**	**59**	**59**	**60**	**61**	**61**	**62**
Space Heating SFD	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Space Heating AP/AT	4.8	4.8	4.8	4.8	4.8	4.8	4.9	4.9	4.9	4.9
Room AC	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Central AC	3.5	3.5	3.5	3.5	3.6	3.6	3.7	3.7	3.8	3.8
Furnace Fan	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2
Lighting	9.7	9.9	10.1	10.2	10.4	10.6	10.8	11.0	11.1	11.3
Refrigeration	3.3	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.3
Freezer	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.5	1.5
Water Heating	5.0	5.0	5.0	5.0	5.0	5.1	5.1	5.2	5.2	5.2
Dish Washer	0.8	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0
Clothes Washer / Dryer	4.3	4.3	4.4	4.4	4.4	4.5	4.5	4.5	4.5	4.6
Miscellaneous	18.0	18.3	18.7	19.0	19.3	19.6	20.0	20.2	20.5	20.9

Source: OPA

Forecast is at the generator and is weather normal.

Table 10: IPSP Reference Forecast by end use – Energy Demand (TWh): Commercial/Institutional

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Commercial/Institutional	**56**	**57**	**57**	**57**	**58**	**59**	**59**	**60**	**60**	**61**	**62**
Space Heating	4.3	4.4	4.5	4.5	4.6	4.8	4.9	5.0	5.1	5.3	5.4
Space Cooling	6.5	6.5	6.5	6.5	6.5	6.6	6.6	6.6	6.7	6.7	6.8
Ventilation	9.5	9.5	9.5	9.5	9.6	9.7	9.8	9.9	10.0	10.1	10.2
Lighting	22.5	22.8	22.9	23.1	23.3	23.6	23.8	24.0	24.2	24.5	24.7
Electric Auxiliary	12.3	12.4	12.5	12.6	12.7	12.9	13.0	13.1	13.3	13.5	13.7
Water Heating	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Commercial/Institutional	**63**	**64**	**65**	**66**	**67**	**68**	**69**	**70**	**71**	**73**
Space Heating	5.6	5.8	6.0	6.3	6.6	6.9	7.2	7.5	7.9	8.3
Space Cooling	6.8	6.9	7.0	7.0	7.1	7.2	7.3	7.4	7.5	7.6
Ventilation	10.4	10.5	10.6	10.8	10.9	11.1	11.3	11.4	11.6	11.7
Lighting	24.9	25.1	25.5	25.6	25.9	26.1	26.4	26.6	26.8	27.0
Electric Auxiliary	13.9	14.2	14.5	14.7	15.0	15.3	15.7	15.9	16.3	16.6
Water Heating	1.1	1.2	1.2	1.2	1.3	1.3	1.4	1.4	1.5	1.5

Source: OPA

Forecast is at the generator and is weather normal.

Table 11: IPSP Reference Forecast by end use – Energy Demand (TWh): Industrial

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Industrial	**48**	**48**	**48**	**48**	**49**	**49**	**49**	**50**	**50**	**51**	**51**
Process Machine Drive	30.8	31.0	31.0	31.1	31.3	31.7	31.8	32.1	32.3	32.8	33.1
Electrochemical Processes	2.3	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5
Steam Production	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heat Production	9.2	9.1	8.9	8.8	8.9	8.9	9.0	9.0	9.1	9.3	9.5
HVAC	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.3	2.3	2.3	2.4
Lighting	3.7	3.7	3.7	3.8	3.8	3.8	3.9	3.9	3.9	4.0	4.0

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Industrial	**52**	**53**	**54**	**54**	**55**	**56**	**58**	**58**	**60**	**61**
Process Machine Drive	33.5	33.9	34.4	34.8	35.2	35.6	36.2	36.5	36.9	37.4
Electrochemical Processes	2.5	2.5	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.7
Steam Production	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heat Production	9.6	9.8	10.0	10.4	10.8	11.3	11.8	12.2	12.7	13.2
HVAC	2.4	2.5	2.5	2.6	2.6	2.7	2.7	2.8	2.8	2.9
Lighting	4.0	4.1	4.1	4.2	4.2	4.3	4.4	4.4	4.5	4.5

Source: OPA

Forecast is at the generator and is weather normal.

4.0 REGIONAL REFERENCE FORECASTS

Table 12: Regional Reference Forecast: Regional Peak at Time of System Summer Peak (MW)

Region	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Northwest	950	938	927	915	890	865	841	817	794	792	790
West	2763	2782	2801	2820	2831	2842	2853	2864	2875	2904	2933
Northeast	1449	1443	1437	1432	1410	1388	1366	1345	1324	1326	1329
Essa	1243	1253	1263	1274	1288	1302	1316	1330	1344	1366	1388
Ottawa	2122	2140	2158	2176	2199	2223	2246	2270	2294	2319	2345
East	1555	1563	1572	1580	1589	1598	1607	1616	1625	1640	1655
Toronto/GTA	10243	10391	10541	10692	10853	11014	11178	11342	11508	11690	11875
Niagara	836	839	843	847	847	848	849	849	850	858	866
Southwest	5070	5112	5153	5195	5241	5287	5333	5378	5424	5499	5575
Bruce	53	54	55	56	57	58	59	60	62	63	64
Ontario	**26282**	**26515**	**26749**	**26986**	**27205**	**27426**	**27648**	**27873**	**28099**	**28457**	**28820**

Region	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Northwest	788	787	785	789	793	798	802	806	811	815
West	2963	2993	3023	3072	3121	3171	3222	3273	3325	3379
Northeast	1331	1334	1336	1343	1351	1358	1365	1373	1380	1388
Essa	1411	1433	1456	1487	1519	1551	1583	1617	1651	1686
Ottawa	2370	2396	2422	2448	2474	2500	2526	2552	2579	2606
East	1670	1685	1701	1734	1769	1804	1840	1876	1913	1951
Toronto/GTA	12062	12252	12445	12678	12915	13157	13403	13653	13907	14167
Niagara	874	882	890	904	919	933	948	963	979	994
Southwest	5652	5730	5809	5918	6028	6141	6255	6371	6490	6611
Bruce	66	67	68	70	72	74	76	78	80	82
Ontario	**29187**	**29559**	**29936**	**30444**	**30960**	**31485**	**32020**	**32563**	**33115**	**33677**

Source: OPA

Forecast is at the generator and is weather normal.

Table 13: Regional Reference Forecast: Regional Energy (TWh)

Region	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Northwest	7	7	7	7	7	7	7	7	7	7	7
West	15	15	15	15	15	16	16	16	16	16	16
Northeast	11	11	11	11	11	11	11	11	11	11	11
Essa	10	10	10	10	10	10	10	10	10	11	11
Ottawa	12	12	12	12	12	12	13	13	13	13	13
East	9	9	9	9	9	9	9	9	9	9	9
Toronto/GTA	56	57	58	58	59	60	60	61	62	63	63
Niagara	5	5	5	5	5	5	5	5	5	5	5
Southwest	31	32	32	32	32	33	33	33	33	34	34
Bruce	0	0	0	0	0	0	0	1	1	1	1
Ontario	**157**	**158**	**159**	**159**	**161**	**162**	**163**	**164**	**165**	**168**	**169**

Region	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Northwest	7	7	7	7	7	7	7	7	7	7
West	16	17	17	17	17	18	18	18	18	19
Northeast	11	11	11	11	11	11	11	11	11	11
Essa	11	11	11	11	12	12	12	12	12	13
Ottawa	13	13	13	14	14	14	14	14	15	15
East	9	9	10	10	10	10	10	10	10	10
Toronto/GTA	64	65	66	68	69	70	71	73	74	75
Niagara	5	5	5	5	5	5	5	5	5	5
Southwest	34	35	35	36	37	37	38	39	39	40
Bruce	1	1	1	1	1	1	1	1	1	1
Ontario	**171**	**173**	**176**	**178**	**181**	**184**	**187**	**189**	**192**	**195**

Source: OPA

Forecast is at the generator and is weather normal.

5.0 REGIONAL ANALYSIS

Table 14: Ontario Electrical Zones and Corresponding Census Divisions

IESO ZONE	Census Division Zone	Census Division
Northwest	Northwest	Kenora District
Northwest	Northwest	Rainy River District
Northwest	Northwest	Thunder Bay District
West	Southwest	Chatham-Kent
West	Southwest	Elgin County
West	Southwest	Essex County
West	Southwest	Lambton County
West	Southwest	Middlesex County
West	Southwest	Oxford County
Northeast	Northeast	Algoma District
Northeast	Northeast	Cochrane District
Northeast	Northeast	Greater Sudbury Division
Northeast	Northeast	Manitoulin District
Northeast	Northeast	Nipissing District*
Northeast	Northeast	Sudbury District
Northeast	Northeast	Timiskaming District
Essa	Central	Haliburton County
Essa	Central	Kawartha Lakes Division
Essa	Central	Muskoka District Municipality
Essa	Central	Peterborough County
Essa	Central	Simcoe County
Essa	Northeast	Parry Sound District
Essa	Northeast	Nipissing District*
Ottawa	East	Ottawa Division
Ottawa	East	Prescott and Russell United Counties
East	Central	Northumberland County
East	East	Frontenac County
East	East	Hastings County
East	East	Lanark County
East	East	Leeds and Grenville United Counties
East	East	Lennox and Addington County
East	East	Prince Edward Division
East	East	Renfrew County
East	East	Stormont, Dundas and Glengarry United Counties
Toronto	GTA	Durham Regional Municipality
Toronto	GTA	Peel Regional Municipality
Toronto	GTA	Toronto Division
Toronto	GTA	York Regional Municipality
Niagara	Central	Niagara Regional Municipality
Southwest	Central	Brant County
Southwest	Central	Dufferin County
Southwest	Central	Haldimand-Norfolk Regional Municipality
Southwest	Central	Hamilton Division
Southwest	Central	Waterloo Regional Municipality
Southwest	Central	Wellington County
Southwest	GTA	Halton Regional Municipality
Southwest	Southwest	Bruce County
Southwest	Southwest	Grey County
Southwest	Southwest	Perth County
Southwest	Southwest	Huron County

Source: OPA
*Nipissing District split equally between Essa and Northeast

6.0 ECONOMIC INDICATORS

Table 15: Ontario GDP Growth Assumptions – Average Annual Growth (%)

Scenario	2005-2010	2010-2015	2015-2020	2020-2025
Reference	2.8%	2.4%	2.5%	2.4%
Low Scenario	2.6%	1.9%	1.8%	1.7%
High Scenario	2.8%	2.9%	3.1%	3.2%

Source: OPA/NRCan/Ontario Ministry of Finance "Toward 2025: Assessing Ontario's Long-Term Outlook".

Table 16: Ontario Commercial/institutional Sector GDP Assumptions – Average Annual Growth (%)

Scenario	2005-2010	2010-2015	2015-2020	2020-2025
Reference	3.1%	2.8%	2.8%	2.7%
Low Scenario	3.1%	2.4%	2.4%	2.3%
High Scenario	3.2%	3.1%	3.2%	3.0%

Source: OPA/Ontario Ministry of Finance "Toward 2025: Assessing Ontario's Long-Term Outlook".

Table 17: Ontario Industrial Sector GDP Assumptions– Average Annual Growth (%)

Scenario	2005-2010	2010-2015	2015-2020	2020-2025
Reference	1.9%	1.6%	1.9%	1.6%
Low Scenario	1.4%	0.5%	0.1%	-0.5%
High Scenario	1.8%	2.5%	3.0%	3.6%

Source: OPA/Ontario Ministry of Finance "Toward 2025: Assessing Ontario's Long-Term Outlook".

Table 18: Ontario Population Projection – Average Annual Growth (%)

Scenario	2005-2010	2010-2015	2015-2020	2020-2025
Reference	1.2%	1.2%	1.1%	1.0%
Low Scenario	0.8%	0.7%	0.6%	0.5%
High Scenario	1.5%	1.5%	1.4%	1.3%

Source: Ontario Ministry of Finance "Ontario Population Projections Update 2006-2031"

Table 19: Ontario Housing Stock Projection – Average Annual Growth (%)

Scenario	2005-2010	2010-2015	2015-2020	2020-2025
Reference	1.4%	1.2%	1.1%	1.1%
Low Scenario	1.0%	0.8%	0.6%	0.6%
High Scenario	1.7%	1.5%	1.4%	1.5%

Source: OPA/MKJA

CONSERVATION POTENTIAL ESTIMATE DETAILS

1.0 ANNUAL TABLES

Annual values for the period 2008-2027 are presented in the tables below.

Section 2.0 provides information on the potential for Conservation identified at the provincial level for each Conservation category.

Section 3.0 provides information on the proposed Conservation savings at the provincial level for each Conservation category.

Section 4.0 provides results on a regional basis.

Section 5.0 provides the allocation of Conservation savings by classifying the provincial savings as base load, intermediate, or peaking.

Section 6.0 provides the proposed energy efficiency forecast by end use.

Section 7.0 provides delivery cost estimates by Conservation category.

2.0 IDENTIFIED CONSERVATION RESOURCES

Table 1: Identified Savings Potential on System Peak (2008-2027) (MW)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Energy Efficiency	116	267	623	1520	1916	2316	2715	3112	3346	3582
Fuel Switching	0	0	70	125	151	178	207	237	254	273
Customer-based Generation	20	64	148	165	198	231	263	296	355	414
Conservation Behaviour	0	0	0	0	0	0	0	0	0	0
Demand Management	115	289	566	765	986	1109	1164	1218	1243	1337
Total Identified Savings	***251***	***620***	***1407***	***2576***	***3250***	***3834***	***4350***	***4863***	***5198***	***5606***

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Energy Efficiency	3814	4043	4260	4416	4569	4722	4872	5011	5231	5456
Fuel Switching	292	310	327	344	360	376	390	407	427	448
Customer-based Generation	477	532	584	634	687	737	797	837	899	947
Conservation Behaviour	0	0	0	0	0	0	0	0	0	0
Demand Management	1440	1466	1493	1522	1552	1581	1612	1645	1704	1765
Total Identified Savings	***6022***	***6351***	***6664***	***6917***	***7169***	***7416***	***7671***	***7900***	***8261***	***8616***

Source: OPA
Note: At the generator, weather normal.

Table 2: Identified Energy Savings Potential (2008-2027) (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Energy Efficiency	0.7	1.5	3.5	8.5	10.5	12.4	14.3	16.3	17.3	18.3
Fuel Switching	0.0	0.0	2.4	4.2	4.9	5.7	6.4	7.1	7.4	7.6
Summer	*0.0*	*0.0*	*0.2*	*0.4*	*0.5*	*0.6*	*0.7*	*0.7*	*0.8*	*0.8*
Off-Summer	*0.0*	*0.0*	*2.2*	*3.8*	*4.4*	*5.1*	*5.7*	*6.3*	*6.6*	*6.8*
Customer-based Generation	0.1	0.4	0.9	1.0	1.2	1.4	1.6	1.9	2.3	2.7
Conservation Behaviour	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Demand Management	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total Identified Savings	***0.8***	***2.0***	**6.9**	**13.8**	**16.7**	**19.6**	**22.5**	**25.4**	**27.1**	**28.7**

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Energy Efficiency	19.3	20.3	21.2	21.9	22.6	23.4	24.1	24.7	25.7	26.8
Fuel Switching	7.9	8.1	8.4	8.6	8.8	9.1	9.3	9.5	9.8	10.1
Summer	*0.9*	*0.9*	*1.0*	*1.0*	*1.1*	*1.1*	*1.1*	*1.2*	*1.2*	*1.3*
Off-Summer	*7.0*	*7.2*	*7.4*	*7.6*	*7.8*	*8.0*	*8.2*	*8.3*	*8.6*	*8.8*
Customer-based Generation	3.1	3.5	3.9	4.2	4.6	4.9	5.3	5.6	6.0	6.3
Conservation Behaviour	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Demand Management	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total Identified Savings	**30.4**	**32.0**	**33.6**	**34.9**	**36.2**	**37.5**	**38.9**	**39.9**	**41.7**	**43.5**

Source: OPA
Note: At the generator, weather normal.

3.0 PROPOSED CONSERVATION RESOURCES

Table 3: Proposed Savings Potential on System Peak (2008-2027) (MW)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Energy Efficiency	116	267	623	886	1149	1412	1675	1938	2092	2248
Fuel Switching	0	0	70	87	104	121	139	156	167	180
Customer-based Generation	20	64	148	156	164	172	180	188	227	265
Conservation Behaviour	0	0	0	0	0	0	0	0	0	0
Demand Management	115	289	566	606	647	687	728	769	780	836
Total Proposed Savings	***251***	***620***	***1407***	***1735***	***2064***	***2393***	***2721***	***3050***	***3266***	***3529***

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Energy Efficiency	2400	2551	2694	2797	2898	2999	3097	3189	3334	3482
Fuel Switching	192	204	215	227	237	248	257	268	281	295
Customer-based Generation	307	343	377	410	445	478	518	544	584	616
Conservation Behaviour	0	0	0	0	0	0	0	0	0	0
Demand Management	899	912	925	940	955	970	986	1004	1036	1069
Total Proposed Savings	***3798***	***4010***	***4211***	***4373***	***4535***	***4694***	***4858***	***5005***	***5235***	***5462***

Source: OPA
Note: At the generator, weather normal.

Table 4: Proposed Energy Savings Potential (2008-2027) (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Energy Efficiency	0.7	1.5	3.5	4.8	6.2	7.5	8.8	10.1	10.8	11.5
Fuel Switching	0.0	0.0	2.4	2.9	3.4	3.8	4.3	4.7	4.8	5.0
Summer	*0.0*	*0.0*	*0.2*	*0.3*	*0.3*	*0.4*	*0.4*	*0.5*	*0.5*	*0.5*
Off-Summer	*0.0*	*0.0*	*2.2*	*2.6*	*3.1*	*3.5*	*3.8*	*4.2*	*4.3*	*4.5*
Customer-based Generation	0.1	0.4	0.9	1.0	1.0	1.1	1.1	1.2	1.5	1.7
Conservation Behaviour	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Demand Management	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total Proposed Savings	***0.8***	***2.0***	**6.9**	**8.8**	**10.7**	**12.4**	**14.3**	**16.1**	**17.2**	**18.3**

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Energy Efficiency	12.1	12.8	13.4	13.8	14.3	14.8	15.3	15.7	16.4	17.1
Fuel Switching	5.2	5.4	5.5	5.7	5.8	6.0	6.1	6.2	6.5	6.7
Summer	*0.6*	*0.6*	*0.6*	*0.7*	*0.7*	*0.7*	*0.7*	*0.8*	*0.8*	*0.8*
Off-Summer	*4.6*	*4.7*	*4.9*	*5.0*	*5.1*	*5.2*	*5.4*	*5.5*	*5.6*	*5.8*
Customer-based Generation	2.0	2.2	2.5	2.7	3.0	3.2	3.4	3.6	3.9	4.1
Conservation Behaviour	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Demand Management	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total Proposed Savings	**19.4**	**20.4**	**21.5**	**22.3**	**23.2**	**24.1**	**25.0**	**25.7**	**26.8**	**28.0**

Source: OPA
Note: At the generator, weather normal.

4.0 REGIONAL CONSERVATION ESTIMATES

Table 5: Proposed Regional Conservation Savings on System Peak (2008-2027) (MW)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Northwest	14	32	64	76	86	96	105	115	123	130
West	30	72	161	196	231	265	300	334	357	385
Northeast	17	42	91	106	120	134	148	162	171	182
Essa	17	43	96	115	134	154	173	193	206	223
Ottawa	15	39	97	123	150	177	204	230	246	266
East	15	37	83	100	117	134	151	168	179	193
GTA	80	201	478	606	737	868	1000	1133	1217	1322
Niagara	7	18	41	51	60	69	79	88	93	101
Southwest	55	135	296	363	429	495	561	628	674	729
Ontario	**251**	**620**	**1407**	**1736**	**2064**	**2393**	**2721**	**3050**	**3266**	**3529**

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Northwest	138	144	149	156	159	164	167	169	174	179
West	413	435	456	476	494	511	529	545	570	595
Northeast	195	202	208	214	219	221	228	229	238	242
Essa	240	253	265	276	287	298	308	318	333	348
Ottawa	287	303	318	326	337	348	359	370	386	402
East	207	217	227	235	242	251	260	266	276	287
GTA	1427	1513	1597	1655	1720	1785	1850	1915	2007	2102
Niagara	108	114	119	123	127	131	135	139	145	151
Southwest	784	830	872	912	949	985	1022	1055	1106	1155
Ontario	**3798**	**4010**	**4211**	**4374**	**4535**	**4694**	**4857**	**5005**	**5235**	**5463**

Source: OPA
Note: Forecast is at the generator and is weather normal.

Table 6: Proposed Regional Energy Conservation Savings (2008-2027) (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Northwest	0.0	0.1	0.2	0.3	0.4	0.5	0.5	0.6	0.7	0.7
West	0.1	0.2	0.7	0.9	1.0	1.2	1.4	1.6	1.7	1.8
Northeast	0.1	0.1	0.6	0.7	0.8	1.0	1.1	1.2	1.3	1.4
Essa	0.1	0.1	0.5	0.6	0.7	0.8	0.9	1.1	1.1	1.2
Ottawa	0.1	0.1	0.6	0.7	0.8	1.0	1.1	1.3	1.4	1.4
East	0.0	0.1	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.0
GTA	0.3	0.7	2.5	3.2	3.8	4.5	5.1	5.8	6.2	6.5
Niagara	0.0	0.1	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.5
Southwest	0.2	0.4	1.3	1.7	2.1	2.4	2.8	3.2	3.4	3.7
Ontario	**0.8**	**2.0**	**6.9**	**8.8**	**10.6**	**12.4**	**14.3**	**16.1**	**17.2**	**18.3**

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Northwest	0.8	0.8	0.9	0.9	1.0	1.0	1.0	1.0	1.1	1.1
West	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.5	2.7	2.8
Northeast	1.5	1.5	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0
Essa	1.3	1.4	1.4	1.5	1.6	1.7	1.7	1.8	1.9	2.0
Ottawa	1.5	1.6	1.7	1.8	1.8	1.9	2.0	2.0	2.1	2.2
East	1.1	1.1	1.2	1.2	1.3	1.3	1.4	1.4	1.5	1.5
GTA	6.9	7.3	7.6	7.8	8.1	8.4	8.7	9.0	9.4	9.8
Niagara	0.5	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.8
Southwest	3.9	4.1	4.4	4.6	4.8	5.0	5.2	5.3	5.6	5.8
Ontario	**19.4**	**20.4**	**21.5**	**22.3**	**23.2**	**24.1**	**24.9**	**25.6**	**26.8**	**28.0**

Source: OPA
Note: Forecast is at the generator and is weather normal.

5.0 ALLOCATION OF CONSERVATION CATEGORIES BY RESOURCE TYPE

Table 7: Allocation of Conservation Categories – Proposed Peak Demand Reduction (2008-2027) (MW)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Base Load	89	223	550	718	887	1055	1224	1392	1506	1622
Intermediate Load	54	145	334	356	379	402	425	448	455	506
Peaking Demand	108	252	524	661	798	935	1073	1210	1305	1401
Total on Peak Savings	**251**	**620**	**1407**	**1736**	**2064**	**2393**	**2721**	**3050**	**3266**	**3529**

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Base Load	1736	1844	1942	2020	2097	2170	2245	2303	2403	2498
Intermediate Load	563	569	575	581	587	591	597	603	615	628
Peaking Demand	1498	1596	1695	1773	1852	1933	2015	2100	2216	2336
Total on Peak Savings	**3798**	**4010**	**4211**	**4374**	**4535**	**4694**	**4857**	**5005**	**5235**	**5463**

Source: OPA
Note: Forecast is at the generator and is weather normal.
Based on the assumption that the 2007 target of 1350 MW has been achieved.

Table 8: Allocation of Conservation Categories – Proposed Energy Reduction (2008-2027) (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Base Load	0.7	1.8	4.5	5.9	7.3	8.6	9.9	11.3	12.1	12.9
Intermediate Load	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Peaking Demand	0.1	0.1	2.3	2.9	3.4	3.8	4.3	4.7	5.1	5.3
Total Energy Savings	**0.8**	**2.0**	**6.9**	**8.8**	**10.7**	**12.4**	**14.3**	**16.1**	**17.2**	**18.3**

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Base Load	13.7	14.5	15.3	15.8	16.4	17.0	17.6	18.0	18.7	19.4
Intermediate Load	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Peaking Demand	5.6	5.8	6.1	6.4	6.6	6.9	7.2	7.4	7.9	8.4
Total Energy Savings	**19.4**	**20.4**	**21.5**	**22.3**	**23.2**	**24.1**	**25.0**	**25.6**	**26.8**	**28.0**

Source: OPA
Note: Forecast is at the generator and is weather normal.

6.0 ENERGY EFFICIENCY SAVINGS BY END USE

Table 9: Proposed Energy Efficiency Savings Allocations (2008-2027)

	Peak (MW)					Energy (TWh)				
	2010	2015	2020	2025	2027	2010	2015	2020	2025	2027
Residential	**213**	**485**	**601**	**663**	**718**	**1.4**	**3.0**	**3.2**	**3.7**	**4.0**
Space Heating SFD	0	0	0	0	0	0.1	0.1	0.3	0.4	0.0
Space Heating AP/AT *	0	0	0	0	0	-0.2	-0.2	-0.3	-0.3	0.1
Room AC	8	19	20	20	21	0.0	0.0	0.0	0.0	0.0
Central AC	90	183	232	235	250	0.1	0.1	0.1	0.1	0.1
Furnace Fan	47	86	125	154	170	0.1	0.1	0.2	0.2	0.2
Lighting	35	58	46	50	55	1.0	1.6	1.3	1.4	1.5
Refrigeration	4	9	13	14	15	0.0	0.1	0.1	0.1	0.1
Freezer	3	8	11	14	16	0.0	0.1	0.1	0.1	0.1
Water Heating	5	59	61	61	64	0.1	0.6	0.6	0.6	0.6
Dish Washer	1	3	4	4	5	0.0	0.0	0.0	0.1	0.1
Clothes Washer / Dryer	4	14	22	28	31	0.0	0.1	0.2	0.2	0.2
Miscellaneous	16	46	67	83	91	0.2	0.4	0.6	0.8	0.9
Commercial/Institutional	**302**	**1044**	**1522**	**1851**	**2035**	**1.3**	**4.2**	**5.9**	**7.1**	**7.9**
Space Heating	0	0	0	0	0	0.1	0.4	0.9	1.4	1.6
Space Cooling	118	531	833	1095	1217	0.1	0.5	0.7	0.9	1.0
Ventilation	30	71	132	185	208	0.2	0.6	1.0	1.4	1.6
Lighting	146	421	523	556	596	0.9	2.5	3.1	3.3	3.6
Electric Auxiliary	5	13	23	13	12	0.0	0.1	0.1	0.1	0.1
Water Heating	3	8	11	2	2	0.0	0.1	0.1	0.0	0.0
Industrial	**107**	**409**	**573**	**675**	**732**	**0.8**	**3.1**	**4.3**	**4.9**	**5.3**
Process Machine Drive	45	211	294	341	368	0.4	1.9	2.6	2.9	3.1
Electrochemical Processes	1	6	10	18	21	0.0	0.1	0.1	0.2	0.2
Steam Production	0	0	0	0	0	0.0	0.0	0.0	0.0	0.0
Heat Production	38	106	135	164	179	0.3	0.8	1.0	1.2	1.3
HVAC	20	74	114	127	136	0.1	0.2	0.4	0.4	0.4
Lighting	3	12	20	25	28	0.0	0.1	0.2	0.2	0.2

Source: OPA, M. K. Jaccard and Associates
Note: At generator, weather normal
* Negative results stem from the increased share of future households in multi-unit dwellings and the result pick up of electricity in space heating.

7.0 ESTIMATED CONSERVATION DELIVERY COSTS

Table 10: Conservation Delivery Cost Estimates (2008 to 2017) ($2007 Millions)

Conservation Resource Category	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Energy Efficiency										
Program Costs	77	86	84	93	95	93	95	95	49	45
Incentive Costs	155	176	172	190	193	189	192	192	99	92
Energy Efficiency Delivery Costs	**232**	**262**	**256**	**283**	**289**	**282**	**286**	**287**	**148**	**138**
Demand Management/Conservation Behaviour										
Program Costs	17	17	18	21	21	21	22	22	22	23
Incentive Costs	97	101	105	132	135	137	140	142	144	155
DR/Conservation Behaviour Delivery Costs	**114**	**119**	**122**	**153**	**156**	**159**	**162**	**164**	**167**	**178**
Fuel Switching										
Program Costs	0	0	62	55	49	42	36	29	13	13
Incentive Costs	0	0	30	41	49	42	36	82	36	38
Fuel Switching Delivery Costs	**0**	**0**	**92**	**96**	**97**	**84**	**72**	**111**	**49**	**51**
Customer-based Generation										
Program Costs	1	1	1	0	0	0	0	0	2	2
Incentive Costs	10	15	24	8	8	7	8	7	32	31
Customer-based Generation Delivery Costs	**11**	**16**	**25**	**8**	**9**	**7**	**8**	**8**	**34**	**33**
Total Conservation Resources										
Total Program Costs	94	105	165	170	165	157	152	146	86	84
Total Incentive Costs	262	292	330	370	385	376	375	424	312	316
Total Conservation Delivery Costs (including Market Transformation)	**356**	**396**	**495**	**540**	**550**	**533**	**528**	**570**	**397**	**400**

Source: OPA

Table 11: Conservation Delivery Cost Estimates (2018 to 2027) ($2007 Millions)

Conservation Resource Category	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Energy Efficiency										
Program Costs	46	46	44	33	34	34	36	26	49	50
Incentive Costs	94	92	89	67	69	69	72	53	100	102
Energy Efficiency Delivery Costs	**140**	**138**	**132**	**99**	**104**	**103**	**108**	**79**	**149**	**152**
Demand Management/Conservation Behaviour										
Program Costs	25	25	25	25	26	26	26	27	27	28
Incentive Costs	166	168	171	173	176	178	181	184	189	194
DR/Conservation Behaviour Delivery Costs	**191**	**193**	**196**	**199**	**201**	**204**	**207**	**211**	**216**	**221**
Fuel Switching										
Program Costs	13	12	11	12	11	11	10	11	16	16
Incentive Costs	35	34	32	34	32	31	28	30	44	44
Fuel Switching Delivery Costs	**48**	**46**	**43**	**46**	**43**	**41**	**38**	**41**	**60**	**60**
Customer-based Generation										
Program Costs	2	1	1	1	1	1	1	1	1	1
Incentive Costs	31	29	28	26	27	26	26	22	29	26
Customer-based Generation Delivery Costs	**32**	**31**	**30**	**28**	**28**	**27**	**27**	**23**	**30**	**27**
Total Conservation Resources										
Total Program Costs	85	84	82	72	73	72	73	65	93	95
Total Incentive Costs	326	325	320	300	304	304	307	289	361	365
Total Conservation Delivery Costs (including Market Transformation)	**411**	**409**	**401**	**372**	**376**	**376**	**380**	**354**	**455**	**460**

Source: OPA

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GROWTH FORECASTS

Population

	2007	2008-2017	2017	2008-2031	2031
County	104,931	19,586	124,517	37,331	143,900
Ingersoll	12,017	2,362	14,379	4,858	17,100
Tillsonburg	15,162	3,122	18,284	6,142	21,600
Blandford-Blenheim	7,401	1,396	8,797	1,949	9,400
East-Zorra Tavistock	7,038	775	7,812	1,491	8,600
Norwich	10,677	1,528	12,206	2,901	13,700
Zorra	8,329	1,516	9,845	2,759	11,200

Households

	2007	2008-2017	2017	2008-2031	2031
County	39,986	7,432	47,418	15,685	56,400
Ingersoll	4,636	842	5,478	1,962	6,700
Tillsonburg	6,476	1,177	7,653	2,591	9,200
Blandford-Blenheim	2,552	424	2,976	717	3,300
East-Zorra Tavistock	2,469	339	2,808	665	3,175
Norwich	3,514	535	4,049	1,125	4,700
Zorra	2,947	544	3,491	1,102	4,100

COUNTY-WIDE POPULATION PER UNIT

	Pre 1996	1996-2006	Total
Singles/Semis			
Household Population	73,505	11,850	85,355
Households	27,125	3,905	31,030
Household Size	2.71	3.03	2.75
Rows			
Household Population	4,695	730	5,425
Households	1,925	360	2,285
Household Size	2.44	2.03	2.37
Apartments			
Household Population	9,265	600	9,865
Households	5,600	370	5,970
Household Size	1.65	1.62	1.65
All Units			
Household Population	87,465	13,180	100,645
Households	34,650	4,635	39,285
Household Size	2.52	2.84	2.56

GROWTH FORECASTS

Employment

	2007	2008-2017	2017	2008-2031	2031
County	53,289	13,731	67,020	17,391	71,100
Ingersoll	9,164	1,296	10,460	2,004	11,300
Tillsonburg	9,970	2,722	12,692	3,757	13,900
Blandford-Blenheim	2,610	466	3,076	660	3,300
East-Zorra Tavistock	2,613	889	3,502	1,138	3,800
Norwich	4,190	1,119	5,309	1,639	5,900
Zorra	3,409	125	3,534	450	3,900

- **Normalized Volume Forecast Table**

THI's weather normalized volume forecast for the 2009TY is provided in table 1 below. The derivation of the data is discussed at E3/T2/S1 and E3/T2/S2.

Table 1 – THI 2009TY Weather Normal Volume Forecast

Customer Class Name	CDM adjusted kWh deliveries	CDM adjusted kW
Residential	50,519,778	
General Service <50 kW	24,890,062	
General Service >50 kW, <500 kW	36,783,954	106,725
General Service >500 to 4999 kW	106,867,703	229,694
Street Lighting	73,943	205
Sentinel Lighting	1,310,738	3,783
Unmetered Scattered Load	472,835	
TOTAL	220,919,014	340,406

Please note that the weather normalized charge parameters have been recast for the proposed 2009TY customer classes as discussed in Exhibit 8.

- **Customer Count Forecast Table**

Table 1 below provides data on THI's number of customers 2006 – 2009.

Table 1 - THI Customer count by year

Customer Class Name	2006 Actual	2007 Actual	2008 Estimated	2009 Weather Normalized
Residential	5,677	5,790	5,892	5,996
General Service <50 kW	648	643	640	637
General Service >50 kW, <500 kW	72	72	72	72
General Service >500 to 4999 kW	12	12	12	12
Street Lighting	1	1	1	1
Sentinel Lighting	79	79	79	79
Unmetered Scattered Load	19	19	19	19
TOTAL	6,537	6,645	6,744	6,845

Please note that the currently authorized GS 500 – 4,999 kW customer class will be partitioned into a GS 500 – 1,499 kW customer class with 8 members and a GS > 1,500 kW customer class with 4 members. Also note that the Sentinel Lighting and Unmetered Scattered Load customer classes will be combined.

Table 1 shows that THI is serving increasing numbers of customers over time chiefly due to increases in the residential customer class.

The increased number of residential customers is attributable to population growth being experienced by the Town of Tillsonburg that is in turn driven by the overall economic growth of the area. These increases in the residential class have not been accompanied by customer growth in either the GS<50 kW or GS 50 – 499 kW customer classes. THI's total number of GS 500-4,999 kW customers has been constant since 2004. As is documented in the Load Forecast Report, THI experienced a new customer attachment in 2006 who has since mothballed its operations; the entry and subsequent exit of this customer are not reflected in the customer number data (or in normalized energy or normalized demand). THI's Unmetered

Scattered Load and Sentinel Lighting customers are stable and did not change over the 2003-2007 period. THI serves one Street Lighting customer.

- **Historical Average Consumption**

THI's historic average consumption by customer class is provided at E3/T2/S5/AttA. Please note that this data is presented using THI's currently authorized customer classes to facilitate comparability.

The data demonstrates that most of THI's customer class' average energy consumption has declined over the 2004-2007 period. It also shows that the rate of growth of average energy consumption per customer is lower in the 2008BY and 2009TY than in the 2004-2007 period.

The average demand per customer trend shows greater variability than does the average energy per customer trend. Overall, the rate of growth in demand per customer in the 2008BY and 2009TY is lower than in the 2004-2007 period.

Energy/Customer

Customer Class Name	2006 EDR Approved	2003 Actual	2004 Actual	2005 Actual	2006□□Actual	2007□□Normalized	2008□□Normalized	2009□□Normalized
Residential	9241.160239	9082.716139	8926.932738	9261.672773	9030.087899	8775.11848	8655.967244	8532.232989
General Service < 50 kW	38213.98323	38873.99543	40653.38906	39589.49694	38974.62654	38930.06376	39261.14063	39568.48666
General Service >50 kW, <500 kW	779257.7975	470498.4265	461815.375	457494.4247	488125.1944	513802.2778	515754.25	517355.1944
General Service >500 kW, <5,000 kW	17228325.8	9908296.909	10341297.09	9856226.182	9025313	9490799.667	8955681.833	9018371.583
Sentinel Lighting	7540.777778	915.48	930.060241	936.835443	935.9873418	935.9873418	935.9873418	935.9873418
Street Lighting	1380896	1272899	1280056	1298589	1304938	1310738	1310738	1310738
Unmetered Scattered Load	8763.45098				23665.47368	24886.05263	24886.05263	24886.05263

Annual % change in Energy/Customer

Customer Class Name								
Residential			-1.72%	3.75%	-2.50%	-2.82%	-1.36%	-1.43%
General Service < 50 kW			4.58%	-2.62%	-1.55%	-0.11%	0.85%	0.78%
General Service >50 kW, <500 kW			-1.85%	-0.94%	6.70%	5.26%	0.38%	0.31%
General Service >500 kW, <5,000 kW			4.37%	-4.69%	-8.43%	5.16%	-5.64%	0.70%
Sentinel Lighting			1.59%	0.73%	-0.09%	0.00%	0.00%	0.00%
Street Lighting			0.56%	1.45%	0.49%	0.44%	0.00%	0.00%
Unmetered Scattered Load						5.16%	0.00%	0.00%

Demand/Customer

Customer Class Name	2006 EDR Approved	2003 Actual	2004 Actual	2005 Actual	2006□□Actual	2007□□Normalized	2008□□Normalized	2009□□Normalized
Residential	0	0	0	0	0	0	0	0
General Service < 50 kW	0	0	0	0	0	0	0	0
General Service >50 kW, <500 kW	2087.443038	1498.352941	1593.236111	1489.273973	1475.305556	1511.722222	1517.458333	1522.166667
General Service >500 kW, <5,000 kW	35482.6	20496.09091	20975.54545	20398.18182	19671.25	21281	19519.5	19656.08333
Sentinel Lighting	22.66666667	2.533333333	2.602409639	2.594936709	2.594936709	2.594936709	2.594936709	2.594936709
Street Lighting	3703	3704	3777	3778	3778	3783	3783	3783
Unmetered Scattered Load	0				0	0	0	0

Annual % change in Demand/Customer

Customer Class Name								
Residential								
General Service < 50 kW								
General Service >50 kW, <500 kW			6.33%	-6.53%	-0.94%	2.47%	0.38%	0.31%
General Service >500 kW, <5,000 kW			2.34%	-2.75%	-3.56%	8.18%	-8.28%	0.70%
Sentinel Lighting			2.73%	-0.29%	0.00%	0.00%	0.00%	0.00%
Street Lighting			1.97%	0.03%	0.00%	0.13%	0.00%	0.00%
Unmetered Scattered Load								

~~Schedule 1 -~~ Other Distribution Revenue

THI forecasts that it will recover $101k from

- Pole rental;
- Specific Service Charges;
- Late Payment Charges;
- Retailer charges;
- Interest; and
- SSS Administration charges.

The 2009TY forecasted revenues recovered through other rates and charges are set out in table 1 below.

Table 1 – 2009TY revenues recovered through other rates and charges

Service	Volume	Rate	Revenue (in $)
Standard Supply Service -- Administrative Charge	86,920	$0.25	21,730
Returned Cheque charge (plus bank charges)	111	$15.00	1,665
Account set up charge / change of occupancy charge	883	$30.00	26,490
Special Meter reads	6	$30.00	180
Late Payment - per month	820,000	1.50%	12,300
Specific Charge for Access to the Power Poles – per pole/year	1,315	$22.35	29,390
Retailer Service Agreement -- standard charge	12	$100.00	1,200
Retailer Service Agreement -- monthly fixed charge (per retailer)	144	$20.00	2,880
Retailer Service Agreement -- monthly variable charge (per customer)	4,938	$0.50	2,469
Distributor-Consolidated Billing -- monthly charge (per customer)	4,782	$0.30	1,435
Service Transaction Request -- request fee (per request)	2,970	$0.25	743
Service Transaction Request -- processing fee (per processed request)	794	$0.50	397
TOTAL			100,878

Specific Service Charges

The forecasted revenues recovered through Specific Service Charges ("SSC") in the 2009TY are $28k. THI has forecasted the revenues recovered through the application of the currently authorized specific service charges at E3/T1/S3/AttC. THI does not propose any changes to the levels of the rates and does not propose any new rates or charges.

Pole Rental Revenue

THI forecasts that it will recover $29k of revenue through the application of pole rental rates in the 2009 TY. This forecast relies on currently authorized pole rental rates applied to the number of poles THI owned as of the end of 2007. The number of poles is not changing due to ongoing undergrounding of the distribution system.

Interest Revenue

THI forecasts that it will generate $28k of interest revenue in the 2009TY. This forecast assumes that THI has average eligible cash and cash equivalents of $700k that will attract carrying charges of 4.08%, the interest rate applicable for determining carrying costs on variance and deferral account balances authorized most recently by the Board.

Revenues recovered from Retailers

THI estimates that it will recover $9k from Retailers in the 2009TY. This forecast was prepared using currently authorized rates charged to retailers applied to the number of retailers active in THI's service area.

Late Payment Charge Revenues

THI forecasts that it will recover $12k of revenue through the application of Late Payment Charges in the 2009 TY. This forecast assumes that the level of LPC revenues generated in 2007 will continue and will increase in direct proportion with increases in the number of residential customers.

~~Schedule 2 –~~ Materiality Analysis on Other Distribution Revenue

E3/T1/S3/AttC provides a continuity presentation of Other Revenue. The variances are due to volume variances and none is considered material. These variances are attributed to factors beyond THI's control; the variance in Late Payment Charge revenues is driven by customers' bill paying habits and the variances in revenues recovered from retailers are driven by the number of retailers active in THI's service area and the number of customers they serve.

~~Schedule 3 -~~ Rate of Return on Other Distribution Revenue

THI does not gather the data required to support this analysis.

~~Schedule 4 –~~ Distribution Revenue Data

Data on THI's distribution revenue is provided at E3/T1/S3/AttA and E3/T1/S3/AttB.

- **Description of Revenue Sharing**

THI does not engage in revenue sharing.

Period Costs – Operating, Maintenance and Administration Costs, Depreciation Expense and Payments in Lieu of Taxes Expense

Overview of Operating Costs

THI forecasts that its 2009TY period expenses will amount to $2,677k and consist of:

- Operations, Maintenance and Administration Expenses $2,103k
- Depreciation Expense $ 502k
- Payments in Lieu of Taxes Expense $ 72k

THI's 2009TY period expenses are $408k or 24.1% greater than the 2008BY period expenses; THI's proposed 2009TY period expenses are 2006EDR Board approved period expenses have increased approximately 10% annually.

The purpose of this evidence is to:
Provide a high level review of THI's proposed period expenses of the 2009TY;

With respect to OM&A:

- Describe that activities supported by THI's OM&A spending;
- Identify and describe the operating efficiencies that THI has achieved;
- Summarize THI's budgeting methodology and its recording of the costs actually incurred in the period;
- Summarize the rationale supporting the provision of resources and services to THI by the Town of TIllsonburg;
- Explain the determination of transfer prices paid by THI to its parent; and
- Explain the reasons for year over year changes in OM&A;

With respect to depreciation expense:

- Describe THI's depreciation accounting policies;
- Describe THI's depreciation assumptions;

- Provide the detailed derivation of the proposed depreciation expense for the 2009TY;
- Explain the reasons for the year over year changes in depreciation expense;

With respect to PILs expense:

- Describe THI's PILs estimation procedures;
- Describe the assumptions and supporting facts relied on to estimate THI's PILs expense;
- Provide the detailed derivation of the 2009TY PILs expense;
- Explain the reasons for the year over year changes in PILs expense.

Summary of Operating Costs

Summary

THI's 2009TY period costs have been determined based on the utility's proposed activities for the Test Year that are required to provide distribution service at an appropriate level of quality and to make appropriate provision to continue to do so in the future. THI proposes to rely on its existing policies and practices in the 2009TY. All costs of the period have been forecast using THI's normal budgeting process and rely on appropriate assumptions.

During the 2009TY THI will incur increased costs to support a succession planning program for its technical staff and to recruit regulatory staff, to commission and implement a new Customer Information System, to file and defend the subject rates application, as well as to undertake a strategic planning exercise. THI will also assume responsibility for paper and postage costs that were borne by the Town in past periods.

Some of these activities give rise to permanent changes in costs (eg., recruiting and retaining regulatory staff) while others will be removed over the longer term (eg., the costs of apprentice linemen temporarily increase the technical staff complement to 9.6 FTE for a period of three to five years while they complete their apprenticeships).

2009TY OM&A activities and costs

THI's 2009 TY OM&A expense is driven by:

- its ongoing period costs incurred to provide electricity distribution service;
- increased spending on labour, specifically to implement a succession plan with respect to the linemen complement and to retain a Regulatory Affairs Manager;
- one time spending to file and defend the subject rates application;
- the planned replacement of the existing Customer Information System;
- inclusion of full responsibility for paper and postage costs;
- general cost increases for materials and cost of living adjustments for labour; and
- Continuing implementation of cost effective efficiency measures.

THI acquires all the resources and assets relied on to operate and maintain the distribution system, to bill customers and collect payment for services and to appropriately administer the business from the Town of Tillsonburg pursuant to a Master Service Agreement (E1/T2/S1/AttA). The Town and THI negotiate the prices charged under the MSA. THI identifies the activities and projects that it will perform or undertake in the upcoming period as well as the resources required to successfully complete them in a safe, reliable and cost effective manner. The Town reviews the fees it charged THI in the previous period and considers the costs it will incur to support the activities THI proposes to undertake in the upcoming period. Both parties rely on the costs incurred in the prior period as the baseline data for estimating the costs that will be incurred in the upcoming period and make appropriate adjustments for new activities, activities that will be completed, ongoing cost pressures, realized efficiencies.

This approach has been relied on since the formation of THI in 2002 and is consistent with the Town's overall strategy. The Town's strategy is premised on achieving economies of scope and scale through the sharing of all human resources and the sharing of those assets that are able to be deployed in support of the provision of more than one service. For example, the Town owns the fleet of axled devices that are relied on for common purposes, such as the bucket trucks that can be used to support the provision of electricity distribution service and the provision of street light maintenance; THI owns the meters that are used to record consumption because they are uniquely appropriate to this aspect of service and cannot be used to serve any other purpose. While the Town of Tillsonburg employs the staff who are engaged in the provision of electricity distribution service it is important to understand that the technical staff are effectively dedicated to the provision of electricity distribution and that the executive, management, customer service and commercial infrastructure support employees (eg., IT, fleet maintenance) are not. In the 2008BY THI expects to have a technical staff complement of 17.05 FTEs that include 9.6 FTE dedicated technical staff, principally linesmen and technologists/technicians. An additional 7.45 FTEs are relied on to provide management services, customer service and clerical service.

The transfer pricing reflected in the MSA reflects the direct costs budgeted to be incurred by the Town. All directly incurred costs of the period (eg., direct labour costs, period costs of facilities such as property taxes, natural gas, insurance) are recovered through the fixed transfer prices charged under the MSA. In order to support the recovery of indirect costs and a portion of the return on capital employed the Town burdens each charge to THI with a 5% Management Fee. In the 2009TY THI will remit approximately $119k to the Town through the application of the Management Fee. These revenues recover indirect labour costs (eg., facilities and IT costs of executive and management team members), the depreciation on assets employed (eg., depreciation on IT hardware, telecommunications gear) and a return on the assets employed. The level of the Management Fee was set several years ago.

Consistent with Canadian GAAP, THI accounts for the fees paid to the Town as expenses of the period. From an economic perspective the transfer prices paid by THI to the Town are more accurately a combination of cost of the period and capital related costs. As a result of correctly accounting for the costs incurred under the MSA as expenses of the period THI is overstating its operating costs of the period and understating its comparable capital costs.

THI is directly responsible for the costs uniquely attributable to providing electricity distribution service, such as bad debt expense, depreciation expense, PILs expense. These will be discussed in greater detail elsewhere in this application.

THI's OM&A budget is prepared by identifying the activities that will need to be carried out in the period and then estimating the resources required to conduct them. THI relies on the Town's time sheet records to estimate the resources required for OM&A activities. It relies on its knowledge of the costs charged under the MSA and the variances, as reported by the Town, as well as anticipated market changes or regulatory changes to identify the resources required for Administrative activities.

THI's 2009TY OM&A is forecast to be $408k greater than the 2008BY OM&A. This change is attributable to:

- the recent hiring of two new apprentice linesmen and the anticipated recruitment of a Regulatory Affairs Manager;
- cost of living adjustments for the existing staff complement;
- the costs of the new Customer Information System;
- Paper and Postage costs; and
- the costs of the subject rates application.

THI's 2009TY depreciation expense is forecast to be $29k greater than the 2008BY depreciation expense. THI depreciates its capital assets over 25 years, consistent with the Board's 2000 EDR Handbook.

THI's 2009TY PILs expense is forecast to be $7k less than the 2008BY PILs expense primarily due to changes in Net Income.

The proposed 2009TY OM&A costs are in an amount appropriate for THI to continue to provide safe, reliable distribution service at the level of quality that THI's customers have enjoyed for many years in the 2009TY.

Activities Supported by THI's OM&A Spending

THI forecasts that it will incur $2,103k of OM&A expenses in the 2009TY. This level of expense will support the activities identified below.

THI incurs Operations costs in support of activities that are undertaken to ensure that the distribution system is functioning within design limits and to minimize system losses. THI forecasts that it will incur $871k of Operations expenses in the 2009TY. Operations activities include:

- Switching, load balancing, load dispatching, voltage balancing, reactive power management and asset management;
- Service restoration and non-outage related emergency response;
- Voltage control;
- System monitoring and inspection;

- Loss management;
- Call Before You Dig service and asset locate service; and
- Record keeping.

THI incurs Maintenance costs to upkeep the distribution system, so that all components of distribution system function within design limits for their intended life and to minimize system losses. THI forecasts that it will incur $186k of Maintenance expenses in the 2009TY. Maintenance activities include:

- Tree trimming;
- Changing transformer taps;
- Complying with revised standards;
- Restoration of service and rehabilitation;
- Environmental issue management; and
- Regularly scheduled component replacement (eg., poles, cross arms).

THI incurs Administration costs to support the provision of electricity distribution service on a commercial basis. THI forecasts that it will incur $1,046k of Administration and Billing and Collecting expenses in the 2009TY. Administration, Billing and Collecting activities include:

- Customer care activities (eg., call centre operations, cashiering services);
- Metering activities (eg., meter reading, data management);
- Billing, credit and collections;
- Customer communications – written, verbal, electronic;
- Regulatory activities – Ontario Energy Board, Electricity Safety Authority, Electricity Distributors Association fees and charges, expenses related to reporting obligations (regulatory audit, OEB Reporting and Record Keeping Requirements), compliance activities, rates application, participating in consultations, reviewing and analyzing bulletins, decisions and amendments to regulations and enforceable instruments;
- Corporate costs including audit, insurance, executive, banking charges, contract management, lease agreements, Board of Directors costs and expenses, executive, human resources, Workers Safety Insurance Board administration, payroll administration, management, special studies; and

- Rent.

THI's Efficiency Initiatives

In past periods THI implemented productivity enhancements such as:

- Subscribing to Standards Forum;
- Implementing and commencing to parameterize a GIS asset data base;
- Appropriately equipping vehicles, such as trouble trucks, with telecommunications devices;
- Conducting an appropriate level of activities in-house and relying on third parties to provide specialized skills or one-time services (eg., testing transformer oil for PCBs and contaminants);
- Relocating distribution plant originally constructed in residential back yards to road allowance areas (eg., when rebuilding portions of the distribution system, when implementing voltage conversion in an area);
- Optimizing distribution system operations (eg., balancing lines, regulating voltage) to eliminate or pre-empt undue system stresses, to promote operating flexibility and to minimize losses;
- Working to eliminate legacy 4.16kV assets to achieve inventory efficiency;
- Standardizing physical plant assets (eg., using common dimension poles to the extent possible);
- Co-ordinating trenching operations with other utilities;
- Acquiring services from the Town to realize economies of scale by, for example, eliminating duplicate infrastructure (eg., one Purchasing department) and efficiently sharing overheads (eg., IT support, executive).

THI's Budgeting Methodology

THI's budget cycle normally commences in September with the development of the Statement of Budget assumptions for budget year. THI's reporting systems and controls rely on the following cost groupings:

- Labour;
- Fleet;
- Materials; and

- Other.

The costs of the past period are examined to establish the level of continuing costs and the actual costs as reported by the Town in the prior period under the MSA are also reviewed. These costs were incurred as a result of the Town's procurement policies and its competitive hiring practices. Project specific estimates are prepared for the phases of Voltage Conversion program that are to be implemented in the budget period to verify that the staff complement is adequate for the level of work planned for the period. The Town has detailed knowledge of its assets, period costs, cost drivers, efficiencies and economies of scale, and associated cost changes and pressures. Because The Town employs all staff it has access to complete knowledge of the activities that will be undertaken in the period, the costs, the controls and efficiencies and so on.

The budgets are rendered in USoA presentation by applying ratios determined using historic data.

Period costs paid to the Town of Tillsonburg under the Master Service Agreement

THI forecasts that it will incur $2,103k of period expenses as follows:

- Operations $871k
- Maintenance: $186k
- Billing and Collecting: $543k
- Administration: $503k
- Total: $2,103k

These amounts are net of costs eligible for capitalization of approximately $93k.

These cost groupings are incurred through the Town's provision of the following services pursuant to the MSA:

- Hydro Operations and Maintenance;
- Electrical Engineering Services;
- Meter Services, including Operations, Maintenance, Reading and Meter Data Management;

- Tree Trimming;
- Customer Services;
- Management;
- Customer Service Centre, Dispatch, Facilities; and
- Settlement, Energy Management.

Changes in OM&A 2008BY versus 2009TY

THI projects that it will incur $1,679k of OM&A expenses in the 2008BY. This is $408k less than the level forecast for the 2009TY. This difference arises because of the following changes:

- Staff complement;
- Commissioning a new Customer Information System;
- Postage and paper costs; and
- The amortization of the costs to file and defend the subject rates application.

Staffing Changes

A variance of $222k arises because of staffing changes. THI will require additional staff resources in the 2009TY versus the level relied on in the 2008BY in order to deal with regulatory matters and to appropriately manage work force transition issues. To this end, THI proposes to recruit a Manager, Regulatory Affairs as well as two apprentice linemen.

THI routinely monitors its work force and discerned the need to prepare for the likely retirement of 2 linemen. Since the exact timing of their retirements is unknown THI recruited and filled these positions of July 28, 2008. For budgeting purposes THI assumed that each position would be filled by mid-2008 and that each Apprentice Linesmen will cost $60k per annum.

The Manager, Regulatory Affairs position will be recruited for in the 2008BY. THI identified the need to fill this position twice previously and was not able to attract and hire an appropriately qualified candidate. Presently, a portion of the duties of the Town's Finance and Regulatory Affairs Manager are conducted by the Town's Financial and Regulatory Affairs Manager. This arrangement has become increasingly unsatisfactory. The position is forecasted to cost

$102k/year, including benefits, and is assumed that this position will be filled mid-2008; the corresponding expense in the 2008BY will amount to $69k.

New Customer Information System

$117k of the variance is attributable to the Town's investment in a new Customer Information System ("CIS") on behalf of THI. This amount will provide for the recovery of the incurred capital costs, $315k over three years, and for the ongoing operating costs, $47k per year, net of the operating costs of existing CIS, $41k.

The existing CIS is relied on to support electricity, water and sewers. The previous vendor has informed the Town of Tillsonburg that:

- it will not support future regulatory upgrades as of December 2008;
- it will continue to assist in technical problems with the last version; and
- it will not provide new versions to meet regulatory changes.

The Town of Tillsonburg, who provides THI with IT assets and services, procured an appropriate CIS, on behalf of THI, through membership in a buying consortium of similarly affected LDCs. They identified and evaluated competing alternatives and the Town and THI decided to adopt the Harris solution. This solution requires a new server and the conversion of existing data files to a form useable by the new system.

The procurement and implementation of this system eliminates the charges previously incurred of $41k.

Rate Rebasing Application

THI proposes to recover $53k in the 2009TY and in each of the three years of the Board's proposed IRM period to offset the anticipated costs to file and defend the subject application.

THI forecasts that it will incur $158k of costs to file and defend the subject application. THI proposes to amortize this amount over the rebasing period, which is assumed to be 4 years. This explains $38k of the year over year change. THI notes that this amount would have been lower if it had been able to attract and retain a Manager, Regulatory Affairs in a prior period.

THI has budgeted for $31k for intervenor costs with respect to the 2009 rates application. At this time THI lacks adequate information to estimate the OEB's costs to process the subject application. As a result THI has included an amount of $25k and undertakes to update this estimate when better information is available. Amortizing all these costs over 4 years explains $14k of the year over year change.

Paper and Postage Costs

In the 2009TY THI will assume responsibility for its budgeted paper and postage costs of $30k. These costs were incorrectly paid by the Town in prior periods.

THI is uniquely responsible for its depreciation expense, bad debt expense and PILs expense.

Depreciation Expense

THI forecasts depreciation expense of $502k in the 2009TY. The detailed derivation of this amount is set out at E2/T2/S4/AttA. This amount is $29k greater than the projected depreciation expense for the 2008BY and is attributable to capital spending net of contributions in aid of construction. THI depreciates its physical distribution plant assets over 25 years, consistent with the OEB's 2000 Electricity Distribution Rates Handbook. THI records the gross value of the plant at the time of commissioning as the direct costs incurred to render the asset used and useful plus a portion of the eligible indirect costs.

PILs Expense

THI forecasts that it will be liable for PILs expense of $72k in the 2009TY. The detailed derivation of this forecast expense is provided at E4/T1/S2/AttA-D. This amount is $7k less than the projected PILs expense for the 2008BY and is attributable to changes in the level of Net Income.

Bad Debt Expense

THI forecasts that it will incur Bad Debt expense of $17k in the 2009TY. This amount is forecast based on past experience and has been increased to reflect that bills are expected to increase, assuming that the subject application is granted by the OEB.

Outside services

External audit and legal services will be retained in the 2009TY and are budgeted. The Town has procured external services to file and support the subject rates application.

Depreciation

THI proposes to recover $502k of depreciation expense through distribution rates. This amount has been determined by applying the Board authorized depreciable lives to THI's eligible rate base using the straight line method. The computed depreciation expense achieves the recovery of the invested capital and does not recover anticipated disposition costs. Please note that because the Town of Tillsonburg provides THI with the assets required to provide corporate services (eg., Information Technology assets) pursuant to the MSA THI does not include the assets utilized to provide these services in rate base. As a result, THI's depreciation expense is confined to its physical distribution plant. All year over year depreciation expense variances are driven by capital investments.

THI's physical distribution plant has approximately 13 years of remaining depreciable life. An examination of account specific accumulated depreciation shows that the distribution plant ranges from a low of 5 years old on average to a high of more than 25 years.

THI's Meters account shows a Net Book Value of approximately $850k. The assets corresponding to this amount will be physically removed from service by the end of the 2010 rate year. Per the Board's current direction, THI will preserve this account and continue to depreciate it over the Board authorized depreciable life.

THI'S 2009TY depreciation expense has derived by:

- depreciating capital additions since 2000, when THI was formed, over the Board approved depreciable life; and
- depreciating the capital acquired when THI was formed in 2000 over the remaining depreciable life.

The 2009TY depreciation expense is derived at E2/T2/S4/AttA.

OM&A Costs Table

THI's OM&A costs for the period 2006-2009 are provided at E4/T2/S1/AttE. A variance analysis is provided at E4/T2/S2/AttF.

Historical Board Approved 2006 EDR to Historical Actual 2006

THI's OM&A costs increased by $269k. This is principally attributable to changes in Operations expenses driven by changes in staffing. In 2006 the Town recruited a Linesmen and a Hydro Technologist, both being dedicated to THI, as well as an Inventory Control Clerk (70% dedicated) and an Asset Management Technologist (25% dedicated); these positions increased THI's Operations expense by $178k from 2005 to 2006. Other significant changes include changes to management costs ($27k increase) and energy settlement cost changes ($17k). The remaining $47k of changes are due to changes in software costs, tree trimming costs and fleet costs.

Historical Actual 2006 to Actual 2007

THI's OM&A costs increased by $75k. This is principally attributable to:

- Increased compensation paid to THI's Board of Directors of $37k;
- Labour cost reductions in Meter Reading and Operations totaling $28k;
- scrap metal favourable variance of $25k;
- Meter reading contract services of $10k; and
- Customer service contract services of $6k.

Bridge 2008 to Historical Actual 2007

THI's OM&A costs increased by $75k. This is principally attributable to increased labour costs of $60k due to: the successful recruitment of two apprentice linemen mid-2008. THI routinely monitors its work force and discerned the need to prepare for the likely retirement of 2 linemen. Two of THI's experienced linesmen are eligible to retire. Since the exact timing of their retirements is unknown THI needs to commence to attract and train new linesmen now. These

positions were successfully recruited and filled as of July 28, 2008. For budgeting purposes THI assumed that each position would be filled mid-2008 and that each Apprentice Linesmen will cost $60k per annum.

Other notable cost increases in the period relate to:

- Increased pole testing costs of $11k; and
- Increased Energy Settlement costs of $7k.

Bridge 2008 to Test 2009

An increase of $408k is projected and is attributable to:

- Staffing Changes: THI intends to recruit a Manager, Regulatory Affairs by the beginning of 2009 at an annual cost of $102k;
- The two recently recruited linesmen apprentices will be on staff for the full year explaining $60k of the computed variance;
- The Town will commission a new CIS for THI's use that will be supported and able to apply Time of Use commodity charges, it gives rise to $117k of the year over year change;
- $54k of the change is due to the amortization of the costs to file and administer the subject rates application;
- $30k is due to THI assuming cost responsibility for paper and postage;
- Other cost changes of $35k relate to overall labour cost increases.

The Manager, Regulatory Affairs position will be recruited for in the 2008BY. THI identified the need to fill this position twice previously and was not able to attract and hire an appropriately qualified candidate. The successful applicant will be expected to undertake several special studies (eg., cost studies to demonstrate compliance with the ARC), file routine and special reports (eg., market monitoring information, special studies such as the Cost Allocation Review – Informational Filing), participate in and monitor consultations on regulatory issues, liaise with regulatory staff at other LDCs and with Ontario Energy Board staff, monitor documents issued by regulatory bodies. Presently, a portion of the duties of the Regulatory Affairs Manager are conducted by the Town's Finance and Regulatory Affairs Manager. This arrangement has become increasingly unsatisfactory as the complexity of regulation and the number of policy consultations increases and as the Board relies increasingly on analytical tools to support the

determination of rates and demonstrate compliance. The OEB's recent audit of THI's variance and deferral account balances noted that THI does not have a regulatory affairs staff member and attributed THI's lack of fluency with OEB decisions to this vacancy. The position of Manager, Regulatory Affairs is forecast to cost $102k/year. For budgeting purposes THI assumes that this position will be filled mid-2008 and that the corresponding expense will amount to $67k.

New Customer Information System

$117k of the variance is attributable to the town's investment in a new Customer Information System ("CIS"). This amount will provide for the recovery of the incurred capital costs, $315k over three years, and for the ongoing operating costs, $47k per year. In this respect, the Town of Tillsonburg, who provides THI with IT assets and services, is actively engaged in procuring an appropriate Customer Information System ("CIS"). The existing CIS is relied on to support electricity, water and sewers. The vendor has informed the Town of Tillsonburg that:

- it will not support future regulatory upgrades as of December 2008;
- it will continue to assist in technical problems with the last version; and
- it will not provide new versions to meet regulatory changes.

This means that the current CIS will not be able to accommodate time of use pricing or the telecommunication interfaces required in support of the province's minimum functionality specifications. Absent this innovation in the Ontario electricity market, the existing CIS would be competent for the foreseeable future.

The Town of Tillsonburg procured an appropriate CIS, on behalf of THI, through membership in a buying consortium of similarly affected LDCs. They identified and evaluated competing alternatives and the Town and THI decided to adopt the Harris solution. This solution requires a new server and the conversion of existing data files to a form useable by the new system.

The procurement and implementation of this system eliminates the charges previously incurred cost of $41k.

Rate Rebasing application

THI proposes to recover $53k in the 2009TY and in each of the years of the IRM period to cover the anticipated costs to file and administer the subject application.

THI forecasts that it will incur $158k of costs to file the 2009 rate rebasing application. THI proposes to amortize this amount over the rebasing period, which is assumed to be 4 years. This explains $38k of the year over year change. THI notes that this amount would have been lower if it had attracted and retained a Manager, Regulatory Affairs in a prior period.

THI has budgeted for $31k for intervenor costs with respect to the 2009 rates application. This assumes that two historic intervenors and one local area customer intervene in the application. At this time THI lacks adequate information to estimate the OEB's costs to process the subject application. As a result THI has included an amount of $25k and undertakes to update this estimate when better information is available. Amortizing all these costs over 4 years explains $14k of the year over year change.

OM&A Costs Table

THI's OM&A costs are provided at E4/T2/S1/AttE.

Appendix 1-2

Account Grouping	2006 EDR Approved	2006 Actual	2007 Actual	2008 Projection	2009 @ existing rates	2009 @ new dist. rates
3500-Distribution Expenses - Operation	403,209	659,328	616,632	681,845	871,060	871,060
3550-Distribution Expenses - Maintenance	145,599	182,352	179,508	162,754	186,092	186,092
3650-Billing and Collecting	327,045	377,483	394,768	426,108	543,447	543,447
3700-Community Relations		25,863	6,458			
3800-Administrative and General Expenses	466,193	376,320	422,904	424,719	502,694	502,694
3950-Taxes Other Than Income Taxes	2,679	-7,200				
OM&A Expenses	1,344,725	1,614,146	1,620,270	1,695,427	2,103,292	2,103,292

Variance Analysis on OM&A Costs Table

Detailed information on THI's OM&A variances is provided at Ex4/T2/S2/AttF.

Appendix 1-3

Account Grouping	2009 @ new dist. rates	2009 @ existing rates	Var $	Var %
3500-Distribution Expenses - Operation	871,060	871,060		
3550-Distribution Expenses - Maintenance	186,092	186,092		
3650-Billing and Collecting	543,447	543,447		
3700-Community Relations				
3800-Administrative and General Expenses	502,694	502,694		
3950-Taxes Other Than Income Taxes				
OM&A Expenses	2,103,292	2,103,292		

Appendix 1-3

Account Grouping	2009 @ existing rates	2008 Projection	Var $	Var %
3500-Distribution Expenses - Operation	871,060	681,845	**189,215**	**27.8%**
3550-Distribution Expenses - Maintenance	186,092	162,754	**23,337**	**14.3%**
3650-Billing and Collecting	543,447	426,108	**117,339**	**27.5%**
3700-Community Relations				
3800-Administrative and General Expenses	502,694	424,719	**77,975**	**18.4%**
3950-Taxes Other Than Income Taxes				
OM&A Expenses	2,103,292	1,695,427	**407,866**	**24.1%**

Appendix 1-3

Account Grouping	2008 Projection	2007 Actual	Var $	Var %
3500-Distribution Expenses - Operation	681,845	616,632	**65,213**	**10.6%**
3550-Distribution Expenses - Maintenance	162,754	179,508	-16,754	(9.3%)
3650-Billing and Collecting	426,108	394,768	**31,340**	**7.9%**
3700-Community Relations		6,458	-6,458	(100.0%)
3800-Administrative and General Expenses	424,719	422,904	1,815	0.4%
3950-Taxes Other Than Income Taxes				
OM&A Expenses	1,695,427	1,620,270	**75,156**	**4.6%**

Appendix 1-3

Account Grouping	2007 Actual	2006 Actual	Var $	Var %
3500-Distribution Expenses - Operation	616,632	659,328	**-42,696**	**(6.5%)**
3550-Distribution Expenses - Maintenance	179,508	182,352	**-2,844**	**(1.6%)**
3650-Billing and Collecting	394,768	377,483	**17,286**	**4.6%**
3700-Community Relations	6,458	25,863	**-19,405**	**(75.0%)**
3800-Administrative and General Expenses	422,904	376,320	**46,584**	**12.4%**
3950-Taxes Other Than Income Taxes		-7,200	**7,200**	**100.0%**
OM&A Expenses	1,620,270	1,614,146	**6,124**	**0.4%**

Appendix 1-3

Account Grouping	2006 Actual	2006 EDR Approved	Var $	Var %
3500-Distribution Expenses - Operation	659,328	403,209	**256,119**	**63.5%**
3550-Distribution Expenses - Maintenance	182,352	145,599	**36,753**	**25.2%**
3650-Billing and Collecting	377,483	327,045	**50,438**	**15.4%**
3700-Community Relations	25,863		**25,863**	
3800-Administrative and General Expenses	376,320	466,193	**-89,873**	**(19.3%)**
3950-Taxes Other Than Income Taxes	-7,200	2,679	-9,879	(368.8%)
OM&A Expenses	1,614,146	1,344,725	**269,421**	**20.0%**

Materiality Analysis on OM&A Costs

Detailed information on THI's material changes in OM&A costs is provided at E4/T1/S2/p13-16. THI has determined material changes to its OM&A levels based on a 1% materiality criteria. The changes that exceed this level appear in bold type.

Shared Services

THI shares services with its corporate parent, the Town of Tillsonburg. Under this arrangement the Town provides THI with the goods and services required to support the provision of electricity distribution service. THI does not provide any goods or services to the Town for its use.

Service Agreement(s)

THI acquires services from the Town of Tillsonburg pursuant to a Master Services Agreement (E1/T2/S1/AttA).

Corporate Cost Allocation

THI's corporate costs are incurred pursuant to the Master Service Agreement ("MSA") between THI and the Town of Tillsonburg. The direct costs incurred by the Town are allocated to THI based on time estimates. THI pays for the goods and services provided by the Town under the MSA on a fixed cost basis. The level of corporate costs is negotiated annually.

Description and Assumptions

THI is provided with the following corporate services pursuant to the MSA:

- Senior management;
- Financial management, Treasury services and Risk Management services;
- Legal and Audit services;
- Procurement and Stores services;
- Records Management services;
- Human Resources services;
- Information Technology management and administration services; and
- All aspects of Customer Care services including Billing and Collections
- Facilities.

These services are provided by staff employed by the Town of Tillsonburg who use appropriate assets (eg., computer hardware and software, facilities) that are owned by the Town. THI forecasts the level of services that will be required and agrees to pay the costs incurred by the Town in providing these services.

The type, level and quality of services to be provided by the Town is documented and enforced through the MSA. The level of service provided is to be consistent with good utility practice. THI projects its needs for corporate services based on prior periods needs and adjusts for known changes.

Methodology and Policy

THI pays for the allocated corporate costs on a fixed charge basis. This provides THI with certainty over its costs of the period. The Town relies on its Time Sheet system to track and correctly assign costs. This detailed cost information is relied on when the parties negotiate the charges for the next period.

The Management Fee is properly applied to recover costs eligible for recovery but not previously identified, to collect funds to offset the indirect costs incurred by the Town in providing service to THI and to offset the costs of capital employed by the Town.

THI bears a risk of service under-provisioning and the Town bears the risk of service over-provisioning. The Town is aware that a well run electricity distribution system that provides good quality service and charges just and reasonable rates is an economic development tool.

Purchase of Services

THI purchases the goods and services required to provide electricity distribution service from the Town of Tillsonburg pursuant to the Master Service Agreement ("MSA"). The Town relies on its staff and the assets it owns to satisfy the requirements of the MSA. The Town procures additional or specialize goods and services from third parties according to its procurement policies (E2/T1/S1/AttA).

THI proposes to recover the costs related to the purchase of services incurred to:

- file and administer the subject rates application; and
- prepare a Load Forecast in support of the proposed rates.

These costs are discussed at E4/T1/S2/p16. THI does not expect to purchase services for any other purpose in the 2009TY.

Employee Description

THI does not have any employees.

THI provides electricity distribution service by relying on staff employed by the Town of Tillsonburg. The positions and the proportion dedicated to THI are documented at E1/T2/S4/AttA.

Loss Adjustment Factor Calculation

THI proposes to rely on the following distribution loss factors in the 2009TY:

Total Primary Metered Customer < 5,000 kW	2.84%
Total Secondary Metered Customer < 5,000 kW	3.88%
Primary Metering Allowance (%)	1.00%

The purpose of this evidence is:

- To explain THI's methodology;
- To discuss the reasons for losses;
- To identify the actions THI is taking to reduce losses.

Methodology

THI relied on the Board's distribution loss factor methodology, as set out in the Retail Settlement Code and the Board's 2006 EDR model. Specifically, THI compared its annual energy receipts from HONI to its annual energy deliveries to its customers for the years 2002 – 2007. This data is provided at E4/T2/S9/AttA and E4/T2/S9/AttB. THI has relied on the Board's default values for the System Facilities Loss Factor and the Primary Adjustment Factor, being 0.45% and 1.00% respectively.

The historic Total Loss Factors are estimated to be:

- 3.81% for 2005
- 3.91% for 2006
- 3.92% for 2007

The three year average of these values is 3.88%.

The corresponding Distribution System Loss Factor is estimated to be 3.41%. This amount is assumed to be the appropriate Secondary Distribution System Loss Factor ("SDSLF"). The Primary Adjustment Factor is applied to the assumed SDSLF to yield the Primary Distribution System Loss Factor ("PDSLF") of 2.38%. The SDSLF and PDSLF are then adjusted by the Primary Adjustment Factor to yield the appropriate TDLF, Primary of 2.84% and the appropriate TDLF, Secondary of 3.88%.

Explanation of Loss >5%

THI's loss factor is less than 5%.

Detail Action Plan for Losses (Past and Future)

Distribution System Losses Drivers and Corrective Actions being taken by THI

Distribution system losses are incurred because of technical and non-technical reasons. Technical losses occur because of the assets relied on to redelivery power and energy and arise because of transformer losses including that incurred at Municipal Stations, meter lags, conductor losses, current fluctuations, due to heat stress. Non-technical reasons include timing differences, theft of power and fraudulent use of power, meter error, meter reading error.

THI's Voltage Conversion program yields tangible benefits in reducing and controlling losses. The removal of each Municipal Station is accompanied by a reduction in technical losses. Other loss related benefits of the Voltage Conversion program include relying on appropriately sized conductor, rebalancing the neutral and overall system rebalancing.

The Voltage Conversion program will not eliminate losses. Upon the completion of the Voltage Conversion program technical losses will continue to exist due the presence and operation of transformers and conductors and the observed losses will be greater during hot days when the distribution system is more heavily loaded and stressed.

Non-technical losses are expected to be reduced somewhat after Smart Meters are deployed throughout the service area. This is because any existing theft of power situations will be detected and corrected, because the drift that is characteristic of electro-mechanical meters will be eliminated with the introduction of electronic meters, because any inappropriate meter installations or configurations will be corrected and because timing differences with respect to the recognition of the sale of power will be eliminated.

Non-technical losses will become easier to detect and identify upon the implementation of Smart Meters. They will not be eliminated, but rather decreased.

Details of Total Losses

THI's total losses for the years 2005, 2006 and 2007 are provided at E4/T2/S9/AttA.

The three year average is 3.88%.

THI proposes to apply the following loss factors in the 2009TY:

- Primary Metered Customers <5,000 kW 2.84%
- Secondary Metered Customers <5,000 kW 3.88%

The proposed loss factors were determined based on the OEB's loss factor methodology set out in the Retail Settlement Code and relied on in the 2006 EDR.

Loss Adjustment Factor Calculation

			2003	2004	2005	2006	2007
a	*taken from CIS*	Total Energy - Wholesale	228,959,235	234,727,082	238,097,540	228,381,104	238,097,540
b		STLT*	-	1,777,198	249,338	57,132	-
c		LTLT* to HO Customers THI Feeder	290,640	329,290	203,610	181,950	227,200
d	*[a-b-c]*	Total Wholesale	228,668,595	232,620,594	237,644,592	228,142,022	237,870,340
e	*taken from CIS*	Retail	218,129,683	223,361,686	229,092,685	219,728,774	229,092,685
f		STLT*	11,985	-	-	-	-
g		LTLT* to THI Customers HO Feeder	322,526	187,418	172,933	174,737	185,520
h	*[e-f-g]*	Total Retail	217,795,172	223,174,268	228,919,752	219,554,037	228,907,165
	[(d)/(h)]	Total Losses	1.0499	1.0423	1.0381	1.0391	1.0392

Tillsonburg Hydro Inc.
Distribution System Losses

		2003	2004	2005	2006	2007
Total Losses		4.99%	4.23%	3.81%	3.91%	3.92%
3 year average				4.34%	3.98%	3.88%
Assumptions						
	Supply Facility Loss Factor	1.0045				
	Primary Adjustment Factor	1.01				
DLF Secondary Metered >5,000kW		1%				
Distribution System Losses				1.038759	1.035175	1.034146
Distribution Loss Factor - Secondary Metered Customer < 5,000 kW				1.038759	1.035175	1.034146
Distribution Loss Factor - Primary Metered Customer < 5,000 kW				1.028371	1.024823	1.023805
Total Loss Factor - Secondary Metered Customer < 5,000 kW				1.043433	1.039833	1.0388
Total Loss Factor - Primary Metered Customer < 5,000 kW				1.032999	1.029435	1.028412

Variance and Materiality Analysis on Distribution Losses

THI's distribution losses do not vary materially except in the year when a Municipal Station is removed from service. THI will not remove a Municipal Station from service during the 2009TY and does not expect to any earlier than 2010.

Retail Transmission Adjustment Calculations

THI has applied its currently authorized Retail Transmission Service Rates ("RTSR"). THI is aware that Hydro One Networks Inc. ("HONI") intends to file a transmission rates application in the near future and undertakes to update its RTSRs based on the Board's Decision.

Tax Calculations Overview

THI seeks to recover $72k through distribution rates to provide sufficient funds to pay its deemed PILs expense. THI's target Net Income for the 2009 TY is $332k. The PILs expense is determined by Taxable Income and applying the prevailing tax rate.

The derivation of the 2009 TY PILs expense is provided at E4/T1/S2/AttA-D.

THI generated loss carry forwards and tax deductions during the period 2000 – 2004 when it incurred financial and tax losses. These tax reducing amounts were exhausted as of 2005. As a result, THI has no ability to reduce its PILs expense through such mechanisms.

THI does not incur capital taxes.

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P1 Undepreciated Capital Costs (UCC)

Class	Description	UCC Balance 31 Dec/07 [1]	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC 2008 Opening Balance
1	Distribution System - post 1987	6,258,804			**6,258,804**
2	Distribution System - pre 1988				
8	General Office/Stores Equip				
10	Computer Hardware/ Vehicles				
10.1	Certain Automobiles				
12	Computer Software				
13.1	Leasehold Improvement # 1				
13.2	Leasehold Improvement # 2				
13.3	Leasehold Improvement # 3				
13.4	Leasehold Improvement # 4				
14	Franchise				
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				
43.1	Certain Energy-Efficient Electrical Generating Equipment				
45	Computers & Systems Software acq'd post Mar 22/04				
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				
47	Distribution System post Feb 22/05	2,140,299			**2,140,299**
	TOTAL	**8,399,103**			**8,399,103**

[1] per Schedule 8 of 2007 corporate tax return

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P1 Undepreciated Capital Costs (UCC)

Class	Description	2008 Projected Additions	2008 Projected Retirements	UCC Before 1/2 Yr Adjustment	1/2 Year Reduction
1	Distribution System - post 1987			6,258,804	
2	Distribution System - pre 1988				
8	General Office/Stores Equip				
10	Computer Hardware/ Vehicles				
10.1	Certain Automobiles				
12	Computer Software				
13.1	Leasehold Improvement # 1				
13.2	Leasehold Improvement # 2				
13.3	Leasehold Improvement # 3				
13.4	Leasehold Improvement # 4				
14	Franchise				
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				
43.1	Certain Energy-Efficient Electrical Generating Equipment				
45	Computers & Systems Software acq'd post Mar 22/04				
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				
47	Distribution System post Feb 22/05	790,123		2,930,422	395,062
	TOTAL	**790,123**		**9,189,226**	**395,062**

[1] per Schedule 8 of 2007 corporate tax return

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P1 Undepreciated Capital Costs (UCC)

Class	Description	Reduced UCC	Rate %	2008 CCA	UCC 31 Dec/08
1	Distribution System - post 1987	6,258,804	4.0%	250,352	6,008,452
2	Distribution System - pre 1988		6.0%		
8	General Office/Stores Equip		20.0%		
10	Computer Hardware/ Vehicles		30.0%		
10.1	Certain Automobiles		30.0%		
12	Computer Software		100.0%		
13.1	Leasehold Improvement # 1		25 years		
13.2	Leasehold Improvement # 2		4 years		
13.3	Leasehold Improvement # 3				
13.4	Leasehold Improvement # 4				
14	Franchise		6 years		
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs		8.0%		
43.1	Certain Energy-Efficient Electrical Generating Equipment		30.0%		
45	Computers & Systems Software acq'd post Mar 22/04		45.0%		
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)		30.0%		
47	Distribution System post Feb 22/05	2,535,361	8.0%	202,829	2,727,593
	TOTAL	**8,794,165**		**453,181**	**8,736,045**

[1] per Schedule 8 of 2007 corporate tax return

RateMaker PILs r1.1 © Elenchus Research Associates

P1 Undepreciated Capital Costs (UCC)

Class	Description	2009 Projected Additions	2009 Projected Retirements	UCC Before 1/2 Yr Adjustment	1/2 Year Reduction
1	Distribution System - post 1987			6,008,452	
2	Distribution System - pre 1988				
8	General Office/Stores Equip				
10	Computer Hardware/ Vehicles				
10.1	Certain Automobiles				
12	Computer Software				
13.1	Leasehold Improvement # 1				
13.2	Leasehold Improvement # 2				
13.3	Leasehold Improvement # 3				
13.4	Leasehold Improvement # 4				
14	Franchise				
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				
43.1	Certain Energy-Efficient Electrical Generating Equipment				
45	Computers & Systems Software acq'd post Mar 22/04				
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				
47	Distribution System post Feb 22/05	556,082		3,283,675	278,041
	TOTAL	**556,082**		**9,292,127**	**278,041**

[1] per Schedule 8 of 2007 corporate tax return

RateMaker PILs r1.1 © Elenchus Research Associates

P1 Undepreciated Capital Costs (UCC)

Class	Description	Reduced UCC	Rate %	2009 CCA	UCC 31 Dec/09
1	Distribution System - post 1987	6,008,452	4.0%	240,338	5,768,114
2	Distribution System - pre 1988		6.0%		
8	General Office/Stores Equip		20.0%		
10	Computer Hardware/ Vehicles		30.0%		
10.1	Certain Automobiles		30.0%		
12	Computer Software		100.0%		
13.1	Leasehold Improvement # 1				
13.2	Leasehold Improvement # 2				
13.3	Leasehold Improvement # 3				
13.4	Leasehold Improvement # 4				
14	Franchise				
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs		8.0%		
43.1	Certain Energy-Efficient Electrical Generating Equipment		30.0%		
45	Computers & Systems Software acq'd post Mar 22/04		45.0%		
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)		30.0%		
47	Distribution System post Feb 22/05	3,005,634	8.0%	240,451	3,043,224
	TOTAL	**9,014,086**		**480,789**	**8,811,338**

[1] per Schedule 8 of 2007 corporate tax return

RateMaker PILs r1.1 © Elenchus Research Associates

P3 Interest Expense

	2008	2009	
Deemed Interest Expense (A)	317,804	303,437	
3900-Interest Expense			
Add: Capitalized Interest (USA #6040)			*Enter credit to P&L as positive number*
Add: Capitalized Interest (USA #6042)			*Enter credit to P&L as positive number*
Less: non-debt interest expense (USA #6035)			
			Enter other adjustments for tax purposes
Total Interest Projected (B)			
Excess Interest Expense			*(B) less (A); if negative: zero*

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P6 Taxable Income

	T2 S1 line #	2006 EDR Approved			2008 Projection	2009 @ existing rates	2009 @ new dist. rates
		Tax Return	Less: Non-Distribution Portion	Utility Only			
Income/(Loss) before PILs/Taxes (Accounting) [1]					368,006	-45,354	332,265
Additions:							
Interest and penalties on taxes	103						
Amortization of tangible assets	104				472,797	501,676	501,676
Amortization of intangible assets	106						
Recapture of capital cost allowance from Schedule 8	107						
Gain on sale of eligible capital property from Schedule 10	108						
Income or loss for tax purposes- joint ventures or partnerships	109						
Loss in equity of subsidiaries and affiliates	110						
Loss on disposal of assets	111						
Charitable donations	112						
Taxable Capital Gains	113						
Political Donations	114						
Deferred and prepaid expenses	116						
Scientific research expenditures deducted on financial statements	118						
Capitalized interest	119						
Non-deductible club dues and fees	120						
Non-deductible meals and entertainment expense	121						
Non-deductible automobile expenses	122						
Non-deductible life insurance premiums	123						
Non-deductible company pension plans	124						
Tax reserves beginning of year	125						
Reserves from financial statements- balance at end of year	126						

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P6 Taxable Income

	T2 S1 line #	2006 EDR Approved			2008 Projection	2009 @ existing rates	2009 @ new dist. rates
		Tax Return	Less: Non-Distribution Portion	Utility Only			
Income/(Loss) before PILs/Taxes (Accounting) [1]					368,006	-45,354	332,265
Soft costs on construction and renovation of buildings	127						
Book loss on joint ventures or partnerships	205						
Capital items expensed	206						
Debt issue expense	208						
Development expenses claimed in current year	212						
Financing fees deducted in books	216						
Gain on settlement of debt	220						
Non-deductible advertising	226						
Non-deductible interest	227						
Non-deductible legal and accounting fees	228						
Recapture of SR&ED expenditures	231						
Share issue expense	235						
Write down of capital property	236						
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237						
Excess Interest Expense							
Total Additions					**472,797**	**501,676**	**501,676**

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P6 Taxable Income

	T2 S1 line #	2006 EDR Approved			2008 Projection	2009 @ existing rates	2009 @ new dist. rates
		Tax Return	Less: Non-Distribution Portion	Utility Only			
Income/(Loss) before PILs/Taxes (Accounting) [1]					368,006	-45,354	332,265
Deductions:							
Gain on disposal of assets per financial statements	401						
Dividends not taxable under section 83	402						
Capital cost allowance from Schedule 8	403				453,181	480,789	480,789
Terminal loss from Schedule 8	404						
Cumulative eligible capital deduction from Schedule 10 CEC	405						
Allowable business investment loss	406						
Deferred and prepaid expenses	409						
Scientific research expenses claimed in year	411						
Tax reserves end of year	413						
Reserves from financial statements - balance at beginning of year	414						
Contributions to deferred income plans	416						
Book income of joint venture or partnership	305						
Equity in income from subsidiary or affiliates	306						
Total Deductions					**453,181**	**480,789**	**480,789**

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P6 Taxable Income

	T2 S1 line #	2006 EDR Approved			2008 Projection	2009 @ existing rates	2009 @ new dist. rates
		Tax Return	Less: Non-Distribution Portion	Utility Only			
Income/(Loss) before PILs/Taxes (Accounting) [1]					368,006	-45,354	332,265
NET INCOME (LOSS) FOR TAX PURPOSES					**387,622**	**-24,467**	**353,152**
Charitable donations from Schedule 2							
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)							
Non-capital losses of preceding taxation years from Schedule 4							
Net-capital losses of preceding taxation years from Schedule 4							
Limited partnership losses of preceding taxation years from Schedule 4							
TAXABLE INCOME (LOSS)					**387,622**	**-24,467**	**353,152**

[1] 2008 Projection = "Earnings before Tax' (sheet E1); 2009 @ existing rates = "Earnings before Tax' (sheet E2); 2009 @ new dist. rates = "Deemed Return On Equity' (sheet E3)

PILs

THI estimates its 2009TY PILs expense to be $72k. The derivation of this amount is provided at E4/T1/S2/AttA-D.

THI estimates that its 2008BY PILs expense will be $79k.

THI's actual 2007HY PILs expense was $187k.

These amounts have been determined consistent with prevailing tax legislation and using the appropriate tax and other applicable rates.

Capital Cost Allowance (CCA)

THI's CCA for the 2009TY is forecast to be $481k. The derivation of this amount and the corresponding amount for the 2008BY is provided at E4/T1/S2/AttA.

Federal T2 tax return

THI's federal T2 Tax Return is provided at E4/T3/S4/AttA.

Canada Revenue Agency | Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

Schedule 200

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec, Ontario, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, and paragraphs mentioned on this return refer to the *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 services office or tax centre. 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 the T2 Corporation – Income Tax Guide (T4012).

055 Do not use this area

Identification

Business number (BN) **001** 86374 2599 RC 0001

Corporation's name

002 Tillsonburg Hydro Inc.

Has the corporation changed its name since the last time you filed your T2 return? **003** ☐ Yes ☒ No

If *Yes*, do you have a copy of the articles of amendment? **004** ☐ Yes ☐ No

(Do Not Submit)

Address of head office

Has this address changed since the last time you filed your T2 return? **010** ☐ Yes ☒ No

(If **yes**, complete lines 011 to 018)

011 200 Broadway, 2nd Floor

012

City: **015** Tillsonburg — Province, territory, or state: **016** ON

Country (other than Canada): **017** — Postal code/Zip code: **018** N4G 5A7

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? **020** Yes ☐ No ☒

(If **yes**, complete lines 021 to 028)

021 c/o Darrell Eddington

022 200 Broadway, 2nd Floor

023

City: **025** Tillsonburg — Province, territory, or state: **026** ON

Country (other than Canada): **027** — Postal code/Zip code: **028** N4G 5A7

Location of books and records

Has the location of books and records changed since the last time you filed your T2 return? **030** ☐ Yes ☒ No

(If **yes**, complete lines 031 to 038)

031 200 Broadway, 2nd Floor

032

City: **035** Tillsonburg — Province, territory, or state: **036** ON

Country (other than Canada): **037** — Postal code/Zip code: **038** N4G 5A7

040 Type of corporation at the end of the tax year

1 ☒ 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**

To which tax year does this return apply?

From **060** 2007/01/01 to **061** 2007/12/31

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? **063** ☐ Yes ☒ No

If **yes**, provide the date control was acquired **065**

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1) ? **066** ☐ Yes ☒ No

Is the corporation a professional corporation that is a member of a partnership? **067** ☐ Yes ☒ No

Is this the first year of filing after:

Incorporation? **070** ☐ Yes ☒ No

Amalgamation? **071** ☐ Yes ☒ No

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** ☐ Yes ☒ No

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? **076** ☐ Yes ☒ No

Is this the final return up to dissolution? **078** ☐ Yes ☒ No

Is the corporation a resident of Canada? **080** ☒ Yes ☐ 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** ☐ Yes ☒ No

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	☒	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	☒	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	☐	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	☐	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207	☐	7
Does the corporation have any property that is eligible for capital cost allowance?	208	☒	8
Does the corporation have any property that is eligible capital property?	210	☐	10
Does the corporation have any resource-related deductions?	212	☐	12
Is the corporation claiming reserves of any kind?	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
Was 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?	255	☐	92 *

*** We do not print this schedule.**

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

Is the corporation inactive? **280** 1 Yes ☐ 2 No ☒

Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers) **281** 1 Yes ☐ 2 No ☒

What is the corporation's major business activity? **282** _____
(Only complete if **yes** was entered at line 281.)

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.

284	Electricity distribution	**285**	100.000 %
286		**287**	%
288		**289**	%

Did the corporation immigrate to Canada during the tax year? **291** 1 Yes ☐ 2 No ☒

Did the corporation emigrate from Canada during the tax year? **292** 1 Yes ☐ 2 No ☒

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI		**300**	602,626	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")			602,626	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions		**355**		D
Taxable income (amount C **plus** amount D)		**360**	602,626	
Income exempt under paragraph 149(1)(t)		**370**		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724 on page 8.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 — **400** 602,626 A

Taxable income from line 360 on page 3, **minus** 10/3 of the amount on line 632 on page 7, **minus** 3 times the amount on line 636 on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax — **405** 602,626 B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

$300,000 x (Number of days in the tax year in 2005 and in 2006 / Number of days in the tax year) = 1

$400,000 x (Number of days in the tax year after 2006 / Number of days in the tax year) 365/365 = 400,000 2

Add amounts at lines 1 and 3 — 400,000 4

Business limit (see notes 1 and 2 below) — **410** 400,000 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 400,000 X **415** D / 11,250 = E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") — **425** 400,000 F

Small business deduction

Amount A, B, C, or F whichever is the least 400,000 x (Number of days in the tax year before January 1, 2008 / Number of days in the tax year) 365/365 x 16% = 64,000 5

Amount A, B, C, or F whichever is the least 400,000 x (Number of days in the tax year after Dec.31, 2007 / Number of days in the tax year) /365 x 17% = 6

Total of amounts 5 and 6 - enter on line 9 of page 7 — **430** 64,000 G

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)] — **435** H

Amount H x (Number of days in the tax year in 2005 / Number of days in the tax year) /365 x 3% = I

Amount H x (Number of days in the tax year in 2006 / Number of days in the tax year) /365 x 5% = J

Amount H x (Number of days in the tax year in 2007 / Number of days in the tax year) 365/365 x 7% = K

Resource deduction – total of amounts I and J — **438** L

(enter amount L on line 10 of page 7)

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3				602,626 A
Amount Z from Part 9 of Schedule 27		x 100 / 7 =		B
Amount QQ from Part 13 of Schedule 27				C
Taxable resource income from line 435 on page 4				D
Amount used to calculate the credit union deduction (from Schedule 17)				E
Amount on line 400, 405, 410, or 425 on page 4, whichever is the least			400,000	F
Aggregate investment income from line 440 of page 6				G
Total of amounts B, C, D, E, F, and G			400,000 ▶	400,000 H
Amount A **minus** amount H (if negative, enter "0")				202,626 I

Amount I	202,626	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365 / 365	x 7% =	14,184 J
Amount I	202,626	x	Number of days in the tax year after Dec. 31, 2007 and before Jan. 1, 2009 / Number of days in the tax year	/ 365	x 8.5% =	K

General tax reduction for Canadian-controlled private corporations - total of amounts J and K — 14,184 L

Enter amount L on line 638 of page 7

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation, and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 on page 3 (for tax years starting after May 1, 2006, Amount Z on page 3)				M
Amount Z from Part 9 of Schedule 27		x 100 / 7 =		N
Amount QQ from Part 13 of Schedule 27				O
Taxable resource income from line 435 on page 4				P
Amount used to calculate the credit union deduction (from Schedule 17)				Q
Total of amounts N, O, P, and Q			▶	R
Amount M **minus** amount R (if negative, enter "0")				S

Amount S		x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year		x 7% =	T
Amount S		x	Number of days in the tax year after Dec. 31, 2007 and before Jan. 1, 2009 / Number of days in the tax year	/ 365	x 8.5% =	U

General tax reduction - total of amounts T and U — V

Enter amount V on line 639 of page 7.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income (from Schedule 7)	**440**		X 26 2/3 % =		A
Foreign non-business income tax credit from line 632 on page 7					
Deduct:					
Foreign investment income (from Schedule 7)	**445**		X 9 1/3 % = (if negative, enter "0")		B
Amount A **minus** amount B (if negative, enter "0")					C
Taxable income from line 360 on page 3			602,626		
Deduct:					
Amount on line 400, 405, 410, or 425 on page 4, whichever is the least		400,000			
Foreign non-business income tax credit from line 632 of page 7		x 25/9 =			
Foreign business income tax credit from line 636 of page 7		x 3 =			
		400,000	400,000		
			202,626	X 26 2/3% = 54,034	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8)			97,300		
Deduct: Corporate surtax from line 600 of page 7			6,749		
Net amount			90,551	90,551	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least				**450** 0	F

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**	0

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3		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 of page 8)			0

Part I tax

Base amount of Part I tax

taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38% — **550** 228,998 A

Corporate surtax calculation

Base amount from line A above		228,998	1
Deduct:			
10% of taxable income (line 360 or amount Z, whichever applies) from page 3		60,263	2
Investment corporation deduction from line 620 below			3
Federal logging tax credit from line 640 below			4
Federal qualifying environmental trust tax credit from line 648 below			5
For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:			
28% of taxable income from line 360 on page 3	a		
28% of taxed capital gains	b		6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F)	90,551 c		
Total of lines 2 to 6		60,263	7
Net amount (line 1 **minus** line 7)		168,735	8

Corporate surtax*

Line 8 168,735 x (Number of days in the tax year before January 1, 2008 / Number of days in the tax year) 365 / 365 x 4% = **600** 6,749 B

*The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from Schedule 31 — **602** C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			i
Taxable income from line 360 on page 3	602,626		
Deduct: Amount on line 400, 405, 410, or 425 of page 4, whichever is the least	400,000		
Net amount	202,626 ▶	202,626	ii

Refundable tax on CCPC's investment income – 6 2/3% of whichever is less: amount i or ii — **604** D

Subtotal (**add** lines A, B, C, and D) — 235,747 E

Deduct:

Small business deduction from line 430 on page 4		64,000	9
Federal tax abatement	**608**	60,263	
Manufacturing and processing profits deduction from Schedule 27	**616**		
Investment corporation deduction (taxed capital gains **624**)	**620**		
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**		
Resource deduction from line 438 on page 4			10
General tax reduction for CCPCs from amount L on page 5	**638**	14,184	
General tax reduction from amount V on page 5	**639**		
Federal logging tax credit from Schedule 21	**640**		
Federal political contribution tax credit	**644**		
Federal political contributions **646**			
Federal qualifying environmental trust tax credit	**648**		
Investment tax credit from Schedule 31	**652**		
Subtotal		138,447 ▶	138,447 F

Part I tax payable – Line E **minus** line F — 97,300 G

Enter amount G on line 700 of page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	97,300
Part I.3 tax payable from Schedule 33, 34, or 35	704	
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		97,300

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, Ontario and Alberta)	760		
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765		
Total tax payable	770	97,300	A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from page 6	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840		
Total credits	890		B
Balance (line A minus line B)		97,300	I

Refund Code **894** ☐ Overpayment

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 97,300
Enclosed payment **898**

Direct Deposit Request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information **910** Branch number

914 Institution number **918** Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? **896** 1 Yes ☒ 2 No ☐ NA ☐

Certification

I, **950** Eddington (Last name) **951** Darrell (First name) **954** Treasurer (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 2008/06/25 (Date) — Signature of the authorized signing officer of the corporation — **956** (519) 842-6428 (Telephone number)

Is the contact person the same as the authorized signing officer? If *no*, complete the information below. **957** 1 Yes ☒ 2 No ☐

958 Name **959** ( ) - Telephone number

Language of correspondence - Langue de correspondance

990 Language of choice/Langue de choix 1 English / Anglais ☒ 2 Français / French ☐

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES

Schedule 1

- 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.

Net income (loss) after taxes and extraordinary items per financial statements			**A**	387,129
Add:				
Provision for income taxes - current	**101**	187,056		
Amortization of tangible assets	**104**	440,419		
Total of fields 101 to 199	**500**	627,475	▶	627,475
Deduct:				
Capital cost allowance - Schedule 8	**403**	411,978		
Total of fields 401 to 499	**510**	411,978	▶	411,978
Net income (loss) for income tax purposes (enter on line 300 of the T2 return)				602,626

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CAPITAL COST ALLOWANCE

Schedule 8

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 **200**	2 UCC at start of year **201**	3 Cost of additions in the year **203**	4 Net adjustments **205**	5 Proceeds of dispositions in the year **207**	7 Adjustment for additions (1/2 x (col 3 - 5)) **211**	8 Base amount for CCA	9 Rate % **212**	10 Recapture of CCA **213**	11 Terminal loss **215**	12 CCA for the year (col 8 x 9 or a lower amount) **217**	13 UCC at the end of the year **220**
1	6,519,588					6,519,588	4			260,784	6,258,804
47	1,488,360	803,133			401,567	1,889,926	8			151,194	2,140,299
Totals	8,007,948	803,133			401,567	8,409,514				411,978	8,399,103

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SHAREHOLDER INFORMATION

Schedule 50

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual or trust) **100**	Business Number (If a corporation is not registered, enter "NR") * **200**	Social Insurance Number * **300**	Trust Number (If a trust number is not available, enter "NA") * **350**	Percentage common shares **400**	Percentage preferred shares **500**
Corporation of the Town of Tillsonburg	12658 7195 RC 0001			100.000	
	RC				

* For a taxation year commencing before January 1, 2004, if the shareholder is a trust, enter NR at field 200 or NA at field 300. Do not enter a trust number in field 350.

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BALANCE SHEET INFORMATION

Schedule 100

Assets	Code	Current year	Prior year
Cash and deposits	**1000**	847,463	365,823
Accounts Receivable	1060	2,904,951	3,401,082
Inventories	1120	361,777	387,308
Prepaid expenses	1484	30,042	26,696
Total tangible capital assets	2008	13,042,205	12,239,072
Accumulated amortization of total tangible capital assets	2009	(7,124,294)	(6,683,875)
Due from corporate shareholder(s)	2182	357,748	
Total long term assets	2589		555,656
Total assets	**2599**	10,419,892	10,291,762

Liabilities	Code	Current year	Prior year
Bank overdraft	**2600**		
Amounts payable and accrued liabilities	2620	1,948,282	2,095,777
Taxes payable	2680	2,000	98,886
Deposits received	2961	275,988	176,437
Due to corporate shareholder(s)	3262		132,099
Total long term liabilities	3450	114,708	96,778
Total liabilities	**3499**	2,340,978	2,599,977

Equity	Code	Current year	Prior year
Common shares	**3500**	6,992,565	6,992,565
Contributed and other surplus	3540	1,190,387	1,190,387
Retained earnings / deficit	**3600**	(104,038)	(491,167)
Total equity	**3620**	8,078,914	7,691,785
Total liabilities and equity	**3640**	10,419,892	10,291,762

Retained earnings	Code	Current year	Prior year
Retained earnings/deficit-start	**3660**	(491,167)	(782,993)
Net income / loss	**3680**	387,129	291,826
Total retained earnings	**3849**	(104,038)	(491,167)

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INCOME STATEMENT INFORMATION

Schedule 125

Details

Operating name, if different from the corporations' legal name

0001

Description of operation, if filing multiple Schedules 125

0002

Revenue	Code	Current year	Prior year
Trade sales of goods and services	**8000**	19,623,994	18,785,778
Total sales of goods and services	**8089**	19,623,994	18,785,778
Realized gains / losses on disposal of assets	8210		(22,115)
Total revenue	**8299**	19,623,994	18,763,663

Cost of sales	Code	Current year	Prior year
Opening inventory	**8300**		
Purchases / cost of materials	8320	16,970,097	16,315,869
Cost of sales	**8518**	16,970,097	16,315,869
Gross profit / loss (item 8089 - item 8518)	**8519**	2,653,897	2,469,909

Operating expenses	Code	Current year	Prior year
Amortization of tangible assets	8670	440,419	409,940
Other expenses	9270	1,639,293	1,631,228
Total operating expenses	**9367**	2,079,712	2,041,168
Total expenses	**9368**	19,049,809	18,357,037
Net non-farming income	**9369**	574,185	406,626

Farming revenue	Code	Current year	Prior year
Grains and oilseeds	**9370**		
Total farm revenue	**9659**		

Farming expenses	Code	Current year	Prior year
Crop expenses	**9660**		
Total farm expenses	**9898**		
Net farm income	**9899**		
Net income / loss before taxes and extraordinary items	**9970**	574,185	406,626

Summary

Complete this section if only one Schedule 125 is filed, Schedule 140 is used to summarize the information from multiple Schedules 125.

Extraordinary items	**9975**	-		-
Legal settlements	**9976**	-		-
Unrealized gains / losses	**9980**	+		+
Unusual items	**9985**	-		-
Current income taxes	**9990**	-	187,056	- 114,800
Future income tax provision	**9995**	-		-
Net income / loss after taxes and extraordinary items	**9999**	=	387,129	= 291,826

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NOTES CHECKLIST

Schedule 141

- This schedule should be completed from the perspective of the person who prepared or reported on the **financial statements**. This person is referred to as the "accounting practitioner", in this schedule.
- For more information, see RC4088, *Guide to the General Index of Financial Information (GIFI) for Corporations* and T4012, *T2 Corporation – Income Tax Guide.*
- Attach a copy of this schedule, along with any Notes to the financial statements, to the GIFI.

Part 1 – Accounting practitioner information

Does the accounting practitioner have a professional designation?	**095**	☒ Yes	☐ No
Is the accounting practitioner connected* with the corporation?	**097**	☐ Yes	☒ No

* 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 accounting practitioner does not have a professional designation or is connected with the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4.

Part 2 – Type of involvement

Choose the option that represents the highest level of involvement of the accounting practitioner: **198**

Completed an auditor's report	1	☒
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** above, answer the following question:

Has the accounting practitioner expressed a reservation?	**099**	☐ Yes	☒ No

Part 4 – Other information

Were notes to the financial statements prepared?	**101**	☒ Yes	☐ No
If *Yes* , complete lines 102 to 107 below:			
Are any values presented at other than cost?	**102**	☐ Yes	☒ No
Has there been a change in accounting policies since the last return?	**103**	☐ Yes	☒ No
Are subsequent events mentioned in the notes?	**104**	☐ Yes	☒ No
Is re-evaluation of asset information mentioned in the notes?	**105**	☐ Yes	☒ No
Is contingent liability mentioned in the notes?	**106**	☒ Yes	☐ No
Is information regarding commitments mentioned in the notes?	**107**	☐ Yes	☒ No
Does the corporation have investments in joint venture(s) or partnership(s)?	**108**	☐ Yes	☒ No
If *Yes* , complete line 109 below:			
Are you filing financial statements of the joint venture(s) or partnership(s)?	**109**	☐ Yes	☐ No

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BUSINESS CONSENT FORM

Complete this form to consent to the release of confidential information about your Business Number (BN) account(s) to the representative named below, or to cancel consent for an existing representative. **Send this completed form to your tax centre**. You can also give or cancel consent by providing the requested information online through My Business Account at **www.cra.gc.ca/mybusinessaccount**.

Note: Read all instructions on the last page before completing this form.

Part 1 - Business Information - Complete this part to identify your business (all fields have to be completed)

Business Name: Tillsonburg Hydro Inc. **Business Number:** 863742599

Telephone Number: (519) 842-6428

Part 2 - Authorize a representative

If you are giving consent for an individual, enter that person's full name or if you are giving consent to a firm, enter the name of the firm and the BN. If you want us to deal with a specific individual in that firm, enter **both** the individual's name and the name of the firm. If you do not identify an individual of the firm then you are giving us consent to deal with anyone from that firm.

Name of Individual: _____ Name of Firm: Scrimgeour & Company, Chartered Accountar

Telephone Number: (519) 672-6811 **BN:** _____

Authorize online access

You can authorize your representative to deal with us through our online services for representatives. You have to provide the RepID of the individual or the Business Number of the firm indicated above. The name of the firm provided above must be the same name that is registered with the Represent a Client service at **www.cra.gc.ca/representatives**. If the firm names differ then online access will not be granted. Our online services do not have a year specific option, so your representative will have access to all years.

RepID: _____ (for above individual) **OR** **BN:** _____ The BN must be registered with the Represent a Client service to be an online representative.

Part 3 - Which Accounts and Which Years?

i) Accounts - Select which accounts the above individual or firm is authorized to access (check only box A or B).

A. ☒ This authorization applies to all BN accounts and all years. **Note: oline access is available for box A only.**

Expiry date: yyyy/mm/dd

OR

B. ☐ This authorization applies only to BN accounts and periods listed in Part 3ii.

Authorization level: check one box

☒ Disclose information only

OR

☐ Disclose information **and** make changes to your BN account(s)

BUSINESS CONSENT FORM (RC59 continued)

ii) Details of accounts and fiscal periods - Complete this area if you checked box "B" in Part 3 i).

If you checked box B in part 3i, you have to provide at least one program identifier (see Instructions on the last page). You can then check the "all accounts" box for that program identifier or enter a specific account number. Provide the authorization level ("1" to disclose information or "2" to disclose information and make changes). You can also check the "All years" box to allow unlimited tax year access or enter a specific fiscal period **(specific period authorization is not available for online access)**. You can also enter an expiry date to automatically cancel authorization. If additional authorizations or more than four program identifiers are needed complete another RC59.

Program identifier	All accounts	Specific account	Authorization level	All years	or	Specific fiscal period (not available for online access) Year End	Expiry date
RC	☐		1	☐	or	yyyy/mm/dd	yyyy/mm/dd
RC	☐		1	☐	or	yyyy/mm/dd	yyyy/mm/dd
RC	☐		1	☐	or	yyyy/mm/dd	yyyy/mm/dd
RC	☐		1	☐	or	yyyy/mm/dd	yyyy/mm/dd

Part 4 - Cancel one or more existing authorizations - Complete this section only to cancel existing authorization(s)

☐ **A**. Cancel **all** authorizations

☐ **B**. Cancel authorization for the individual or firm identified below.

Name of Individual: _____ Name of Firm: _____

Part 5 - Certification

This form must be signed by an authorized person of the business such as a proprietor of a proprietorship, a partner of a partnership, a director of a corporation, an officer of a non profit organization or a trustee of an estate. By signing and dating this form, you authorize the CRA to deal with the individual or firm listed in Part 2 of this form and/or cancel the authorizations listed in Part 4.

First name: Darrell Last name: Eddington

Title: Treasurer

Sign here ▶ _____ Date 2008/06/25

WE WILL NOT PROCESS THIS FORM UNLESS IT IS SIGNED AND DATED BY AN AUTHORIZED PERSON OF THE BUSINESS.

Canada

Ontario CT23 tax return

THI's Ontario CT23 Tax Return is provided at E4/T3/S5/AttA.

Ontario

Ministry of Finance
Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

2007 CT23 Corporations Tax and Annual Return

For taxation years commencing after December 31, 2004

Corporations Tax Act - Ministry of Finance (MOF)
Corporations Information Act - Ministry of Government Services (MGS)

This form is a combination of the Ministry of Revenue (MOR) **CT23 Corporations Tax Return** and the Ministry of Government Services (MGS) **Annual Return.** Page 1 is a common page required for both Returns. For tax purposes, depending on which criteria the corporation satisfies, it must complete either the **Exempt from Filing (EFF)** declaration on page 2 or file the **CT23 Return** on pages 3-17. Corporations that **do not** meet the EFF criteria but **do** meet the Short-Form criteria, may request and file the **CT23 Short-Form Return** (see page 2).

The **Annual Return** (common page 1 and MGS Schedule A on pages 18 and 19, and Schedule K on page 20) contains non-tax information collected under the authority of the *Corporations Information Act* for the purpose of maintaining a public database of corporate information. This return must be completed by Ontario share-capital corporations or Foreign-Business share-capital corporations that have an extra-provincial licence to operate in Ontario.

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* ☒ Yes ☐ No

Ministry Use

Corporation's Legal Name *(including punctuation)*
Tillsonburg Hydro Inc.

Ontario Corporations Tax Account No. (MOF)
1800285

Mailing address
Darrell Eddington
200 Broadway, 2nd Floor

City	Province	Country	Postal code
Tillsonburg	ON	CA	N4G 5A7

This Return covers the Taxation Year
Start 2007/01/01
End 2007/12/31

Has the mailing address changed since last filed CT23 Return? ☐ Yes | Date of Change | year month day

Date of Incorporation or Amalgamation
2000/10/26

Registered/Head Office Address
200 Broadway, 2nd Floor

City	Province	Country	Postal code
Tillsonburg	ON	CA	N4G 5A7

Ontario Corporation No. (MGS) 1800285

Location of Books and Records
200 Broadway, 2nd Floor

City	Province	Country	Postal code
Tillsonburg	ON	CA	N4G 5A7

Canada Revenue Agency Business No.
863742599RC0001

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
Darrell Eddington	(519) 842-6428	( ) -

Jurisdiction Incorporated: Ontario

Address of Principal Office in Ontario (*Extra-Provincial Corporations only*) (MGS)

City	Province	Country	Postal code

If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased:
Commenced
Ceased
☒ *Not Applicable*

Former Corporation Name (*Extra-Provincial Corporations only*) ☐ *Not Applicable* (MGS)

Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). ▶

No. of Schedule(s): 6

If there is **no change** to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check ☑ this box. Schedule(s) A and K are not required (MGS). ▶ ☐ **No Change**

Preferred Language / *Langue de préférence*
☒ English *anglais* ☐ French *français*

Ministry Use

Certification (MGS)

I certify that all information set out in the **Annual Return** is true, correct and complete.

Name of Authorized Person
Darrell Eddington

Title D ☐ Director O ☒ Officer P ☐ Other individuals having knowledge of the Corporation's business activities

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Taxation Year End

Exempt From Filing (EFF) Corporations Tax Return Declaration

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)

This EFF Declaration must be filed for each taxation year that the corporation is exempt from filing and must be filed within 6 months after the corporation's taxation year end.

Criteria for exempt from filing status:

a) has filed a federal Income Tax Return (T2) with Canada Revenue Agency for the taxation year;
b) had no Ontario taxable income for the taxation year (subject to the provisions in Note 2 below);
c) had no Ontario Corporations Tax payable for the taxation year;
d) was a Canadian-controlled private corporation throughout the taxation year (i.e. generally a private corporation with 50% or more shares owned by Canadian residents as defined by the *Income Tax Act* (Canada));
e) has provided its Canada Revenue Agency business number to the Ministry of Revenue; and
f) is **not** subject to the Corporate Minimum Tax (i.e. alone or as part of an associated group whose total assets exceed $5 million or whose total revenue exceeds $10 million for the taxation year).

Note 1: Filing of this declaration and the Annual Return does not constitute the filing of a Corporations Tax Return under section 75 of the *Corporations Tax Act*.

Note 2: The following loss situations will require otherwise EFF corporations to file a CT23 tax return complete with all related schedules and financial statements:

- If a corporation has a loss in the current taxation year that is to be carried back and applied to a previous taxation year(s), regardless of whether the loss is the same as for federal purposes or not, a CT23 tax return is required for the current taxation year. The corporation must also provide information indicating that the loss is to be carried back and specify the year and the amount of loss to be carried back to each taxation year.
- If a corporation has a prior year loss, that is not the same for both federal and Ontario purposes and the corporation is applying a loss carryforward from the prior year to the current year, a CT23 tax return is required for the current taxation year, and if not previously filed, a CT23 tax return for the prior taxation year in which the loss was incurred is also required. Although a tax return for the loss year is not required where the loss is not being applied, the ministry will accept the filing of a tax return for a loss year at the time the loss is incurred.
- If a corporation has a prior year loss, that is the same for both federal and Ontario purposes, but in the current taxation year the corporation is applying a different amount of loss for Ontario than the loss amount being applied for federal income tax purposes, the corporation is required to file a CT23 tax return for the current taxation year only.

The following 3 items MUST be completed for EFF declarations only. In cases where the Annual Return, which includes page 1, is **also** being filed, completion of these fields is **not** required.

1. Corporation's Mailing Address

City | Province | Country | Postal code

2. Ontario Corporation No. (MGS)

3. Canada Revenue Agency Business No.
RC

I, _____ declare that:

The above corporation meets **all** of the exempt from filing criteria (a) through (f) above for the taxation year and therefore qualifies under the *Corporations Tax Act* as exempt from filing an Ontario Corporations Tax Return.

Signature	Title/Relationship to Corporation	Telephone number ( ) -	Date

Please note that making a false statement to avoid compliance with the *Corporations Tax Act* is an offence which can result in a penalty and/or fine.

If you check "Yes" to ALL of the following criteria, you are eligible to file the CT23 Short-Form Corporations Tax Return. To obtain a copy, contact the Ministry Information Centre at the numbers listed on page 2 of the Guide.

Yes	No		Yes	No	
☒	☐	(a) The corporation is a Canadian-controlled private corporation (CCPC) throughout the taxation year. Indicate Share Capital with full voting rights owned by Canadian Residents (nearest whole percentage) 100 %	☐	☒	(d) The corporation's taxation year ends on or after January 1, 2001, and its gross revenue and total assets are each $1,500,000 or less and the corporation is not a financial institution; or The corporation's taxation year commences after September 30, 2001, and its gross revenue and total assets are each $3,000,000 or less and the corporation is not a financial institution.
☐	☒	(b) The corporation's taxable income for the taxation year is $200,000 or less. For a taxation year with less than 51 weeks, taxable income must be grossed-up. (*Refer to Guide.*)	☐	☒	(e) The corporation is **not** claiming a tax credit other than the Incentive Deduction for Small Business Corporations (IDSBC), Co-operative Education Tax Credit (CETC), Graduate Transitions Tax Credit (GTTC) or Apprenticeship Training Tax Credit (ATTC).
☒	☐	(c) The corporation is **not** a member of a partnership/joint venture or a member of an associated group of corporations during the taxation year.	☒	☐	(f) The corporation's Ontario allocation factor is 100%.

Note: Family Farm or Fishing corporations that have a taxation year ending on or after January 1, 2000 and are **not** subject to the Corporate Minimum Tax, may also use the **CT23 Short-Form Corporations Tax Return** if the corporation checks "Yes" to a), b), c), e) and f) above.

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

Please check applicable (✓) box(es) and complete required information.

Type of Corporation

1

- 1 ☒ Canadian-controlled private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))
- 2 ☐ Other Private
- 3 ☐ Public
- 4 ☐ Non-share Capital
- 5 ☐ Other (*specify*)

Share Capital with full voting rights owned by Canadian Residents (nearest percent) 100 %

2

- 1 ☐ Family Farm corporation s.1(2)
- 2 ☐ Family Fishing corporation s.1(2)
- 3 ☐ Mortgage Investment corporation s.47
- 4 ☐ Credit Union s.51
- 5 ☐ Bank Mortgage subsidiary s.61(4)
- 6 ☐ Bank s.1(2)
- 7 ☐ Loan and Trust corporation s.61(4)
- 8 ☐ Non-resident corporation s.2(2)(a) or (b)
- 9 ☐ Non-resident corporation s.2(2)(c)
- 10 ☐ Mutual Fund corporation s.48
- 11 ☐ Non-resident owned investment corporation s.49
- 12 ☐ Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)
- 14 ☐ Bare Trustee corporation
- 15 ☐ Branch of Non-resident s.63(1)
- 16 ☐ Financial institution prescribed by Regulation only
- 17 ☐ Investment Dealer
- 18 ☐ Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale
- 19 ☐ Hydro successor, municipal electrical utility or subsidiary of either
- 20 ☒ Producer and seller of steam for uses other than for the generation of electricity
- 21 ☐ Insurance Exchange s.74.4
- 22 ☐ Farm Feeder Finance Co-operative corporation
- 23 ☐ Professional corporation (incorporated professionals only)

- ☐ This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)
- ☐ Amended Return
- ☐ Taxation year end change - Canada Revenue Agency approval required
- ☐ Final taxation year up to dissolution (*Note: for discontinued businesses, see guide.*)
- ☐ Final taxation year before amalgamation
- ☐ The corporation has a floating fiscal year end
- ☐ There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario
- ☐ There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year

  If checked, date control was acquired _____
- ☐ The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)
- ☐ First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)
- ☐ Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes	No	
☐	☒	Was the corporation inactive throughout the taxation year?
☒	☐	Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?
		Are you requesting a refund due to:
☐	☒	the Carry-back of a Loss?
☐	☒	an Overpayment?
☐	☒	a Specified Refundable Tax Credit?
☐	☒	Are you a Member of a Partnership or Joint Venture?

Complete if applicable

Ontario Retail Sales Tax Vendor Permit no. (Use Head Office no.) _____

Ontario Employer Health Tax Account no. (Use Head Office no.) _____

Specify major business activity
Electricity distribution

Income Tax

Allocation – If you carry on a business through a permanent establishment in a jurisdiction outside Ontario, you may allocate that portion of taxable income deemed earned in that jurisdiction to that jurisdiction (s.39) (Int.B. 3008).

Net income (loss) for Ontario purposes (per reconciliation schedule, page 15)	From 690 ±	602,626	
Subtract: Charitable donations	1 -		
Subtract: Gifts to Her Majesty in right of Canada or a province and gifts of cultural property *(Attach schedule 2)*	2 -		
Subtract: Taxable dividends deductible, per federal Schedule 3	3 -		
Subtract: Ontario political contributions *(Attach schedule* 2A) (Int.B. 3002R)	4 -		
Subtract: Federal Part VI.1 tax X 3	5 -		
Subtract: Prior years' losses applied - Non-capital losses	From 704 -		
From 715 inclusion			
Net capital losses (page 16) X rate 50.000000 % =	714 -		
Farm losses	From 724 -		
Restricted farm losses	From 734 -		
Limited partnership losses	From 754 -		
Taxable income (Non-capital loss)	10 =	602,626	
Addition to taxable income for unused foreign tax deduction for federal purposes	11 +		
Adjusted taxable income 10 + 11 (if **10** is negative, enter **11**)	20 =	602,626	

Taxable Income

Number of days in Taxation Year

					Days after Dec. 31, 2002 and before Jan. 1, 2004		Total Days				
From **10** (or **20**)	602,626	X **30**	100.0000 %	X 12.5% X	**33**	÷	**73** 365	=	**29** +		
			Ontario Allocation		Days after Dec. 31, 2003		Total Days				
From **10** (or **20**)	602,626	X **30**	100.0000 %	X 14.0% X	**34** 365	÷	**73** 365	=	**32** +	84,368	
			Ontario Allocation								
Income Tax Payable (before deduction of tax credits) **29 + 32**									**40** =	84,368	

Incentive Deduction for Small Business Corporations (IDSBC) (s.41)

if this section is not completed, the IDSBC will be denied.

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the taxation year? (✓) ☒ Yes ☐ No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a))	**50**	602,626	
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	**51** +	602,626	
Add: Losses of other years deducted for federal purposes (fed.s.111)	**52** +		
Subtract: Losses of other years deducted for Ontario purposes (s.34)	**53** -		
	= 602,626 ▶	**54**	602,626
Federal Business limit (line 410 of the T2 return) for the year before the application of fed.s.125(5.1)	**55** +	400,000	

Ontario Business Limit Calculation

	Days after Dec. 31, 2002 and before Jan. 1, 2004					
320,000 X **31**		÷ ** 365	=+ **46**			
	Days after Dec. 31, 2003					
400,000 X **34**	365	÷ ** 365	=+ **47**	400,000		

Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated.

Business limit for Ontario purposes **46** + **47**	= **44**	400,000	X **48**	100.0000 % =	**45**	400,000	
Income eligible for the IDSBC	From **30**	100.0000 %	X **56**	400,000	**60** =	400,000	
		***Ontario Allocation		Least of **50**, **54** or **45**			

* ***Note***: *Modified by s.41(6) and (7) for corporations that are members of a partnership. (Refer to Guide.)*

** ***Note***: *Adjust accordingly for a floating taxation year and use 366 for a leap year.*

*** ***Note***: *Ontario Allocation for IDSBC purposes may differ from **30** if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).*

continued on Page 5

Income Tax *continued from Page 4*

Calculation of IDSBC Rate

Number of Days in Taxation Year

7.0% X **31** ____ (Days after Dec. 31, 2002 and before Jan. 1, 2004) ÷ **73** ____ (Total Days) = **89** + ____

8.5% X **34** 365 (Days after Dec. 31, 2003) ÷ **73** 365 (Total Days) = **90** + 8.5000

IDSBC Rate for Taxation Year **89 + 90** **78** = 8.5000

Claim From **60** 400,000 X From **78** 8.5000 % **70** = 34,000

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount in **114** below.

Surtax on Canadian-controlled Private Corporations (s.41.1)

Applies if you have claimed the Incentive Deduction for Small Business Corporations.

Associated corporation - The Taxable Income of associated corporations is the taxable income for the taxation year ending on or before the date of this corporation's taxation year end.

*** Taxable Income of the corporation** From **10** (or **20** if applicable) **80** + 602,626

If you are a member of an associated group (✓) **81** ☐ (Yes)

Name of associated corporation (Canadian & foreign)	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		* Taxable Income (if loss, enter nil)
			+ **82**	
			+ **83**	
			+ **84**	

Aggregate Taxable Income **80 + 82 + 83 + 84**, etc. **85** = 602,626

Number of days in Taxation Year

320,000 X **31** ____ (Days after Dec. 31, 2002 and before Jan. 1, 2004) ÷ **73** 365 (Total Days) = **115** + ____

400,000 X **34** 365 (Days after Dec. 31, 2003) ÷ **73** 365 (Total Days) = **116** + 400,000

115 + 116 = 400,000 ▶ **114** - 400,000

(If negative, enter nil) **86** = 202,626

Calculation of Specified Rate for Surtax

Number of Days in Taxation Year

4.667% X **38** 365 (Days after Dec. 31, 2002) ÷ **73** 365 (Total Days) = **97** + 4.6670

From **86** 202,626 X From **97** 4.6670 % = **87** = 9,457

From **87** 9,457 X From **60** 400,000 ÷ From **114** 400,000 **88** = 9,457

Surtax Lesser of **70** or **88** **100** = 9,457

**** Note: Short Taxation Years*** - Special rules apply where the taxation year is less than 51 weeks for the corporation and/or any corporation associated with it.

continued on Page 6

Income Tax *continued from Page 5*

Additional Deduction for Credit Unions (s.51(4)) *(Attach schedule 17)*

110

Manufacturing and Processing Profits Credit (M&P) (s.43)

Applies to Eligible Canadian Profits from manufacturing and processing, farming, mining, logging and fishing carried on in Canada, as determined by regulations.

Eligible Canadian Profits from mining are the "resource profits from the mining operations", as determined for Ontario depletion purposes, after deducting depletion and resource allowances but excluding amounts from sale of Canadian resource property, rentals or royalties. If you are claiming this credit, attach a copy of Ontario schedule 27.

The whole of the active business income qualifies as Eligible Canadian Profits if: **a)** your active business income from sources other than manufacturing and processing, mining, farming, logging or fishing is 20% or less of the total active business income and **b)** the total active business income is $250,000 or less.

Eligible Canadian Profits		**120** +	
Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC)	From **56**	-	400,000
Add: Adjustment for Surtax on Canadian-controlled private corporations From **100** 9,457 ÷ From **30** 100.0000 % ÷ From **78** 8.5000 % = **121** 111,259 *Ontario Allocation			
Lesser of **56** or **121**		**122** +	111,259
120 - 56 + 122		**130** =	
Taxable income	From **10**	+	602,626
Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC)	From **56**	-	400,000
Add: Adjustments for Surtax on Canadian-controlled private corporations	From **122**	+	111,259
Subtract: Taxable income **10** X Allocation % to jurisdictions outside Canada		**140** -	
Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses		**141** -	
10 - 56 + 122 - 140 - 141		**142** =	313,885

Claim

Number of Days in Taxation Year

143 _____ (Lesser of **130** or **142**) X From **30** 100.0000 % (*Ontario Allocation) X 1.5% X **33** _____ (Days after Dec. 31, 2002 and before Jan. 1, 2004) ÷ **73** 365 (Total Days) = **154** +

143 _____ (Lesser of **130** or **142**) X From **30** 100.0000 % (*Ontario Allocation) X 2.0% X **34** 365 (Days after Dec. 31, 2003) ÷ **73** 365 (Total Days) = **156** +

M&P claim for taxation year **154** + **156** **160** =

****Note**: Ontario Allocation for M&P Credit purposes may differ from **30** if Taxable Income is allocated to foreign jurisdictions. See special rules (s.43(1))*

Manufacturing and Processing Profits Credit for Electrical Generating Corporations

161 =

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity

162 =

Credit for Foreign Taxes Paid (s.40)

Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). *(Attach schedule)* **170**

Credit for Investment in Small Business Development Corporations (SBDC)

Applies if you have an unapplied, previously approved credit from prior years' investments in new issues of equity shares in Small Business Development Corporations. Any unused portion may be carried forward indefinitely and applied to reduce subsequent years' income taxes. (Refer to the former *Small Business Development Corporations Act*)

Eligible Credit **175** _____ Credit Claimed **180**

Subtotal of Income Tax **40 - 70 + 100 - 110 - 160 - 161 - 162 - 170 - 180**

190 = 59,825

continued on Page 7

Income Tax *continued from Page 6*

Specified Tax Credits *(Refer to Guide)*

Ontario Innovation Tax Credit (OITC) (s.43.3) ***Applies*** to scientific research and experimental development in Ontario.
Eligible Credit from **5620** OITC Claim Form *(Attach original Claim Form)* **191** +

Co-operative Education Tax Credit (CETC) (s.43.4) ***Applies*** to employment of eligible students.
Eligible Credit from **5798** CT23 Schedule 113 *(Attach Schedule 113)* **192** +

Ontario Film & Television Tax Credit (OFTTC) (s.43.5)
Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions. Name of Production **204**
Eligible Credit from **5850** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* **193** +

Graduate Transitions Tax Credit (GTTC) (s.43.6) No. of Graduates From **6596** **194**
Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005.
Eligible Credit from **6598** CT23 Schedule 115 *(Attach Schedule 115)* **195** +

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)
Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.
Eligible Credit from **6900** OBPTC Claim Form
*(Attach **both** the original Claim Form and the Certificate of Eligibility)* **196** +

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)
Applies to labour relating to computer animation and special effects on an eligible production.
Eligible Credit from **6700** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) **197** +

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)
Applies to qualifying R&D expenditures under an eligible research institute contract.
Eligible Credit from **7100** OBRITC Claim Form *(Attach original Claim Form)* **198** +

Ontario Production Services Tax Credit (OPSTC) (s.43.10)
Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.
Eligible Credit from **7300** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* **199** +

Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11)
Applies to qualifying labour expenditures of eligible products for the taxation year.
Eligible Credit from **7400** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* **200** +

Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)
Applies to qualifying expenditures in respect of eligible Canadian sound recordings.
Eligible Credit from **7500** OSRTC Claim Form
*(Attach **both** the original Claim Form and the Certificate of Eligibility)* **201** +

Apprenticeship Training Tax Credit (ATTC) (s.43.13) No. of Apprentices From **5896** **202**
Applies to employment of eligible apprentices.
Eligible Credit from **5898** CT23 Schedule 114 *(Attach Schedule 114)* **203** +

Total Specified Tax Credits 191 **192 + 193 + 195 + 196 + 197 + 198 + 199 + 200 + 201 + 203** **220** =

Specified Tax Credits ***Applied to reduce Income Tax*** **225** =

Income Tax 190 - 225 OR Enter NIL if reporting Non-Capital Loss *(amount cannot be negative)* **230** = 59,825

To determine if the Corporate Minimum Tax (CMT) is applicable to your Corporation, see **Determination of Applicability** section for the CMT on **Page 8**. If CMT is not applicable, transfer amount in **230** to Income Tax in **Summary** section on **Page 17**.

OR

If CMT is not applicable for the current taxation year but your corporation has CMT Credit Carryovers that you want to apply to reduce income tax otherwise payable, then proceed to and complete the **Application of CMT Credit Carryovers** section part B, on **Page 8**.

Corporate Minimum Tax (CMT)

Total Assets of the corporation 240 + 10,419,892

Total Revenue of the corporation 241 + 19,623,994

The above amounts include the corporation's and associated corporations' share of any partnership(s) / joint venture(s) total assets and total revenue.

If you are a member of an associated group (✓) 242 ☐ (Yes)

Name of associated corporation (Canadian & foreign)	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Total Assets	Total Revenue
		+ 243	+ 244	
		+ 245	+ 246	
		+ 247	+ 248	

Aggregate Total Assets **240 + 243 + 245 + 247**, etc. 249 = 10,419,892

Aggregate Total Revenue **241 + 244 + 246 + 248**, etc. 250 = 19,623,994

Determination of Applicability

Applies if ***either*** Total Assets **249** exceeds $5,000,000 ***or*** Total Revenue **250** exceeds $10,000,000.

Short Taxation Years - Special rules apply for determining total revenue where the taxation year of the corporation or any associated corporation or any fiscal period of any partnership(s) / joint venture(s) of which the corporation or associated corporation is a member, is less than 51 weeks.

Associated Corporation - The total assets or total revenue of associated corporations is the total assets or total revenue for the taxation year ending on or before the date of the claiming corporation's taxation year end.

If CMT is applicable to current taxation year, complete section **Calculation: CMT** below and **Corporate Minimum Tax Schedule 101.**

Calculation: CMT *(Attach Schedule 101.)*

Gross CMT Payable - CMT Base From Schedule 101 **2136** 574,185 (If negative, enter zero) X From **30** 100.0000 (Ontario Allocation) % X 4% **276** = 22,967

Subtract: Foreign Tax Credit for CMT purposes *(Attach schedule)* **277** -

Subtract: Income Tax From **190** - 59,825

Net CMT Payable (if negative, enter Nil on page 17.) **280** =

If **280** is less than zero and you do not have a CMT credit carryover, transfer **230** from **Page 7** to **Income Tax Summary, on Page 17.**

If **280** is less than zero and you have a CMT credit carryover, complete A & B below.

If **280** is greater than or equal to zero, transfer **230** to **Page 17** and transfer **280** to **Page 17, and** to **Part 4 of Schedule 101: Continuity of CMT Credit Carryovers.**

CMT Credit Carryover available From Schedule 101 From **2333**

Application of CMT Credit Carryovers

A.

Income Tax (before deduction of specified credits) From **190** + 59,825

Gross CMT Payable From **276** + 22,967

Subtract: Foreign Tax Credit for CMT purposes From **277** -

If **276 - 277** is negative, enter NIL in **290** = 22,967 ▶ **290** - 22,967

Income Tax eligible for CMT Credit **300** = 36,858

B.

Income Tax (after deduction of specified credits) From **230** + 59,825

Subtract: CMT credit used to reduce income taxes **310** -

Income Tax **320** = 59,825

Transfer to Page 17

***If A & B apply,* 310 *cannot exceed the lesser of* 230, 300 *and your CMT credit carryover available* 2333.**

If only B applies,* 310 *cannot exceed the lesser of* 230 *and your CMT credit carryover available 2333.

Capital Tax *(Refer to Guide and Int.B. 3011R)*

If your corporation is a Financial Institution (s.58(2)), complete lines **480** *and* **430** *on page 10 then proceed to page 13.*

If your corporation is not a member of an associated group and/or partnership and the Gross Revenue and Total Assets as calculated on page 10 in **480** *and* **430** *are both $3,000,000 or less, your corporation is exempt from Capital Tax for the taxation year, except for a branch of a non-resident corporation. A corporation that meets these criteria should disregard all other Capital Tax items (including the calculation of Taxable Capital). Enter NIL in* **550** *on page 12 and complete the return from that point. All other corporations must compute their Taxable Capital in order to determine their Capital Tax payable.*

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation. If Investment Allowance is claimed, Total Assets must be adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

Any Assets and liabilities of a corporation that are being utilized in a joint venture must be included along with the corporation's other Assets and liabilities when calculating its Taxable Paid-up Capital.

Special rules and rates apply to Non-Resident corporations (s.63, s.64 and s.69(3)).

Paid-up Capital of Non-resident: Paid-up capital employed in Canada of a non-resident subject to tax by virtue of s. 2(2)(a) or 2(2)(b), and whose **business is not carried on solely in Canada** is deemed to be the **greater** of (1) taxable Income in Canada divided by 8 percent or (2) total assets in Canada minus certain indebtedness in accordance with the provisions of s.63(1)(a) (Int.B. 3010).

Paid-up Capital

Paid-up capital stock (Int.B. 3012R and 3015R)	**350**	+	6,992,565
Retained earnings (if deficit, deduct) (Int.B. 3012R)	**351**	±	(104,038)
Capital and other surpluses, excluding appraisal surplus (Int.B. 3012R)	**352**	+	1,190,387
Loans and advances *(Attach schedule)* (Int.B. 3013R)	**353**	+	
Bank loans (Int.B. 3013R)	**354**	+	
Bankers acceptances (Int.B. 3013R)	**355**	+	
Bonds and debentures payable (Int.B. 3013R)	**356**	+	
Mortgages payable (Int.B. 3013R)	**357**	+	
Lien notes payable (Int.B. 3013R)	**358**	+	
Deferred credits (including income tax reserves, and deferred revenue where it would also be included in paid-up capital for the purposes of the large corporations tax) (Int.B. 3013R)	**359**	+	
Contingent, investment, inventory and similar reserves (Int.B. 3012R)	**360**	+	
Other reserves not allowed as deductions for income tax purposes *(Attach schedule)* (Int.B. 3012R)	**361**	+	
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	**362**	+	
Subtotal	**370**	=	8,078,914
Subtract: Amounts deducted for income tax purposes in excess of amounts booked *(Retain calculations. Do not submit.)* (Int.B. 3012R)	**371**	-	
Deductible R&D expenditures and ONTTI costs deferred for income tax if not already deducted for book purposes (Int.B. 3015R)	**372**	-	
Total Paid-up Capital	**380**	=	8,078,914
Subtract: Deferred mining exploration and development expenses (s.62(1)(d)) (Int.B. 3015R)	**381**	-	
Electrical Generating Corporations Only - All amounts with respect to electrical generating assets, except to the extent that they have been deducted by the corporation in computing its income for income tax purposes for the current or any prior taxation year, that are deductible by the corporation under clause 11(10)(a) of the *Corporations Tax Act*, and the assets are used both in generating electricity from a renewable or alternative energy source and are qualifying property as prescribed by regulation	**382**	-	
Net Paid-up Capital	**390**	=	8,078,914

Eligible Investments *(Refer to Guide and Int.B. 3015R)*

Attach computations and list of corporation names and investment amounts. Short-term investments (bankers acceptances, commercial paper, etc.) are eligible for the allowance only if issued for a term of and held for 120 days or more prior to the year end of the investor corporation.

Bonds, lien notes and similar obligations, (similar obligations, e.g. stripped interest coupons, applies to taxation years ending after October 30, 1998)	**402**	+	
Mortgages due from other corporations	**403**	+	
Shares in other corporations (certain restrictions apply) *(Refer to Guide)*	**404**	+	
Loans and advances to unrelated corporations	**405**	+	
Eligible loans and advances to related corporations (certain restrictions apply) *(Refer to Guide)*	**406**	+	
Share of partnership(s) or joint venture(s) eligible investments *(Attach schedule)*	**407**	+	
Total Eligible Investments	**410**	=	

continued on Page 10

Capital Tax *continued from Page 9*

Total Assets (Int.B. 3015R)

Total Assets per balance sheet	420 +	10,419,892
Mortgages or other liabilities deducted from assets	421 +	
Share of partnership(s)/joint venture(s) total assets *(Attach schedule)*	422 +	
Subtract: Investment in partnership(s)/joint venture(s)	423 -	
Total Assets as adjusted	430 =	10,419,892
Amounts in **360** and **361** (if deducted from assets)	440 +	
Subtract: Amounts in **371**, **372** and **381**	441 -	
Subtract: Appraisal surplus if booked	442 -	
Add or Subtract: Other adjustments (specify on an attached schedule)	443 ±	
Total Assets	450 =	10,419,892

Investment Allowance (410 ÷ 450) X 390 — **Not to exceed 410**	460 =	
Taxable Capital 390 - 460	470 =	8,078,914

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)

Gross Revenue of the corporation	19,623,994		
Corporation's Share of partnership(s)/joint venture(s) Gross Revenue *(Attach schedule)*			
Aggregate of Gross Revenue	19,623,994	480	19,623,994
Total Assets (as adjusted)	From	430	10,419,892

Calculation of Capital Tax for all Corporations except Financial Institutions

Note: *This version (2007) of the CT23 may only be used for a taxation year that commenced after December 31, 2004.*
Financial Institutions use calculations on page 13.

Important: If the corporation is a family farm corporation, family fishing corporation or a credit union that is not a Financial Institution, complete only Section A below.

OR If the corporation is **not** a member of an associated group and/or partnership, complete Section B below, then review only the Capital Tax calculations in Section C on page 11, selecting and completing the one specific subsection (e.g. C3) that applies to the corporation.

OR If the corporation **is** a member of an associated group and/or partnership, complete Section B below and Section D on page 11, and if applicable, complete Section E or Section F on page 12. Note: if the corporation is a member of a connected partnership, please refer to the CT23 Guide for additional instructions before completing the Capital Tax section.

SECTION A

This section applies only if the corporation is a family farm corporation, a family fishing corporation or a credit union that is not a Financial Institution (Int.B. 3018).

Enter NIL in **550** on page 12 and complete the return from that point.

SECTION B

B1. Calculation of Taxable Capital Deduction (TCD)

			Number of Days in Taxation Year				
			Days after Dec. 31, 2004 and before Jan. 1, 2006		Total Days		
7,500,000	X	**36**		÷	**73** 365	= **501** +	
			Days after Dec. 31, 2005 and before Jan. 1, 2007		Total Days		
10,000,000	X	**37**		÷	**73** 365	= **502** +	
			Days after Dec. 31, 2006 and before Jan. 1, 2008		Total Days		
12,500,000	X	**38**	365	÷	**73** 365	= **504** +	12,500,000
			Days after Dec. 31, 2007		Total Days		
15,000,000	X	**39**		÷	**73** 365	= **505** +	
		Taxable Capital Deduction (TCD)			**501 + 502 + 504 + 505**	**503** =	12,500,000

B2. This section applies to corporations to calculate the prorated capital tax rate.

Calculation of Capital Tax Rate

			Number of Days in Taxation Year				
			Days before Jan. 1, 2007		Total Days		
0.3 %	X	**556**		÷	**73** 365	= **511**	%
			Days after Dec. 31, 2006 and before Jan. 1, 2009		Total Days		
0.285 %	X	**557**	365	÷	**73** 365	= **512**	0.2850 %
Capital Tax Rate			**511 + 512**			= **516**	0.2850 %

continued on Page 11

Capital Tax Calculation *continued from Page 10*

SECTION C

This section applies if the corporation is **not** a member of an associated group and/or partnership.

C1. If **430** and **480** on page 10 are both $3,000,000 or less, enter NIL in **550** on page 12 and complete the return from that point.

C2. If Taxable Capital in **470** is **equal to or less than the TCD** in **503**, enter NIL in **550** on page 12 and complete the return from that point.

C3. If Taxable Capital in **470 exceeds the TCD** in **503**, complete the following calculation and transfer the amount from **523** to **543** on page 12, and complete the return from that point.

+ From **470**										
- From **503**										
= **471**		x From **30**		% x From **516**	0.2850	% x	**555**		= **523** +	
			Ontario Allocation		Capital Tax Rate		365 (366 if leap year) *If floating taxation year, refer to Guide.*	Days in taxation year		*Transfer to **543** on page 12 and complete the return from that point*

SECTION D

This section applies ONLY to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either **509** or **524** and complete this section before you can calculate your Capital Tax calculation under either Section E o Section F.

D1. ☐ **509** (✓ if applicable)

All corporations that you are associated with do **not** have a permanent establishment in Canada.
If Taxable Capital **470** on page 10 is equal to or less than the TCD **503** on page 10, enter NIL in **550** on page 12 and complete the return from that point.

If Taxable Capital **470** on page 10 exceeds the TCD **503** on page 10, proceed to **Section E**, enter the TCD amount in **542** in Section E, and complete Section E and the return from that point.

D2. ☐ **524** (✓ if applicable)

One or more of the corporations that you are associated with **maintains** a permanent establishment in Canada.

You and your associated group may continue to allocate the TCD by completing the Calculation below. Or, the associated group **may file an election** under subsection 69(2.1) of the *Corporations Tax Act*, whereby total assets are used to allocate the TCD among the associated group. Once a ss.69(2.1) election is filed, all members of the group will then be required to file in accordance with the election and allocate a portion (portion is henceforth referred to as **Net Deduction**) of the capital tax effect relating to the TCD to each corporation in the group on the basis of the ratio that each corporation's total assets multiplied by its Ontario allocation is to the total assets of the group.

The total asset amounts and Ontario allocation percentages to be used for this calculation must be taken from each corporation's financial information from its last taxation year ending in the immediately preceding calendar year.

In addition, although each corporation in the associated group may deduct its Net Deduction amount as apportioned by the total asset formula, the group may, at the group's option, reallocate the group's total Net Deduction among the group on what ever basis the corporate group wishes, as long as the total of the reallocated amounts does not exceed the group's total Net Deduction amount originally calculated for the associated group.

D2. Calculation is on next page

continued on Page 12

Capital Tax Calculation *continued from Page 11*

Calculation Do **not** complete this calculation if ss.69(2.1) election is filed

Taxable Capital from **470** on page 10 From **470** +

Determine aggregate taxable capital of an associated group (excluding financial institutions and corporations exempt from capital tax) and/or partnership having a permanent establishment in Canada

Names of associated corporations (excluding Financial Institutions and corporations exempt from Capital Tax) having a permanent establishment in Canada	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Taxable Capital
		+ **531**	
		+ **532**	
		+ **533**	

Aggregate Taxable Capital **470 + 531 + 532 + 533**, etc. **540** =

If **540** above is equal to or less than the TCD **503** on page 10, the corporation's Capital Tax for the taxation year, is NIL. Enter NIL in **523** in section E below, as applicable.
If **540** above is greater than the TCD **503** on page 10, the corporation must compute its share of the TCD below in order to calculate its Capital Tax for the taxation year under Section E below.

From **470** ÷ From **540** X From **503** **541** =
*Transfer to **542** in Section E below*

Ss.69(2.1) Election Filed

☐ **591** (✓ if applicable) **Election filed.** *Attach a copy of Schedule 591 with this CT23 Return.* Proceed to **Section F** below.

SECTION E

This section applies if the corporation **is** a member of an associated group and/or partnership whose total **aggregate** Taxable Capital **540** above, exceeds the TCD **503** on page 10.

Complete the following calculation and transfer the amount from **523** to **543**, and complete the return from that point.

+ From **470**							**Total Capital Tax for the taxation year**
- **542**					Days in taxation year		
= **471**	x From **30** Ontario Allocation	% x From **516** 0.2850 % Capital Tax Rate	x **555** *365 (366 if leap year)	= **523** +			

*Transfer to **543** and complete the return from that point*

SECTION F

This section applies if a corporation is a member of an associated group and the associated group has filed a ss.69(2.1) election

+From **470**	X From **30** Ontario Allocation	% x From **516** 0.2850 % Capital Tax Rate	= **561** +

- Capital tax deduction from **995** relating to **your corporation's** Capital Tax deduction, on Schedule 591 From **995** -
562 =

Capital Tax	**562**	X	Days in taxation year **555** *365 (366 if leap year)	= **563** + **Total Capital tax for the taxation year**

*Transfer to **543** and complete the return from that point*

* *If floating taxation year, refer to Guide.*

Capital Tax before application of specified credits **543** =
Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)* **546** -
Capital Tax **543 - 546** *(amount cannot be negative)* **550** =
Transfer to Page 17

continued on Page 13

Capital Tax *continued from Page 12*

Calculation of Capital Tax for Financial Institutions

1.1 Credit Unions Only

For taxation years commencing **after May 4, 1999** enter NIL in **550** on page 12, and complete the return from that point.

1.2 Other than Credit Unions

*(Retain details of calculations for amounts in boxes **565** and **570**. Do not submit with this tax return.)*

565 _____ Lesser of adjusted Taxable Paid Up Capital and Basic Capital Amount in accordance with Division B.1

x **567** 0.5700 % Capital Tax Rate(1) *(Refer to Guide)*

x From **30** _____ % Ontario Allocation

x **555** _____ Days in taxation year *365 (366 if leap year)

= **569** +

570 _____ Adjusted Taxable Paid Up Capital in accordance with Division B.1 in excess of Basic Capital Amount

x **571** _____ % Capital Tax Rate(2) *(Refer to Guide)*

x From **30** _____ % Ontario Allocation

x **555** _____ Days in taxation year *365 (366 if leap year)

= **574** +

Capital Tax for Financial Institutions - other than Credit Unions (before Section 2) 569 + 574 **575** =

** If floating taxation year, refer to Guide.*

2. Small Business Investment Tax Credit

(Retain details of eligible investment calculation and, if claiming an investment in CSBIF, retain the original letter approving the credit issued in accordance with the Community Small Business Investment Fund Act. Do not submit with this tax return.)

Allowable Credit for Eligible Investments **585** -

Financial Institutions: Claiming a tax credit for investment in Community Small Business Investment Fund (CSBIF)? (✓) ☐ Yes

Capital Tax - Financial Institutions 575 - 585 **586** =

*Transfer to **543** on Page 12*

Premium Tax (s.74.2 & 74.3) *(Refer to Guide)*

(1) Uninsured Benefits Arrangements **587** _____ x 2% **588** =

Applies to Ontario-related uninsured benefits arrangements.

(2) Unlicensed Insurance (enter premium tax payable in **588** and attach a detailed schedule of calculations. If subject to tax under (1) above, add both taxes together and enter total tax in **588**.)

Applies to Insurance Brokers and other persons placing insurance for persons resident or property situated in Ontario with unlicensed insurers.

Deduct: Specified Tax Credits applied to reduce premium tax *(Refer to Guide)* **589** -

Premium Tax 588 - 589 **590** =

Transfer to Page 17

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

Net Income (loss) for federal income tax purposes, per federal T2 Schedule 1 **600** ± 602,626
Transfer to Page 15

Add:

Federal capital cost allowance	**601** +	411,978
Federal cumulative eligible capital deduction	**602** +	
Ontario taxable capital gain	**603** +	
Federal non-allowable reserves. Balance beginning of year	**604** +	
Federal allowable reserves. Balance end of year	**605** +	
Ontario non-allowable reserves. Balance end of year	**606** +	
Ontario allowable reserves. Balance beginning of year	**607** +	
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE)	**608** +	
Federal resource allowance *(Refer to Guide)*	**609** +	
Federal depletion allowance	**610** +	
Federal foreign exploration and development expenses	**611** +	
Crown charges, royalties, rentals, etc. deducted for Federal purposes *(Refer to Guide)*	**617** +	

Management fees, rents, royalties and similar payments to non-arms' length non-residents

Number of Days in Taxation Year

		Days after Dec. 31, 2002 and before Jan. 1, 2004	Total Days		
612	X 5/12.5 X **33**	÷ **73**	365	= **633** +	

		Days after Dec. 31, 2003	Total Days		
612	X 5/14.0 X **34**	365 ÷ **73**	365	= **634** +	

Total add-back amount for Management fees, etc. **633 + 634** =	▶ **613** +		
Federal Scientific Research Expenses claimed in year from line **460** of fed. form T661 excluding any negative amount in **473** from Ont. CT23 Schedule 161	**615** +		
Add any negative amount in **473** from Ont. CT23 Schedule 161	**616** +		
Federal allowable business investment loss	**620** +		
Total of other items not allowed by Ontario but allowed federally *(Attach schedule)*	**614** +		
Total of Additions 601 to 611 + 617 + 613 + 615 + 616 + 620 + 614	=	411,978 **640**	411,978

Transfer to Page 15

Deduct:

Ontario capital cost allowance (excludes amounts deducted under **675**)	**650** +	411,978
Ontario cumulative eligible capital deduction	**651** +	
Federal taxable capital gain	**652** +	
Ontario non-allowable reserves. Balance beginning of year	**653** +	
Ontario allowable reserves. Balance end of year	**654** +	
Federal non-allowable reserves. Balance end of year	**655** +	
Federal allowable reserves. Balance beginning of year	**656** +	
Ontario exploration expenses (e.g. CEDE, CEE, CDE, COGPE) *(Retain calculations. Do not submit.)*	**657** +	
Ontario depletion allowance	**658** +	
Ontario resource allowance *(Refer to Guide)*	**659** +	
Ontario current cost adjustment *(Attach schedule)*	**661** +	
CCA on assets used to generate electricity from natural gas, alternative or renewable resources.	**675** +	
Subtotal of deductions for this page 650 to 659 + 661 + 675	**681**	411,978

Transfer to Page 15

continued on Page 15

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

continued from Page 14

Net income (loss) for federal income tax purposes, per federal Schedule 1	From 600 ±	602,626	
Total of Additions on page 14	From 640 =	411,978	
Sub Total of deductions on page 14	From 681 =	411,978	

Deduct:

Ontario New Technology Tax Incentive (ONTTI) Gross-up
(***Applies*** only to those corporations whose Ontario allocation is less than 100% in the current taxation year.)

Capital Cost Allowance (Ontario) (CCA) on prescribed qualifying intellectual property deducted in the current taxation year **662** _____

ONTTI Gross-up deduction calculation:

From **662** _____ Gross-up of CCA x 100/ **30** 100.0000 - From **662** _____ **663** =
Ontario Allocation

Workplace Child Care Tax Incentive (WCCT)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: **665** _____ x 30% x 100/ **30** From 100.0000 **666** =
Ontario Allocation

Workplace Accessibility Tax Incentive (WATI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: **667** _____ x 100% x 100/ **30** From 100.0000 **668** =
Ontario Allocation

Number of Employees accommodated **669**

Ontario School Bus Safety Tax Incentive (OSBSTI)
(***Applies*** to the eligible acquisition of school buses purchased after May 4, 1999 and before January 1, 2006.) *(Refer to Guide)*

Qualifying expenditures: **670** _____ x 30% x 100/ **30** From 100.0000 **671** =
Ontario Allocation

Educational Technology Tax Incentive (ETTI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: **672** _____ x 15% x 100/ **30** From 100.0000 **673** =
Ontario Allocation

Ontario allowable business investment loss	**678** +		
Ontario Scientific Research Expenses claimed in year in 477 from Ont. CT23 Schedule 161	**679** +		
Amount added to income federally for an amount that was negative on federal form T661, line 454 or 455 (if filed after June 30, 2003)	**677** +		
Total of other deductions allowed by Ontario *(Attach schedule)*	**664** +		
Total of Deductions 681 + 663 + 666 + 668 + 671 + 673 + 678 + 679 + 677 + 664	=	411,978 **680**	411,978

Net income (loss) for Ontario Purposes 600 + 640 - 680 **690** = 602,626
Transfer to Page 4

Continuity of Losses Carried Forward

	Non-Capital Losses (1)	Total Capital Losses	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year	700 (2)	710 (2)	720 (2)	730	740	750
Add: Current year's losses (7)	701	711	721	731	741	751
Losses from predecessor corporations (3)	702	712	722	732		752
Subtotal	703	713	723	733	743	753
Subtract: Utilized during the year to reduce taxable income	704 (2)	715 (2)(4)	724 (2)	734 (2)(4)	744 (4)	754 (4)
Expired during the year	705		725	735	745	
Carried back to prior years to reduce taxable income (5)	706 (2) To Pg 17	716 (2) To Pg 17	726 (2) To Pg 17	736 (2) To Pg 17	746	
Subtotal	707	717	727	737	747	757
Balance at End of Year	709 (8)	719	729	739	749	759

Analysis of Balance at End of Year by Year of Origin

Year of Origin (oldest year first)	Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800 9th preceding taxation year	817 (9)	860 (9)		850	870
801 8th preceding taxation year	818 (9)	861 (9)		851	871
802 7th preceding taxation year 2000/12/31	819 (9)	862 (9)		852	872
803 6th preceding taxation year 2001/12/31	820	830	840	853	873
804 5th preceding taxation year 2002/12/31	821	831	841	854	874
805 4th preceding taxation year 2003/12/31	822	832	842	855	875
806 3rd preceding taxation year 2004/12/31	823	833	843	856	876
807 2nd preceding taxation year 2005/12/31	824	834	844	857	877
808 1st preceding taxation year 2006/12/31	825	835	845	858	878
809 Current taxation year 2007/12/31	826	836	846	859	879
Total	829	839	849	869	889

Notes:

(1) Non-capital losses include allowable business investment losses, fed.s.111(8)(b), as made applicable by s.34.

(2) Where acquisition of control of the corporation has occurred, the utilization of losses can be restricted. See fed.s.111(4) through 111(5.5), as made applicable by s.34.

(3) Includes losses on amalgamation (fed.s.87(2.1) and s.87(2.11)) and/or wind-up (fed.s.88(1.1) and 88(1.2)), as made applicable by s.34.

(4) To the extent of applicable gains/income/at-risk amount only.

(5) Generally a three year carry-back applies. See fed.s.111(1) and fed.s.41(2)(b), as made applicable by s.34.

(6) Where a limited partner has limited partnership losses, attach loss calculations for each partnership.

(7) Include amount from **11** if taxable income is adjusted to claim unused foreign tax credit for federal purposes.

(8) Amount in **709** must equal total of **829** + **839**.

(9) Include non-capital losses incurred in taxation years ending after March 22, 2004.

Request for Loss Carry-Back (s.80(16))

Applies to corporations requesting a reassessment of the return of one or more previous taxation years under s.80(16) with respect to one or more types of losses carried back.

- If, after applying a loss carry-back to one or more previous years, there is a balance of loss available to carry forward to a future year, it is the corporation's responsibility to claim such a balance for those years following the year of loss within the limitations of fed.s.111, as made applicable by s.34.
- Where control of a corporation has been acquired by a person or group of persons, certain restrictions apply to the carry-forward and carry-back provisions of losses under fed.s.111(4) through 111(5.5), as made applicable by s.34.
- Refunds arising from the loss carry-back adjustment may be applied by the Minister of Finance to amounts owing under **any Act administered by the Ministry of Finance.**
- Any late filing penalty applicable to the return for which the loss is being applied will not be reduced by the loss carry-back.
- The application of a loss carry-back will be available for interest calculation purposes on the day that is the latest of the following:
  1) the first day of the taxation year after the loss year,
  2) the day on which the corporation's return for the loss year is delivered to the Minister, or
  3) the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.
- If a loss is being carried back to a **predecessor corporation**, enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses	Non-Capital Losses	Total Capital Losses	Farm Losses	Restricted Farm Losses
	910	920	930	940
Total amount of loss				
Deduct: Loss to be carried back to preceding taxation years and applied to reduce taxable income. **Predecessor Corporation's Tax Account No. (MOF)** / **Taxation Year Ending**	911	921	931	941
i) 3rd preceding 901 2004/12/31	912	922	932	942
ii) 2nd preceding 902 2005/12/31	913	923	933	943
iii) 1st preceding 903 2006/12/31	From 706	From 716	From 726	From 736
Total loss to be carried back	919	929	939	949
Balance of loss available for carry-forward				

Summary

Income Tax	From 230 or 320	+	59,825
Corporate Minimum Tax	From 280	+	
Capital Tax	From 550	+	
Premium Tax	From 590	+	
Total Tax Payable	950	=	59,825
Subtract: Payments	960	-	
Capital Gains Refund (s.48)	965	-	
Qualifying Environmental Trust Tax Credit *(Refer to Guide)*	985	-	
Specified Tax Credits *(Refer to Guide)*	955	-	
Balance	970	=	59,825
If payment due Enclosed *	990	=	
If overpayment: Refund *(Refer to Guide)*	975	=	
Apply to	980		

(Includes credit interest)

* Make your cheque (drawn on a Canadian financial institution) or a money order in Canadian funds, payable to the **Minister of Finance** and print your Ontario Corporation's Tax Account No. (MOF) on the back of cheque or money order. *(Refer to Guide for other payment methods.)*

Certification

I am an authorized signing officer of the corporation. I certify that this CT23 return, including all schedules and statements filed with or as part of this CT23 return, has been examined by me and is a true, correct and complete return and that the information is in agreement with the books and records of the corporation. I further certify that the financial statements accurately reflect the financial position and operating results of the corporation as required under section 75 of the *Corporations Tax Act*. The method of computing income for this taxation year is consistent with that of the previous year, except as specifically disclosed in a statement attached.

Name
Darrell Eddington

Title
Treasurer

Full Residence Address
200 Broadway, 2nd Floor

City
Tillsonburg

Province	Country	Postal Code
ON	CA	N4G 5A7

Signature

Date
2008/06/25

Note: Section 76 of the *Corporations Tax Act* provides penalties for making false or misleading statements or omissions.

Schedule A: Information on Ontario Corporations

(Corporations that are incorporated, continued or amalgamated under the *Ontario Business Corporations Act)*

MGS

Schedule A

To submit additional Director or Officer Information, please photocopy this page and attach the completed schedules with you return.

Identification

Corporation's Legal Name (*including punctuation*)	Ontario Corporation No. (MGS)	Date of Incorporation or Amalgamation
Tillsonburg Hydro Inc.	1800285	2000/10/26

Director/Officer Information

Full Name and Address for Service:

Last Name	First Name	Middle Name(s)
DiGiovanni	Joe	

Street Number and Name: 7 Woodside Drive — Suite:

City/Town/Village	Province/State	Country	Postal/Zip Code
Tillsonburg	ON	CA	N4G 5P9

Director

Are you a resident Canadian? *(Applies to directors of business corporations only)*

☒ Yes ☐ No

Date Elected: 2001/01/01

Date Ceased:

Officer

State the appointment period for each of the following

	Date Appointed (year month day)	Date Ceased (year month day)
President		
Secretary		
Treasurer		
General Manager		
Other *(specify)*		

Other Titles *(please specify)*

- ☐ Chair
- ☐ Chair Person
- ☐ Chairman
- ☐ Chairwoman
- ☐ Vice-Chair
- ☐ Vice-President
- ☐ Assistant Secretary
- ☐ Assistant Treasurer
- ☐ Chief Manager
- ☐ Executive Director
- ☐ Managing Director
- ☐ Chief Executive Officer
- ☐ Chief Financial Officer
- ☐ Chief Info. Officer
- ☐ Chief Operating Officer
- ☐ Chief Administrative Officer
- ☐ Comptroller
- ☐ Authorized Signing Officer
- ☐ Other (untitled)

Director/Officer Information

Full Name and Address for Service:

Last Name	First Name	Middle Name(s)
Armstrong	John	

Street Number and Name: 336 Broadway Street — Suite:

City/Town/Village	Province/State	Country	Postal/Zip Code
Tillsonburg	ON	CA	N4G 3S3

Director

Are you a resident Canadian? *(Applies to directors of business corporations only)*

☒ Yes ☐ No

Date Elected: 2001/01/01

Date Ceased:

Officer

State the appointment period for each of the following:

	Date Appointed (year month day)	Date Ceased (year month day)
President		
Secretary		
Treasurer		
General Manager		
Other *(specify)*		

Other Titles *(please specify)*

- ☐ Chair
- ☐ Chair Person
- ☐ Chairman
- ☐ Chairwoman
- ☐ Vice-Chair
- ☐ Vice-President
- ☐ Assistant Secretary
- ☐ Assistant Treasurer
- ☐ Chief Manager
- ☐ Executive Director
- ☐ Managing Director
- ☐ Chief Executive Officer
- ☐ Chief Financial Officer
- ☐ Chief Info. Officer
- ☐ Chief Operating Officer
- ☐ Chief Administrative Officer
- ☐ Comptroller
- ☐ Authorized Signing Officer
- ☐ Other (untitled)

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Schedule A: Information on Ontario Corporations

(Corporations that are incorporated, continued or amalgamated under the *Ontario Business Corporations Act*)

MGS

Schedule A

To submit additional Director or Officer Information, please photocopy this page and attach the completed schedules with you return.

Identification

Corporation's Legal Name (*including punctuation*)	Ontario Corporation No. (MGS)	Date of Incorporation or Amalgamation
Tillsonburg Hydro Inc.	1800285	2000/10/26

Director/Officer Information

Full Name and Address for Service:

Last Name	First Name	Middle Name(s)
Esseltine	Phil	

Street Number and Name: 15 Hyman Street — Suite:

City/Town/Village	Province/State	Country	Postal/Zip Code
Tillsonburg	ON	CA	N4G 2C3

Director

Are you a resident Canadian? *(Applies to directors of business corporations only)*

☒ Yes ☐ No

Date Elected: 2001/01/01

Date Ceased:

Officer

State the appointment period for each of the following

	Date Appointed (year month day)	Date Ceased (year month day)
President		
Secretary		
Treasurer		
General Manager		
Other *(specify)*	2001/01/01	

Other Titles *(please specify)*

- ☐ Chair
- ☐ Chair Person
- ☐ Chairman
- ☐ Chairwoman
- ☒ Vice-Chair
- ☐ Vice-President
- ☐ Assistant Secretary
- ☐ Assistant Treasurer
- ☐ Chief Manager
- ☐ Executive Director
- ☐ Managing Director
- ☐ Chief Executive Officer
- ☐ Chief Financial Officer
- ☐ Chief Info. Officer
- ☐ Chief Operating Officer
- ☐ Chief Administrative Officer
- ☐ Comptroller
- ☐ Authorized Signing Officer
- ☐ Other (untitled)

Director/Officer Information

Full Name and Address for Service:

Last Name	First Name	Middle Name(s)
Molnar	Stephen	

Street Number and Name: 51 Parkwood Drive — Suite:

City/Town/Village	Province/State	Country	Postal/Zip Code
Tillsonburg	ON	CA	N6G 2B7

Director

Are you a resident Canadian? *(Applies to directors of business corporations only)*

☒ Yes ☐ No

Date Elected: 2001/01/01

Date Ceased:

Officer

State the appointment period for each of the following:

	Date Appointed (year month day)	Date Ceased (year month day)
President		
Secretary		
Treasurer		
General Manager		
Other *(specify)*		

Other Titles *(please specify)*

- ☐ Chair
- ☐ Chair Person
- ☐ Chairman
- ☐ Chairwoman
- ☐ Vice-Chair
- ☐ Vice-President
- ☐ Assistant Secretary
- ☐ Assistant Treasurer
- ☐ Chief Manager
- ☐ Executive Director
- ☐ Managing Director
- ☐ Chief Executive Officer
- ☐ Chief Financial Officer
- ☐ Chief Info. Officer
- ☐ Chief Operating Officer
- ☐ Chief Administrative Officer
- ☐ Comptroller
- ☐ Authorized Signing Officer
- ☐ Other (untitled)

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Schedule A: Information on Ontario Corporations

MGS

(Corporations that are incorporated, continued or amalgamated under the *Ontario Business Corporations Act)*

Schedule A

To submit additional Director or Officer Information, please photocopy this page and attach the completed schedules with you return.

Identification

Corporation's Legal Name *(including punctuation)*	Ontario Corporation No. (MGS)	Date of Incorporation or Amalgamation
Tillsonburg Hydro Inc.	1800285	2000/10/26

Director/Officer Information

Full Name and Address for Service:

Last Name	First Name	Middle Name(s)
Lewis	Fred	

Street Number and Name: 111 Bidwell Street — Suite:

City/Town/Village	Province/State	Country	Postal/Zip Code
Tillsonburg	ON	CA	N4G 3V4

Director

Are you a resident Canadian? *(Applies to directors of business corporations only)*

☒ Yes ☐ No

Date Elected: 2001/01/01

Date Ceased:

Officer

State the appointment period for each of the following

	Date Appointed (year month day)	Date Ceased (year month day)
President		
Secretary		
Treasurer		
General Manager		
Other *(specify)*		

Other Titles *(please specify)*

- ☐ Chair
- ☐ Chair Person
- ☐ Chairman
- ☐ Chairwoman
- ☐ Vice-Chair
- ☐ Vice-President
- ☐ Assistant Secretary
- ☐ Assistant Treasurer
- ☐ Chief Manager
- ☐ Executive Director
- ☐ Managing Director
- ☐ Chief Executive Officer
- ☐ Chief Financial Officer
- ☐ Chief Info. Officer
- ☐ Chief Operating Officer
- ☐ Chief Administrative Officer
- ☐ Comptroller
- ☐ Authorized Signing Officer
- ☐ Other (untitled)

Director/Officer Information

Full Name and Address for Service:

Last Name	First Name	Middle Name(s)
Renaud	Mark	

Street Number and Name: 96 Glendale Drive — Suite:

City/Town/Village	Province/State	Country	Postal/Zip Code
Tillsonburg	ON	CA	N4G 5R2

Director

Are you a resident Canadian? *(Applies to directors of business corporations only)*

☒ Yes ☐ No

Date Elected: 2001/01/01

Date Ceased:

Officer

State the appointment period for each of the following:

	Date Appointed (year month day)	Date Ceased (year month day)
President		
Secretary		
Treasurer		
General Manager		
Other *(specify)*	2001/01/01	

Other Titles *(please specify)*

- ☒ Chair
- ☐ Chair Person
- ☐ Chairman
- ☐ Chairwoman
- ☐ Vice-Chair
- ☐ Vice-President
- ☐ Assistant Secretary
- ☐ Assistant Treasurer
- ☐ Chief Manager
- ☐ Executive Director
- ☐ Managing Director
- ☐ Chief Executive Officer
- ☐ Chief Financial Officer
- ☐ Chief Info. Officer
- ☐ Chief Operating Officer
- ☐ Chief Administrative Officer
- ☐ Comptroller
- ☐ Authorized Signing Officer
- ☐ Other (untitled)

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Schedule A: Information on Ontario Corporations

MGS

(Corporations that are incorporated, continued or amalgamated under the *Ontario Business Corporations Act)*

Schedule A

To submit additional Director or Officer Information, please photocopy this page and attach the completed schedules with you return.

Identification

Corporation's Legal Name *(including punctuation)*	Ontario Corporation No. (MGS)	Date of Incorporation or Amalgamation
Tillsonburg Hydro Inc.	1800285	2000/10/26

Director/Officer Information

Full Name and Address for Service:

Last Name	First Name	Middle Name(s)
Morris	David	

Street Number and Name: 20 Devon Court — Suite:

City/Town/Village	Province/State	Country	Postal/Zip Code
Tillsonburg	ON	CA	N4G 4K5

Director

Are you a resident Canadian? *(Applies to directors of business corporations only)*

☒ Yes ☐ No

Date Elected: 2001/01/01

Date Ceased:

Officer

State the appointment period for each of the following

	Date Appointed (year month day)	Date Ceased (year month day)
President		
Secretary		
Treasurer		
General Manager		
Other *(specify)*		

Other Titles *(please specify)*

☐ Chair ☐ Chief Executive Officer
☐ Chair Person ☐ Chief Financial Officer
☐ Chairman ☐ Chief Info. Officer
☐ Chairwoman ☐ Chief Operating Officer
☐ Vice-Chair ☐ Chief Administrative
☐ Vice-President Officer
☐ Assistant Secretary ☐ Comptroller
☐ Assistant Treasurer ☐ Authorized Signing
☐ Chief Manager Officer
☐ Executive Director
☐ Managing Director ☐ Other (untitled)

Director/Officer Information

Full Name and Address for Service:

Last Name	First Name	Middle Name(s)
Lessif	John	

Street Number and Name: 5 Bridle Path Lane — Suite:

City/Town/Village	Province/State	Country	Postal/Zip Code
Tillsonburg	ON	CA	N4G 5L9

Director

Are you a resident Canadian? *(Applies to directors of business corporations only)*

☒ Yes ☐ No

Date Elected: 2007/01/01

Date Ceased:

Officer

State the appointment period for each of the following:

	Date Appointed (year month day)	Date Ceased (year month day)
President		
Secretary		
Treasurer		
General Manager		
Other *(specify)*		

Other Titles *(please specify)*

☐ Chair ☐ Chief Executive Officer
☐ Chair Person ☐ Chief Financial Officer
☐ Chairman ☐ Chief Info. Officer
☐ Chairwoman ☐ Chief Operating Officer
☐ Vice-Chair ☐ Chief Administrative
☐ Vice-President Officer
☐ Assistant Secretary ☐ Comptroller
☐ Assistant Treasurer ☐ Authorized Signing
☐ Chief Manager Officer
☐ Executive Director
☐ Managing Director ☐ Other (untitled)

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Schedule A: Information on Ontario Corporations

MGS

(Corporations that are incorporated, continued or amalgamated under the *Ontario Business Corporations Act)*

Schedule A

To submit additional Director or Officer Information, please photocopy this page and attach the completed schedules with you return.

Identification

Corporation's Legal Name *(including punctuation)*	Ontario Corporation No. (MGS)	Date of Incorporation or Amalgamation
Tillsonburg Hydro Inc.	1800285	2000/10/26

Director/Officer Information

Full Name and Address for Service:

Last Name	First Name	Middle Name(s)
Sibbick	Bryce	

Street Number and Name: 17 Whispering Pine Lane — Suite:

City/Town/Village	Province/State	Country	Postal/Zip Code
Tillsonburg	ON	CA	N4G 5V4

Director

Are you a resident Canadian? *(Applies to directors of business corporations only)*

☒ Yes ☐ No

Date Elected: 2007/01/01

Date Ceased:

Officer

State the appointment period for each of the following

	Date Appointed (year month day)	Date Ceased (year month day)
President		
Secretary		
Treasurer		
General Manager		
Other *(specify)*		

Other Titles *(please specify)*

☐ Chair ☐ Chief Executive Officer
☐ Chair Person ☐ Chief Financial Officer
☐ Chairman ☐ Chief Info. Officer
☐ Chairwoman ☐ Chief Operating Officer
☐ Vice-Chair ☐ Chief Administrative
☐ Vice-President Officer
☐ Assistant Secretary ☐ Comptroller
☐ Assistant Treasurer ☐ Authorized Signing
☐ Chief Manager Officer
☐ Executive Director
☐ Managing Director ☐ Other (untitled)

Director/Officer Information

Full Name and Address for Service:

Last Name	First Name	Middle Name(s)
Lund	Steve	

Street Number and Name: 22 Woodland Cresc. — Suite:

City/Town/Village	Province/State	Country	Postal/Zip Code
Tillsonburg	ON	CA	N4G 1B3

Director

Are you a resident Canadian? *(Applies to directors of business corporations only)*

☐ Yes ☐ No

Date Elected:

Date Ceased:

Officer

State the appointment period for each of the following:

	Date Appointed (year month day)	Date Ceased (year month day)
President		
Secretary		
Treasurer		
General Manager	2000/10/26	
Other *(specify)*		

Other Titles *(please specify)*

☐ Chair ☐ Chief Executive Officer
☐ Chair Person ☐ Chief Financial Officer
☐ Chairman ☐ Chief Info. Officer
☐ Chairwoman ☐ Chief Operating Officer
☐ Vice-Chair ☐ Chief Administrative
☐ Vice-President Officer
☐ Assistant Secretary ☐ Comptroller
☐ Assistant Treasurer ☐ Authorized Signing
☐ Chief Manager Officer
☐ Executive Director
☐ Managing Director ☐ Other (untitled)

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Schedule A: Information on Ontario Corporations

(Corporations that are incorporated, continued or amalgamated under the *Ontario Business Corporations Act)*

MGS

Schedule A

To submit additional Director or Officer Information, please photocopy this page and attach the completed schedules with you return.

Identification

Corporation's Legal Name *(including punctuation)*	Ontario Corporation No. (MGS)	Date of Incorporation or Amalgamation
Tillsonburg Hydro Inc.	1800285	2000/10/26

Director/Officer Information

Full Name and Address for Service:

Last Name	First Name	Middle Name(s)
Graves	Michael	

Street Number and Name: 42 North Street — Suite:

City/Town/Village	Province/State	Country	Postal/Zip Code
Tillsonburg	ON	CA	N4G 1B3

Director

Are you a resident Canadian? *(Applies to directors of business corporations only)*

☐ Yes ☐ No

Date Elected:

Date Ceased:

Officer

State the appointment period for each of the following

	Date Appointed (year month day)	Date Ceased (year month day)
President		
Secretary	2003/01/01	
Treasurer		
General Manager		
Other *(specify)*		

Other Titles *(please specify)*

☐ Chair ☐ Chief Executive Officer
☐ Chair Person ☐ Chief Financial Officer
☐ Chairman ☐ Chief Info. Officer
☐ Chairwoman ☐ Chief Operating Officer
☐ Vice-Chair ☐ Chief Administrative
☐ Vice-President Officer
☐ Assistant Secretary ☐ Comptroller
☐ Assistant Treasurer ☐ Authorized Signing
☐ Chief Manager Officer
☐ Executive Director
☐ Managing Director ☐ Other (untitled)

Director/Officer Information

Full Name and Address for Service:

Last Name	First Name	Middle Name(s)
Eddington	Darrell	

Street Number and Name: 268 Centre Street — Suite:

City/Town/Village	Province/State	Country	Postal/Zip Code
Ingersol	ON	CA	N5C 1X6

Director

Are you a resident Canadian? *(Applies to directors of business corporations only)*

☐ Yes ☐ No

Date Elected:

Date Ceased:

Officer

State the appointment period for each of the following:

	Date Appointed (year month day)	Date Ceased (year month day)
President		
Secretary		
Treasurer	2003/01/01	
General Manager		
Other *(specify)*		

Other Titles *(please specify)*

☐ Chair ☐ Chief Executive Officer
☐ Chair Person ☐ Chief Financial Officer
☐ Chairman ☐ Chief Info. Officer
☐ Chairwoman ☐ Chief Operating Officer
☐ Vice-Chair ☐ Chief Administrative
☐ Vice-President Officer
☐ Assistant Secretary ☐ Comptroller
☐ Assistant Treasurer ☐ Authorized Signing
☐ Chief Manager Officer
☐ Executive Director
☐ Managing Director ☐ Other (untitled)

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Ontario
Ministry of Finance
Corporations Tax
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

ONTARIO CAPITAL COST ALLOWANCE

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Tillsonburg Hydro Inc.	1800285	2007/12/31

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year	3 Cost of acquisitions during the the year See note 1 below	4 Net adjustments	5 Proceeds of dispositions during the year	6 Ontario undepreciated capital cost (col 2 + 3 or col 2 - 4 - 5)	7 50% rule See note 2 below	8 Reduced undepreciated capital cost (col 6 - 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (col 8 x 9 or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (col 6 - 12)
1	6,519,588				6,519,588		6,519,588	4			260,784	6,258,804
47	1,488,360	803,133			2,291,493	401,567	1,889,926	8			151,194	2,140,299
								Totals			411,978	

Enter in box **650** on the CT23

Note 1. 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) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.

Ontario

Ministry of Finance
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Authorizing or Cancelling a Representative

Complete this form to:

- **authorize** the release of confidential information about the Corporations Tax, Mining Tax or Electricity Act account(s) to the representative named below.
- **cancel** an existing authorization.

Part 1 Client Information

Legal name: Tillsonburg Hydro Inc.

Phone number: (519) 842-6428

Mailing address
Apt./Suite/Unit no. Street number and name / PO Box, RR: 200 Broadway, 2nd Floor

City: Tillsonburg

Province/Territory: ON

Postal code: N4G 5A7

This authorization applies to the following statute(s) and account number(s).

- [X] Corporations Tax Act — 1800285
- [ ] Mining Tax Act
- [ ] Electricity Act

Part 2 Authorize the release of information to a representative

Name of representative (If a firm, name of firm.): Scrimgeour & Company, Chartered Accountant

Phone number: (519) 672-6811

Fax number: (519) 672-9757

Mailing address
Apt./Suite/Unit no. Street number and name / PO Box RR: 950-495 Richmond Street

City: London

Province/Territory: ON

Postal code: N6A 5A9

If your representative is a firm, and you want a specific person in the firm to represent you, state their name and title.
If you do not identify a specific individual in the firm, you are authorizing the Ministry of Finance to deal with anyone from that firm.

Title

Richard G. Scrimgeour, CGA, CFP, TEP

Part 3 Authorization scope and applicable years

- [X] Representative to **deal fully** on your behalf with the Ministry of Finance.

or

- [ ] Representative to **deal in a limited manner** on your behalf, for matters specified here. (e.g., account inquiry, applications, annual returns, payments, etc.) ▼

- [X] Representative to act for **all years**, including all previous and future years.

or

- [ ] Representative to act for **specific year or years** (describe). ▼

Part 4 Cancel the release of information to a representative

Name of representative (If a firm, name of firm.)

Last | First

If your representative is an individual within a firm, state their name and title.

Name of person in firm

Last | First

Title

Part 5 Signature *This form will not be accepted unless it is completed fully, signed and dated.*

I authorize the Ministry of Finance to:

- release confidential information about the tax accounts specified in Part 1 and to deal with the representative named in Part 2 in the manner described in Part 3; and/or
- cancel an existing authorization as described in Part 4.

Name

Last: Eddington

First: Darrell

Title / Relationship to Corporation: Treasurer

Phone number: (519) 842-6428

Signature

Date: 2008/06/25

Canada Revenue Agency | Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

Schedule 200

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec, Ontario, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, and paragraphs mentioned on this return refer to the *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 services office or tax centre. 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 the T2 Corporation – Income Tax Guide (T4012).

055 Do not use this area

Identification

Business number (BN) **001** 86374 2599 RC 0001

Corporation's name

002 Tillsonburg Hydro Inc.

Has the corporation changed its name since the last time you filed your T2 return? **003** ☐ Yes ☒ No

If *Yes*, do you have a copy of the articles of amendment? **004** ☐ Yes ☐ No *(Do Not Submit)*

Address of head office

Has this address changed since the last time you filed your T2 return? **010** ☐ Yes ☒ No

(If **yes**, complete lines 011 to 018)

011 200 Broadway, 2nd Floor

012

City: **015** Tillsonburg — Province, territory, or state: **016** ON

Country (other than Canada): **017** — Postal code/Zip code: **018** N4G 5A7

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? **020** Yes ☐ No ☒

(If **yes**, complete lines 021 to 028)

021 c/o Darrell Eddington

022 200 Broadway, 2nd Floor

023

City: **025** Tillsonburg — Province, territory, or state: **026** ON

Country (other than Canada): **027** — Postal code/Zip code: **028** N4G 5A7

Location of books and records

Has the location of books and records changed since the last time you filed your T2 return? **030** ☐ Yes ☒ No

(If **yes**, complete lines 031 to 038)

031 200 Broadway, 2nd Floor

032

City: **035** Tillsonburg — Province, territory, or state: **036** ON

Country (other than Canada): **037** — Postal code/Zip code: **038** N4G 5A7

040 Type of corporation at the end of the tax year

1 ☒ 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**

To which tax year does this return apply?

From **060** 2007/01/01 to **061** 2007/12/31

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? **063** ☐ Yes ☒ No

If **yes**, provide the date control was acquired **065**

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1) ? **066** ☐ Yes ☒ No

Is the corporation a professional corporation that is a member of a partnership? **067** ☐ Yes ☒ No

Is this the first year of filing after:

Incorporation? **070** ☐ Yes ☒ No

Amalgamation? **071** ☐ Yes ☒ No

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** ☐ Yes ☒ No

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? **076** ☐ Yes ☒ No

Is this the final return up to dissolution? **078** ☐ Yes ☒ No

Is the corporation a resident of Canada? **080** ☒ Yes ☐ 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** ☐ Yes ☒ No

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	☒	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	☒	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	☐	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	☐	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or			
ii) is the corporation claiming the refundable portion of Part I tax?	207	☐	7
Does the corporation have any property that is eligible for capital cost allowance?	208	☒	8
Does the corporation have any property that is eligible capital property?	210	☐	10
Does the corporation have any resource-related deductions?	212	☐	12
Is the corporation claiming reserves of any kind?	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
Was 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?	255	☐	92 *

*** We do not print this schedule.**

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

Is the corporation inactive?	280	1 Yes ☐	2 No ☒
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281	1 Yes ☐	2 No ☒
What is the corporation's major business activity?	282		
(Only complete if **yes** was entered at line 281.)			
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.

284	Electricity distribution	285	100 000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes ☐	2 No ☒
Did the corporation emigrate from Canada during the tax year?	292	1 Yes ☐	2 No ☒

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI	300	602,626	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")		602,626	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355		D
Taxable income (amount C **plus** amount D)	360	602,626	
Income exempt under paragraph 149(1)(t)	370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724 on page 8.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 — **400** 602,626 A

Taxable income from line 360 on page 3, **minus** 10/3 of the amount on line 632 on page 7, **minus** 3 times the amount on line 636 on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax — **405** 602,626 B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

$300,000 x (Number of days in the tax year in 2005 and in 2006 / Number of days in the tax year) (/ 365) = 1

$400,000 x (Number of days in the tax year after 2006 / Number of days in the tax year) (365 / 365) = 400,000 2

Add amounts at lines 1 and 3 — 400,000 4

Business limit (see notes 1 and 2 below) — **410** 400,000 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 400,000 X **415** D / 11,250 = E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") — **425** 400,000 F

Small business deduction

Amount A, B, C, or F whichever is the least 400,000 x (Number of days in the tax year before January 1, 2008 / Number of days in the tax year) (365 / 365) x 16% = 64,000 5

Amount A, B, C, or F whichever is the least 400,000 x (Number of days in the tax year after Dec.31, 2007 / Number of days in the tax year) (/ 365) x 17% = 6

Total of amounts 5 and 6 - enter on line 9 of page 7 — **430** 64,000 G

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)] — **435** H

Amount H x (Number of days in the tax year in 2005 / Number of days in the tax year) (/ 365) x 3% = I

Amount H x (Number of days in the tax year in 2006 / Number of days in the tax year) (/ 365) x 5% = J

Amount H x (Number of days in the tax year in 2007 / Number of days in the tax year) (365 / 365) x 7% = K

Resource deduction – total of amounts I and J — **438** L

(enter amount L on line 10 of page 7)

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3				602,626 A
Amount Z from Part 9 of Schedule 27		x 100 / 7 =		B
Amount QQ from Part 13 of Schedule 27				C
Taxable resource income from line 435 on page 4				D
Amount used to calculate the credit union deduction (from Schedule 17)				E
Amount on line 400, 405, 410, or 425 on page 4, whichever is the least			400,000	F
Aggregate investment income from line 440 of page 6				G
Total of amounts B, C, D, E, F, and G			400,000 ▶	400,000 H
Amount A **minus** amount H (if negative, enter "0")				202,626 I

Amount I	202,626	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365 / 365	x 7% =	14,184 J
Amount I	202,626	x	Number of days in the tax year after Dec. 31, 2007 and before Jan. 1, 2009 / Number of days in the tax year	/ 365	x 8.5% =	K

General tax reduction for Canadian-controlled private corporations - total of amounts J and K — 14,184 L

Enter amount L on line 638 of page 7

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation, and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 on page 3 (for tax years starting after May 1, 2006, Amount Z on page 3)				M
Amount Z from Part 9 of Schedule 27		x 100 / 7 =		N
Amount QQ from Part 13 of Schedule 27				O
Taxable resource income from line 435 on page 4				P
Amount used to calculate the credit union deduction (from Schedule 17)				Q
Total of amounts N, O, P, and Q			▶	R
Amount M **minus** amount R (if negative, enter "0")				S

Amount S		x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	/	x 7% =	T
Amount S		x	Number of days in the tax year after Dec. 31, 2007 and before Jan. 1, 2009 / Number of days in the tax year	/ 365	x 8.5% =	U

General tax reduction - total of amounts T and U — V

Enter amount V on line 639 of page 7.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income (from Schedule 7)	440		X 26 2/3 % =		A
Foreign non-business income tax credit from line 632 on page 7					
Deduct:					
Foreign investment income (from Schedule 7)	445		X 9 1/3 % = (if negative, enter "0")		B
Amount A **minus** amount B (if negative, enter "0")					C
Taxable income from line 360 on page 3			602,626		
Deduct:					
Amount on line 400, 405, 410 or 425 on page 4, whichever is the least		400,000			
Foreign non-business income tax credit from line 632 of page 7		x 25/9 =			
Foreign business income tax credit from line 636 of page 7		x 3 =			
		400,000	400,000		
			202,626	X 26 2/3% =	54,034 D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8)			97,300		
Deduct: Corporate surtax from line 600 of page 7			6,749		
Net amount			90,551		90,551 E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least				450	0 F

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	0

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3		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 of page 8)			0

Part I tax

Base amount of Part I tax

taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38% — 550 — 228,998 A

Corporate surtax calculation

Base amount from line A above		228,998	1
Deduct:			
10% of taxable income (line 360 or amount Z, whichever applies) from page 3		60,263	2
Investment corporation deduction from line 620 below			3
Federal logging tax credit from line 640 below			4
Federal qualifying environmental trust tax credit from line 648 below			5
For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:			
28% of taxable income from line 360 on page 3	a		
28% of taxed capital gains	b		6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F)	90,551 c		
Total of lines 2 to 6		60,263	7
Net amount (line 1 **minus** line 7)		168,735	8

Corporate surtax*

Line 8 168,735 x (Number of days in the tax year before January 1, 2008 / Number of days in the tax year) 365/365 x 4% = 600 — 6,749 B

*The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from Schedule 31 — 602 — C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			i
Taxable income from line 360 on page 3	602,626		
Deduct: Amount on line 400, 405, 410, or 425 of page 4, whichever is the least	400,000		
Net amount	202,626 ▶	202,626	ii

Refundable tax on CCPC's investment income – 6 2/3% of whichever is less: amount i or ii — 604 — D

Subtotal (**add** lines A, B, C, and D) — 235,747 E

Deduct:

Small business deduction from line 430 on page 4		64,000	9
Federal tax abatement	608	60,263	
Manufacturing and processing profits deduction from Schedule 27	616		
Investment corporation deduction (taxed capital gains 624)	620		
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		
Resource deduction from line 438 on page 4			10
General tax reduction for CCPCs from amount L on page 5	638	14,184	
General tax reduction from amount V on page 5	639		
Federal logging tax credit from Schedule 21	640		
Federal political contribution tax credit	644		
Federal political contributions 646			
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652		
Subtotal		138,447 ▶	138,447 F

Part I tax payable – Line E **minus** line F — 97,300 G

Enter amount G on line 700 of page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	97,300
Part I.3 tax payable from Schedule 33, 34, or 35	704	
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		97,300

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, Ontario and Alberta)	760	
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765	
	▶	
Total tax payable	770	97,300 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund from page 6	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	B
Balance (line A minus line B)		97,300 I

Refund Code 894 ☐ Overpayment

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 97,300
Enclosed payment 898

Direct Deposit Request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☒ 2 No ☐ NA ☐

Certification

I, 950 Eddington (Last name) 951 Darrell (First name) 954 Treasurer (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 2008/06/25 (Date) Signature of the authorized signing officer of the corporation 956 (519) 842-6428 (Telephone number)

Is the contact person the same as the authorized signing officer? If *no*, complete the information below. 957 1 Yes ☒ 2 No ☐

958 Name 959 ( ) - Telephone number

Language of correspondence - Langue de correspondance

990 Language of choice/Langue de choix 1 English / Anglais ☒ 2 Français / French ☐

Canada Revenue Agency / Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

Schedule 1

- 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.

Net income (loss) after taxes and extraordinary items per financial statements			A	387,129
Add:				
Provision for income taxes - current	101	187,056		
Amortization of tangible assets	104	440,419		
Total of fields 101 to 199	500	627,475	▶	627,475
Deduct:				
Capital cost allowance - Schedule 8	403	411,978		
Total of fields 401 to 499	510	411,978	▶	411,978
Net income (loss) for income tax purposes (enter on line 300 of the T2 return)				602,626

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CAPITAL COST ALLOWANCE

Schedule 8

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 **200**	2 UCC at start of year **201**	3 Cost of additions in the year **203**	4 Net adjustments **205**	5 Proceeds of dispositions in the year **207**	7 Adjustment for additions (1/2 x (col 3 - 5)) **211**	8 Base amount for CCA	9 Rate % **212**	10 Recapture of CCA **213**	11 Terminal loss **215**	12 CCA for the year (col 8 x 9 or a lower amount) **217**	13 UCC at the end of the year **220**
1	6,519,588					6,519,588	4			260,784	6,258,804
47	1,488,360	803,133			401,567	1,889,926	8			151,194	2,140,299
Totals	8,007,948	803,133			401,567	8,409,514				411,978	8,399,103

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SHAREHOLDER INFORMATION

Schedule 50

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual or trust)	Business Number (If a corporation is not registered, enter "NR") *	Social Insurance Number *	Trust Number (If a trust number is not available, enter "NA") *	Percentage common shares	Percentage preferred shares
100	200	300	350	400	500
Corporation of the Town of Tillsonburg	12658 7195 RC 0001			100.000	
	RC				

* For a taxation year commencing before January 1, 2004, if the shareholder is a trust, enter NR at field 200 or NA at field 300. Do not enter a trust number in field 350.

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BALANCE SHEET INFORMATION

Schedule 100

Assets	Code	Current year	Prior year
Cash and deposits	**1000**	847,463	365,823
Accounts Receivable	1060	2,904,951	3,401,082
Inventories	1120	361,777	387,308
Prepaid expenses	1484	30,042	26,696
Total tangible capital assets	2008	13,042,205	12,239,072
Accumulated amortization of total tangible capital assets	2009	(7,124,294)	(6,683,875)
Due from corporate shareholder(s)	2182	357,748	
Total long term assets	2589		555,656
Total assets	**2599**	10,419,892	10,291,762

Liabilities	Code	Current year	Prior year
Bank overdraft	**2600**		
Amounts payable and accrued liabilities	2620	1,948,282	2,095,777
Taxes payable	2680	2,000	98,886
Deposits received	2961	275,988	176,437
Due to corporate shareholder(s)	3262		132,099
Total long term liabilities	3450	114,708	96,778
Total liabilities	**3499**	2,340,978	2,599,977

Equity	Code	Current year	Prior year
Common shares	**3500**	6,992,565	6,992,565
Contributed and other surplus	3540	1,190,387	1,190,387
Retained earnings / deficit	**3600**	(104,038)	(491,167)
Total equity	**3620**	8,078,914	7,691,785
Total liabilities and equity	**3640**	10,419,892	10,291,762

Retained earnings	Code	Current year	Prior year
Retained earnings/deficit-start	**3660**	(491,167)	(782,993)
Net income / loss	**3680**	387,129	291,826
Total retained earnings	**3849**	(104,038)	(491,167)

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INCOME STATEMENT INFORMATION

Schedule 125

Details

Operating name, if different from the corporations' legal name

0001

Description of operation, if filing multiple Schedules 125

0002

Revenue	Code	Current year	Prior year
Trade sales of goods and services	8000	19,623,994	18,785,778
Total sales of goods and services	8089	19,623,994	18,785,778
Realized gains / losses on disposal of assets	8210		(22,115)
Total revenue	8299	19,623,994	18,763,663

Cost of sales	Code	Current year	Prior year
Opening inventory	8300		
Purchases / cost of materials	8320	16,970,097	16,315,869
Cost of sales	8518	16,970,097	16,315,869
Gross profit / loss (item 8089 - item 8518)	8519	2,653,897	2,469,909

Operating expenses	Code	Current year	Prior year
Amortization of tangible assets	8670	440,419	409,940
Other expenses	9270	1,639,293	1,631,228
Total operating expenses	9367	2,079,712	2,041,168
Total expenses	9368	19,049,809	18,357,037
Net non-farming income	9369	574,185	406,626

Farming revenue	Code	Current year	Prior year
Grains and oilseeds	9370		
Total farm revenue	9659		

Farming expenses	Code	Current year	Prior year
Crop expenses	9660		
Total farm expenses	9898		
Net farm income	9899		
Net income / loss before taxes and extraordinary items	9970	574,185	406,626

Summary

Complete this section if only one Schedule 125 is filed, Schedule 140 is used to summarize the information from multiple Schedules 125.

Extraordinary items	9975	-		-
Legal settlements	9976	-		-
Unrealized gains / losses	9980	+		+
Unusual items	9985	-		-
Current income taxes	9990	-	187,056	- 114,800
Future income tax provision	9995	-		-
Net income / loss after taxes and extraordinary items	9999	=	387,129	= 291,826

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NOTES CHECKLIST

Schedule 141

- This schedule should be completed from the perspective of the person who prepared or reported on the **financial statements**. This person is referred to as the "accounting practitioner", in this schedule.
- For more information, see RC4088, *Guide to the General Index of Financial Information (GIFI) for Corporations* and T4012, *T2 Corporation – Income Tax Guide*.
- Attach a copy of this schedule, along with any Notes to the financial statements, to the GIFI.

Part 1 – Accounting practitioner information

Does the accounting practitioner have a professional designation?	095 ☒ Yes	☐ No
Is the accounting practitioner connected* with the corporation?	097 ☐ Yes	☒ No

* 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 accounting practitioner does not have a professional designation or is connected with the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4.

Part 2 – Type of involvement

Choose the option that represents the highest level of involvement of the accounting practitioner:	198
Completed an auditor's report	1 ☒
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** above, answer the following question:

Has the accounting practitioner expressed a reservation?	099 ☐ Yes	☒ No

Part 4 – Other information

Were notes to the financial statements prepared?	101 ☒ Yes	☐ No
If *Yes*, complete lines 102 to 107 below:		
Are any values presented at other than cost?	102 ☐ Yes	☒ No
Has there been a change in accounting policies since the last return?	103 ☐ Yes	☒ No
Are subsequent events mentioned in the notes?	104 ☐ Yes	☒ No
Is re-evaluation of asset information mentioned in the notes?	105 ☐ Yes	☒ No
Is contingent liability mentioned in the notes?	106 ☒ Yes	☐ No
Is information regarding commitments mentioned in the notes?	107 ☐ Yes	☒ No
Does the corporation have investments in joint venture(s) or partnership(s)?	108 ☐ Yes	☒ No
If *Yes*, complete line 109 below:		
Are you filing financial statements of the joint venture(s) or partnership(s)?	109 ☐ Yes	☐ No

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BUSINESS CONSENT FORM

Complete this form to consent to the release of confidential information about your Business Number (BN) account(s) to the representative named below, or to cancel consent for an existing representative. **Send this completed form to your tax centre**. You can also give or cancel consent by providing the requested information online through My Business Account at **www.cra.gc.ca/mybusinessaccount**.

Note: Read all instructions on the last page before completing this form.

Part 1 - Business Information - Complete this part to identify your business (all fields have to be completed)

Business Name: Tillsonburg Hydro Inc. **Business Number:** 863742599

Telephone Number: (519) 842-6428

Part 2 - Authorize a representative

If you are giving consent for an individual, enter that person's full name or if you are giving consent to a firm, enter the name of the firm and the BN. If you want us to deal with a specific individual in that firm, enter **both** the individual's name and the name of the firm. If you do not identify an individual of the firm then you are giving us consent to deal with anyone from that firm.

Name of Individual: _____ Name of Firm: Scrimgeour & Company, Chartered Accounta

Telephone Number: (519) 672-6811 **BN:** _____

Authorize online access

You can authorize your representative to deal with us through our online services for representatives. You have to provide the RepID of the individual or the Business Number of the firm indicated above. The name of the firm provided above must be the same name that is registered with the Represent a Client service at **www.cra.gc.ca/representatives**. If the firm names differ then online access will not be granted. Our online services do not have a year specific option, so your representative will have access to all years.

RepID: _____ (for above individual) **OR** **BN:** _____ The BN must be registered with the Represent a Client service to be an online representative.

Part 3 - Which Accounts and Which Years?

i) Accounts - Select which accounts the above individual or firm is authorized to access (check only box A or B).

A. ☒ This authorization applies to all BN accounts and all years. **Note: oline access is available for box A only.**

Expiry date: yyyy/mm/dd

OR

B. ☐ This authorization applies only to BN accounts and periods listed in Part 3ii.

Authorization level: check one box

☒ Disclose information only

OR

☐ Disclose information **and** make changes to your BN account(s)

BUSINESS CONSENT FORM (RC59 continued)

ii) Details of accounts and fiscal periods - Complete this area if you checked box "B" in Part 3 i).

If you checked box B in part 3i, you have to provide at least one program identifier (see Instructions on the last page). You can then check the "all accounts" box for that program identifier or enter a specific account number. Provide the authorization level ("1" to disclose information or "2" to disclose information and make changes). You can also check the "All years" box to allow unlimited tax year access or enter a specific fiscal period **(specific period authorization is not available for online access)**. You can also enter an expiry date to automatically cancel authorization. If additional authorizations or more than four program identifiers are needed complete another RC59.

Program identifier	All accounts	Specific account	Authorization level	All years	or	Specific fiscal period (not available for online access)	Expiry date
						Year End	
RC	☐	or	1	☐	or	yyyy/mm/dd	yyyy/mm/dd
RC	☐	or	1	☐	or	yyyy/mm/dd	yyyy/mm/dd
RC	☐	or	1	☐	or	yyyy/mm/dd	yyyy/mm/dd
RC	☐	or	1	☐	or	yyyy/mm/dd	yyyy/mm/dd

Part 4 - Cancel one or more existing authorizations - Complete this section only to cancel existing authorization(s)

☐ **A**. Cancel **all** authorizations

☐ **B**. Cancel authorization for the individual or firm identified below.

Name of Individual: _____ Name of Firm: _____

Part 5 - Certification

This form must be signed by an authorized person of the business such as a proprietor of a proprietorship, a partner of a partnership, a director of a corporation, an officer of a non profit organization or a trustee of an estate. By signing and dating this form, you authorize the CRA to deal with the individual or firm listed in Part 2 of this form and/or cancel the authorizations listed in Part 4.

First name: Darrell Last name: Eddington

Title: Treasurer

Sign here ▶ _____ Date 2008/06/25

WE WILL NOT PROCESS THIS FORM UNLESS IT IS SIGNED AND DATED BY AN AUTHORIZED PERSON OF THE BUSINESS.

Description of Deferral and Variance Accounts

THI's proposed 2009TY rate riders are summarized in Table 1 below.

Table 1 – Proposed Rate Riders

Proposed Rate Riders	
Residential	$0.0012/kWh
General Service < 50 kW	$0.0003/kWh
General Service >50 kW, <500 kW	$0.0311/kW
General Service >500 kW, <1,499 kW	$0.0352/kW
General Service >1,500 kW	$0.0146/kW
Street Lighting	$0.1530/kW
Unmetered Scattered Load	$0.0008/kWh

As of December 31, 2007 THI had recorded $(857)k of principal and an associated $(65)k of carrying charges for a net balance of $(922)k in Board authorized variance and deferral accounts. THI proposes to dispose of the balances recorded in some of these accounts through rate riders that will be charged in the 2009TY and 2010 rate year. The proposed rate riders have been determined by:

- Identifying the accounts to be disposed of through rates;
- appropriately allocating the balances recorded in each account to the specific customer classes; and
- applying the relevant charge parameter consistent with past Board Decisions.

The purpose of this evidence is to:

- Identify the accounts that THI proposes to dispose of through rates in the 2009TY and the supporting rationale;
- Identify the accounts that THI does not propose to dispose of through rates in the 2009TY and the supporting rationale;
- Document the findings of the Board's audit of THI's variance and deferral account balances and THI's response to each finding;
- Explain the adjustments made to the 2006 and 2007 balances previously reported to the Board;

- Describe THI's methodology for deriving the proposed rate riders; and
- Provide the derivation of the proposed rate riders.

Calculation of Balances by Account

Account specific information on the annual balances recorded by THI is provided at E5/T1/S2/AttA. The Board auditor's report and THI's response to each issue is provided at E5/T1/S2/AttB.

All 2006 opening account balances are consistent with the closing 2005 balances previously reported to the Board. The opening 2006 balances have been adjusted so that the closing balances reconcile with the amount previously reported to the Board.

The 2007 balances have been similarly adjusted. In addition THI has made further adjustments to the closing 2007 balances reported in accounts 1508, 1570 and 1571 consistent with the implementation of its response to the findings of the Board's auditors. THI has adjusted the balance in account 2425 for its Lost Revenue Adjustment Mechanism and Shared Savings Mechanism claim. These adjustments are discussed in greater detail below.

Account 1508

THI has increased the 2007 principal balance by $41,744 and the associated carrying costs by $5,580. The adjustment to the principal has been determined as follows:

- The removal of $19,192 being the OEB assessment incurred after May 1, 2006
- The inclusion of Past Employee Pension and Benefits costs eligible for deferral of $60,936;

The net increase in carrying charges associated with these adjustments amounts to $5,580. Each adjustment is discussed further below.

Board Assessment Costs

The adjustment for Board cost assessments reflects the expense incurred up to and including April 30, 2006. THI has not included any amounts assessed on or after May 1, 2006. The Board previously authorized the deferral of OEB costs through an FAQ posted on its website in December 2005. The derivation of the amount is provided at E5/T1/S2/AttC.

OMERs Expense

The adjustment for Past Employee Pension and Benefits was determined by estimating the difference between:

- The actual OMERs expense incurred monthly for 2005 and the first 4 months of 2006; and
- the amount recovered through rates.

This difference attracted carrying charges at the Board authorized rate.

The expense incurred was determined by:

- identifying the actual OMERs expense incurred by the Town for each employee who provides service to THI;
- weighting that cost according to the proportion of time that the employee provides service to THI;
- summing the weighted costs and then reducing it for the amount recovered through rates.

The derivation of this amount is provided at E5/T1/S2/AttD.

The Board provided direction that these costs were eligible for deferral through an FAQ that was posted on the Board's website in December 2005. THI notes that it is responsible for the OMERs expense of the Town employees who provide services to THI and that it has not previously accrued these unrecovered expenses. THI also notes that the Board has previously decided this issue (OEB Decision, EB-2007-0931; attached as E5/T1/S2/AttE). The Board found that PUC was eligible to recover its past deferred OMERs costs through rates. The Board's Decision was not informed by PUC's status as a virtual utility; rather it authorized just and reasonable rates that recover the ongoing costs of distributing electricity that include the recovery of OMERs pension costs.

Account 1525

Engineering Study Costs

The Board's audit identified that the $10,470 principal cost of a past engineering study of the impact to THI of the AIM PowerGen generating station had been incorrectly recorded in account 1525. THI management disagrees with the audit finding. The associated carrying charges amount to $3,728.

Hydro One conducted the required Customer Impact Assessment ("CIA") on the AIM PowerGen wind farm in 2005 and engaged the potentially affected local area LDCs in its review. Hydro One's transmittal letter indicates that short circuit levels and impacts of the generating station on the recipient's facilities should be considered; the letter is provided at E5/T1/S2/AttF. THI's Board of Directors authorized THI to retain an appropriately qualified third party to review Hydro One's CIA. Elecsar Engineering Inc. ("Elecsar") was retained and provided a report to THI on June 9, 2005 at a cost of $10,470.

THI retained Elecsar in good faith to provide a detailed technical review of the CIA and to comment on the generating station's potential impact on THI's facilities and operations. An appropriate technical study would have been required to support negotiations concerning revisions to the proposed protections, control or grounding systems; ultimately the report confirmed that such negotiations were not necessary. The report also provided THI with an accurate assessment of the generating station's impact on the number and level of transients and other phenomena. As a result of the report having been prepared and tabled, THI's Board of Directors were able to confirm that there were no undesirable or unanticipated impacts likely to occur on THI's system or to its customers.

THI seeks to recover these costs through rates because:

- it lacked the internal resources to conduct the required technical review;
- it was not possible to determine the impact of the subject generator on THI without a technical review;
- Elecsar was retained in good faith;
- Elecsar's costs were prudently incurred; and
- It is appropriate for THI management to seek the opinion of objective third parties so that it is appropriately prepared to understand impacts and, where necessary, to negotiate appropriate protections for THI's customers.

Account 1570

THI carefully reviewed the Board's auditor's finding that it had incorrectly recorded $142,202.46 in this account and concurs with the findings. THI has removed this amount.

THI elected a minimum review of its Transition Costs as part of its 2006 EDR application. Consistent with the Board's Decision with Reasons RP-2004-0118, RP-2004-0100, RP-2004-0069, RP-2004-0064, THI has made the subject adjustment.

Account 1571

For the same reasons as cited under the discussion of the treatment of the balance recorded in account 1570, THI has removed $12k of interest that remained from account 1571.

Account 2425

THI estimates its Lost Revenue Adjustment Mechanism ("LRAM") and Shared Savings Mechanism ("SSM") award for the period 2005-2007 to be $46.7k and the associated carrying costs to be $3.2k. THI has estimated these amounts consistent with the Board's directions and relying on the information previously provided to the Board in its annual CDM reports. The derivation of the award is provided at E5/T1/S2/AttG.

Other Accounts

THI does not propose to dispose of the balances recorded as of December 31, 2007 in accounts 1580, 1582, 1584, 1586, 1588 or 1590 pending the outcome of the Board's generic review of these accounts and the balances recorded in them.

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B5 Deferral / Variance Account Balances

Interest Rate (from sheet Y1) = 4.08%	1-Jan-2005 to 31-Dec-2005					
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1505-Unrecovered Plant and Regulatory Study Costs						
1508-Other Regulatory Assets			21,376			912
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail						
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits			18,005			3,916
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-RCVASTR						
1550-LV Variance Account						
1555-Smart Meters Capital Variance Account						
1556-Smart Meters OM&A Variance Account						
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes			12,322			4,525
1563-Account 1563 - Deferred PILs Contra Account						
1565-Conservation and Demand Management Expenditures and Recoveries			366,044			-4,370
1566-CDM Contra Account						
1570-Qualifying Transition Costs			387,550			112,333
1571-Pre-market Opening Energy Variance			110,292			20,262
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS			494,235			77,008
1582-RSVAONE-TIME			20,918			2,882
1584-RSVANW			103,669			20,654
1586-RSVACN			74,609			14,410
1588-RSVAPOWER			-1,163,106			-63,007
1592-2006 PILs/Taxes Variance						
2425-Other Deferred Credits		4,136	4,136		300	300
TOTAL		**4,136**	**450,049**		**300**	**189,826**

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B5 Deferral / Variance Account Balances

Interest Rate (from sheet Y1) = 4.08%	1-Jan-2006 to 31-Dec-2006					
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1505-Unrecovered Plant and Regulatory Study Costs						
1508-Other Regulatory Assets	21,376	2,085	23,461	912	221	1,132
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail						
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits	18,005	10,471	28,476	3,916	1,535	5,451
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-RCVASTR						
1550-LV Variance Account						
1555-Smart Meters Capital Variance Account		-14,353	-14,353		-139	-139
1556-Smart Meters OM&A Variance Account						
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes	12,322	-69,328	-57,006	4,525	-4,881	-356
1563-Account 1563 - Deferred PILs Contra Account						
1565-Conservation and Demand Management Expenditures and Recoveries	366,044	-451,264	-85,220	-4,370	4,370	
1566-CDM Contra Account						
1570-Qualifying Transition Costs	387,550		387,550	112,333	20,886	133,220
1571-Pre-market Opening Energy Variance	110,292		110,292	20,262	5,944	26,206
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	494,235	-329,203	165,032	77,008	22,005	99,013
1582-RSVAONE-TIME	20,918	14	20,931	2,882	1,128	4,010
1584-RSVANW	103,669	-81,642	22,027	20,654	4,770	25,424
1586-RSVACN	74,609	-46,871	27,738	14,410	3,946	18,356
1588-RSVAPOWER	-1,163,106	940,907	-222,199	-63,007	7,695	-55,312
1592-2006 PILs/Taxes Variance						
2425-Other Deferred Credits	4,136	21,317	25,453	300	1,000	1,300
TOTAL	**450,049**	**-17,866**	**432,183**	**189,826**	**68,479**	**258,305**

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B5 Deferral / Variance Account Balances

Interest Rate (from sheet Y1) = 4.08%	1-Jan-2007 to 31-Dec-2007						31-Dec-2007 Balance		
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**	**Principal**	**Interest**	**Total**
1505-Unrecovered Plant and Regulatory Study Costs									
1508-Other Regulatory Assets	23,461	54,318	77,779	1,132	7,062	8,194	77,779	8,194	85,973
1510-Preliminary Survey and Investigation Charges									
1515-Emission Allowance Inventory									
1516-Emission Allowances Withheld									
1518-RCVARetail									
1520-Power Purchase Variance Account									
1525-Miscellaneous Deferred Debits	28,476	-18,005	10,471	5,451	-1,723	3,728	10,471	3,728	14,199
1530-Deferred Losses from Disposition of Utility Plant									
1540-Unamortized Loss on Reacquired Debt									
1545-Development Charge Deposits/ Receivables									
1548-RCVASTR									
1550-LV Variance Account									
1555-Smart Meters Capital Variance Account	-14,353	-19,347	-33,700	-139	-1,008	-1,147	-33,700	-1,147	-34,847
1556-Smart Meters OM&A Variance Account									
1560-Deferred Development Costs									
1562-Deferred Payments in Lieu of Taxes	-57,006		-57,006	-356	-2,630	-2,986	-57,006	-2,986	-59,992
1563-Account 1563 - Deferred PILs Contra Account									
1565-Conservation and Demand Management Expenditures and Recoveries	-85,220	85,220							
1566-CDM Contra Account									
1570-Qualifying Transition Costs	387,550	-387,550		133,220	-133,220				
1571-Pre-market Opening Energy Variance	110,292	-110,292		26,206	-26,206				
1572-Extraordinary Event Costs									
1574-Deferred Rate Impact Amounts									
1580-RSVAWMS	165,032	-566,121	-401,089	99,013	-92,097	6,916	-401,089	6,916	-394,174
1582-RSVAONE-TIME	20,931	-20,845	87	4,010	-3,941	69	87	69	156
1584-RSVANW	22,027	-143,853	-121,826	25,424	-27,209	-1,785	-121,826	-1,785	-123,611
1586-RSVACN	27,738	-40,630	-12,892	18,356	-15,024	3,332	-12,892	3,332	-9,561
1588-RSVAPOWER	-222,199	-143,067	-365,266	-55,312	-29,226	-84,538	-365,266	-84,538	-449,804
1592-2006 PILs/Taxes Variance									
2425-Other Deferred Credits	25,453	21,232	46,685	1,300	1,905	3,205	46,685	3,205	49,890
TOTAL	**432,183**	**-1,288,942**	**-856,759**	**258,305**	**-323,317**	**-65,012**	**-856,759**	**-65,012**	**-921,771**

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B5 Deferral / Variance Account Balances

Interest Rate (from sheet Y1) = 4.08%	1-Jan-08 to 30-Apr-08			1-May-08 to 31-Dec-08		
Deferral / Variance Account	**Interest**	**Other**	**Balance**	**Interest**	**Other**	**Balance**
1505-Unrecovered Plant and Regulatory Study Costs						
1508-Other Regulatory Assets	1,058		87,031	2,116		89,146
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail						
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits	142		14,341	285		14,626
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-RCVASTR						
1550-LV Variance Account						
1555-Smart Meters Capital Variance Account	-458		-35,305	-917		-36,222
1556-Smart Meters OM&A Variance Account						
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes	-775		-60,767	-1,551		-62,317
1563-Account 1563 - Deferred PILs Contra Account						
1565-Conservation and Demand Management Expenditures and Recoveries						
1566-CDM Contra Account						
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	-5,455		-399,628	-10,910		-410,538
1582-RSVAONE-TIME	1		157	2		160
1584-RSVANW	-1,657		-125,268	-3,314		-128,582
1586-RSVACN	-175		-9,736	-351		-10,087
1588-RSVAPOWER	-4,968		-454,772	-9,935		-464,707
1592-2006 PILs/Taxes Variance						
2425-Other Deferred Credits	635		50,525	1,270		51,795
TOTAL	**-11,652**		**-933,423**	**-23,304**		**-956,726**

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B5 Deferral / Variance Account Balances

Interest Rate (from sheet Y1) = 4.08%	1-Jan-09 to 30-Apr-09		
Deferral / Variance Account	**Interest**	**Other**	**Balance**
1505-Unrecovered Plant and Regulatory Study Costs			
1508-Other Regulatory Assets	1,058		90,204
1510-Preliminary Survey and Investigation Charges			
1515-Emission Allowance Inventory			
1516-Emission Allowances Withheld			
1518-RCVARetail			
1520-Power Purchase Variance Account			
1525-Miscellaneous Deferred Debits	142		14,768
1530-Deferred Losses from Disposition of Utility Plant			
1540-Unamortized Loss on Reacquired Debt			
1545-Development Charge Deposits/ Receivables			
1548-RCVASTR			
1550-LV Variance Account			
1555-Smart Meters Capital Variance Account	-458		-36,680
1556-Smart Meters OM&A Variance Account			
1560-Deferred Development Costs			
1562-Deferred Payments in Lieu of Taxes	-775		-63,093
1563-Account 1563 - Deferred PILs Contra Account			
1565-Conservation and Demand Management Expenditures and Recoveries			
1566-CDM Contra Account			
1570-Qualifying Transition Costs			
1571-Pre-market Opening Energy Variance			
1572-Extraordinary Event Costs			
1574-Deferred Rate Impact Amounts			
1580-RSVAWMS	-5,455		-415,993
1582-RSVAONE-TIME	1		161
1584-RSVANW	-1,657		-130,239
1586-RSVACN	-175		-10,262
1588-RSVAPOWER	-4,968		-469,675
1592-2006 PILs/Taxes Variance			
2425-Other Deferred Credits	635		52,430
TOTAL	**-11,652**		**-968,378**

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B5 Deferral / Variance Account Balances

Interest Rate (from sheet Y1) = 4.08%	31-Dec-07 Balance + Interest to 30-Apr-09			1-May-09 to 31-Dec-09		
Deferral / Variance Account	**31-Dec-07**	**Interest**	**Total**	**Interest**	**Other**	**Balance**
1505-Unrecovered Plant and Regulatory Study Costs						
1508-Other Regulatory Assets	85,973	4,231	90,204	2,116		92,320
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail						
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits	14,199	570	14,768	285		15,053
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-RCVASTR						
1550-LV Variance Account						
1555-Smart Meters Capital Variance Account	-34,847	-1,833	-36,680	-917		-37,597
1556-Smart Meters OM&A Variance Account						
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes	-59,992	-3,101	-63,093	-1,551		-64,643
1563-Account 1563 - Deferred PILs Contra Account						
1565-Conservation and Demand Management Expenditures and Recoveries						
1566-CDM Contra Account						
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	-394,174	-21,819	-415,993	-10,910		-426,903
1582-RSVAONE-TIME	156	5	161	2		163
1584-RSVANW	-123,611	-6,627	-130,239	-3,314		-133,552
1586-RSVACN	-9,561	-701	-10,262	-351		-10,613
1588-RSVAPOWER	-449,804	-19,870	-469,675	-9,935		-479,610
1592-2006 PILs/Taxes Variance						
2425-Other Deferred Credits	49,890	2,540	52,430	1,270		53,699
TOTAL	**-921,771**	**-46,608**	**-968,378**	**-23,304**		**-991,682**

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August 19, 2008

Steve Lund
General Manager
Tillsonburg Hydro Inc.
10 Lisgar Avenue
Tillsonburg ON
N4G 5A5

Dear Mr. Lund,

Re: Review of Regulatory Deferral and Variance Accounts

This letter sets out the results of our recent review of Tillsonburg Hydro Inc (THI) on the matters described below. The review was completed on August 12, 2008, and the results of the review as set out in this letter reflect the status of the matters under review as at that date.

This review was conducted further to the Board's letter of June 12, 2008. Specifically, the objectives of the review were to assess whether accounting policies and procedures were properly and consistently applied. The review focused on regulatory asset and liability accounts in the 1500 and 2400 series of account numbers in the Uniform System of Accounts. The review was conducted in accordance with generally accepted standards for review engagements and consisted primarily of enquiry, analytical procedures and discussion related to information and materials provided by THI or available to the Board from filings made under the Board's Electricity Reporting and Record Keeping Requirements.

The results of our review are summarized as follows.

- We identified several instances where the Board's regulatory accounting requirements were not followed. We have provided details and recommendations on these instances in the Appendix. Management provided responses to these observations and the recommendations.

  We have not examined all of the accounts of THI. Nothing in the documentation that we have reviewed or that was identified during our discussions with representatives of THI would cause us to believe that the accounting of the corporation is not otherwise in accordance with the Board's regulatory accounting requirements.

As indicated in the Board's letter of June 12, 2008, the results of this review and associated documentation will be provided to other Board staff to assist them in their review and analysis of your forward test year application, and may ultimately be provided as evidence in the hearing of your application.

No statutory power of decision has been delegated to me, and the findings, conclusions, impacts and recommendations expressed in this letter (including Appendix) are not binding

on the Board. The Chief Regulatory Auditor provides no assurance that addressing the review recommendations alone will resolve the findings.

Thank you very much for the support and assistance provided to the audit team and the ideas that you provided for enhancing distributor accounting/reporting activities. Do not hesitate to contact me should you have any questions.

Yours truly,



Bill Cowan, P.Eng., C.A.
Chief Regulatory Auditor
Phone: (416) 440-7648
Bill.cowan@oeb.gov.on.ca

cc.

Mark Renaud, Chair, Tillsonburg Hydro Inc. Board of Directors
Darrell Eddington, Director of Finance
W. John Gott, Finance Regulatory Affairs Manager

Attachment

Appendix – Tillsonburg Hydro Inc. – Detailed Observations

DETAILED OBSERVATIONS

GENERAL OBSERVATIONS

1. The distributor has difficulty keeping current of Ontario Energy Board (OEB) Decisions and Guidance, as well as meeting the filing and other requirements of the OEB on a timely basis. Tillsonburg Hydro Inc. (THI) has devoted limited human, financial and technical resources to regulatory affairs.

   Audit makes no specific recommendation on this matter.

   Management Response

   THI has reviewed its staffing needs and due to the increasing regulatory burden, a new Operations Regulatory Affairs Manager position has been created and is currently being advertised. THI's Board of Directors intends to further discuss this matter at their September meeting.

2. THI used the cash basis for calculating interest and for reporting RRR 2.1.1 (Deferral & Variance Accounts) and the accrual basis for reporting the general ledger trial balance, RRR 2.1.7.

   This is not in accordance with current guidance, as the Electricity Distributor Recovery of Regulatory Assets, Phase 2 Decision RP-2004-0118, RP-2004-0100, RP-2004-0069, RP-2004-0064, sections 2.0.23 and 2.0.24 and Article 490 (b), "Non-competitive Electricity Charges - Mechanics" of the Accounting Procedures Handbook (APH) which states that the distributor may elect to use accrual or billed method, as long as the method is consistently applied on an ongoing basis to all RSVAs.

   Audit recommends that, going forward, THI change their accounting procedures to conform to this decision.

   Management Response

   THI has reviewed this audit finding and agrees to amend its accounting methodology to rely on the accrual method exclusively on a go-forward basis. THI will seek to dispose of the balances as reported in its RRR 2.1.7 filing through a rate adder in the 2009 Rate Application.

SPECIFIC OBSERVATIONS

3. ACCOUNTS 1508, OTHER REGULATORY ASSETS

Observation

Sub-Account, OEB Costs Assessments

THI has been recording the variance between actual OEB Cost assessments and the rates billed to customers for two periods. The total balance was approximately $38,500 as of December 31, 2007.

In the first period prior to May 1, 2006, THI calculated the variance by using the revenue associated with 1999 OEB Cost Assessments and the 2004 to April 30, 2006 actual costs. The approximate value of this is $15,500 as of December 31, 2007. This is consistent with Board guidance.

After April 30, 2006, THI did not include an OEB Cost Assessment expense in its revenue requirement in the 2006 EDR due to an oversight in the application of the 2006 EDR model. Therefore, there was no revenue associated with this expense in rates. THI has been accruing 100% of OEB Cost Assessments in this account since May 1, 2006. The approximate value of this is $23,000 as of December 31, 2007. This is not in accordance with the Board guidelines of the December 2005 Frequently Asked Questions (FAQs) # 10 and December 20, 2004 OEB letter to Electricity Local Distribution Companies (LDCs) which do not authorize the use of account 1508 for OEB costs after May 1, 2006.

Audit recommends that account 1508 – sub account OEB Cost Assessment be adjusted to remove the unauthorized amounts from the account.

Management Response

THI has reviewed the Board approved 2006 EDR Model and notes that $6,927 was included in the approved rates for OEB cost assessments. THI agrees that effective May 1, 2006 OEB cost assessments were not to be deferred. Therefore, THI's Board of Directors has approved a write off of $19,698.25. This treatment will be reflected in the restated 2007 financial statements for 2006. THI will not seek disposition of this amount through rates in its 2009 rate application.

4. ACCOUNT 1525, MISC DEFERRED DEBITS

Observation

THI has a balance of approximately $14,000 in account 1525. The balance is related only to cost of a connection assessment performed in 2005, plus associated interest. The deferred costs from rebate cheques and associated interest have already been completely cleared during the 2006 EDR, with the transfer to 1590 occurring in 2007.

The connection assessment was for a wind farm. THI's Board of Directors decided that the costs should be deferred.

While generally such costs are borne by the generator, Audit notes that the amount in question is relatively small, and encourages THI to bring this to the Board in the rate application expected to be submitted in August 2008.

Management Response

THI is of the opinion that this is a prudent expense that is recoverable through rates.

Hydro One requested that THI provide input to the AIM PowerGen Customer Impact Assessment. THI did not have the required in-house expertise and THI's Board of Directors authorized retaining a third party to conduct the required study. Elecsar was retained to review the project's impact and to provide their expert opinion to THI's Board of Directors.

THI will seek to dispose of the balance through a rate rider in the 2009 Rate Application.

5. ACCOUNT 1570, QUALIFYING TRANSITION COSTS

Observations

This account currently has a balance of approximately $142,000 as of December 31, 2007.

During the 2006 EDR, THI opted for minimum review of its regulatory assets during the Phase II process, entailing a $60 per customer claim. This resulted in $285,977 principal and associated carrying charges being claimed, while the amount over $60 per customer or $101,573 principal and associated carrying charges, were not claimed. Through the accumulation of interest since that date, this amount has increased to $142,202 as of December 31, 2007. THI has stated that they were advised by their consultant that the amount not claimed to achieve minimum review could be requested for disposition at a later date. However, the Board Phase 2 Decision was that to achieve a minimum review, the amount that was not claimed was required to be written off.

THI's treatment is not in accordance with the Electricity Distributor Recovery of Regulatory Assets, Phase 2 Decision RP-2004-0118, RP-2004-0100, RP-2004-0069, RP-2004-0064, Section 10 nor with Regulatory Asset Filing Guidelines for Phase 2 review for remaining distributors.

Audit recommends that the balance in account 1570 be written off.

Management Response

THI has reviewed the materials cited by the auditors and agrees with the finding. THI's Board of Directors has approved a write off of $142,202.46 which will be reflected in the restated 2007 financial statements for 2006. THI will not seek to dispose of this balance through a rate rider as part of its 2009 rate application.

6. ACCOUNT 1571, PRE-MARKETING OPENING ENERGY VARIANCE

Observations

This account currently has a balance of approximately $12,000 as of December 31, 2007. The amount is related to a portion of the interest that the distributor forgot to include in its claim during the 2006 EDR. The Board gave final disposition for the principal balances in the 2006 EDR, which were moved to account 1590 in 2007. The utility did not write off the unclaimed portion of 1571.

This is not in accordance with Regulatory Assets Phase 2 Decision RP-2004-0117, RP-2004-0118, RP-2004-0100, RP-2004-0069, RP-2004-0064, Section 10 nor with Regulatory Asset Filing Guidelines for Phase 2 review for remaining distributors.

Audit recommends that the balance in account 1571 be written off.

Management Response

THI agrees with this finding. THI's Board of Directors has approved a write off of $12,617.79 which will be reflected in the restated 2007 financial statements for 2006. THI will not seek to dispose of this balance through a rate rider as part of its 2009 rate application.

7. RSVA ACCOUNTS - 1580, 1582, 1584, 1586 & 1588

Observation 1

Table A shows the accounts used by THI to record IESO charge codes in the following expense accounts and their mapping to the RSVA accounts:

TABLE A - MAPPING

IESO CHARGE CODE	THI CURRENT PRACTICE		APH CORRECT ACCOUNTS	
	THI APH EXPENSE ACCOUNT	ASSOCIATED RSVA ACCOUNT	THI APH EXPENSE ACCOUNT	ASSOCIATED RSVA ACCOUNT
163	4712	1582	4708	1580
700	4712	1582	4708	1580
750	4712	1582	4708	1580
753	4712	1582	4708	1580
850	4712	1582	4708	1580
IESO application fee	4712	1582	4708	1580

This is not in accordance with the Board letter of direction dated June 1, 2006 and Chapter 11 of the 2000 EDR Handbook.

Audit recommends that the utility map its accounts in accordance with the APH.

Management Response

THI concurs with the audit finding and will change the account mapping as indicated above for fiscal 2008. THI notes that this change will not impact its 2009 rate application.

Observation 2

Although the Global Adjustments (GA) are in account 1588, they are not segregated in a separate sub-account in the General Ledger (GL). They are lumped together with the cost of power in one account. THI has been tracking them separately in a spreadsheet and reporting the global adjustments in RRR 2.1.1 (sub account 1588-GA) separately from account 1588 –Power. The carrying charges for the cost of power and the global adjustments are also recorded in one account.

This is not in accordance with the Board letter of direction dated February 15, 2005 and Article 220 of the APH.

Audit recommends that the utility segregate its GA as well as the carrying charges related to cost of power and global adjustments in separate sub-accounts within account 1588 in its GL.

Management Response

THI concurs with the audit finding and will segregate the account as indicated above for fiscal 2008. THI notes that this change will not impact its 2009 rate application.

Tillsonburg Hydro Inc.																
			January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Total**
2005	Interest Rate		5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%
	Number of days in the period		31	28	31	30	31	30	31	31	30	31	30	31	365
															Without Prior
		Prior year													**Year Balance**
1508-V	Other Regulatory Assets - OEB	$ 5,113.00	-$ 875.75			$ 2,893.25		$ 2,893.25			$ 1,735.25			$ 2,611.00	$ 9,257.00
1508-I	Other Regulatory Assets - Interest	$ 60.91	$ 24.97	$ 18.69	$ 20.69	$ 20.03	$ 34.82	$ 33.70	$ 48.95	$ 48.95	$ 47.37	$ 57.43	$ 55.57	$ 57.43	$ 468.60
		$ 5,173.91	$ (850.78)	$ 18.69	$ 20.69	$ 2,913.28	$ 34.82	$ 2,926.95	$ 48.95	$ 48.95	$ 1,782.62	$ 57.43	$ 55.57	$ 2,668.43	$ 9,725.60

Tillsonburg Hydro Inc.																
			January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Total**
2006	Interest Rate		5.75%	5.75%	5.75%	5.75%	4.14%	4.14%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.90%
	Number of days in the period		31	28	31	30	31	30	31	31	30	31	30	31	365
															Without Prior
		Prior year													**Year Balance**
1508-V	Other Regulatory Assets - OEB	$ 14,370.00	$ (875.75)		$ 3,349.08										$ 2,473.33
1508-I	Other Regulatory Assets - Interest	$ 529.51	$ 70.18	$ 59.52	$ 65.90	$ 79.60	$ 59.22	$ 57.31	$ 65.66	$ 65.66	$ 63.54	$ 65.66	$ 63.54	$ 65.66	$ 781.47
		$ 14,899.51	$ (805.57)	$ 59.52	$ 3,414.98	$ 79.60	$ 59.22	$ 57.31	$ 65.66	$ 65.66	$ 63.54	$ 65.66	$ 63.54	$ 65.66	$ 3,254.80

Tillsonburg Hydro Inc.																
			January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Total**
2007	Interest Rate		4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	5.14%	5.14%	5.14%	4.73%
	Number of days in the period		31	28	31	30	31	30	31	31	30	31	30	31	365
															Without Prior
		Prior year													**Year Balance**
1508-V	Other Regulatory Assets - OEB	$ 16,843.33													$ -
1508-I	Other Regulatory Assets - Interest	$ 1,310.98	$ 65.66	$ 59.31	$ 65.66	$ 63.54	$ 65.66	$ 63.54	$ 65.66	$ 65.66	$ 63.54	$ 73.53	$ 71.16	$ 73.53	$ 796.46
		$ 18,154.31	$ 65.66	$ 59.31	$ 65.66	$ 63.54	$ 65.66	$ 63.54	$ 65.66	$ 65.66	$ 63.54	$ 73.53	$ 71.16	$ 73.53	$ 796.46
														OEB Assessment	$ 12,574.00
														Rate Recovery	$ (6,927.00)
															$ 5,647.00

Tillsonburg Hydro Inc.								
2005	Interest Rate							
	Number of days in the period							
			With Prior					
			Year Balance					
1508-V	Other Regulatory Assets - OEB		$ 14,370.00					
1508-I	Other Regulatory Assets - Interest		$ 529.51					
			$ 14,899.51					
Tillsonburg Hydro Inc.								
2006	Interest Rate							
	Number of days in the period							
			With Prior					
			Year Balance					
1508-V	Other Regulatory Assets - OEB		$ 16,843.33					
1508-I	Other Regulatory Assets - Interest		$ 1,310.98					
			$ 18,154.31					
Tillsonburg Hydro Inc.								
2007	Interest Rate							
	Number of days in the period							
			With Prior	**Before**				
			Year Balance	**Restatement**	**No deferral Var**	**Rate Recov Red**	**Further Variance**	
1508-V	Other Regulatory Assets - OEB		$ 16,843.33	$ 36,035.33	$ 19,192.00	$ 11,545.00	$ 7,647.00	
1508-I	Other Regulatory Assets - Interest		$ 2,107.44	$ 2,613.69	$ 506.25	$ 151.64	$ 354.61	
			$ 18,950.77	$ 38,649.02	$ 19,698.25	$ 11,696.64	$ 8,001.61	
			2006:	$6927*8/12=	$ 4,618.00			
			2007:	$6927*12/12=	$ 6,927.00			
					$ 11,545.00			

Tillsonburg Hydro Inc.																		
			January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Total**		
2005	Interest Rate		3.88%	3.88%	3.88%	3.88%	3.88%	3.88%	3.88%	3.88%	3.88%	3.88%	3.88%	3.88%	3.88%		
	Number of days in the period		31	28	31	30	31	30	31	31	30	31	30	31	365		
															Without Prior		**With Prior**
		Prior year													**Year Balance**		**Year Balance**
1508-V	Other Regulatory Assets - OMERS	$ -	$ 3,488.39	$ 3,488.39	$ 3,488.39	$ 3,488.39	$ 3,488.39	$ 3,488.39	$ 3,488.39	$ 3,488.39	$ 3,488.39	$ 3,488.39	$ 3,488.39	$ 3,488.39	$ 41,860.68		$ 41,860.68
1508-I	Other Regulatory Assets - Interest	$ -	$ -	$ 10.38	$ 22.99	$ 33.37	$ 45.98	$ 55.62	$ 68.97	$ 80.47	$ 89.00	$ 103.46	$ 111.25	$ 126.45	$ 747.95		$ 747.95
		$ -	$ 3,488.39	$ 3,498.77	$ 3,511.38	$ 3,521.76	$ 3,534.37	$ 3,544.01	$ 3,557.36	$ 3,568.86	$ 3,577.39	$ 3,591.85	$ 3,599.64	$ 3,614.84	$ 42,608.63		$ 42,608.63

Tillsonburg Hydro Inc.																		
			January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Total**		
2006	Interest Rate		3.88%	3.88%	3.88%	3.88%	4.14%	4.14%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.28%		
	Number of days in the period		31	28	31	30	31	30	31	31	30	31	30	31	365		
															Without Prior		**With Prior**
		Prior year													**Year Balance**		**Year Balance**
1508-V	Other Regulatory Assets - OMERS	$ 41,860.68	$ 4,768.71	$ 4,768.71	$ 4,768.71	$ 4,768.71									$ 19,074.84		$ 60,935.52
1508-I	Other Regulatory Assets - Interest	$ 747.95	$ 137.95	$ 138.79	$ 169.37	$ 179.12	$ 214.26	$ 207.35	$ 237.55	$ 237.55	$ 229.89	$ 237.55	$ 229.89	$ 237.55	$ 2,456.80		$ 3,204.74
		$ 42,608.63	$ 4,906.66	$ 4,907.50	$ 4,938.08	$ 4,947.83	$ 214.26	$ 207.35	$ 237.55	$ 237.55	$ 229.89	$ 237.55	$ 229.89	$ 237.55	$ 21,531.64		$ 64,140.26

Tillsonburg Hydro Inc.																		
			January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Total**		
2007	Interest Rate		4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	5.14%	5.14%	5.14%	4.73%		
	Number of days in the period		31	28	31	30	31	30	31	31	30	31	30	31	365		
															Without Prior		**With Prior**
		Prior year													**Year Balance**		**Year Balance**
1508-V	Other Regulatory Assets - OMERS	$ 60,935.52													$ -		$ 60,935.52
1508-I	Other Regulatory Assets - Interest	$ 3,204.74	$ 237.55	$ 214.56	$ 237.55	$ 229.89	$ 237.55	$ 229.89	$ 237.55	$ 237.55	$ 229.89	$ 266.01	$ 257.43	$ 266.01	$ 2,881.42		$ 6,086.16
		$ 64,140.26	$ 237.55	$ 214.56	$ 237.55	$ 229.89	$ 237.55	$ 229.89	$ 237.55	$ 237.55	$ 229.89	$ 266.01	$ 257.43	$ 266.01	$ 2,881.42		$ 67,021.68

Ontario

EB-2007-0931

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

AND IN THE MATTER OF an application by PUC Distribution Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2008.

BEFORE: Paul Vlahos
Presiding Member

Bill Rupert
Member

DECISION

PUC Distribution Inc. ("PUC" or the "Company") filed an application with the Ontario Energy Board, received on November 30, 2007, under section 78 of the *Ontario Energy Board Act*, *1998*, seeking approval for changes to the rates that it charges for electricity distribution, to be effective May 1, 2008.

PUC is one of over 80 electricity distributors in Ontario that are regulated by the Board. In 2006, the Board announced the establishment of a multi-year electricity distribution rate-setting plan for the years 2007-2010. On May 4, 2007, as part of the plan, the Board indicated that PUC would be one of the electricity distributors to have its rates rebased in 2008. Accordingly, PUC filed a cost of service application based on 2008 as the forward test year.

The Board issued a Notice of Application and Hearing dated December 14, 2007. The Vulnerable Energy Consumers Coalition ("VECC") intervened in the proceeding. The evidence in the application was tested through written interrogatories from Board staff

and VECC. Board staff and VECC filed written submissions and PUC filed written reply submissions. The submissions phase was completed on April 7, 2008.

The full record is available at the Board's offices. The Board has chosen to summarize the record to the extent necessary to provide context to its findings on certain issues.

RATE BASE

For a distributor, rate base consists of net fixed assets (gross fixed assets minus accumulated depreciation and any contributed capital) plus an allowance for cash working capital. Net fixed assets are determined as the average of the beginning and the end year values, and reflect capital additions for the test year. The Board's guidelines stipulate a level of cash working capital equal to 15% of the sum of OM&A expenses and the cost of power. The cost of power consists of the commodity cost of power and transmission charges.

The Board deals below with the following issues: smart meters; capital expenditures; and working capital.

Smart Meters

PUC is not one of the 13 distributors currently authorized by the Government to undertake smart meter activities and is not named in the combined smart meter proceeding, EB-2007-0063. PUC does not intend to install smart meters until authorized to do so by the Board. However, in order to meet the Government's targets for smart meter installations for itself and the other participants in a northeastern Ontario group of distributors, the Company has formulated a plan to install 31,522 smart meters in 2008. This would consist of 30,587 residential smart meters and 935 meters for General Service < 50 kW customers.

PUC estimated capital expenditures for smart meters of $6,200,000, before capitalization of overhead, and $365,000 for associated operating expenses in 2008. The Company included these expenditures in its 2008 rate base and revenue requirement in its original filing. PUC also recorded an expenditure of $53,625 in 2007, relating to: 1) formation of a northeast Ontario smart metering working group; 2) hiring of a consultant; 3) evaluation of AMI and smart meter installation vendors; and 4) preparation of the 2008 smart meter capital expenditure budget.

The Company modified its proposal for smart meters. It now proposes to address the recovery of smart meter costs through a smart meter rate adder and the use of deferral and variance accounts established for this purpose. PUC has not proposed a specific smart meter rate adder. PUC proposes to use the OEB smart meter rate adder model to determine the final smart meter rate adder for 2008 rates. The resulting smart meter rate adder would be applied to all metered customers. In its reply submission, PUC acknowledged that this would also require that $6,200,000 be removed from capital expenditures and rate base and that $365,000 be removed from operating expenses.

VECC argued that the smart meter rate adder should be discounted to recognize the uncertainty associated with PUC actually being authorized and able to complete the proposed deployment of smart meters by the end of 2008. VECC submitted that the level of discounting is a matter of judgement, but suggested that a 2008 smart meter rate adder be set between 50% and 75% of the adder assuming full deployment in 2008. PUC opposed an arbitrary discount factor.

Board Findings

The Government has established a phased approach to the implementation of smart meters across the province. Unless there are exceptional circumstances, the Board is not inclined to order the deployment of smart meters for distributors that have not received government authorization via regulation. The Board concludes that PUC does not represent an exceptional circumstance. The Board agrees with PUC that the proposed smart meter spending should not be included in the 2008 rate base. The Board also will require reduction of 2008 OM&A expense by the $365,000 related to smart meters.

The Board finds that it is appropriate to set a revised smart meter rate adder for PUC. The new rate adder will be $1.00 per month per metered customers. This rate adder takes account of the funds already collected, the cost estimates provided by PUC, and the Ministry of Energy's December 21, 2007 letter to London Hydro indicating that the Ministry intends to recommend to Cabinet that Regulation 427/06 be amended to authorize more distributors to install smart meters. This higher rate adder will allow PUC to collect additional funds and will reduce the need for a further application to the Board as and when authorization to proceed is received.

Capital Expenditures

The Company proposed $5,422,771 in non-smart meter capital expenditures for 2008. Table 1 provides a summary of actual or budgeted capital expenditures for 2006 to 2008.

Table 1: Summary of Capital Expenditures 2006-2008

Project	2006 actual	2007 budget	2008 budget
Install services to meet customer demand	$ 776,639	$ 748,705	$ 760,698
Replace wooden poles	420,988	422,997	700,929
Convert to 12 kV south of Wellington St. E	288,145	581,621	787,866
Construct miscellaneous lines and switches	222,196	317,248	163,007
Install underground service in new subdivisons	163,240	277,063	260,811
Distribution and transmission station equipment	-	583,194	1,065,599
Extend 35 kV along Third Line East	-	-	489,020
All other capital projects	1,484,836	900,409	1,194,841
Capital expenditiures, excluding smart meters	3,356,044	3,831,237	5,422,771
Reallocation of overhead from smart meter project	-	-	537,612
Total capital expenditures, excluding smart meters	**$ 3,356,044**	**$ 3,831,237**	**$ 5,960,383**
Overhead included in capital expenditure totals	$ 125,369	$ 207,750	$ 960,431

As noted in the preceding section of this Decision, the Board has not authorized PUC to include the estimated cost of installing smart meters in its 2008 rate base. The Company noted that its smart meter budget included $537,612 of capitalized overhead, which the Company said would have to be absorbed by other capital projects if the smart meter program is not carried out in 2008.

In support of its proposed capital program, PUC filed two reports – an internal report on long-term capital and O&M needs, and a review of PUC's capital expenditure and O&M plans prepared by BDR North America Inc. and Metsco Inc. Those reports documented the condition of PUC's system and the need to renew the system.

The Company noted that it had budgeted $875,000 for capital expenditures in 2007 that did not occur. These carry-over expenditures for 2008 include: $400,000 for pole replacements; $220,000 for 35 kV cables at substations; and $255,000 for TS equipment.

As indicated in the last row in Table 1, the amount of overhead capitalized in 2008 is expected to be significantly higher than in previous years due to a change in policy as recommended in the Full Absorption Cost Allocation Report prepared for by the Company by RDI Consulting Inc.

VECC made no specific submissions regarding PUC's proposed capital program. However, VECC questioned the Company's ability to complete the proposed 2008 system renewal and voltage conversion projects, in light of PUC's inability to meet its budgeted 2007 capital spending due to internal staffing issues and lack of external contractor resources.

In its reply submission, the Company concurred that the availability of qualified labour is severely limited across northern Ontario. However, the Company noted that it will use an apprenticeship approach to acquire the necessary human resources.

Section 2.3 of the Board's Filing Requirements for Transmission and Distribution Applications states that an applicant should file profitability indices ("PI") related to customer additions and system expansions, where applicable, as part of its rate application and in support of the proposed rate base and capital expenditures. Board staff noted that PUC did not provide such information in its application.

In response to a Board staff interrogatory, PUC stated that the economic analyses that would largely form the necessary basis for PI values for customer demand projects was not completed for projects proposed in this application. However, it intends to review and improve the method used to calculate and handle contributed capital in the future.

VECC commented that, as the Company did not carry out the required economic evaluations for its Customer Demand projects to determine capital contribution requirements and as there is no allowance for such contributions in the rate base, 2008 rates would be overstated if any contributions are subsequently established during this year. To mitigate against any such overstatement, VECC suggested that the Board should approve less than the requested spending levels for Customer Demand projects, suggesting a "nominal" 10% reduction, as an example.

In its reply submission, the Company stated that the Board's Distribution System Code (the "DSC") does not outline the method for calculating a Profitability Index , and that, in Ontario, the Profitability Index is applicable to natural gas distributors but not to electricity distributors. PUC also stated that Appendix B of the DSC outlines the method for conducting an economic evaluation to determine what, if any, capital contribution is required for "expansion facilities" projects.

PUC submitted that customer demand capital expenditures in 2006 and 2007 were for upgrades to existing services and to connect new services along PUC's existing distribution network, and that these should not be considered as system expansions for purposes of the analysis required by Appendix B of the DSC. PUC also noted that the 2008 amounts shown in Table 1 for "Install services to meet customer demand" and "Install underground services in new subdivisions" are net of budgeted capital contributions of $150,000 and $360,000, respectively. Those amounts exceed the 10% nominal reduction proposed by VECC.

Board Findings

PUC has proposed that the amount of overhead it would have capitalized on its smart meter spending ($537,612) be included in its spending for other capital projects. The Board does not understand the basis for that reallocation. Capitalization of overheads should be driven by the size and nature of capital projects. It is counterintuitive to maintain the same amount of overhead capitalization when the total capital budget is lower by $6.2 million. Accordingly, the $537,612 of overhead that has been reallocated should be included in OM&A expenses.

There is no doubt that the proposed levels of capital expenditure are extraordinary compared to historical norms. Extraordinary spending proposals must be supported by compelling evidentiary support which is commensurate with the extent of the increases sought. The evidence in this case goes some way for the need for increased spending, but not to the level proposed.

The Company maintains that it will be able to staff up to carry out the work in 2008. The Board shares VECC's concerns, however, about the ability of the Company to actually complete its 2008 capital expenditure program given its inability to complete a much smaller program in 2007. The Board approves capital expenditures of $4.9 million or approximately 90% of the proposed 2008 capital expenditure budget after the

adjustment for capitalized overhead and exclusive of smart meters for purposes of calculating the 2008 rate base.

Working Capital

VECC submitted that the cost of power component of PUC's working capital determination should reflect the transmission charge reductions approved for 2008. In its reply submission, PUC submitted that the estimated cost of energy used for the working capital allowance calculation is reasonable compared to 2007 actual results.

Board Findings

Later in this Decision, the Board accepts PUC's proposed transmission charges; therefore, the cash working capital does not change on account of transmission charges. However, later in this Decision, the Board finds a lower OM&A expense for 2008 than proposed. In its Draft Rate Order, PUC should therefore re-calculate the cash working capital which will be lower than the amount proposed.

In Chapter 2 of the Board's filing requirements for distributors, the Board suggests that, when filing, the cost of power will be that available from the most recent Board-approved RPP. In the Board's view, there are benefits and no cost for the electricity distribution sector and for the Board to have one common cost of commodity power forecast. As long as the Board is required to produce a cost of power forecast in its responsibility to set RPP prices, and to the extent that the Board's forecast covers a period which can subsume in whole or in large part the test period for setting distribution rates, it makes good sense to utilize that forecast. Applying individual efforts by each distributor can lead to inconsistencies among distributors, can be expensive and is unnecessary. The Navigant forecast used by the Board to set RPP prices for May 1, 2008 onward covers the Company's test year filing. The Board prefers that the use of Navigant's forecast prices should be used in this case and it so finds. The Board directs the Company to reflect in its re-calculation of cash working capital an all-in supply cost of $0.0545/kWh derived from Board's Price Report issued April 11, 2008.

OPERATING COSTS

Operating costs include OM&A expenses, depreciation and amortization expenses, payments in lieu of taxes (PILs taxes), and any transformer allowance payments to customers. PILs taxes are proxies for capital and income taxes that, otherwise, would

have to be paid if the distributor was not owned by a municipality or the Ontario government.

The final PILs tax allowance for ratemaking purposes is determined after the Board makes its findings on other relevant parts of the Company's application.

Operating costs also include interest charges on the Company's debt. These are dealt with in the cost of capital section of the Decision.

The Board deals below with the following issues: Controllable OM&A Expenses; and PILs Taxes.

Controllable OM&A Expenses

Table 2 shows the components of the proposed controllable OM&A expenses for 2008 and compares them with previous years.

Table 2: Controllable OM&A Expenses

	2006 Board Approved	2006 Actual	2007 Bridge	2008 Test
Operations	$ 1,496,528	$ 2,051,174	$ 2,156,507	$ 3,018,799
Maintenance	1,793,258	1,430,922	1,448,545	2,277,648
Billing and Collections	959,171	941,104	934,991	1,338,873
Community Relations	375,332	428,632	408,719	473,852
Administrative and General Expenses	2,215,726	1,832,913	2,361,110	1,397,298
Total Controllable OM&A	**$ 6,840,015**	**$ 6,684,745**	**$ 7,309,872**	**$ 8,506,470**

PUC has no employees of its own; it has a services agreement with its affiliate PUC Services Inc. ("PUC Services") to operate its distribution system. PUC noted that $1.5 million of the difference in OM&A costs from 2006 to 2008 is owing to: (i) additional smart meter costs, (ii) the one-time reduction in 2006 costs as a result of an adjustment for prior period pension expense and (iii) increased staff levels as detailed in the Long-

Term Capital and OM&A Needs Report and the Review of Capex and O&M Plan. PUC stated that smaller items such as the PCB removal program and wage rate increases over the two-year period accounted for the remainder of the difference.

In its decision related to PUC's 2006 rate application (RP-2005-0020/EB-2005-0412), the Board expressed concern about the adequacy of the information provided by PUC in support of its application and stated that in its next rate case the Company must provide detailed financial information on its operations, and details of costs incurred by its affiliates in providing services to the Company.

To address the Board's concerns, PUC engaged a third party, RDI Consulting Inc., to undertake a review, which culminated in the Full Absorption Cost Allocation Report. PUC stated that it was implementing the recommendations of this review effective January 1, 2008.

PUC noted that its shared services costs in 2008 totaled $3.2 million, or just under 40% of its total controllable OM&A costs. Board staff noted that the Company has proposed a significant increase in these costs for 2008 of 20%, or $560,390, over 2007 levels.

The Company explained that this increase was due to three factors. The first was a new cost of capital charge, accounting for $381,391 of the increase. This charge applies to all PUC affiliates and is designed to recover the financing costs by PUC Services for assets used to service the affiliates. PUC justified this charge on the basis of the Report which recommended the implementation of such a charge.

The second factor was a "Use of Assets Charge", a depreciation expense related to assets used by PUC and owned by PUC Services. This has an impact of $89,564 and was explained by the Company as being the result of the use of additional vehicles by the utility due to the increased operations staff and the implementation of upgraded software driven by the need to better maintain records. The Company further stated that the asset charge allocation had also been revised to use more appropriate allocators as per the Report.

The third factor was the joint services allocation, which increased by $89,435. The Company explained that this increase was due to a reduction in the percentage of joint services costs allocated as per the Report, offset by wage increases of 3% and the addition of a shared billing supervisor and a shared IT manager.

VECC interrogatory #18a sought to isolate the impacts of implementing the recommendations of the Report from general cost increases in this area. PUC's response indicated that $175,728 of the 2007-2008 increase of $560,390 resulted from the Report's recommendation and the remainder of $384,663 was due to changes in actual costs incurred by PUC Services.

PUC also noted that one other reason for the increase in OM&A costs since 2006 is because of a one-time $350,000 reduction in 2006 costs as a result of an adjustment for prior period pension expense. PUC explained that the adjustment had come about as a result of an external review of its regulatory accounting procedures aimed at ensuring compliance with the Accounting Procedures Handbook. PUC stated that the review revealed that PUC had overstated OMERs costs for the 16-month period ending May 1, 2006. The adjustment, which was processed in 2006, resulted in 2006 expenses appearing to be lower than normal. PUC reiterated that the adjustment resulted in a one-time reduction in 2006 expenses pertaining to a prior period pension expense and understates the true costs in 2006. PUC submitted that the 2006 expense level used to compare to the 2008 test year should exclude the credit that reduces 2006 costs.

PUC stated that PUC Services expects to increase staff complement from 45 employees in 2006 to 54 employees in 2008, an increase of 20%. In response to a Board staff interrogatory, PUC identified anticipated wage increases of 3% in 2007 and 2008. In its reply argument, PUC clarified that one additional employee was hired in 2007 and nine additional employees are proposed for 2008, but of the nine additional employees, only one employee, a billing supervisor, is a shared employee.

PUC stated that the additional employees will not be hired until the final outcome of this proceeding is known; if the proposed rates are not approved, not all proposed employees will be hired and not all proposed programs will be implemented.

PUC justified the proposed increases on the basis that the current level of OM&A and capital programs are inadequate to maintain and upgrade its distribution infrastructure. As part of its application, PUC filed an independent report conducted by METSCO on the Company's OM&A and capital needs, confirming these concerns, which had originally arisen based on an internal report prepared by PUC staff.

VECC, in its submission, stated that the implicit wage increases of 3% appeared reasonable and that the forecast staff increases were generally supported by PUC's long term capital needs and OM&A report.

Board Findings

As noted earlier in this decision under "Rate Base – Capital Expenditures", the Board has found that $537,612 of overhead that PUC proposed to include in capital expenditures should be included in OM&A expenses for the test year.

The Board accepts PUC's explanation that a comparison in controllable OM&A from 2006 should reflect the $350,000 credit applied in 2006. The Board also notes that the 2008 controllable OM&A proposed expenses will be reduced by $365,000, to $8,141,470, to eliminate 2008 smart meter OM&A. After those adjustments, the proposed 2008 controllable OM&A expenses are $8,679,082 (that is, $8,506,470 per Table 2, plus the $537,612 of reallocated overhead, less $365,000 of smart meter OM&A). That amount is higher than actual 2006 expenses (adjusted for the $350,000 pension credit) and projected 2007 expenses by approximately 23% and 19%, respectively.

In determining an appropriate amount for controllable OM&A expenses, the Board has considered that a 20% increase in shared services expenses over 2007 is excessive. The Board will allow an increase of $0.5 million in overall controllable OM&A expenses for 2008 over 2007. This represents an increase from the 2007 level of just under 7%, which the Board considers reasonable in the circumstances facing the Company. The Board therefore approves a total amount of controllable OM&A expenses of $7,810,000 for ratemaking purposes in the 2008 test year.

PILs Taxes

In response to Board staff interrogatory #2 (d), PUC submitted a PILs calculation that excluded the interest addition and deduction, and used the combined effective tax rate of 33.5%.

VECC submitted that the Board has already addressed the treatment of interest in PILs calculations in its EB-2007-0723 Decision regarding PUC's 2007 rates. VECC noted that in response to VECC interrogatory #21, PUC updated its CCA schedule calculations for 2008 to reflect the impact of the March 2007 Federal budget. VECC submitted that these revised values should be used in PUC's 2008 PILs calculations.

Board Findings

In calculating the PILs provision, the Board directs PUC to reflect in its Draft Rate Order the new combined income tax rate for 2008 of 33.5%, the Ontario capital tax exemption amount of $15 million, and the new applicable CCA class rates. The final PILs amount that PUC will use in its Draft Rate Order will reflect changes resulting from other Board findings in this decision, as appropriate.

OPERATING REVENUES

For the purposes of setting base distribution rates for the electricity sector, the Board determines the operating revenues from sales and subtracts revenues associated with certain other charges levied by the distributor other than base rates. The Board deals below with the issue of load forecast.

Load Forecast

The Company's load forecast was developed using a normalized average consumption ("NAC") estimate for a given rate class multiplied by a customer count forecast for that rate class. The NAC value is based on 2004 consumption data that was developed with the assistance of Hydro One. PUC's load forecast is based on a forecast customer count of 41,610 for 2008, an increase of 0.1% annual average growth during the 2006 to 2008 period; the historical growth rate was 0.2% per annum. The resulting load forecast is a negative 0.3% annual average kWh change from 2006 to 2008 which compares with a historical negative 0.6% per annum change.

Board staff observed that the Company's methodology utilized only a single year of weather-normalized historical load to determine the future load. Board staff noted that this assumed that no CDM improvements had occurred over the past few years and that none were expected in the immediate future, and might therefore result in a filed load forecast that is about 1%-2% higher than the data would suggest. VECC indicated that while it had similar concerns about this approach, it was not clear that, in the short term, a better alternative existed. VECC stated that the Company's approach is preferable to the one suggested by Board staff.

In its reply argument, PUC stated that it was also concerned that the weather-normalized kWh forecast used to design the proposed rates is too high based on recent historical usage. PUC stated that the Hydro One weather-normalization data was

based on 31 years of average weather which is reflective of times when Sault Ste Marie had much colder winters than it does now. PUC also submitted that it may be more appropriate to use the average usage per customer from the past 5 years as the NAC values for 2008.

Board Findings

The Board will accept PUC's load forecast for setting PUC's 2008 rates as originally filed. Notwithstanding PUC's contention regarding weather normalization and average use, there is no other specific quantitative proposal by the Company for the Board to consider for purposes of setting rates in this proceeding.

CAPITALIZATION / COST OF CAPITAL

Capitalization refers to the financing of total rate base through common equity, preference share capital (if applicable), long term debt and short term debt. Cost of capital refers to the cost rates for debt and preference share capital and the Board-authorized rate of return on common equity.

PUC's actual capital structure is 90% debt and 10% equity. However, the Company stated that it intends to restructure its capital structure to conform to the Board's final deemed capital structure, comprising of 60% debt and 40% equity.

Table 3 summarizes PUC's proposed capitalization and cost of capital.

Table 3: Proposed Capital Structure/Cost of Capital

Parameter	PUC Proposal
Capital Structure	53.3% debt (composed of 49.3% long-term debt and 4.0% short-term debt) and 46.7% common equity
Short-Term Debt Rate	4.77%, but to be updated
Long-Term Debt Rate	6.35% for a long-term debt with its parent company (affiliated debt) and for forecasted new third-party debt. PUC used a forecast rate of 5.82% in its Application originally.
Return on Common Equity	8.69%, but to be updated.

In its application, PUC stated that it intends to incur new third-party debt in 2008. PUC provided a calculated cost rate of 5.82% for the affiliated debt in 2007 and 2008, and also used the 5.82% rate as the forecasted rate for the new third-party debt. PUC noted that the municipal debt instruments are being renegotiated.

Board staff submitted that, as per the Board's guidelines for the cost of capital set out in its *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* ("Board Report"), the updated deemed debt rate should be used for the new debt which was forecasted for 2008, but had not been set. VECC noted that PUC's proposed cost of capital was consistent with the policies documented in the Board Report.

PUC clarified its cost of capital proposal further in its reply submission, stating that its intent in its application was to use the deemed equity rate at the updated equity rate of return level, the lower of its actual long term debt rate with the shareholder and the Board's updated long term debt rate, and the Board's updated short term debt rate.

Board Findings

The Board finds PUC's proposals regarding capitalization and cost of capital reasonable. The Board notes that renegotiation of the affiliated debt has not been completed and the forecasted rate for the new third-party debt is unchanged from the Company's original application. It is the Board's view that both forms of debt should be considered new debt and attract the updated cost of long term debt pursuant to section 2.2.1 of the Board Report. The Board deals with the updates of the components of the cost of capital under the "Implementation Matters" section at the end of this Decision.

COST ALLOCATION AND RATE DESIGN

Revenue to Costs Ratios

PUC filed results of a cost allocation study in the Informational Filing EB-2007-0001, based on its 2006 approved revenue requirement and rates. In its current application, PUC proposed to increase its distribution rates proportionately more to those rate classes with revenue to cost ratios below 100% and proportionately less to those with ratios above 100%. The result of this re-balancing can be seen in the following table, by comparing columns 1 and 2. For ease of comparison, the Board's target range is shown in column 3.

Table 4: Revenue to Cost Ratios (%)

Customer Class	Informational Filing Col 1	Current Application Col 2	Board Target Range Col 3
Residential	90	93	85 – 115
GS < 50 kW	137	120	80 – 120
GS > 50 kW	132	128	80 – 180
Street Lights	17	40	70 – 120
Sentinel Lights	38	40	70 – 120
USL	82	82	80 -- 120

PUC noted that a move to the lower boundary of the Board's target range for the Street Lights and Sentinel Lights rate classes would increase total customer bills by 66% and 71%, respectively. VECC argued that rates for the Street Lights class should be increased to yield a ratio of 44% and rates for the Sentinel Rates class should be increased to yield a ratio of at least 54%, to bring both ratios halfway to the lower boundaries stipulated in the Board's policy. VECC also submitted that the Board should direct PUC to implement increases in 2009 and beyond, to reach a revenue to cost ratio in the acceptable range.

Board staff and VECC noted that the general service classes would have ratios above 100% if PUC's proposed rates were implemented, and submitted that the rates could be decreased if more revenue were generated from the Street Lights and Sentinel Lights rate classes.

Board Findings

As the Board has noted in its Cost Allocation Report regarding revenue to cost ratios, cost causality is a fundamental principle in setting rates. However, observed limitations in data affect the ability or desirability of moving immediately to a revenue to cost framework around 100%. The Board's target ranges are a compromise until such time as data is refined and experience is gained.

The Board is prepared to adopt the general principle that, where the proposed ratio for a given class (Column 2) is above the Board's target range (Column 3), there should be a

move of 50% toward the top of the range from what was reported in its Informational Filing (Column 1). None of PUC's classes are in this situation. Where the revenue to cost ratios in the Informational Filing (Column 1) are below the Board's ranges (Column 3), the rates for 2008 shall be set so that the ratios for these classes shall move by 50% toward the bottom of the Board's target ranges.

Under this approach, rates for two classes would be adjusted to achieve the following revenue to cost ratios:

Streetlights	44%
Sentinel Lights	54%

The Board expects the Company to achieve the remaining 50% move by equal increments in years 2009 and 2010.

As a result of these findings, there will be a lower net revenue requirement that needs to be recovered from the other classes. Of these classes, the two General Service rate classes will be over-contributing based on the Company's proposal. The Board finds that the additional revenue from the Street Lights and Sentinel Lights rate classes shall be allocated to the General Service classes so that the over-contribution will be reduced. The allocation shall be prorated on the basis of forecast revenue for the two classes. The Board expects the Company to apply this allocation method when it applies for rate adjustments in 2009 and 2010.

In filing its Draft Rate Order, the Company shall provide the information necessary to establish its compliance with the above directions for 2008 rates.

Fixed Charges

With one exception, no changes to the monthly service charges were proposed. The exception is a proposal to increase the monthly service charge of the GS < 50 kW class from $11.20 to $15.40. PUC's rationale for the proposed change is to reduce revenue volatility from that rate class. Board staff and VECC noted that the monthly service charge would be below the 2006 ceiling amount calculated by the cost allocation model in the PUC's Informational Filing.

Board Staff noted that the monthly service charge to customers in the GS > 50 – 4,999 kW rate class is above the ceiling calculated in the Informational Filing. However, Board staff noted that PUC's proposal not to change the service rate is consistent with the Board report, *Cost Allocation for Electricity Distributors*, dated November 28, 2007.

Board Findings

The Board finds PUC's monthly service charge proposals to be reasonable and approves them.

Retail Transmission Service (RTS) Rates

On October 17, 2007, the Board issued its EB-2007-0759 Rate Order, setting new Uniform Transmission Rates for Ontario transmitters, effective November 1, 2007. The Board approved a decrease of 18% to the wholesale transmission network rate, a decrease of 28% to the wholesale transmission line connection rate, and an increase of 7% to the wholesale transformation connection rate. PUC receives only network service from the transmitter. It does not incur costs for line connection or transformation connection services.

On October 29, 2007, the Board issued a letter to all electricity distributors directing them to propose an adjustment to their retail transmission service (RTS) rates to reflect the new Uniform Transmission Rates for Ontario transmitters effective November 1, 2007. The objective of resetting the rates was to minimize the prospective balance in variance accounts 1584 and 1586 and also to mitigate intergenerational inequities. PUC proposed to decrease its rates Retail Transmission Service Rate – Network by approximately 11%. VECC submitted that these rates should be reduced by at least 18%, which is the reduction in the wholesale charge.

PUC submitted that it had considered its wholesale cost from May 2006 to September 2007, and projected that the cost at the new wholesale rate would have been $4.096 million. PUC's revenue during the same period based on its currently approved retail transmission rates was $4.577 million. PUC submitted, therefore, that only an 11% reduction in its retail transmission rates is required.

Board Findings

The Board notes that there is a variance account mechanism for all distributors to capture differences between their transmission costs and the charges to their customers. The issue is not whether the distributors or the customers would be financially harmed. Good ratemaking suggests that, to the extent possible and practical, rates and charges at a point in time should reflect the most current information so that any differences captured in variance accounts would be minimized. This would lead to smoother rate making and reduced concerns about inter-generational inequities.

The Board notes that PUC had reduced its Retail Transmission Service Rates- Network in 2006, adapting to the amount in its variance account at that time. In light of PUC's review of its revenues and costs in the interim, the Board finds that PUC's proposed reduction of its Retail Transmission Service Rates- Network by 11% is acceptable.

DEFERRAL AND VARIANCE ACCOUNTS

The table below shows the deferral and variance account balances that PUC is seeking to recover. All amounts, except for the balance in Account 1590, are as at December 31, 2006 plus forecast interest to April 30, 2008. The balance in Account 1590 reflects both forecast interest and the expected recoveries through the existing rate rider over the period January 1, 2007 to April 30, 2008.

Table 5: Deferral and Variance Accounts Proposed for Disposition

ACCOUNT	ACCOUNT NAME	BALANCE
1508	Other Regulatory Assets	$ 509,595
1518	RCVA – Retail	(152,514)
1548	RCVA – STR	56,068
1580	RSVA – Wholesale Market Service Charge	(510,825)
1584	RSVA – Retail Transmission Network Charges	(468,200)
1588	RSVA – Power	(592,397)
1590	Recovery of Regulatory Asset Balances	540,928
Total		**$ (617, 345)**

PUC's proposal is to refund these balances to customers over two years beginning May 1, 2008.

Account 1508 – Other Regulatory Assets

PUC is requesting the disposition of the balances of 1508 sub-account OEB cost assessments and 1508 sub-account OMERS costs that were generated up to April 30, 2006. No party noted concerns with these balances.

The Board approves disposition of these balances over two years.

Accounts 1580, 1584, 1588 – Retail Settlement Variance Accounts

Under section 78 (6.1) of the *Ontario Energy Board Act 1998*, the Board is obligated to review each quarter the balance in Account 1588, RSVA – Power. The Board recently announced that it intends to launch an initiative on a review and disposition process. The Board also indicated that it is considering extending this initiative to include all the RSVA accounts, including Accounts 1580, RSVA – Wholesale Market Service Charge, and 1584, RSVA – Retail Transmission Network Charge. The Board, therefore, does not approve clearance of these accounts at this time.

Accounts 1518, 1548 – Retail Cost Variance Accounts

The Board's announced review noted above may include also RCVA accounts. For that reason, the Board finds that it would be appropriate to await the outcome of this initiative and therefore will not order disposition of the Company's RCVA accounts in this proceeding.

Account 1590

PUC is proposing to dispose of the April 30, 2008 forecasted balance in this account. Board staff noted that the Board, in its Phase 2 decision for the Review and Recovery of Regulatory Assets, determined that the balance in this account should be recovered over three years (ending April 30, 2008) and that any residual balance should be disposed of at the end of the period. Board staff pointed out that the final balance cannot be determined in advance of April 30, 2008, when the rate rider ends. VECC submitted that the approach by PUC was inconsistent with the Board's Phase 2 decision.

In its submission, Board staff sought clarification of the quantum of the balance of this account. VECC submitted that any questions regarding the appropriateness of the balances (including interest calculations) in this account and related regulatory asset accounts needed to be resolved before they are disposed of. In its reply submission, the Company implied that the interrogatory responses had already addressed the issues regarding the calculation of the balance in 1590.

Board Findings

The Board finds that it is not appropriate to forecast the principal balance in this account or to dispose of this account at this time. The current rate riders for regulatory assets were designed to recover the approved amounts over two years. Those rate riders expire on April 30, 2008, after which PUC will be able to accurately determine the residual balance.

Request for New Deferral Accounts

In its application, PUC proposed to establish three new accounts:

1. Full year return and depreciation on smart meter assets for 2009 and 2010
2. Meter Data Management Repository Account
3. Capital works during the non-rebasing years

PUC withdrew its request for the first two accounts in its reply argument.

PUC's request for account "Capital works during the non-rebasing years" is to record the revenue requirement associated with the cost of construction during the non-rebasing years. Board staff stated that this account is analogous to including a capital investment factor in a year where an electricity distributor's application for distribution rates is subject to an Incentive Rate Mechanism ("IRM") process.

Board staff noted that PUC's request may be premature as the mechanism for the 3rd Generation IRM has not yet been finalized and may include a capital component.

VECC noted that the Company's response to interrogatories indicated that this account would address the revenue requirement impact of variances in the forecasted capital spending for the test year. VECC submitted that capital spending for the test year should be dealt with in the application, and not through a deferral account. VECC

concluded that it is premature to approve new accounts at this time, and that the use of such accounts should be established on an industry wide basis and be based on a common set of rules established at that time.

PUC, in its reply submission, stated that it understands that the proposed account is analogous with a capital investment factor in an IRM year. However, PUC further stated that, as of the date of its reply submission, the Board had not approved the capital component in the 3rd Generation IRM, and that it is only prudent for PUC to request the establishment of a new deferral account for capital works during the non-rebasing years.

Board Findings

The Board does not approve a deferral account for capital expenditures in non-rebasing years. The Board is currently considering the structure of its 3rd Generation IRM framework, including whether capital expenditures should be incorporated in some fashion in rates during the incentive period. PUC has not made a case that its needs may not be met by that process. For PUC, the issue is best dealt with in that process.

SERVICE RELIABILITY INDICES

Board staff submitted that, despite the apparent degradation in system reliability, there is no information on whether or how PUC has addressed service reliability improvement in conjunction with developing and implementing its asset management plan.

In its reply submission, PUC explained that the tables provided in its application had errors in the underlying data, and provided revised figures, with explanations.

Board Findings

The Board is undertaking a separate consultation on Electricity Service Quality Regulation and will look at these issues more closely on an industry-wide basis.

IMPLEMENTATION MATTERS

Cost of Capital Update

In mid-2006, the Board initiated a consultative process to examine the cost of capital applicable to the Ontario electricity distribution sector. This process was conducted in conjunction with the development of the 2nd Generation Incentive Regulation plan. The product of these consultations was the Board Report, issued December 20, 2006 noted earlier in this decision under "Capitalization/Cost of Capital". The Board Report considered the extensive consultation record and established, in part, guidelines for setting and updating the cost of capital parameters for distribution rate-setting from 2007 onwards, including the return on common equity ("ROE"), the deemed short-term debt rate, and, as appropriate, the deemed long-term debt rate.

The Board Report established that the approved ROE to be used for rate-setting purposes should be calculated by application of the formula in Appendix B of the Board Report. In setting the ROE for the establishment of 2008 rates, the Board has used the *Consensus Forecasts* and published Bank of Canada data for January 2008, in accordance with the Board's guidelines. In fixing new rates and charges for PUC, the Board has applied the policies described in the Board Report. Based on the final 2007 data published by *Consensus Forecasts* and the Bank of Canada, the Board has established the ROE to be 8.57%.

The Board Report also established that the short-term debt rate should be updated using the methodology in section 2.2.2 of the Board Report. The Board has set the short-term debt rate at 4.47% using data from *Consensus Forecasts* and the Bank of Canada for January 2008.

The Board Report also established that the deemed long-term debt rate should be updated using the methodology in Appendix A of the Board Report. The deemed long-term debt rate acts as a proxy for or ceiling on the allowed debt rate for new, affiliated or variable rate debt, and may be applicable for establishing the embedded cost of debt in the test year period depending on the nature of the distributor's debt financing. The Board has set the deemed long-term debt rate at 6.10% based on data from Consensus Forecasts and TSX Inc. for January 2008.

Draft Rate Order

The Board has made numerous findings throughout this Decision. These are to be appropriately reflected in a Draft Rate Order prepared by the Company.

The Board issued an Interim Rates Order on April 17, 2008 declaring rates interim as of May 1, 2008. However, as the Company was three and one half months late in filing its application, and given the time that is typically required to settle matters before the Rate Order can be issued, the Board has determined that the effective date of the new rates shall be July 1, 2008, the date of implementation. The current rates therefore shall continue until July 1, 2008. For additional clarity, the new rates to be filed by the Company shall be calculated on the basis that the revenue requirement arising from this Decision is recoverable over a twelve month period, but the new rates will not be effective and implemented until July 1, 2008.

The July 1, 2008 effective date is predicated on the Company complying with the timelines set out at the end of the Decision and its Draft Rate Order properly reflects the Board's findings. Should these not be reasonably adhered to, the effective date may be further delayed.

In filing its Draft Rate Order, it is the Board's expectation that the Company will not use a calculation of a revised revenue deficiency to reconcile the new distribution rates with the Board's findings in this Decision. Rather, the Board expects the Company to file detailed supporting material, including all relevant calculations showing the impact of this Decision on the Company's proposed revenue requirement, the allocation of the approved revenue requirement to the classes and the determination of the final rates. The Draft Rate Order shall also include customer rate impacts and detailed calculations of the revised variance account rate riders.

A Rate Order will be issued after the processes set out below are completed.

1. The Company shall file with the Board, and shall also forward to VECC, a Draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision, within 14 days of the date of this Decision.

2. VECC may file with the Board and forward to the Company any responses to the Company's Draft Rate Order within 20 days of the date of this Decision.

3. The Company shall file with the Board and forward to VECC responses to any comments on its Draft Rate Order within 26 days of the date of this Decision.

A cost awards decision will be issued after the steps set out below are completed.

4. VECC shall file with the Board and forward to the Company their respective cost claims within 26 days from the date of this Decision.

5. The Company may file with the Board and forward VECC any objections to the claimed costs within 40 days from the date of this Decision.

6. VECC may file with the Board and forward to the Company any responses to any objections for cost claims within 47 days of the date of this Decision.

The Company shall pay the Board's costs of, and incidental to, this proceeding upon receipt of the Board's invoice.

DATED at Toronto, May 22, 2008
ONTARIO ENERGY BOARD

Original Signed By

Paul Vlahos
Presiding Member

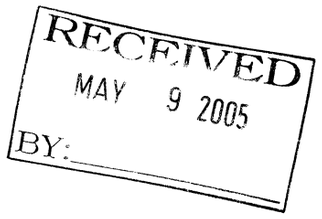
Original Signed By

Bill Rupert
Member

Hydro One Networks Inc.
www.HydroOne.com

hydro one

May 2, 2005



Mr. Steve Lund
General Manager & Secretary
Tillsonburg Hydro Inc.
200 Broadway Street, 2nd Floor
Tillsonburg, Ontario
N4G 5A7

Subject: Customer Impact Assessment – Proposed AIM Erie Shores Wind Farm Generating Facility

Dear Steve:

AIM PowerGen Corp. is proposing to build a 99 MW wind farm generating facility located along the north shores of Lake Erie in the area of Port Burwell. In accordance with the electricity market rules in Ontario, AIM PowerGen has applied to the Independent Electricity System Operator (IESO) to assess the impact of connecting this proposed generating facility to the IESO controlled grid. On April 20, 2005 the IESO issued the System Impact Assessment (SIA) report for this project and it has been posted on their web site. As part of the connection assessment process, AIM PowerGen has requested Hydro One to prepare a Customer Impact Assessment (CIA) for the proposed generating facility. This requires Hydro One to obtain feedback and comments from impacted transmission customers in the general electrical area of the proposed facility. Consequently we are asking for your input. A copy of this report is included as an attachment in the e-mail version of this request and will also be included as a hard copy in the mailed version to you. Pay particular attention to the increases in system short circuit levels in the report and the impact the proposed generating facility may have on your facilities. The findings of this report essentially confirm the conclusions in the Preliminary Customer Impact Assessment report that was presented during the November 26th, 2004 meeting attended by Tillsonburg Hydro and Erie Thames Power.

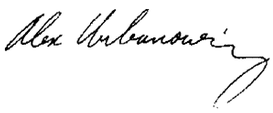
Please provide your comments within 30 days electronically to my e-mail address. If there are no comments a short note indicating the same would be appreciated.

Contacts are provided below if you have any questions concerning the report.

AIM PowerGen Corp.	- Ansar Gafur	(416) 502 0993 ext. 223
Hydro One Networks Inc.	- Mike Dang	(416) 345 5392
Hydro One Networks Inc.	- Witold Kellermann	(416) 345 6983

Thank you in advance for you cooperation.

Yours very truly,



Alex Urbanowicz
Account Executive

Attachment: Customer Impact Assessment Report

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

CUSTOMER IMPACT ASSESSMENT

ERIE SHORES WIND FARM

99 MW WIND TURBINE GENERATION CONNECTION

Plan/Project: **# 12582**

Date: **April 18, 2005**

Issued by: **Generation Connections Department**
System Development Division
Hydro One Networks Inc.

Prepared by:

Alain Elen, P.Eng.
Senior Engineer
System Development Department
Department

Approved by:

John Sabiston, P.Eng
Supervisor
Transmission System Planning

CUSTOMER IMPACT ASSESSMENT
ERIE SHORES WIND FARMS
99 MW WIND TURBINE GENERATION CONNECTION

1.0 INTRODUCTION

1.1 Background

AIM PowerGen Corporation (**AIM**) was one of the ten successful proponents in the Ontario Government's Request for Proposal (RFP) for 300 MW of renewable power.

AIM is to construct, in Phase I, a new 99 MW wind farm along the north shores of Lake Erie in the area of Port Burwell. The Erie Shores Wind Farm (**ESWF**) is to consist of 66 GE sle 1.5 MW, 60 Hz wind turbines connected by four (4) 34.5 kV overhead collector lines using 666.6 kcmil ACSR conductors. The collectors are to be terminated at the main transformer substation located at Port Burwell and tied to Hydro One's WT1T circuit from Tillsonburg TS via a 34.5/115 kV, 125 MVA transformer and 30 km of 115 kV overhead line as shown in Fig. 1.

Each wind turbine unit is rated 575 V, 1.5 MW and capable of operating at a power factor ranging from 0.90 lagging to 0.95 leading.

Circuit W8T is a 115 kV circuit and emanates from the Buchanan TS to feed two radial station loads at Aylmer (about 40 km from Buchanan) and Tillsonburg TS (about 60 km from Buchanan). The W8T circuit name changes to WT1A and WT1T at some junction point 34 km away from Buchanan. WT1A is the section that feeds Aylmer TS, and WT1T is the section that feeds Tillsonburg TS. For simplicity WT1T will be referred to as W8T.

This assessment assumed the ESWF generation output between 0 and 100 MW.

As part of the Connection Assessment and Approval (**CAA**) process, the IMO carried out a System Impact Study (SIA) with the help of POWER-tek Global Inc. The proposed ESWF connection and the results of their studies were given in a Report dated May, 2004 *entitled "Erie Shores Wind Farm System Impact Study"*. The Report essentially concluded:

- System wide conditions: With double-wound generator, the ESWF can survive all the major system faults under BLIP -1500 and 3000 MW. The most severe fault was the Bruce-Milton fault (B560V/B561M). The five other major faults were:
    - Loss of Buchanan 220/115 kV transformer
    - Loss of M31/32W (Buchanan-Middleport)
    - Loss of D4/5W (Buchanan-Detweiler)
    - Loss of W44/45LC (Buchanan-Chatham-Longwood)
    - Loss of N21/22W (Buchanan-Scott)
- Local Area conditions: An additional 24 MVAR capacitor at the Tillsonburg 34.5 kV is required to compensate for a sudden loss of the ESWF generation.

Hydro One Networks Inc (**Hydro One**) carried out Customer Impact Assessment (**CIA**) studies to assess the impact of the proposed ESWF connection on facilities owned by other load and generation customers in the Buchanan area. This is in accordance with the Market Rules (Chapter 4, Section 6) and IMO's CAA process.

1.2 The Erie Shores Wind Farms

1.2.1 Wind Turbine

The ESWF project consists of 4 groups of 11x1.5 MW, 12x1.5 MW, 22x1.5 MW and 21x1.5 MW wind turbine units totaling 99 MW. Each group is protected by a circuit breaker before connecting to the ESWF main 34.5 kV bus. The main 34.5 kV bus is connected to a 115 kV bus via one 115/34.5 kV transformer. From the main 115 kV bus, a 29.8 km 115 kV line connects to circuit W8T via a circuit breaker and motorized line disconnect switch. This junction is about 1.5 km from Tillsonburg TS.

Each turbine generator is equipped with a regulator designed to supply reactive power to the transmission Grid to regulate and stabilize the voltage. In addition, each turbine generator is equipped with a pad-mounted 575V/34.5 kV step-up transformer located at the foot of the tower.

1.3 Connected Customers

The customers connected to the Tillsonburg TS are:

- Hydro One Distribution,
- The Corporation of the Town of Tillsonburg PUC.

The customers connected to the Aylmer TS are:

- Hydro One Distribution,
- Erie Thames Power.

2.0 METHODOLOGY & CRITERIA

2.1 Study Assumptions

Load flow and short-circuit studies assumed the following:

- Line Data – All transmission facilities in Hydro One system are assumed to be in-service.
- Transformer/Phase Shifter Data – All existing transformers and phase shifters are assumed to be in-service
- Generation Data – The short-circuit studies considered all existing generating stations in Ontario to be in-service including the following considerations:

  - Lakeview GS units are assumed out-of-service
  - Lambton G1 to G4 units are assumed in-service
  - Nanticoke G1 to G8 units are assumed in-service
  - 2 Bruce 'A' units and all of Pickering 'A' units are assumed in-service
  - Brighton Beach Power is assumed to be in service
  - Imperial Oil -Sarnia is assumed to be in service, and
  - ESWF 99MW wind turbine generation is to be connected on W8T in service.

- Machine Data

  - Machine data exist in the short-circuit study database for existing generators. These are in the form of $X"_d$ (sub-transient reactance) in p.u. on machine rating.

- The ESWF wind turbine generator data used in the studies are given in Appendix A.

New transformers at Tillsonburg TS are planned in service in November 2004. Presently there are three 34.5/115 kV transformers. The three transformers will all be removed, and will be replaced by two new transformers with greater MVA ratings.

2.2 Planning Criteria

To establish the adequacy of Hydro One transmission and distribution system incorporating the proposed ESWF generation facilities, the following post-fault voltage decline criteria were applied. As per "IMO Transmission Assessment Criteria"

http://www.theimo.com/imoweb/pubs/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

- The loss of a single transmission circuit should not result in a voltage decline greater than 10% for pre- transformer tap-changer (including station loads) and 10% post- transformer tap-changer action (5% for station loads) ;
- The loss of a double transmission circuit should not result in a voltage decline greater than 10% for pre- transformer tap-changer (including station loads) and 10% post- transformer tap-changer action (5% for station loads) ;
- Voltages below 50 kV shall be maintained in accordance with CSA 235.

2.3 Power System Analysis

Power system analysis is an integral part of the transmission and distribution planning process. It is used by Hydro One to evaluate the capability of the existing network to deliver power and energy from generating stations to provide a reliable supply to customers.

a. Load Flow Studies: The PTI PSS/E AC load flow program was used to set up detailed base cases with the 99 MW ESWF generation facilities planned to come in service during the spring of 2006.

b. Short-Circuit Studies: Hydro One's in-house short-circuit study program, *FAULT*, was used to determine the impact of ESWF generation (in isolation) on Aylmer and Tillsonburg customers at the point of connection.

3. Short-Circuit Study Analysis

Short-circuit studies were carried out to assess the fault contribution when the 99 MW ESWF generating facilities get connected near the Tillsonburg TS. See Figure 1.

The existing three transformers at Tillsonburg were assumed in service. With two transformers, the SC results at Tillsonburg 34.5 kV will be lower.

The study results are summarized in Tables 1, 2A and 2B below showing both symmetric and asymmetric fault currents in kA.

3.1 Present Hydro One Systems

Table 1: Present Fault Levels

Buchanana-Aylemr-Tillsonburg	*Fault Levels (kA)*			
	Symmetrical		*Asymmetrical*	
	3-Phase	*L-G*	*3-Phase*	*L-G*
Buchanan 230 kV	30.13	25.44	33.05	28.39
Buchanan 115 kV	23.65	27.81	29.63	33.57
Tillsonburg 115 kV	2.48	2.72	2.52	2.83
Tillsonburg 34.5 kV	6.40	6.62	6.67	7.14
Aylmer 115 kV	2.93	2.53	2.95	2.55
Aylmer 34.5 kV	4.21	4.82	4.46	5.27

The short-circuit study results in Table 1 above also assumes the following:

- Base case assumes existing & committed generating facilities in-service.
- Pre-fault voltage of 250 kV, 127 kV, and 29 kV were assumed for the 230 kV, 115 kV, and 34.5 kV stations.

3.2 The Incorporation of ESWF

Short-circuit studies were carried out for both GE and VESTA wind turbine generator models and the study results are summarized in Tables 2A and 2B below.

Table 2A: Incorporation of ESWF with GE Wind Turbine Generator Units

Huron-Area Customers	*Fault Levels (kA)*				*Percentage Increase (%)*	
	Symmetrical		*Asymmetrical*		*Symmetrical*	
	3-Phase	*L-G*	*3-Phase*	*L-G*	*3-Phase*	*L-G*
Buchanan 230 kV	30.59	25.68	33.56	28.66	1.53	0.94
Buchanan 115 kV	24.56	28.67	30.77	34.12	3.85	3.09
Tillsonburg 115 kV	3.60	3.91	3.70	4.07	45.16	43.75
Tillsonburg 34.5 kV	8.35	7.89	8.84	8.76	30.47	19.18
Aylmer 115 kV	3.70	2.97	3.73	2.99	26.28	17.39
Aylmer 34.5 kV	4.53	5.11	4.88	5.67	7.60	6.02

Note : Percentage (%) increase is based on Table 1 Base Case values

Table 2B: Incorporation of ESWF with VESTA Wind Turbine Generator Units

Huron-Area Customers	*Fault Levels (kA)*				*Percentage Increase (%)*	
	Symmetrical		*Asymmetrical*		*Symmetrical*	
	3-Phase	*L-G*	*3-Phase*	*L-G*	*3-Phase*	*L-G*
Buchanan 230 kV	30.54	25.66	33.50	28.64	1.36	0.86
Buchanan 115 kV	24.46	28.58	30.65	34.01	3.42	2.77
Tillsonburg 115 kV	3.44	3.79	3.53	3.95	38.71	39.34
Tillsonburg 34.5 kV	8.10	7.75	8.58	8.60	26.56	17.07
Aylmer 115 kV	3.57	2.93	3.59	2.95	21.84	15.81
Aylmer 34.5 kV	4.50	5.08	4.85	5.64	6.89	5.39

Note : Percentage (%) increase is based on Table 1 Base Case values

Tables 2A and 2B are included in the Report for completeness. While the results show close to 30% increase in short-circuit level at Tillsonburg 34.5kV, the actual increase is less than 2.3 kA and raises the maximum level to only 8.84 kA. This is well below the rated capability of the facilities at Tillsonburg.

The short-circuit study results show that the increase in the short-circuit levels are small (less than 2.3 kA) and within the capability of the existing Hydro One facilities. Since the existing short-circuit levels at Aylmer and Tillsonburg are low and the actual increases are small, it can be concluded that the incorporation of Erie Shores Wind Farms will have no adverse impact on the short-circuit levels for customers supplied at these stations.

4.0 Voltage Performance Analysis

Load flow studies were carried out to assess local voltage performance with the incorporation of 99 MW wind power generation near the Tillsonburg TS. The major study area encompassed the Buchanan TS, Aylmer TS and Tillsonburg TS. Only the peak load was assessed (Aylmer 11.4 MW, 4.4 MVAR and Tillsonburg 98 MW, 36 MVAR). However, the 220 kV system at Buchanan was stressed at two BLIP levels (around -1500 and 3000 MW).

The ESWF was assumed to provide voltage support of close to 120 kV on the high side of the 34.5/115 kV step-up transformer.

With respect to local voltage decline, the loss of the 99 MW wind turbine was deemed to be the most critical contingency for the customers at Aylmer TS and Tillsonburg TS.

The two new transformers were assumed in service at Tillsonburg TS.

Table 3: 2-TRFR @ TILLSONBURG...
Voltage Comparison for Single Contingency
Loss of ESWF WTG

BLIP -1500

Station Bus	*Customer Voltage (kV)[2] At the Point of Connection*		*Voltage Decline (%)[1] For Loss of ESWF Generation*	
		Proposed ESWF WTG		*Proposed ESWF WTG*
BUCHANAN 220	-	233.10	-	0.64%
BUCHANAN118.05	-	124.80	-	0.96%
AYLMER 118.05	-	121.20	-	4.04%
AYLMER 34.5	-	28.80	-	3.13%
TILSONBG118.05	-	118.50	-	5.06%
TILSONBG34.5	-	27.70	-	-2.53%

BLIP 3000

Station Bus	*Customer Voltage (kV)[2] At the Point of Connection*		*Voltage Decline (%)[1] For Loss of ESWF Generation*	
		Proposed ESWF WTG		*Proposed ESWF WTG*
BUCHANAN 220	-	237.5	-	0.38%
BUCHANAN118.05	-	125.9	-	0.64%
AYLMER 118.05	-	121.9	-	3.36%
AYLMER 34.5	-	28.9	-	2.08%
TILSONBG118.05	-	118.8	-	4.12%
TILSONBG34.5	-	27.5	-	-1.82%

Note: (1) After *under-load tap-changer* (ULTC) operation to restore low tension-load bus voltages
(2) Customer bus voltages are monitored at the points of connections.

Load flow studies thus confirmed that the incorporation of 99 MW of wind turbine generation near Tillsonburg TS will have no adverse impact to the customers supplied from the Buchanan TS, via the 115 kV circuits W8T. The voltage declines are well within the guideline of 5% or less voltage drop (following the loss of the ESWF) at Aylmer and Tillsonburg 34.5 kV buses.

As shown in Table 3 the most severe voltage profile is at peak load with BLIP at -1500. Under such condition, approximately 24 MVAR of additional shunt capacitor, will maintain similar voltage profile at Tillsonburg TS (on the 115 kV side) when the ESWF is offline (no MW output) compared to online. The additional MVAR can be connected on the Tillsonburg 34.5 kV bus or on the ESWF main 34.5 kV bus. This confirms the findings in the SIA.

5.0 REACTIVE POWER REQUIREMENT

Wind farms (WF) systems are highly inductive, as there are many step-up transformers. When a WF is generating power the inherent inductive load is compensated within the WF system. However, when the WF is not producing any power, the wind farm acts as an inductive load to the system (Hydro One) it is connected to. This may drag the voltage at a lower level at the connecting point, compared to having no WF connected.

The difference in voltage between V_0 (without the WF system connected) and V_i (with the WF system connected but at 0 MVA output) is the required reactive power compensation.

In this assessment, the reactive power requirement was not performed, as the equivalent (or detailed) inductive load of the ESWF system was not available. However, it is believed that the 24 MVAR of additional shunt capacitor at Tillsonburg 34.5 kV bus or at ESWF's Port Burwell substation – as recommended in the SIA – will be adequate.

6.0 W8T LINE RATING (115 KV CIRCUIT)

The ESWF can, in theory, provide 99 MW on W8T (WT1T) towards Buchanan 115 kV TS, if the Tillsongurg TS is offline. The lowest line rating on the existing W8T (WT1T) is the section between Cranberry Junction and Tillsonburg TS (see Figure 1). This line section is rated at 160 MVA continuous. Therefore, the proposed 100 MW ESWF will not exceed the ampacity of the existing circuit W8T.

7.0 CUSTOMER RELIABILITY

While the proposed ESWF will provide additional voltage support to Aylmer and Tillsonburg TS, the added 30 kilometers length will expose circuit W8T (WT1A and WT1T) to more line faults. This will affect the reliability at Aylmer and Tillsonburg TS.

To mitigate the reduced reliability at Aylmer and Tilssonburg TS, a circuit breaker - instead of a circuit switcher as proposed in the SIA - is REQUIRED near Tillsonburg TS (1.5 Km) along with the associated protection facilities to isolate faults on the new line section. See Figure 2.

8.0 CONCLUSIONS AND RECOMMENDATIONS

This Customer Impact Assessment (**CIA**) Report presents results of short-circuit and voltage performance study analyses. ESWF is REQUIRED to install the following facility as part of their connection:

- A circuit breaker near Tillsonburg and associated protection facilities are required to isolated faults on the new line section. Otherwise, the reliability at Aylmer and Tillsonburg TS is drastically reduced.

Figure 2 depicts Hydro One's additional requirements.

With the added 24 MVAR at Tillsonburg TS or at ESWF's Port Burwell substation - as recommended in the SIA - the Report has confirmed the ESWF can be incorporated, without any adverse impact to the customers connected to Aylmer and Tillsonburg TS, provided that the REQUIRED facility is installed.

Figure 1 : AIM's PROPOSAL

Buchanan , Aylmer, Tillsonburg, & ESWF One Line Diagram

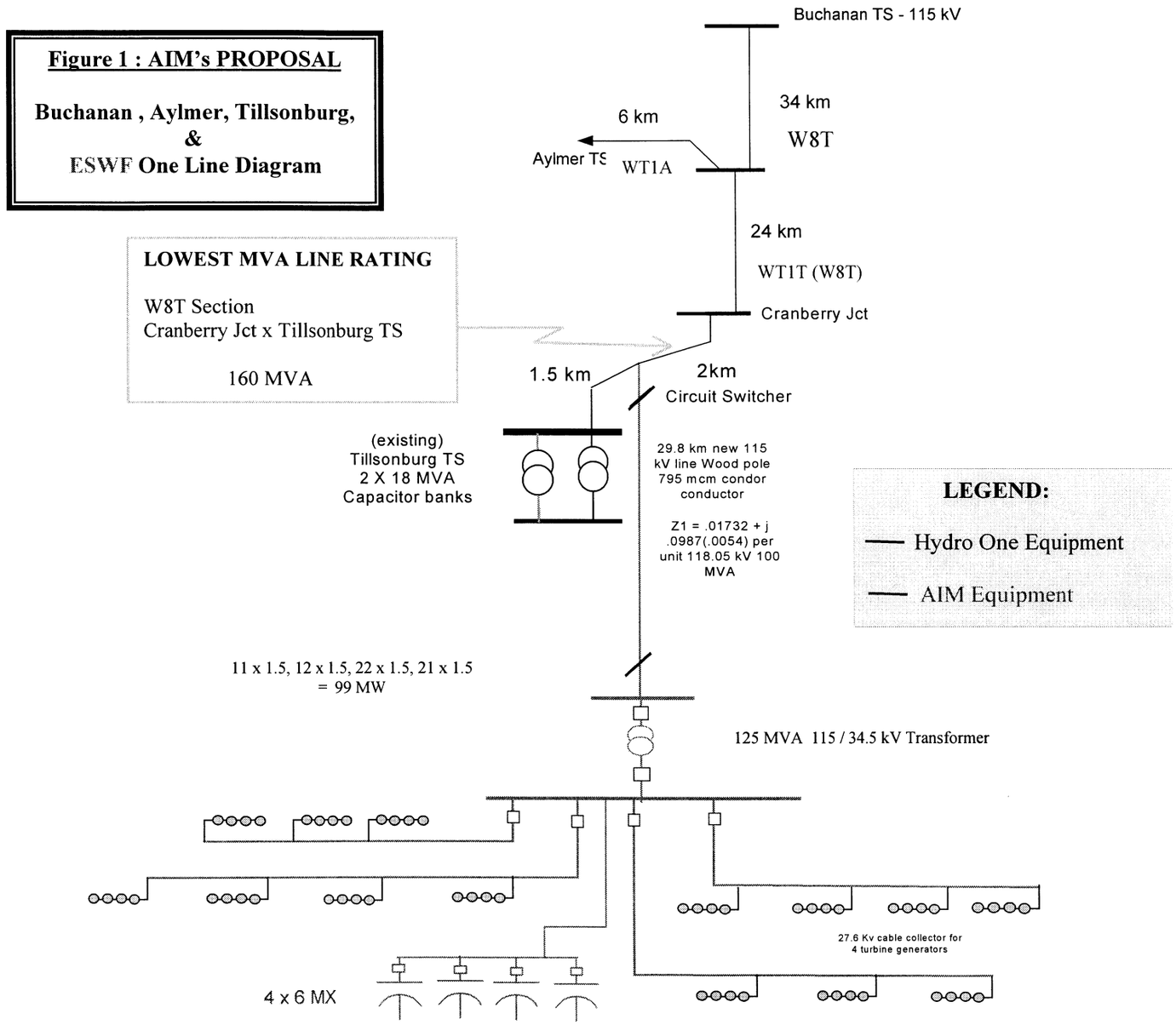
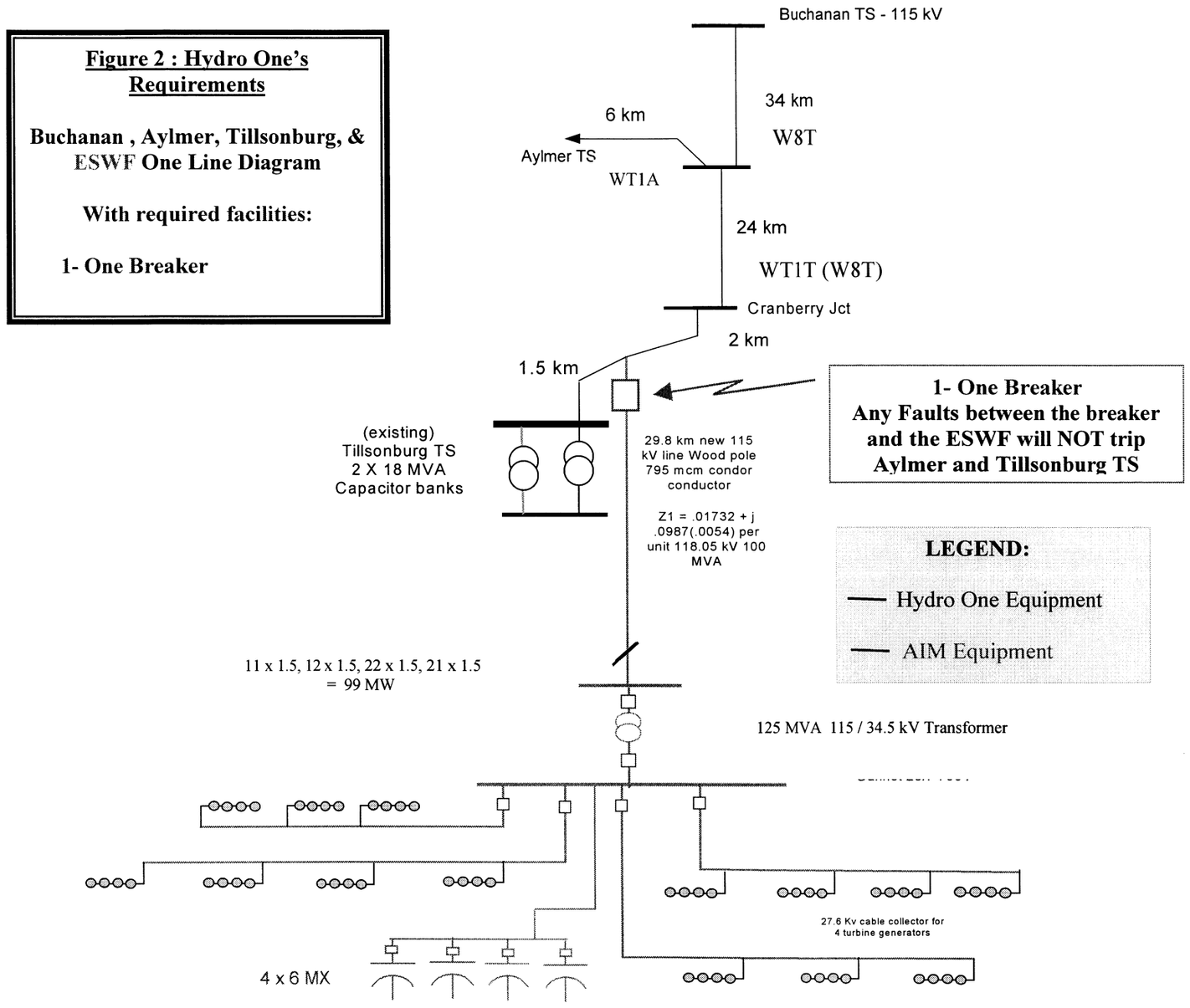


Figure 2 : Hydro One's Requirements

Buchanan , Aylmer, Tillsonburg, & ESWF One Line Diagram

With required facilities:

1- One Breaker



APPENDIX A

AIM-ESWF Wind Turbine Generator

Double Wound Induction Generator Parameters per unit on Machine Base

Machine Rating and MVA base 1.667 MVA, 0.575 kV
Power Factor 0.9 lagging (exporting MVAR) to 0.9 Leading

Stator resistance	R_A =	0.00706	
Stator leakage reactance	X_A =	0.1714	
Magnetizing reactance	X_m =	2.904	
Rotor resistance	R1 =	0.005	
Rotor reactance	X1=	0.1563	
Voltage	U =	0.575	V
Frequency	f =	60	Hz
Inertia of Generator only		0.62 seconds	

The GE Double Wound Induction Generator has rotor voltage control to control power output and reactive power output which has been modeled. The Wind Turbine and its controls are also modeled. All these controls and the associated data are contained in Appendix A of the Main SIA Report.

Dynamics Data for Induction Generator (Simplified Model for GE 1.5 MWCIMTR3) Per Unit on Machine Base 1.667 MVA 575 V

Transient open-circuit time constant	T' =	0.073	sec
Sub-transient open-circuit time constant	T" =	0.016	sec
Inertia constant	H =	0.62	sec (generator only)
	H =	6.4	sec (generator + turbine)
Synchronous reactance	X =	3.29	p.u.
Transient reactance	X' =	0.3	p.u.
Sub-transient reactance	X" =	0.2	p.u.
Leakage reactance	X_l =	0.09	p.u.
Saturation	E_l =	1.0	
Saturation	$S(E_l)$ =	0.1	
Saturation	E_2 =	1.2	
Saturation	$S(E_2)$ =	0.4	

Operating Data for 1.5MW, 1.667 MVA 575V, 60 Hz Double Wound Induction Generator

Machine Rating and MVA base 1.667 MVA, 0.575 kV
Power Factor 0.9 lagging (exporting MVAR) to 0.9 Leading

Tillsonburg Hydro Inc.
Lost Revenue Adjustment Mechanism and Shared Savings Mechanism Claims

Lost Revenue Adjustment Mechanism

Program		Savings			Average Monthly Savings			Variable Distribution Rates			Lost Revenue			
		2005	2006	2007	2005	2006	2007	2005	2006	2007	2005	2006	2007	TOTAL
Eligible Programs - 2005														
Program 1 - savings in kWh		119,897	119,897	119,897	9,991.42	9,991.42	9,991.42	0.014	0.0158	0.0159	$1,119	$1,822	$1,902	$4,844
Years of savings	4													
Benefitting class	Residential													
Eligible Programs - 2006														
Program 1 - savings in kWh			162,151	162,151	0.00	13,512.58	13,512.58	0.014	0.0158	0.0159		$2,465	$2,573	$5,037
Years of savings	4													
Benefitting class	Residential													
Program 2 - savings in kWh			16,397	16,397	0.00	1,366.42	1,366.42	0.014	0.0158	0.0159		$249	$260	$509
Years of savings	4													
Benefitting class	Residential													
Program 3 - savings in kWh			1,039,727	1,039,727	0.00	86,643.92	86,643.92	0.014	0.0158	0.0159		$15,804	$16,497	$32,301
Years of savings	4													
Benefitting class	Residential													
Eligible Programs - 2007										0.0159		$0		$0
Program 1 - savings in kWh	4													
Years of savings														
Benefitting class	Residential													
TOTAL		119,897	1,338,172	1,338,172							$1,119	$20,340	$21,232	**$42,692**

Shared Savings Mechanism

Program		Net Benefits			SSM Factor			Shared Savings Mechanism			
		2005	2006	2007	2005	2006	2007	2005	2006	2007	TOTAL
Eligible Programs - 2005											
Program 1		$60,332			5%			$3,017			$3,017
Benefitting class	Residential										
Eligible Programs - 2006											
Program 2			$19,534			5%			$977		$977
Benefitting class	Residential										
Program 3											
Benefitting class	Residential										
TOTAL		$60,332	$19,534					$3,017	$977		$3,993
								$4,136	$21,317	$21,232	$46,685

Carrying Charges	Eligible Amount			Rate			Carrying Charges			
	2005	2006	2007	2005	2006	2007	2005	2006	2007	TOTAL
	$4,136	$21,317	$21,232	7.25%	4.69%	4.08%	300	1,000	1,905	3,204

	2005	2006	2007	TOTAL
TOTAL	**$4,435**	**$22,317**	**$23,137**	**$49,889**

Discussion of the Balances Recorded in the Accounts to be Disposed of Through Rates in the 2009TY

Please refer to E5/T1/S2 for a discussion of the proposed balances to be recovered through rate riders in the 2009TY.

2009 Rate Rider

THI proposed 2009TY Rate Riders are provided at E5/T1/S1/p1.

The proposed rate riders were derived as follows:

- The accounts to be disposed of as of December 31, 2007 were identified;
- The balances were adjusted as discussed at E5/T1/S2;
- The account balances were allocated to specific customer classes consistent with the Board's Decision in the Regulatory Assets Phase 2 Decision;
- The amounts to be recovered from each customer class were applied against the volumetric charge parameter to estimate the rate rider.

THI considered the impact of recovering the balances recorded over one year versus two years and proposes a two year recovery period to mitigate bill impacts. The detailed derivation of the proposed rate riders is provided at E5/T1/S2/AttH.

Other Amounts to be Recovered Through 2009TY Rate Riders

Consistent with the Board's recent 2008 rate rebasing decisions, THI proposes to charge a 2009 Smart Meter Rate Adder of $1.00/metered-customer/month.

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C7 Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Residential	General Service < 50 kW	General Service >50 kW, <500 kW	General Service >500 kW, <5,000 kW
1505-Unrecovered Plant and Regulatory Study Costs						
1508-Other Regulatory Assets	90,204	Distribution Revenue (existing rates)	56,836	15,349	6,482	
1510-Preliminary Survey and Investigation Charges		Distribution Revenue (existing rates)				
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail						
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits	14,768	Customers / Connections	12,992	1,380	156	
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-RCVASTR						
1550-LV Variance Account						
1555-Smart Meters Capital Variance Account						
1556-Smart Meters OM&A Variance Account						
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes						
1563-Account 1563 - Deferred PILs Contra Account						
1565-Conservation and Demand Management Expenditures and Recoveries						
1566-CDM Contra Account						
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS						
1582-RSVAONE-TIME						
1584-RSVANW						
1586-RSVACN						
1588-RSVAPOWER						
1592-2006 PILs/Taxes Variance						
2425-Other Deferred Credits	52,430		52,430			
Sub-Total for recovery	**157,402**		**122,257**	**16,729**	**6,638**	

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C7 Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Sentinel Lighting	Street Lighting	Unmetered Scattered Load	General Service >500 kW, <1,500 kW
1505-Unrecovered Plant and Regulatory Study Costs						
1508-Other Regulatory Assets	90,204	Distribution Revenue (existing rates)		1,155	701	5,111
1510-Preliminary Survey and Investigation Charges		Distribution Revenue (existing rates)				
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail						
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits	14,768	Customers / Connections		2	212	17
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-RCVASTR						
1550-LV Variance Account						
1555-Smart Meters Capital Variance Account						
1556-Smart Meters OM&A Variance Account						
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes						
1563-Account 1563 - Deferred PILs Contra Account						
1565-Conservation and Demand Management Expenditures and Recoveries						
1566-CDM Contra Account						
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS						
1582-RSVAONE-TIME						
1584-RSVANW						
1586-RSVACN						
1588-RSVAPOWER						
1592-2006 PILs/Taxes Variance						
2425-Other Deferred Credits	52,430					
Sub-Total for recovery	**157,402**			1,157	914	5,129

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C7 Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	General Service >1,500 kW	General Serfvice > 500 kW, <3,000 kW	General Service >3,000 kW
1505-Unrecovered Plant and Regulatory Study Costs					
1508-Other Regulatory Assets	90,204	Distribution Revenue (existing rates)	4,569		
1510-Preliminary Survey and Investigation Charges		Distribution Revenue (existing rates)			
1515-Emission Allowance Inventory					
1516-Emission Allowances Withheld					
1518-RCVARetail					
1520-Power Purchase Variance Account					
1525-Miscellaneous Deferred Debits	14,768	Customers / Connections	9		
1530-Deferred Losses from Disposition of Utility Plant					
1540-Unamortized Loss on Reacquired Debt					
1545-Development Charge Deposits/ Receivables					
1548-RCVASTR					
1550-LV Variance Account					
1555-Smart Meters Capital Variance Account					
1556-Smart Meters OM&A Variance Account					
1560-Deferred Development Costs					
1562-Deferred Payments in Lieu of Taxes					
1563-Account 1563 - Deferred PILs Contra Account					
1565-Conservation and Demand Management Expenditures and Recoveries					
1566-CDM Contra Account					
1570-Qualifying Transition Costs					
1571-Pre-market Opening Energy Variance					
1572-Extraordinary Event Costs					
1574-Deferred Rate Impact Amounts					
1580-RSVAWMS					
1582-RSVAONE-TIME					
1584-RSVANW					
1586-RSVACN					
1588-RSVAPOWER					
1592-2006 PILs/Taxes Variance					
2425-Other Deferred Credits	52,430				
Sub-Total for recovery	**157,402**		**4,578**		

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C7 Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Residential	General Service < 50 kW	General Service >50 kW, <500 kW	General Service >500 kW, <5,000 kW
1590-Recovery of Regulatory Asset Balances (residual)		kWh's				
Total Recoveries Required (2 years)	**157,402**		**122,257**	**16,729**	**6,638**	
Annual Recovery Amounts	78,701		61,129	8,364	3,319	
Annual Volume			50,519,778	24,890,062	106,725	
Proposed Rate Rider			**$0.0012**	**$0.0003**	**$0.0311**	
per			kWh	kWh	kW	kW

[1] per sheet C6

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C7 Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Sentinel Lighting	Street Lighting	Unmetered Scattered Load	General Service >500 kW, <1,500 kW
1590-Recovery of Regulatory Asset Balances (residual)		kWh's				
Total Recoveries Required (2 years)	**157,402**			1,157	914	5,129
Annual Recovery Amounts	78,701			579	457	2,564
Annual Volume				3,783	546,778	72,828
Proposed Rate Rider				**$0.1530**	**$0.0008**	**$0.0352**
per			kW	kW	kWh	kW

[1] per sheet C6

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C7 Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	General Service >1,500 kW	General Serfvice > 500 kW, <3,000 kW	General Service >3,000 kW
1590-Recovery of Regulatory Asset Balances (residual)		kWh's			
Total Recoveries Required (2 years)	**157,402**		**4,578**		
Annual Recovery Amounts	78,701		2,289		
Annual Volume			156,866		
Proposed Rate Rider			**$0.0146**		
per			kW	kW	kW

[1] per sheet C6

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C7 Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Residential	General Service < 50 kW	General Service >50 kW, <500 kW	General Service >500 kW, <5,000 kW
Allocators	**Data Source**	**2009 Projection Total**	**Residential**	**General Service < 50 kW**	**General Service >50 kW, <500 kW**	**General Service >500 kW, <5,000 kW**
Customers / Connections	C1	6,816	5,996	637	72	
kWh's	C1	220,919,016	50,519,778	24,890,062	36,783,954	
Distribution Revenue (existing rates)	C4	2,575,538	1,622,798	438,242	185,078	
Distribution Revenue (proposed rates)	F4	3,802,076	1,884,959	573,129	272,236	614,522
Transmission Connection Revenue	C2	959,263	223,820	99,006	160,173	
Approved Recoveries	C5	100.0%	47.3%	10.4%	13.9%	27.8%

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C7 Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Sentinel Lighting	Street Lighting	Unmetered Scattered Load	General Service >500 kW, <1,500 kW
Allocators	**Data Source**	**2009 Projection Total**	**Sentinel Lighting**	**Street Lighting**	**Unmetered Scattered Load**	**General Service >500 kW, <1,500 kW**
Customers / Connections	C1	6,816		1	98	8
kWh's	C1	220,919,016		1,310,738	546,778	33,649,353
Distribution Revenue (existing rates)	C4	2,575,538		32,986	20,027	145,944
Distribution Revenue (proposed rates)	F4	3,802,076	3,502	25,472	25,472	128,954
Transmission Connection Revenue	C2	959,263		4,662	2,062	148,875
Approved Recoveries	C5	100.0%	0.1%	0.2%	0.5%	

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C7 Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	General Service >1,500 kW	General Serfvice > 500 kW, <3,000 kW	General Service >3,000 kW
Allocators	**Data Source**	**2009 Projection Total**	**General Service >1,500 kW**	**General Serfvice > 500 kW, <3,000 kW**	**General Service >3,000 kW**
Customers / Connections	C1	6,816	4		
kWh's	C1	220,919,016	73,218,353		
Distribution Revenue (existing rates)	C4	2,575,538	130,464		
Distribution Revenue (proposed rates)	F4	3,802,076	273,828		
Transmission Connection Revenue	C2	959,263	320,665		
Approved Recoveries	C5	100.0%			

Amounts to be recovered through Rate Adders in the 2009TY

THI seeks Board authorization to recover a 2009TY Smart Meter Rate Adder of $1.00/metered-customer/month.

THI is actively preparing to procure and deploy Smart Meters throughout its service area. For example, the Town of Tillsonburg, acting on THI's behalf, is a member of the London Hydro RfP for Smart Meters and was also a member of the CODAC group that is procuring and commissioning CISs capable of applying time of use commodity prices to metered time of day data.

THI is aware that some distributors have recently been authorized to charge SMRA of $1.00/metered-customer/month and seeks similar treatment. If THI is authorized to charge a 2009SMRA in this amount it does not anticipate that its customers will experience rate shock and it will have access to increased financial resources to appropriately support this activity.

Method of Recovery

THI proposes to recover the balances recorded in the variance and deferral accounts through rate riders that are to be charged for 2 years, being the 2009TY and 2010RY. The proposed rate riders are provided at E5/T1/S1/p1.

Overview of Cost of Capital and Return

THI seeks to recover $636k through distribution rates in the 2009TY for deemed interest expense and allowed return on equity. THI has relied on the Board's capital structure and cost of capital policies to derive its proposed 2009TY cost of capital.

The purpose of this evidence is to:

- Provide a high level summary of THI's submission;
- Estimate the amount to be recovered through rates for the deemed cost of hypothetical debt;
- Estimate the amount to be recovered through rates for the allowed return on equity, based on the Board's hypothetical capital structure; and
- Summarize and discuss the reasons for year over year changes in the cost of capital for rate making purposes.

Summary

THI proposes to recover $636k or a weighted average cost of capital of 7.11% through its 2009TY rates. The derivation of these amounts is provided in table 1 below.

Table 1 – Derivation of 2009TY cost of capital

	2009 TY				
Capitalization		Cost Rates		Costs	
Short Term Debt	$357,883	k(STD)	4.47%	Short Term Debt	$15,997
Long Term Debt	$4,712,427	k(LTD)	6.10%	Long Term Debt	$287,458
Total Debt	$5,070,310	WAk(D)	5.98%	Total Debt	$303,455
Equity	$3,876,770	RoE	8.57%	Equity	$332,239
Total Capitalization	$8,947,080			Total Cost	$635,695

THI is 100% equity financed; this is set out in the 2007 audited Financial Statements (E1/T3/S2/AttA). THI has remained 100% equity financed since its formation in 2000 and has never paid a dividend to its parent.

THI has not entered into any long term debt instruments and has two credit facilities, as follows;

- A Letter of Credit in the amount of $956,406 with a Schedule A bank that secures its prudential obligations to the Independent Electricity System Operator; and
- A Line of Credit in the amount of $500,000 also with a Schedule A bank.

The Line of Credit has not been drawn upon to date.

Both credit facilities are secured by a general security agreement over THI's distribution assets and are the subject of restrictive covenants. THI pays a $50/month administration fee and an annual stamping charge of 0.75% with respect to the Letter of Credit. In the 2009TY THI estimates that it will incur approximately $10k in fees related to these credit facilities.

For rate making purposes for the 2009TY, THI adheres to the Board's policy on the cost of capital and capital structure.

2009TY Cost of Capital

THI proposes to rely on a weighted average cost of capital of 7.11% for rate making purposes for the 2009TY, it is derived in Table 2 below.

Table 2 – derivation of 2009TY Weighted Average Cost of Capital

	Capital Structure		Cost Rates		Weighted Costs
STDR	4.00%	k(STD)	4.47%	STDR	0.18%
LTDR	52.67%	k(LTD)	6.10%	LTDR	3.21%
DR	56.67%	WAk(D)	5.98%	DR	3.39%
CER	43.33%	RoE	8.57%	CER	3.71%
Total	100.00%			Total	7.11%

Cost of Debt

Long Term Debt

For rate making purposes, THI proposes to recover $287k through distribution rates in the 2009TY for the deemed cost of hypothetical long term debt.

As discussed previously, THI does not have any third party debt – provided by either an affiliated entity or an at arm's length entity. For rate making purposes for the 2009TY, THI has relied on the Board's policy and adopted the hypothetical long term debt ratio of 52.67% and the Board's deemed cost of long term debt of 6.1%. THI undertakes to update this evidence and all associated and consequential schedules supporting the proposed distribution rates when the Board next updates the parameters of its Cost of Capital and Capital Structure policies.

THI proposes this treatment so that its distribution rates are set at just and reasonable levels. Adopting the Board's policies also improves comparability between the rates THI proposes to charge its customers and those paid by rate payers in the neighbouring communities served by the adjacent distributor.

Short Term/Unfunded Debt

For rate making purposes, THI proposes to recover $16k through distribution rates in the 2009TY for the deemed cost of hypothetical short term debt. THI forecasts the cost of credit

facilities to be $10k in 2009. THI does not anticipate drawing on these credit facilities during the 2009TY.

For rate making purposes for the 2009TY, THI has relied on the Board's policy and adopted the Board's hypothetical short term debt ratio of 4% and the deemed cost of short term debt of 4.47%. THI undertakes to update this evidence and all associated and consequential schedules supporting the proposed distribution rates when the Board next updates the parameters of its Cost of Capital and Capital Structure policies.

Preference Shares

THI does not propose to include any preference share component in its hypothetical capital structure for the 2009TY. THI notes that the Board's approved policy on capital structure does not require that a preferred share component be included.

Common Equity

For rate making purposes, THI proposes to recover $332k of Net Income through distribution rates in the 2009TY. This amount is computed based on the Board authorized return on equity and common equity ratio.

THI's actual common equity ratio is 100%. THI has been 100% equity financed since it was formed in 2000, upon the dissolution of the former Tillsonburg PUC. Because THI's shareholders have not received dividend payments from THI, the LDC has full access to internally generated funds.

Return on Common Equity

THI proposes that its distribution rates for the 2009TY be set at a level that will permit an opportunity to earn a return on equity of 8.57%. This is consistent with the Board's approved policy. THI undertakes to update all necessary and appropriate schedules when the Board next updates the allowed return on equity.

Calculation of Cost by Item from Test Year

Please refer to E6/T1/S1/p1.

Justification of Forecast Costs by Item (Including Economic Assumptions)

THI has relied on the Board's letter of March 7, 2008, corrected March 12, 2008, that sets out the updated cost of long term debt, cost of short term debt and maximum allowed return on equity. The economic assumptions supporting these determinations are identified in the letter.

Profit and Loss on Redemption of Debt and/or Preference Shares

Please note that THI has not issued debt or preference shares.

Consensus Forecasts – Government of Canada Bond Yields

Please see the Consensus Forecast Report for February, 2008.

Calculation of Return on Equity and Debt

THI proposes that the allowed return on equity for the 2009TY be set at 8.57%, consistent with Board policy; THI undertakes to update this data and all associated schedules supporting the proposed distribution rates when the Board next updates the allowed return on equity and cost of debt.

2008 Bridge Year Cost of Capital

THI's cost of capital for the 2008BY is estimated to be $607k or 7.19%; its derivation is provided in Table 3 below.

Table 3 - 2008BY Cost of Capital

Capitalization	2008 BY	Cost Rates		Costs	
Short Term Debt	$337,788	k(STD)	4.47%	Short Term Debt	$15,099
Long Term Debt	$4,166,616	k(LTD)	6.10%	Long Term Debt	$254,164
Total Debt	$4,504,404	WAk(D)	5.98%	Total Debt	$269,263
Equity	$3,940,298	RoE	8.57%	Equity	$337,684
Total Capitalization	$8,444,703			Total Cost	$606,946

Capital Structure	2008 BY	Cost Rates		Weighted Costs	
STDR	4.00%	k(STD)	4.47%	STDR	0.18%
LTDR	49.34%	k(LTD)	6.10%	LTDR	3.01%
DR	53.34%	WAk(D)	5.98%	DR	3.19%
CER	46.66%	RoE	8.57%	CER	4.00%
Total	100.00%			Total	7.19%

All capitalization amounts are computed using THI's proposed rate base and the Board's hypothetical capital structure. All costs have been determined using Board authorized cost rates.

THI's actual cost of capital is estimated to be $10k, the cost of THI's credit facilities which are unchanged since the facilities were first entered into.

THI's cost of capital for the 2009TY is $29k greater than that of the 2008BY and is due to:

- an $502k increase in capital due to increased rate base that causes an overall increase of $36k; and
- changes in the hypothetical capital structure (specifically an increase to the long term debt component from 46% to 52.67% and a reduction to the common equity ratio from 50% to 43.3%) that causes a $7k decrease in the cost of capital.

2007 Historic Year Cost of Capital

THI's deemed cost of capital for the 2007AY is estimated to be $665k or 8.13%; the derivation of these amounts is set provided in table 4 below.

Table 4 – 2007AY Cost of Capital

2007 AY					
Capitalization		Cost Rates		Costs	
Short Term Debt	$0	k(STD)	0.00%	Short Term Debt	$0
Long Term Debt	$4,090,444	k(LTD)	7.25%	Long Term Debt	$296,557
Total Debt	$4,090,444	WAk(D)	7.25%	Total Debt	$296,557
Equity	$4,090,444	RoE	9.00%	Equity	$368,140
Total Capitalization	$8,180,887			Total Cost	$664,697

2007 AY					
Capital Structure		Cost Rates		Weighted Costs	
STDR	0.00%	k(STD)	0.00%	STDR	0.00%
LTDR	50.00%	k(LTD)	7.25%	LTDR	3.63%
DR	50.00%	WAk(D)	7.25%	DR	3.63%
CER	50.00%	RoE	9.00%	CER	4.50%
Total	100.00%			Total	8.13%

All capitalization amounts are computed using THI's actual rate base and the Board's hypothetical capital structure. All costs have been determined using Board authorized cost rates.

THI incurred an actual cost of capital of $10k in 2007, being the costs of the credit facilities originally entered into in 2005.

The deemed cost of capital for the 2007AY is $58k greater than that of the 2008BY. This is due to:

- a $264k increase in rate base;
- the introduction of a short term debt component to the hypothetical capital structure at 4.47% that results in $15k of return;

- changes to the deemed cost of long term debt and to the long term debt rate that in combination reduces the overall cost of debt by $27k; and
- changes to the allowed return on equity that in combination with the reduced common equity ratio reduces the cost of capital by $30k.

2006 Historic Year Cost of Capital

THI's deemed cost of capital for the 2006AY is estimated to be $652k or 8.13%; the derivation of these amounts is set out in table 5 below.

Table 5 – 2006AY Cost of Capital

Capitalization		Cost Rates			2006 AY Costs
Short Term Debt	$0	k(STD)	0.00%	Short Term Debt	$0
Long Term Debt	$4,013,917	k(LTD)	7.25%	Long Term Debt	$291,009
Total Debt	$4,013,917	WAk(D)	7.25%	Total Debt	$291,009
Equity	$4,013,917	RoE	9.00%	Equity	$361,253
Total Capitalization	$8,027,834			Total Cost	$652,262

	Capital Structure	Cost Rates			2006 AY Weighted Costs
STDR	0.00%	k(STD)	0.00%	STDR	0.00%
LTDR	50.00%	k(LTD)	7.25%	LTDR	3.63%
DR	50.00%	WAk(D)	7.25%	DR	3.63%
CER	50.00%	RoE	9.00%	CER	4.50%
Total	100.00%			Total	8.13%

All capitalization amounts are computed using THI's proposed rate base and the Board's hypothetical capital structure. All costs have been determined using Board authorized cost rates.

THI incurred an actual cost of capital of $10k in 2006, being the costs of the credit facilities originally entered into in 2005.

The deemed cost of capital for the 2006 AY is $12k less than that of the 2007 AY. This is due to a $153k increase in rate base that at the allowed return of 8.13% yields $12k.

2006 EDR Cost of Capital

THI's deemed cost of capital for rate making purposes in 2006 as determined by the Board was $668k or 8.13%. The derivation of this data is set out in table 6 below.

Table 6 – 2006EDR Cost of Capital

Capitalization		Cost Rates			2006 EDR Costs
Short Term Debt	$0	k(STD)	0.00%	Short Term Debt	$0
Long Term Debt	$4,109,023	k(LTD)	7.25%	Long Term Debt	$297,904
Total Debt	$4,109,023	WAk(D)	7.25%	Total Debt	$297,904
Equity	$4,109,023	RoE	9.00%	Equity	$369,812
Total Capitalization	$8,218,046			Total Cost	$667,716

		Cost Rates			2006 EDR Weighted Costs
STDR	0.00%	k(STD)	0.00%	STDR	0.00%
LTDR	50.00%	k(LTD)	7.25%	LTDR	3.63%
DR	50.00%	WAk(D)	7.25%	DR	3.63%
CER	50.00%	RoE	9.00%	CER	4.50%
Total	100.00%			Total	8.13%

All capitalization amounts are computed using THI's proposed rate base and the Board's hypothetical capital structure. All costs have been determined using Board authorized cost rates.

The deemed cost of capital for the 2006AY is $15k less than that of the 2006EDR. This is due to a $190k reduction in rate base that, when applied to the unchanged costs of capital, results in the computed $15k reduction.

Variance Analysis

2009TY versus 2008BY

THI's cost of capital for the 2009TY is $29k greater than that of the 2008BY and is due to:

- an $502k increase in capital due to increased rate base that causes an overall increase of $36k; and
- changes in the hypothetical capital structure (specifically an increase to the long term debt component from 46% to 52.67% and a reduction to the common equity ratio from 50% to 43.3%) that causes a $7k decrease in the cost of capital.

2008BY versus 2007AY

The deemed cost of capital for the 2007AY is $61k less than that of the 2008BY. This is due to:

- a $264k increase in rate base;
- the introduction of a short term debt component to the hypothetical capital structure at 4.47% that results in $15k of return;
- changes to the deemed cost of long term debt and to the long term debt rate that in combination reduces the overall cost of debt by $27k; and
- changes to the allowed return on equity that in combination with the reduced common equity ratio reduces the cost of capital by $30k.

2007AY versus 2006AY

The deemed cost of capital for the 2006 AY is $12k less than that of the 2007 AY. This is due to a $153k increase in rate base that at the allowed return of 8.13% yields $12k.

2006AY versus 2006EDR

The deemed cost of capital for the 2006AY is $15k less than that of the 2006EDR. This is due to a $190k reduction in rate base that, when applied to the unchanged costs of capital, results in the computed $15k reduction.

Cost of Debt

THI proposes to recover $303k in the 2009TY for the deemed cost of debt. This amount consists of $16k for the deemed cost of short term debt and $287k for the deemed cost of long term debt.

THI forecasts that it will incur a cost of $10k due to its Letter of Credit and Line of Credit.

Long Term Debt

THI forecasts hypothetical long term debt of $4,712k for the 2009TY. THI's hypothetical long term debt by year is provided in table 7 below.

Table 7 – THI's Hypothetical Long Term Debt

Year	2006EDR	2006AY	2007AY	2008BY	2009TY
Hypothetical Long Term Debt	$4,109,023	$4,013,917	$4,090,444	$4,166,616	$4,712,427

Short Term/Unfunded Debt

THI forecasts hypothetical short term debt of $358k for the 2009TY. THI's hypothetical long term debt by year is provided in table 8 below.

Table 8 – THI's Hypothetical Short Term Debt

Year	2006EDR	2006AY	2007AY	2008BY	2009TY
Hypothetical Short Term Debt	$0	$0	$0	$337,788	$357,883

Preference Shares

THI does not rely on preference shares.

Common Equity

THI forecasts hypothetical equity of $3,877k for the 2009TY. THI's hypothetical common equity by year is provided in table 9 below.

Table 9 – THI's Hypothetical Common Equity

Year	2006EDR	2006AY	2007AY	2008BY	2009TY
Hypothetical Equity	$4,109,023	$4,013,917	$4,090,444	$3,940,298	$3,876,770

Return on Equity

THI proposes that its distribution rates for the 2009TY be set at a level that will permit an opportunity to earn a return on equity of 8.57% and that will recover $332k of Net Income. This is consistent with the Board's approved policy. This amount is computed based on the Board authorized return on equity and common equity ratio. THI undertakes to update all necessary and appropriate schedules when the Board next updates the allowed return on equity.

Justification of Forecast Costs by Item (Including Economic Assumptions)

THI has relied on the Board's report on the Cost of Capital and its annual update of the cost rates for each component of the hypothetical capital structure.

Profit and Loss on Redemption of Debt and/or Preference Shares

Not applicable

Consensus Forecasts – Government of Canada Bond Yields

Please see the Consensus Forecast Report for February, 2008.

CALCULATION OF REVENUE DEFICIENCY OR SURPLUS

Overview of Utility Revenue

THI estimates that its 2008 authorized distribution rates will result in a gross revenue deficiency of $747k in the 2009TY.

The purpose of this evidence is to:

- Discuss THI's Utility Revenue;
- Summarize THI's calculated revenue deficiency and its drivers; and
- Explain the year over year changes in the revenue deficiency.

Overview of Utility Revenue

THI's annual utility revenue is provided in Table 1 below.

Table 1 – Annual Utility Revenue

	2006EDR	2006	2007	2008	2009
Revenue	1,579,935	2,469,910	2,653,899	2,541,622	2,566,138
Period Costs	1,640,574	2,024,086	2,061,274	2,168,005	2,604,896
Income before Taxes	-60,639	445,824	592,625	373,617	-38,758
PILs	7,163	122,000	187,056	79,539	0
Utility Revenue	-67,802	323,824	405,569	294,078	-38,758

Determination of Revenue Deficiency or Surplus

THI's projected 2009TY Gross Revenue Deficiency, based on projected revenues recovered through existing rates less the forecast costs of the period, will be $747k. It is derived in table 1 below.

Table 1 – Derivation of 209TY Gross Revenue Deficiency

		2009 Projection
Utility Income	*(see below)*	-38,758
Utility Rate Base	*from sheet G6*	8,947,080
Indicated Rate of Return		(0.43%)
Requested / Approved Rate of Return	*from sheet D3*	7.11%
Sufficiency / (Deficiency) in Return		(7.54%)
Net Revenue Sufficiency / (Deficiency)		-674,460
Provision for PILs/Taxes *		-72,332
Gross Revenue Sufficiency / (Deficiency)		-746,792
Deemed Overall Debt Rate	*from sheet D3*	*5.98%*
Deemed Cost of Debt	*from sheet D3*	*303,437*
Utility Income less Deemed Cost of Debt		*-342,195*
Return On Deemed Equity		*(8.83%)*
UTILITY INCOME	*from sheets E1 & E2 (except PILS / Income Taxes)*	
Total Net Revenues		2,566,138
OM&A Expenses		2,103,292
Depreciation & Amortization		501,604
Taxes other than PILs / Income Taxes		
Total Costs & Expenses		2,604,896
Utility Income before Income Taxes / PILs		-38,758
PILs / Income Taxes	*from sheet E4*	
Utility Income		-38,758

The 2009TY utility income is estimated to be $(39)k which yields a return on the 2009TY Rate Base of -0.4%. Using the Board's hypothetical capital structure and its deemed cost of short term debt, deemed cost of long term debt and allowed return on equity the allowed return on rate base is 7.11%. This results in a net deficiency of 7.54% which when applied to the 2009TY rate base yields a net revenue deficiency of $675k. Assuming that an appropriate provision for Payments in Lieu of Taxes is $72k the resulting gross revenue deficiency is $747k.

The 2009TY gross revenue deficiency is attributable to:

- the continuation of the 2008BY gross revenue deficiency of $306k;
- increased OM&A costs and depreciation expense of $437k;
- increased distribution revenues of $25k;
- reduced PILs expense of $7k; and
- increased allowed return of $36k.

Year over Year Changes

The year over year changes in the gross revenue deficiency and the significant changes that contribute to the change are summarized in table 2 below.

Table 2 – year over year changes in Gross Revenue Deficiency

	2006EDR	2006	2007	2008
Opening Deficiency	-813,789	-402,429	-334,531	-380,855
Changes				
Revenue	889,975	183,989	-112,277	24,516
Period Costs	498,349	102,244	-786	357,352
Cost of Capital	-15,455	12,436	-58,439	29,437
PILs	-4,279	1,411	-6,727	3,382
Net	411,360	67,898	-46,325	-365,654
Closing Deficiency	-402,429	-334,531	-380,855	-746,510

2006EDR to 2006AY

The gross revenue deficiency was reduced by $411k in this period due to the combined effect of:

- a $190k reduction in rate base that gives rise to a $20k reduction in allowed return and associated PILs expense;
- a $890k increase in revenues recovered through distribution rates; and
- a $498k increase in period costs.

The increase in period costs includes:

- a $114k increase in depreciation expense;
- a $256k increase in Operations costs and an overall increase in OM&A of $279k; and

- a $115k increase in PILs expense.

2006AY to 2007AY

The gross revenue deficiency was reduced by $68k in this period due to the combined effect of:

- a $184k increase in revenues recovered through distribution rates;
- changed allowed return and associated PILs expense of $14k;
- a $102k increase in period costs.

The increase in period costs are attributable to a $32k increase in depreciation expense and a $65k increase in PILs expense.

2007AY to 2008BY

The gross revenue deficiency increased to $381k. This is mainly due to:

- a reduction in distribution revenues of $112k;
- an decrease in period expenses of $1k;
- a $250k increase in Rate Base that in combination with a reduction to the allowed return on Rate Base from 8.12% to 7.18% yields a $65k decrease.

2008BY to 2009TY

The gross revenue deficiency increased to $747k. This is mainly due to:

- the continuation of the 2008BY net deficiency of $306k;
- a $25k increase in distribution revenues;
- increased period expenses of $437k;
- reduced PILs expense of $7k; and
- a $502k increase in Rate Base that in combination with a reduction to the allowed return on Rate Base from 7.18% to 7.11% yields a $36k increase.

COST ALLOCATION

Overview and Summary

THI has completed a Run 1 version of the Board's Cost Allocation Review – Informational Filing ("CAR-IF") model and has amended it to support the following proposed changes to THI's customer classes:

- partitioning the existing General Service 500 – 4,999 kW customer class into two new customers classes:
    - General Service 500 – 1,499 kW; and
    - General Service > 1,500 kW;
- A revised Unmetered Scattered Load customer class that includes the Sentinel Lighting customer class members.

The results of the CAR-IF Run 1 show that THI's Street Lighting rates are higher than they ought to be and that its General Service 500 – 4,999 kW rates are much lower than they ought to be; the rates charged all other customer classes are within or relatively close to the Board's target Revenue:Cost ratio ranges. The proposed partitioning of the General Service 500 – 4,999 kW is motivated by concerns over an existing intra-class subsidization and a lack of homogeneity among the customers included in this class. THI examined the load and consumption data of the customers in the existing General Service 500 – 4,999 kW customer class and analyzed two alternate partitions of the class – one partition at 1,500 kW, THI's proposal, and the other at 3,000 kW, THI's alternative. The proposed reclassification of the Sentinel Lighting to the Unmetered Scattered Load ("USL") customer class is motivated by homogeneity issues.

The purpose of this evidence is:

- To summarize and analyze the results of THI's Run 1 CAR-IF;
- To summarize the adjustments made to THI's Run 1 CAR-IF that support the proposed changes to the existing customer classes; and
- To summarize the adjustments made to THI's Run 1 CAR-IF that support an alternative proposal with respect to the existing customer classes.

THI's Cost Allocation Review – Informational Filing Model: Overview

As explained throughout this submission, THI has operated with very limited resources while providing service and managing operations in a safe and reliable manner. One direct consequence of having limited resources is that some administrative tasks and record keeping duties are not able to be performed; the timely submission of a completed Cost Allocation Review - Informational Filing is one example. THI proposes to recruit a Regulatory Affairs Manager in the 2008BY to overcome these deficiencies. The CAR-IF that supports this 2009TY rates application became available to THI management in the second quarter of 2008.

Overall, THI's ratepayers have benefited from low rates due to operating cost savings and the realization of economies of scale. The results of the CAR-IF demonstrate, however, that some customer classes have paid more and others less than the allocated costs incurred by THI to provide electricity distribution service. This rates application is the first opportunity to adjust distribution rates so that the revenues generated recover the costs incurred overall and on a customer class specific level.

THI's proposed changes to its existing distribution rates are provided in Exhibit 9 and are supported with information generated by the CAR-IF model and are consistent with the Board's policy on revenue-to-cost ratios. The Board's CAR-IF provides the best available information available, at this time; THI intends to validate these results in its next rate rebasing application.

Use of the CARIF Model

Pending the outcome of the Board's Fundamental Rate Review, which is not expected to be available until 2011, THI proposes to rely on the 2004 CAR-IF model and the results it generates to support its proposed rates adjustments and customer class changes.

THI assessed the relevance of relying on the 2004 CAR-IF by examining the stability of its infrastructure and operations costs, customer count and customer class shares of billed kWh and kW. THI tested whether the underlying costs and allocators are stable over the 2004-2009

period to understand whether the proportional allocation of costs to each customer class can be expected to change significantly.

The information on THI's rate base (Exhibit 2) and Operating and Maintenance costs (Exhibit 4) show that the underlying infrastructure has been stable and that operating costs are budgeted to increase in the 2009TY. Exhibit 3 shows that the customer count has also been stable. E3/T2/S1/AttA shows that the 2006 EDR Approved and 2009 forecast class shares of billed kWh and kW are stable, if the historic General Service >50kW customer class is relied on . For these reasons THI believes it is not unreasonable to rely on the revenue:cost ratios identified by the CAR-IF run on 2004 data. THI does not consider it prudent to incur costs to complete a full cost allocation study for the 2009TY because:

- the proportions of kWh and kW attributable to each rate class have not changed significantly between the 2006 EDR approved shares and the 2009TY forecast, if the historic General Service >50 kW customer class is applied;
- THI's capital costs do not exhibit material or significant discontinuities;
- THI's operating costs in the period 2004-2008 demonstrated stability;
- THI will deploy Smart Meters in 2008, 2009 and 2010 that will provide better quality data for a subsequent cost allocation study;
- time of use commodity pricing can be expected to alter demand and consumption, thereby altering allocators used in cost allocation studies;
- the Board's Rate Design Review consultation is expected to necessitate new cost allocation studies;
- Updating THI's cost allocation would require a significant investment of time and money to obtain the required data and to update the cost allocation model with 2009 forecast cost information that could quickly become stale.

THI is aware of the concerns identified by other parties of using CARIF results. However, it is the best information that could be made available at this time and it would not be practical or cost-effective for THI to under take a new cost allocation study.

THI proposes to use the 2004 CAR-IF results as an interim measure in this proceeding until it can complete a new cost study. THI notes that other distributors have relied on the 2004 CAR-IF and gained Board approval to implement the results. THI requests that the Board do the same in this case.

Summary of the CAR-IF Results

In preparing the evidence for this section of its application, THI used the Board authorized CAR-IF model to generate the revenue-to cost ratios shown in Table 8.1. These ratios were determined using worksheet O1 of the CAR-IF; it is provided at E8/T1/S1/AttA.1. Please note that this presentation relies on THI's currently authorized customer classes and is provided to facilitate comparison.

THI has determined that the results generated by the CAR-IF analysis are reasonable and able to support the proposed rate design and customer class changes. For example, the revenue-to-cost ratios determined by the CAR-IF indentifies the significant over contribution to revenues from the Street Lighting customer. As shown in E8/T1/S1/AttA.1, THI's Street Lighting customer pays almost three and a half times more than what is required to cover its allocated costs. This conclusion is sustained by an examination of THI's load and revenue data. The Street Lighting load is approximately 1.5% that of the total GS 500 – 4,999 kW customer class load while the Street Lighting revenues represent 16.8% (over ten times the load percentage) of the total revenues for GS 500 – 5,000 kW class.

THI populated the CAR-IF consistent with the Board's instructions. HONI provided load data based on THI's currently authorized customer classes. Because THI's Board approved 2006 EDR model reflects its legacy customer class structure it was necessary to adapt the information obtained from that model to populate the CAR-IF. This was achieved through the following steps:

- THI retrieved the 2004 energy and consumption data of the then 10 customers in the General Service 500 - 4,999 kW customer class;

- THI summed the energy and consumption data of the Board approved 2006 EDR model of the General Service >50 kW Regular, General Service >50 kW Time of Use and (proposed) Large User customer classes (the "Legacy Classes");
- THI took the difference of the summed Legacy Classes and the historic General Service 500 – 4,999 kW customer class and treated it as the General Service 50 – 499 kW customer class;
- THI applied the 2004 rates levels that were inputted to the 2006 EDR to derive the revenues of the currently authorized customer classes;
- Where the data from the Board approved 2006 EDR matched the data for the 2004 CAR-IF no further adjustments were made; however, where differences did occur the 2004 data was relied on to establish customer class shares that were applied to the data required to complete the 2004 CAR-IF.

New Customer Classes

General Service 500 – 1,499 kW and General Service > 1,500 kW

One area of concern that can be addressed in this application, and verified in the next rate rebasing application, is the elimination of heterogeneity and cross-subsidization within the GS 500 – 4,999 kW customer class. The load and use patterns of the customers in this class are sufficiently different to warrant creating two separate classes. To address these differences THI proposes to partition the existing customer class at 1,500 kW thereby creating two new customer classes, each being more homogeneous than the legacy customer class. For comparison purposes, an alternative was examined using a partition point of 3,000 kW,

THI examined the CAR-IF results for three different scenarios all of which are populated with the 2004 operating and financial data using the current rates from the existing GS 500 – 5,000 customer class:

- Baseline (status quo): based on the currently approved GS 500 – 5,000 kW customer class;
- THI Proposal: transferring the existing GS 500 – 5,000 kW customers into a GS 500 – 1,499 kW customer class and a GS > 1,500 kW customer class; and
- Comparison: transferring the existing GS 500 – 5,000 kW customers into a GS 500 – 2,999 kW customer class; and a GS > 3,000 kW customer class.

The CAR-IF results for the status quo, the THI proposal and the comparison are shown in Table 1 below.

Table 1

Class / Option	STATUS QUO	**THI PROPOSAL**	COMPARISON	OEB RANGE
Res	125.05	**125.98%**	125.65%	85% to 115%
GS<50	114.75	**115.14%**	114.93%	80% to 120%
GS>50-499	63.45%	**63.47%**	63.42%	80% to 180%
Proposed: GS>500-1499		**60.68%**		80% to 180%
Proposed: GS>1500		**34.26%**		80% to 180%
Alternative: GS>500-2999			49.45%	80% to 180%
Alternative : GS>3000			33.30%	80% to 180%
Existing: GS>500-5000	42.59%			80% to 180%
Street Lighting	342.92%	**342.95%**	342.92%	70% to 120%
Sentinel Lighting	130.28%		130.42%	70% to 120%
USL	78.24%		78.46%	80% to 120%
Proposed:USL & Sentinel		**74.33%**		

Table 2 below summarizes data on the General Service 500 – 4,999 kW customer class based on 2004 data.

Table 2

			Range Data	
Number of Customers	Metric	Average	Low	High
	kW	1,851 kW	517 kW	5,503 kW
GS 500 – 4,999 kW	Power Factor	88%	83%	90+%
GS 500 – 4,999 kW	Hours of Operation	65%	65%	65%
Proposed GS 500 – 1,499 kW	kW	3,273 kW		
	% of kW	70.7%	29.7%	8.9%
Proposed GS 500 – 1	Power Factor	89%		
Proposed GS 500 – 1	Hours of Operation			
	kW	902 kW	517 kW	1,070 kW
Proposed GS > 1	% of kW			
Proposed GS > 1	Power Factor	83%		
Proposed GS > 1	Hours of Operation	65%	65%	65%

The need for the customer class separation is also verified by the computed revenue-to-cost ratios. The current revenue:cost ratio for the existing GS 500 – 4,999 kW customer class is 42.59%. The ratios of the proposed GS 500 – 1,499 kW and GS > 1,500 kW customer classes are 60.68% and 34.26% respectively. The 1.75:1 ratio of the respective revenue to cost ratios indicates that the GS 500 – 1,499 kW customers are contributing nearly twice as much revenue towards their allocated costs as the GS > 1,500 kW customers are, thereby demonstrating the significance of the intra-class subsidization.

Another way of demonstrating the significance of inter-class subsidization is to compare the rate increases that would be required to bring the revenue-to-cost ratios of the two proposed customer classes to unity, using the rates currently approved for the GS 500 – 5,000 kW customers class. The rates for the proposed GS 500 – 1,500 kW class would need to increase by 150% while the rates for the proposed GS > 1,500 kW class would need to increase 300%, - twice as much on a percentage basis.

THI has made adjustments to the 2004 load, consumption and customer count of the GS 500 – 5,000 kW customer class to partition it into a GS 500 – 1,500 kW customer class and a GS > 1,500 kW customer class. THI reviewed its 2004 energy and demand data for the subject 10 customers. These customers were separated into two groups based on metered demand; one group having demand <1,500 kW and >500 kW and the other having demand >1,500kW. The Coincident Peak and Non-Coincident Peak data for the General Service 500 – 4,999 kW customer class provided by THI's load data service provider was prorated based on the kW shares of the two groups. When completing the adjustments to the CAR-IF THI assumed that the four largest customers had the most expensive meters and required the most expensive metering service.

Comparison with Partition at 3000kW

To verify the appropriateness of its recommended GS 500 – 1,500 kW customer class, THI compared it to an alternative partitioning at 3000kW. THI adjusted that data in the same manner described at E8/T1/S2/p4-5. As table 1 shows, the resulting inter-class subsidization between the two alternative customer classes increased slightly when the customer class partition was increased from 1500 kW to 3000 kW and the revenue contributions from the other customer classes increased a bit, moving most of the revenue-to-cost ratios away from the Board approved ranges and increasing the over-contribution of revenues for most customers. For these reasons, this alternative was not considered further.

Sentinel Lighting Customer Class

THI proposes to reassign its Sentinel Lighting customers to the Unmetered Scattered Load ("USL") customer class and to eliminate the Sentinel Lighting customer class. This proposal is

motivated by the perceived homogeneity between these customer classes. This proposed aggregation has three immediate benefits:

- The over contributions from the Sentinel Lighting customers will help to supplement the under contribution of the USL customers;
- customers requiring similar services will be treated in similar fashion from a ratemaking perspective; and ,
- the complexity of THI rates will be reduced by eliminating an homogeneous class.

The appropriateness of continuing this change on a permanent basis will be assessed by THI and reported to the Board in the next rebasing application pending the release of the Board's report on Fundamental Rate Design.

The loads served by these two customer classes are very similar and the distribution system infrastructure relied on to deliver power and energy is as well. Implementing this proposal will overcome customer class homogeneity issues by treating similar customers in similar fashion thereby achieving a greater level of fairness. The USL customer class generates approximately $6k of distribution revenue at currently authorized rates. Neither the USL nor the Sentinel Lighting customer class is metered. The USL class includes loads such as billboards that are conceptually similar to the loads in the Sentinel Lighting class, as well as other loads, such as battery mats, cathodic protection for buried pipelines.

Based on the load forecasts for these classes, the average bill amount to a Sentinel Lighting customer under either currently authorized Sentinel Lighting rates or currently authorized USL rates is relatively comparable. Hence, the bill impact of the proposed change should be comparable.

Table 3 Consolidation of Sentinel Lighting and USL Rates

	Sentinel Lighting	USL Rates	Proposed Rate
Monthly charges	$1.18	$12.38	$20.00
Average load	2.6 kW	952 kWh*	465 kWh
Variable rate	$7.3155/kW	$0.0100/kWh	$0.0036/kWh
Variable charge	$18.98	$9.52	$1.67
Total Distribution Charge	$20.16	$21.90	$21.67
			* 2.6 kW @ 12 hours/day @ 30.5 days/month

THI made the adjustments to the CAR-IF that support the proposed change by adding the data inputs of the currently authorized customer classes.

Proposed Method (if different from Board Approved Method)

THI does not propose any changes to the Board CAR-IF methodology. THI has altered the data available through the Board approved 2006 EDR model and for the proposed changes to customer classes.

2006 COST ALLOCATION INFORMATION FILING

7

TILLSONBURG HYDRO INC

EB-2005-0420 EB-2006-0247

January 0, 1900

Ontario

Sheet O1 Revenue to Cost Summary Worksheet - First Run THI v.1

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS 50-500 kW	7 Street Light	9 Unmetered Scattered Load	12 GS<50 kW	13 GS 500-1500 kW	14 GS >1500 kW
crev	Distribution Revenue (sale)	$2,436,569	$1,553,396	$182,169	$32,338	$15,375	$442,022	$90,697	$120,573
mi	Miscellaneous Revenue (mi)	$119,518	$86,252	$6,751	$183	$4,101	$12,198	$3,095	$6,938
	Total Revenue	$2,556,087	$1,639,647	$188,920	$32,521	$19,477	$454,220	$93,792	$127,511
	Expenses								
di	Distribution Costs (di)	$559,963	$254,688	$77,541	$2,861	$2,476	$68,513	$42,804	$111,079
cu	Customer Related Costs (cu)	$465,377	$312,271	$22,932	$42	$12,441	$104,035	$8,352	$5,303
ad	General and Administration (ad)	$468,872	$258,945	$46,078	$1,334	$6,791	$78,803	$23,469	$53,452
dep	Depreciation and Amortization (dep)	$295,849	$132,508	$42,092	$1,461	$1,252	$39,878	$22,272	$56,386
INPUT	PILs (INPUT)	$139,400	$62,436	$19,833	$689	$590	$18,790	$10,494	$26,568
INT	Interest	$256,814	$115,025	$36,538	$1,268	$1,087	$34,616	$19,333	$48,946
	Total Expenses	$2,186,275	$1,135,872	$245,014	$7,656	$24,638	$344,635	$126,725	$301,734
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$369,812	$165,636	$52,615	$1,827	$1,566	$49,847	$27,840	$70,482
	Revenue Requirement (includes NI)	$2,556,087	$1,301,508	$297,629	$9,483	$26,204	$394,482	$154,565	$372,217
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$7,504,802	$3,361,329	$1,067,747	$37,068	$31,771	$1,011,582	$564,970	$1,430,336
gp	General Plant - Gross	$0	$0	$0	$0	$0	$0	$0	$0
accum dep	Accumulated Depreciation	($1,302,387)	($583,327)	($185,297)	($6,433)	($5,514)	($175,550)	($98,045)	($248,221)
co	Capital Contribution	($538,500)	($241,184)	($76,613)	($2,660)	($2,280)	($72,595)	($40,539)	($102,632)
	Total Net Plant	$5,663,915	$2,536,818	$805,836	$27,975	$23,978	$763,436	$426,386	$1,079,482
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$15,682,815	$3,545,291	$4,276,206	$95,921	$40,474	$1,741,312	$1,582,107	$4,401,505
	OM&A Expenses	$1,494,212	$825,904	$146,551	$4,238	$21,709	$251,352	$74,625	$169,834
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$17,177,027*	*$4,371,195*	*$4,422,757*	*$100,158*	*$62,182*	*$1,992,663*	*$1,656,732*	*$4,571,340*
	Working Capital	$2,576,554	$655,679	$663,413	$15,024	$9,327	$298,900	$248,510	$685,701
	Total Rate Base	$8,240,469	$3,192,498	$1,469,250	$42,999	$33,305	$1,062,336	$674,896	$1,765,183
		Rate Base Input equals Output							
	Equity Component of Rate Base	$4,120,235	$1,596,249	$734,625	$21,500	$16,653	$531,168	$337,448	$882,592
	Net Income on Allocated Assets	$369,812	$503,775	($56,095)	$24,865	($5,162)	$109,585	($32,933)	($174,223)
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$369,812	$503,775	($56,095)	$24,865	($5,162)	$109,585	($32,933)	($174,223)
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES %	100.00%	125.98%	63.47%	342.95%	74.33%	115.14%	60.68%	34.26%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($0)	$338,139	($108,710)	$23,038	($6,727)	$59,738	($60,773)	($244,706)
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.98%	31.56%	-7.64%	115.65%	-31.00%	20.63%	-9.76%	-19.74%

Ontario

2006 COST ALLOCATION INFORMATION FILING

TILLSONBURG HYDRO INC

EB-2005-0420 EB-2006-0247

January 0, 1900

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - First Run THI v.1

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	7	9	12	13	14
	Residential	**GS 50-500 kW**	**Street Light**	**Unmetered Scattered Load**	**GS<50 kW**	**GS 500-1500 kW**	**GS >1500 kW**
Customer Unit Cost per month - Avoided Cost	$4.25	$33.32	$2.60	$10.44	$10.27	$147.15	$138.31
Customer Unit Cost per month - Directly Related	$6.14	$43.88	$3.96	$15.96	$13.88	$198.51	$187.19
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$13.32	$53.95	$14.80	$23.96	$28.17	$223.53	$232.47
Fixed Charge per approved 2006 EDR	$11.29	$110.51	$1,324.84	$12.26	$24.52	$1,115.23	$1,115.23

Information to be Used to Allocate PILs, ROD, ROE and A&G

	Total	1 Residential	2 GS 50-500 kW	7 Street Light	9 Unmetered Scattered Load	12 GS<50 kW	13 GS 500-1500 kW	14 GS >1500 kW
General Plant - Gross Assets	$0	$0	$0	$0	$0	$0	$0	$0
General Plant - Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0
General Plant - Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
General Plant - Depreciation	$0	$0	$0	$0	$0	$0	$0	$0
Total Net Fixed Assets Excluding General Plant	$5,663,903	$2,536,813	$805,834	$27,975	$23,978	$763,434	$426,386	$1,079,482
Total Administration and General Expense	$468,872	$258,945	$46,078	$1,334	$6,791	$78,803	$23,469	$53,452
Total O&M	$1,025,340	$566,958	$100,473	$2,904	$14,918	$172,549	$51,156	$116,382

2006 COST ALLOCATION INFORMATION FILING
TILLSONBURG HYDRO INC
EB-2005-0420 EB-2006-0247
January 0, 1900
Sheet I6 Customer Data Worksheet - First Run THI v.1

Total kWhs	225,773,862
Total kWs	346,432
Total Approved Distribution Revenue ($)	$2,436,569

			1	2	7	9	12	13	14
	ID	**Total**	**Residential**	**GS 50-500 kW**	**Street Light**	**Unmetered Scattered Load**	**GS<50 kW**	**GS 500-1500 kW**	**GS >1500 kW**
Billing Data									
kWh from approved EDR model, Sheet 7-1, Col M	**CEN**	225,773,862	51,038,928	61,561,366	1,380,896	582,670	25,068,373	22,776,421	63,365,208
kW from approved EDR model, Sheet 7-1, Col S	**CDEM**	346,432		129,944	3,703	408		56,154	156,223
kW, included in CDEM, from customers with line transformer allowance from approved EDR model, Sheet 6-3, Col P		213,147		770				56,154	156,223
Optional - 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 Particlpants	**CEN EWMP**	225,773,862	51,038,928	61,561,366	1,380,896	582,670	25,068,373	22,776,421	63,365,208
kWh - 30 year weather normalized amount		227,668,187	50,107,738	42,732,919	1,354,376	516,517	27,053,080	28,001,606	77,901,950
Approved Distribution Rev from approved EDR, Sheet 7-1, Col AK + Sheet 7-3 Col H	**CREV**	$2,436,569	$1,553,396	$182,169	$32,338	$15,375	$442,022	$90,697	$120,573
Bad Debt 3 Year Historical Average from Approved EDR Model	**BDHA**	$4,187	$0	$0	$0	$0	$4,187	$0	$0
Late Payment 3 Year Historical Average	**LPHA**	$7,401	$7,401	$0	$0	$0			
Weighting Factor - Services			1.0	2.0	1.0	1.0	1.0	10.0	10.0
Weighting Factor - Billings			1.0	2.0	1.0	5.0	1.0	7.0	7.0
Number of Bills	**CNB**	76,056	66,276	948	12	828	7,872	72	48
Number of Connections (Unmetered)	**CCON**	69				69			
Total Number of Customer from Approved EDR, Sheet 7-1, Col H excluding connections	**CCA**	6,338	5,523	79	1	69	656	6	4
Bulk Customer Base	**CCB**	-	-	-		-		-	-
Primary Customer Base	**CCP**	6,338	5,523	79	1	69	656	6	4
Line Transformer Customer Base	**CCLT**	6,338	5,523	79	1	69	656	6	4
Secondary Customer Base	**CCS**	6,333	5,523	78	1	69	656	5	1
Weighted - Services	**CWCS**	6,465	5,523	156	1	69	656	50	10
Weighted Meter -Capital	**CWMC**	787,025	295,560	148,050	-	-	280,415	39,200	23,800
Weighted Meter Reading	**CWMR**	6,916	5,529	10	-	-	887	294	196
Weighted Bills	**CWNB**	81,036	66,276	1,896	12	4,140	7,872	504	336
Data Mismatch Analysis									
Revenue with 30 year weather normalized kWh		2,433,609	1,525,054	126,453	31,717	13,630	477,017	111,504	148,234

Weather Normalized Data from Hydro One

	Total	**Residential**	**GS 50-500 kW**	**Street Light**	**Unmetered Scattered Load**	**GS<50 kW**	**GS 500-1500 kW**	**GS >1500 kW**
kWh - 30 year weather normalized amount	236,770,421	**52,222,285**	44,390,956	1,411,531	538,314	28,194,720		
2006 EDR Distribution Loss Factor		**1.0422**	**1.0388**	**1.0422**	**1.0422**	**1.0422**		

Bad Debt Data from EDR 2006

Sheet ADJ5 rows 26 - 32, column E	-
Sheet ADJ5 rows 26 - 32, column F	-

2006 COST ALLOCATION INFORMATION FILING
TILLSONBURG HYDRO INC
EB-2005-0420 EB-2006-0247
January 0, 1900
Sheet O1 Revenue to Cost Summary Worksheet - First Run THI v.1

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS 50-500 kW	3 GS 500-5000 kW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	12 GS<50 kW
crev	Distribution Revenue (sale)	$2,436,568	$1,553,396	$182,169	$211,269	$32,338	$3,210	$12,165	$442,022
mi	Miscellaneous Revenue (mi)	$119,518	$87,441	$6,784	$9,625	$183	$61	$3,083	$12,340
	Total Revenue	$2,556,086	$1,640,837	$188,953	$220,894	$32,521	$3,271	$15,249	$454,361
	Expenses								
di	Distribution Costs (di)	$559,963	$254,925	$77,543	$153,614	$2,861	$684	$1,796	$68,540
cu	Customer Related Costs (cu)	$465,377	$319,093	$23,039	$8,658	$43	$203	$9,360	$104,981
ad	General and Administration (ad)	$468,872	$262,154	$46,128	$74,527	$1,334	$406	$5,078	$79,245
dep	Depreciation and Amortization (dep)	$295,849	$132,620	$42,093	$78,538	$1,461	$339	$907	$39,891
INPUT	PILs (INPUT)	$139,400	$62,489	$19,834	$37,006	$689	$160	$428	$18,796
INT	Interest	$256,814	$115,122	$36,539	$68,175	$1,268	$295	$788	$34,627
	Total Expenses	$2,186,275	$1,146,403	$245,176	$420,517	$7,657	$2,087	$18,356	$346,079
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$369,812	$165,775	$52,616	$98,173	$1,827	$424	$1,134	$49,863
	Revenue Requirement (includes NI)	$2,556,087	$1,312,178	$297,793	$518,690	$9,483	$2,511	$19,490	$395,942
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$7,504,802	$3,364,164	$1,067,769	$1,992,266	$37,067	$8,609	$23,020	$1,011,907
gp	General Plant - Gross	$0	$0	$0	$0	$0	$0	$0	$0
accum dep	Accumulated Depreciation	($1,302,387)	($583,819)	($185,301)	($345,739)	($6,433)	($1,494)	($3,995)	($175,607)
co	Capital Contribution	($538,500)	($241,387)	($76,615)	($142,950)	($2,660)	($618)	($1,652)	($72,618)
	Total Net Plant	$5,663,915	$2,538,958	$805,853	$1,503,577	$27,975	$6,497	$17,373	$763,682
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$15,682,815	$3,545,291	$4,276,206	$5,983,612	$95,921	$9,428	$31,045	$1,741,312
	OM&A Expenses	$1,494,212	$836,172	$146,711	$236,798	$4,239	$1,293	$16,233	$252,766
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$17,177,027*	*$4,381,464*	*$4,422,917*	*$6,220,411*	*$100,159*	*$10,721*	*$47,278*	*$1,994,078*
	Working Capital	$2,576,554	$657,220	$663,438	$933,062	$15,024	$1,608	$7,092	$299,112
	Total Rate Base	$8,240,469	$3,196,177	$1,469,291	$2,436,639	$42,999	$8,105	$24,465	$1,062,794
		Rate Base Input equals Output							
	Equity Component of Rate Base	$4,120,235	$1,598,089	$734,645	$1,218,319	$21,499	$4,053	$12,233	$531,397
	Net Income on Allocated Assets	$369,811	$494,434	($56,223)	($199,623)	$24,864	$1,184	($3,107)	$108,282
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$369,811	$494,434	($56,223)	($199,623)	$24,864	$1,184	($3,107)	$108,282
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES %	100.00%	125.05%	63.45%	42.59%	342.92%	130.28%	78.24%	114.75%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($1)	$328,659	($108,839)	($297,796)	$23,037	$760	($4,242)	$58,419
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.98%	30.94%	-7.65%	-16.39%	115.65%	29.23%	-25.40%	20.38%

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2006 COST ALLOCATION INFORMATION FILING

TILLSONBURG HYDRO INC

EB-2005-0420 EB-2006-0247

January 0, 1900

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - First Run THI v.1

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7	8	9	12
	Residential	GS 50-500 kW	GS 500-5000 kW	Street Light	Sentinel	Unmetered Scattered Load	GS<50 kW
Customer Unit Cost per month - Avoided Cost	$4.33	$33.40	$209.97	$2.64	$0.85	$10.62	$10.37
Customer Unit Cost per month - Directly Related	$6.26	$44.00	$274.34	$4.01	$1.25	$16.24	$14.03
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$13.46	$54.10	$325.75	$14.87	$8.11	$24.24	$28.34
Fixed Charge per approved 2006 EDR	$11.29	$110.51	$1,115.23	$1,324.84	$1.17	$12.26	$24.52

Information to be Used to Allocate PILs, ROD, ROE and A&G

	Total	1 Residential	2 GS 50-500 kW	3 GS 500-5000 kW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	12 GS<50 kW
General Plant - Gross Assets	$0	$0	$0	$0	$0	$0	$0	$0
General Plant - Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0
General Plant - Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
General Plant - Depreciation	$0	$0	$0	$0	$0	$0	$0	$0
Total Net Fixed Assets Excluding General Plant	$5,663,903	$2,538,953	$805,851	$1,503,574	$27,975	$6,497	$17,373	$763,680
Total Administration and General Expense	$468,872	$262,154	$46,128	$74,527	$1,334	$406	$5,078	$79,245
Total O&M	$1,025,340	$574,018	$100,583	$162,272	$2,904	$887	$11,155	$173,521

2006 COST ALLOCATION INFORMATION FILING

TILLSONBURG HYDRO INC

EB-2005-0420 EB-2006-0247

January 0, 1900

Sheet I6 Customer Data Worksheet - First Run THI v.1

Total kWhs	225,773,862
Total kWs	346,432
Total Approved Distribution Revenue ($)	$2,436,569

			1	2	3	7	8	9	12
	ID	**Total**	**Residential**	**GS 50-500 kW**	**GS 500-5000 kW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**GS<50 kW**
Billing Data									
kWh from approved EDR model, Sheet 7-1, Col M	**CEN**	225,773,862	51,038,928	61,561,366	86,141,630	1,380,896	135,734	446,936	25,068,373
kW from approved EDR model, Sheet 7-1, Col S	**CDEM**	346,432		129,944	212,377	3,703	408		
kW, included in CDEM, from customers with line transformer allowance from approved EDR model, Sheet 6-3, Col P		213,147		770	212,377				
Optional - 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**	225,773,862	51,038,928	61,561,366	86,141,630	1,380,896	135,734	446,936	25,068,373
kWh - 30 year weather normalized amount		227,668,187	50,107,738	42,732,919	105,903,556	1,354,376	103,274	413,244	27,053,080
Approved Distribution Rev from approved EDR, Sheet 7-1, Col AK + Sheet 7-3 Col H	**CREV**	$2,436,568	$1,553,396	$182,169	$211,269	$32,338	$3,210	$12,165	$442,022
Bad Debt 3 Year Historical Average from Approved EDR Model	**BDHA**	$4,187	$0	$0	$0	$0	$0	$0	$4,187

Late Payment 3 Year Historical Average	**LPHA**	$7,401	$7,401	$0	$0	$0	$0	$0	
Weighting Factor - Services			1.0	2.0	10.0	1.0	1.0	1.0	1.0
Weighting Factor - Billings			1.0	2.0	7.0	1.0	0.1	5.0	1.0
Number of Bills	**CNB**	75,996	66,276	948	60	12	216	612	7,872
Number of Connections (Unmetered)	**CCON**	69					18	51	
Total Number of Customer from Approved EDR, Sheet 7-1, Col H excluding connections	**CCA**	6,333	5,523	79	5	1	18	51	656
Bulk Customer Base	**CCB**	-	-	-	-		-	-	
Primary Customer Base	**CCP**	6,333	5,523	79	5	1	18	51	656
Line Transformer Customer Base	**CCLT**	6,333	5,523	79	5	1	18	51	656
Secondary Customer Base	**CCS**	6,329	5,523	78	2	1	18	51	656
Weighted - Services	**CWCS**	6,425	5,523	156	20	1	18	51	656
Weighted Meter -Capital	**CWMC**	787,025	295,560	148,050	63,000	-	-	-	280,415
Weighted Meter Reading	**CWMR**	6,454	5,529	10	28	-	-	-	887
Weighted Bills	**CWNB**	79,558	66,276	1,896	420	12	22	3,060	7,872
Data Mismatch Analysis									
Revenue with 30 year weather normalized kWh		2,433,668	1,525,054	126,453	259,737	31,717	2,443	11,248	477,017

Weather Normalized Data from Hydro

	Total	**Residential**	**GS 50-500 kW**	**GS 500-5000 kW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**GS<50 kW**
kWh - 30 year weather normalized amount	236,770,421	**52,222,285**	44,390,956	110,012,614	1,411,531	107,632	430,683	28,194,720
2006 EDR Distribution Loss Factor		**1.0422**	**1.0388**	**1.0388**	**1.0422**	**1.0422**	**1.0422**	**1.0422**

Bad Debt Data from EDR 2006

Sheet ADJ5 rows 26 - 32, column E	-							
Sheet ADJ5 rows 26 - 32, column F	-							
Sheet ADJ5 rows 26 - 32, column G	37,244	**24,682**						12,562
Three-year average	**12,415**	**8,227**	**-**	**-**				**4,187**

Summary of Results and Proposed Changes

THI's CAR-IF identifies the revenue to cost ratios provided in the table below.

Class / Option	**THI PROPOSAL**	OEB RANGE
Res	**125.98%**	85% to 115%
GS<50	**115.14%**	80% to 120%
GS>50-499	**63.47%**	80% to 180%
Proposed: GS>500-1499	**60.68%**	80% to 180%
Proposed: GS>1500	**34.26%**	80% to 180%
Street Lighting	**342.95%**	70% to 120%
Proposed:USL & Sentinel	**74.33%**	

Rate Design Overview

THI proposed 2009TY rates and other charges are provided at E1/T1/S5/AttA.

The purpose of this evidence is to:

- Summarize the impact to customers of the proposed rates; and
- Describe THI's rate design considerations.

THI's proposed 2009TY rates have been determined consistent with sound rate making methodologies and practices and are proposed so that THI is able to continue to provide distribution service to its customers at an appropriate level of quality, recover the ongoing costs of providing distribution service and have an opportunity to earn the allowed rate of return. THI's proposal is:

- to charge rates that recover the ongoing costs of providing service and that move to the Board's authorized revenue:cost ranges; and
- to recover the balances recorded in certain variance and deferral accounts and to recover its Lost Revenue Adjustment Mechanism and Shared Savings Mechanism awards

both over a two year period. This proposal is motivated by concerns over bill impacts to rate payers, by a desire to charge predictable rates and to balance the affected interests.

THI proposes to continue to rely on its long standing rate design:

- to charge fixed monthly rates and variable rates;
- to charge rate riders; and
- to continue to provide a transformer allowance to those customers who own their transformers.

THI proposes to transition from its existing revenue:cost to the Board's authorized revenue:cost range over a two year period. This transition period is proposed so that customer's rates

change in a smoother pattern and more predictable manner and so that the bill impact to THI's rate payers is not unacceptably high.

THI has determined the proposed fixed and variable distribution rates by considering:

- Whether a similar proportion of revenue is generated by the proposed fixed rates;
- Whether the resulting Revenue:Cost ratio is within the Board's approved limits and is reasonable;
- Whether the proposed rates are predictable and understandable to the customer;
- Whether there are unacceptable discontinuities at the class thresholds;
- Whether the average rate per kWh or kW, depending on the authorized charge parameter, is appropriate; and
- Whether the variable rate for customer classes eligible for Transformer Allowance Credit exceed the amount of the historic credit.

THI's examination of the impact to its General Service rate payers of achieving revenue:cost ratios consistent with the Board's target range has resulted in a proposed two year phase in period. Despite this phase in period it was not possible to constrain all customer class' bill increases to less than 10%. THI's proposed General Service 500 – 1,499 kW and proposed General Service >1,500 kW customer classes are expected to experience bill impacts greater than 10%.

This evidence considers two sets of proposed distribution rates:

- THI's proposal is based on truncating the currently authorized GS 500 – 5,000 kW class to GS 500 – 1,500 kW and introducing a newly formed GS > 1,500 kW customer class and eliminating the Sentinel Lighting customer class by merging it with the existing USL customer class.; and
- THI's currently authorized customer classes.

When determining distribution rates under each scenario THI balanced the following considerations:

- Maintaining the ratio of revenue recovered through fixed distribution rates to total distribution revenue, so as not to introduce new financial risks;

- Achieving revenue:cost ratios consistent with the OEB's policy at the end of a two year transition period; and
- Achieving acceptable bill impacts.

THI deviated from the first consideration when estimating the fixed rate for the Unmetered Scattered Load customer class; for this class, THI proposes to set the fixed rate at a level that recovers nearly 100% of the allocated revenue requirement.

THI's Proposal

THI proposes to apply the following distribution rates in the 2009TY:

Customer Class	Fixed charge	Variable Rate	Rate Rider
Residential	$14.30	$0.0184	$0.012/kWh
General Service <50 kW	$29.15	$0.0144	$0.0003/kWh
General Service >50 kW, <500 kW	$111.00	$1.6646	$0.0311/kW
General Service >500 to 1,500 kW	$751.00	$1.3820	$0.0352/kW
General Service > 1,500 kW	$1,151.00	$1.9937	$0.0146/kW
Street Lighting	$1,150.00	$3.0855/kW	$0.1530/kW
Unmetered Scattered Load	$20.00	$0.0036/kWh	$0.008/kWh

The revenue:cost ratios resulting from THI's proposal are provided in the table below.

Customer Class	Revenue:Cost Ratio
Residential	119%
General Service <50 kW	115%
General Service >50 kW, <500 kW	72%
General Service >500 to 1,500 kW	65%
General Service > 1,500 kW	57%
Street Lighting	210%
Unmetered Scattered Load	88%

THI has estimated appropriate distribution rates that recover the proposed revenue requirement and result in revenue:cost ratios consistent with the Board's targets. These rates are provided at E1/T1/S5/AttA.

THI is aware of the Board's consultation on distribution rate design and of the issues under consideration. THI is also aware that the implementation of time of use commodity rates is expected to elicit changes to customer's consumption patterns that will also trigger rate design changes.

Determination of Service Revenue Requirement

THI's 2009TY proposed Service Revenue Requirement is $3,313k. It has been determined consistent with the Board's practice as the sum of:

- Period expenses of $2,677k; and
- The allowed return on capital of $636k.

The evidence supporting the period expenses is provided at Exhibit 4. The evidence supporting the return on capital is provided at Exhibits 2 and 6.

Reducing the Service Revenue Requirement by the Revenue Offsets of $129k yields the 2009TY Base Revenue Requirement of $3,184k.

Reconciliation of Rate Class Revenue to total Revenue Requirement

THI's proposed 2009TY rates have been designed such that they recover $2,038 more than the proposed revenue requirement. This is because the proposed residential rates recover $1,567 more than the allocated costs and the proposed General Service < 50 kW rates recover $466 more. This difference is considered immaterial and is attributed to rounding.

A reconciliation of the revenues recovered through the proposed 2009TY rates and the revenue requirement is provided at E9/T1/S3/AttA.

Calculation of Difference between Revenue and Allocated Cost under Current and Proposed Rates

THI's 2009TY allocated revenue requirement by customer class is provided at E9/T1/S3/AttB. IT shows that under current and proposed rates, the residential customer class yields the single most substantial over contribution. It also shows the existing intra-class subsidization in THI's existing General Service 500 – 4,999 kW. The proposed partitioning of this class into a General Service 500 – 1,500 kW and General Service >1,500 kW clarifies that the larger customers have been cross-subsidized by other customer classes.

Revenue/Cost Ratios

THI's proposed 2009TY rates result in Revenue:Cost ratios that are consistent with the Board's target ratios. The resulting Revenue:Cost ratios and a comparison of the Revenue:Cost ratios of current rates is provided at E9/T1/S3/AttA and at E9/T1/S1/p3.

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F6 Reconciliation of Rates with Revenue / Recovery Requirements

DISTRIBUTION CHARGES

	Fixed Charge			Variable Charge			Gross Revenue from Distribution Charges		
Customer Class Name	**Rate [1]**	**Volume [2]**	**Revenue [3]**	**Rate [1]**	**Volume [2]**	**Revenue [3]**	**Calculated ***	**Allocated ****	**Difference**
Residential	$13.30	71,952	956,962	$0.0184	50,519,778	929,564	1,886,526	1,884,959	1,567
General Service < 50 kW	$28.15	7,644	215,179	$0.0144	24,890,062	358,417	573,595	573,129	466
General Service >50 kW, <500 kW	$110.00	864	95,040	$1.6646	106,725	177,654	272,694	272,698	-4
Street Lighting	$1,150.00	12	13,800	$3.0855	3,783	11,672	25,472	25,472	0
Unmetered Scattered Load	$20.00	1,176	23,520	$0.0036	546,778	1,968	25,488	25,472	16
General Service >500 kW, <1,500	$750.00	96	72,000	$1.3820	72,828	100,649	172,649	172,651	-2
General Service >1,500 kW	$1,150.00	48	55,200	$1.9937	156,866	312,743	367,943	367,948	-5
TOTAL			**1,431,700**			**1,892,668**	**3,324,368**	**3,322,330**	**2,038**

[1] From sheet F5, rounded off to decimals displayed

[2] Fixed Charge = # Customers (Connections) multiplied by 12 (months); Variable Charge = # kW's or kWh's, as applicable (per sheet C1)

[3] Rate x Volume

** Sum of 'Revenue' columns*

*** From sheet F4 (Gross Base Revenue Requirement)*

DEFERRAL/VARIANCE ACCOUNT RECOVERY CHARGES (CREDITS)

	Variable Charge (Credit)			Proceeds from Recovery Charges (Credits)		
Customer Class Name	**Rate [1]**	**Volume [2]**	**Proceeds [3]**	**Calculated ***	**Allocated ****	**Difference**
Residential	$0.0012	50,519,778	60,624	60,624	61,129	-505
General Service < 50 kW	$0.0003	24,890,062	7,467	7,467	8,364	-897
General Service >50 kW, <500 kW	$0.0311	106,725	3,319	3,319	3,319	0
Street Lighting	$0.1530	3,783	579	579	579	0
Unmetered Scattered Load	$0.0008	546,778	437	437	457	-19
General Service >500 kW, <1,500 kW	$0.0352	72,828	2,564	2,564	2,564	-1
General Service >1,500 kW	$0.0146	156,866	2,290	2,290	2,289	1
TOTAL			**77,280**	**77,280**	**78,701**	**-1,421**

[1] From sheet C7 ('Proposed Rate Rider'), rounded off to decimals displayed

[2] Variable Charge = # kW's or kWh's, as applicable (per sheet C1)

[3] Rate x Volume

** = 'Proceds' column*

*** From sheet C7 ('Annual Recovery Amounts')*

Rate Mitigation

THI proposes to mitigate its rates by:

- relying on a two year implementation period to comply with the Board's revenue:cost ratio target ranges; and
- recovering certain variance and deferral account balances Lost Revenue Adjustment Mechanism ("LRAM") and Shared Savings Mechanism ("SSM") awards over the same two year period.

THI's 2009TY revenue deficiency is approximately 25% of the revenues recovered under currently authorized rates. The balances of the variance and deferral accounts that it proposes to clear through rate riders and the recovery of the LRAM and SSM awards that are also to be recovered through rate riders amount to $157k; this amounts to more than 5% of the amount recovered under currently authorized rates. Finally, THI is aware that changing rates for customer classes whose observed revenue:cost ratio is different from the lowest amount authorized by the Board by more than 20 basis points risks hardship to the rate payer.

For these reasons THI examined all combinations of phasing in the changes to rates related to achieving the Board's target revenue:cost ratio and periods to charge the proposed rate riders over. THI believes that its proposal balances the affected interests. Most customer classes are expected to experience a bill impact of less than 10% and no customer class will experience a bill impact greater than 20%, THI will not recover its variance and deferral account balances over the shortest period possible and THI's rate payers will experience smoother rate changes over the next two years.

The estimated bill impacts are provided at E1/T1/S6/AttA.

Existing Rate Classes

THI's existing rate classes are provided at E1/T1/S4/AttA.

Existing Rate Schedule

THI's existing rate schedule is provided at E1/T1/S4/AttA.

Proposed Rate Classes (if different than existing)

THI proposes to discontinue its existing General Service 500 – 5,000 kW customer class and to replace it with:

- General Service 500 – 1,500 kW customer class; and
- General Service > 1,500 kW customer class.

THI has provided an amended Cost Allocation Review – Informational Filing in support of this proposal.

THI estimates that the customers in these classes will experience bill impacts less than 20%; the calculated bill impacts are provided at E1/T1/S6/AttA.

Proposed Rate Schedule

THI's proposed rate schedule is provided at E1/T1/S5/AttA.

Rate Impacts

THI has estimated the bill impacts to its customers under a range of scenarios. The estimated rate impacts are provided at E1/T1/S6/AttA.

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User Guide

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