TORONTO HYDRO

Standard Design Practice Amendment

Date: January 9, 2012
Effective Date: January 30, 2012

Issue Number: SDP-2011-01

This amendment is issued to inform the affected stakeholders that there is a change to **Standard Design Practice** (**SDP) #008 Rev.00 - Rear Lot Conversion**. This change is enforceable by the effective date, and will be included in the next SDP update.

Change	Summary of Changes	Training Requirements
Section 1.2.1	**For situations where typical underground projects are receiving negative feedback by the community, a hybrid overhead design option can be investigated. The hybrid overhead design option is to re-design the electrical distribution system to minimize the number of underground/pad-mounted transformers by re-evaluating the current proposed transformer locations and utilizing existing overhead assets. Wherever possible, transformers can be installed on existing overhead civil infrastructure.**	☐ **Yes** √ **No, awareness only** **Affected stakeholders:** Design Supervisors, Designers, Project Planning Supervisors, Project Planners and Construction & Maintenance Supervisors.
Appendix “G”	**Appendix “G” Hybrid Overhead Design Option drawing added.**	

This SDP Amendment is issued by email to all the affected stakeholders. You can also find this information in the following location on Plugged In: **Plugged In > Asset Management > Standards and Policy Planning > Standard Practices**

The purpose of a SDP Amendment is to communicate changes that are required throughout the year and will be incorporated in the next SDP revision. This will ensure that the affected stakeholders receive the latest information in a timely manner, and that the latest changes can be incorporated in new designs.

A SDP Amendment adds, removes or revises information in an existing Standard Design Practice. It also identifies training requirements, if applicable, regarding the changes described in the amendment. Each SDP Amendment consists of a cover sheet, the entire updated section(s) from the SDP with changes included in blue and any relevant attachments such as drawings or tables. It does not contain information that is applicable to other sections of the SDP.

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Updated Section in SDP #008 – Rear Lot Conversion

Section 1.2.1 Design Options

Existing rear lot areas are to be converted to front lot underground with pad-mounted or submersible transformers, and underground conduit service lines to customers.

The first design initiative is to install pad-mounted transformers. If there is strong opposition from key stakeholders (customers and their representatives) to have pad-mounted transformers installed, then the alternative is to install submersible transformers and vaults. Customer Communications & Public Relations will handle all contacts and communications with customers and their representatives to obtain "buy-in".

In situations where the above design options are not accepted by the key stakeholders, then a hybrid overhead design option can be investigated. The hybrid overhead design option is to re-design the electrical distribution system to minimize the number of underground/pad-mounted transformers by re-evaluating the current proposed transformer locations and utilizing existing overhead assets. Wherever possible, transformers can be installed on existing overhead distribution poles, and dipped underground to service existing rear lot customers. Refer to the drawing in **Appendix "G"** for further information.

In general, Designers shall use the following table in determining the design requirements for their front lot conversion projects:

Design Guideline Table – *Front Lot Pad-mounted Transformers*	
Electrical	
Transformers	1. Install new single-phase pad-mounted transformers. 2. Remove existing overhead or pad-mounted transformers.
Primary Distribution Cable	3. Install between new transformers, splice boxes, switchgear and pole locations. 4. Remove existing primary cable where practical.
Overhead Distribution	5. Remove existing overhead primary and secondary lines.
Secondary Bus	6. Install from new transformer location to new tap box location(s).
Secondary Service Cables	7. Install from new tap box to existing or new customer meter base, which is to be maintained at existing location. 8. Existing overhead service cables are to be removed, and existing underground service cables are to be abandoned.
Street Lighting	9. Replace existing street light circuits. Install new cable from the tap box to the existing pole's handhole.
Civil	
Transformer Pads	10. Install new transformer pads. 11. Remove existing pad from the rear lot.

Tap Boxes	12. Install new tap boxes where necessary.
Primary Cable Duct/Trench	13. Install new concrete encased duct(s) between new pads, splice boxes, switching cubicles and poles. 14. Trench to remove existing primary cable where practical.
Secondary Bus Duct	15. Install new concrete encased duct(s) from new pad to new tap boxes.
Secondary Service Cable Duct	16. Install new concrete encased duct(s) from new tap boxes in the main trench and terminate at street line. Directional bore to the existing meter base location.
Poles	17. Remove existing hydro owned poles where appropriate.
Street Lighting Duct	18. Install new concrete encased duct(s) from new tap boxes in the main trench and terminate 450mm from base of pole.

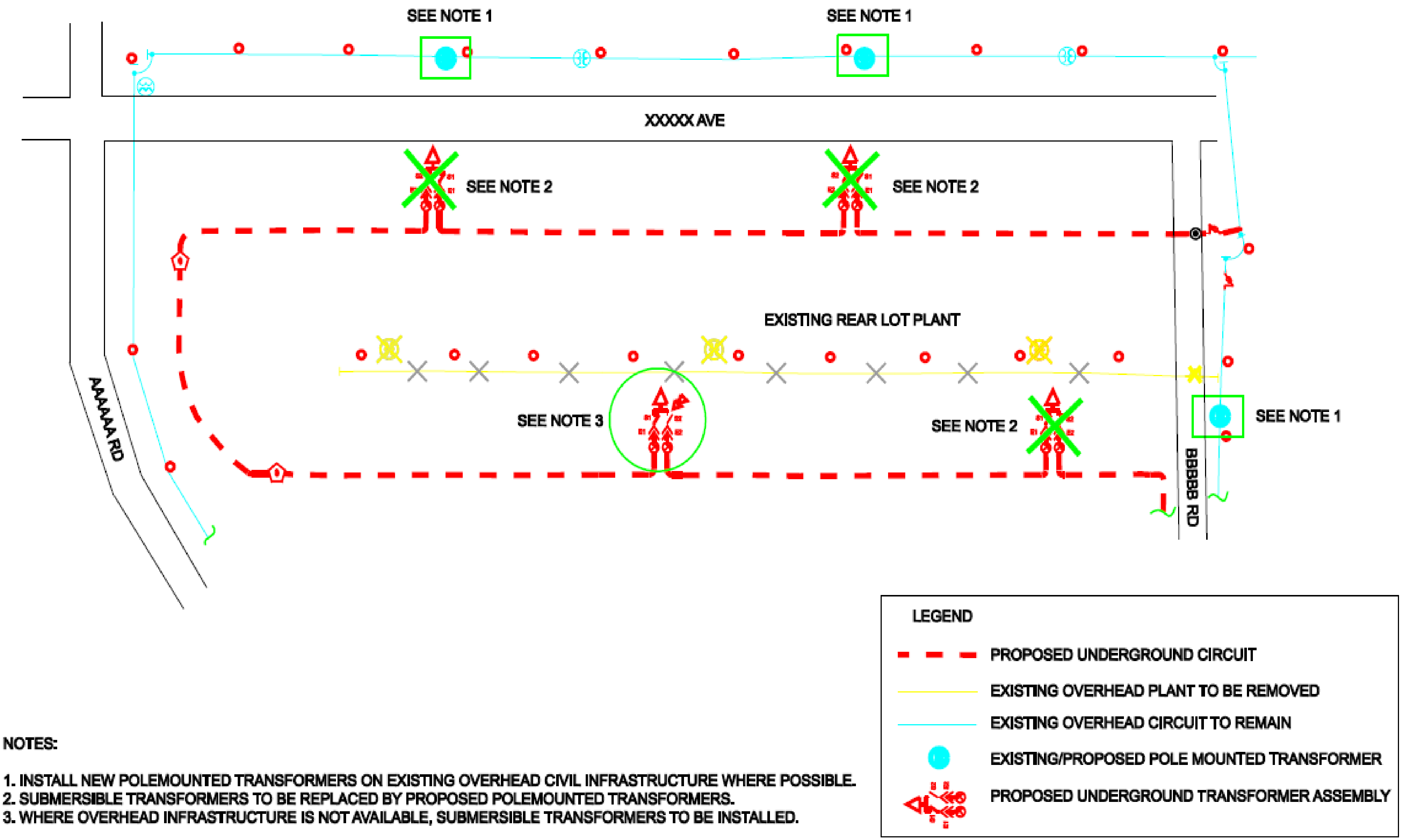
Refer to Appendix "D" for sample illustrations on the above design guidelines.

Design Guideline Table – *Front Lot Submersible Transformers*	
Electrical	
Transformers	1. Install new single-phase submersible transformers. 2. Remove existing overhead or pad-mounted transformers.
Primary Distribution Cable	3. Install between new transformers, splice boxes, switchgear and pole locations. 4. Remove existing primary cable where practical.
Overhead Distribution	5. Remove existing overhead primary and secondary lines.
Secondary Bus	6. Install from new transformer location to new tap box location(s).
Secondary Service Cables	7. Install from new tap box to existing or new customer meter base, which is to be maintained at existing location. 8. Existing overhead service cables are to be removed, and existing underground service cables are to be abandoned.
Street Lighting	9. Replace existing street light circuits. Install new cable from the tap box to the existing pole's handhole.
Civil	
Transformer Vaults/Pads	10. Install new submersible transformer vaults with drain. 11. Remove existing pads from the rear lot.

Tap Boxes	12. Install new tap boxes where necessary.
Primary Cable Duct/Trench	13. Install new concrete encased duct(s) between new vaults, splice boxes, switching cubicles and poles. 14. Trench to remove existing primary cable where practical.
Secondary Bus Duct	15. Install new concrete encased duct(s) from new vault to new tap boxes.
Secondary Service Cable Duct	16. Install new concrete encased duct(s) from new tap boxes in the main trench and terminate at street line. Directional bore to the existing meter base location.
Poles	17. Remove existing hydro owned poles where appropriate.
Street Lighting Duct	18. Install new concrete encased duct(s) from new tap boxes in the main trench and terminate 450mm from base of pole.

Refer to Appendix "D" for sample illustrations on the above design guidelines.

Appendix “G” Hybrid Overhead Design Option



NOTES:

1. INSTALL NEW POLEMOUNTED TRANSFORMERS ON EXISTING OVERHEAD CIVIL INFRASTRUCTURE WHERE POSSIBLE.
2. SUBMERSIBLE TRANSFORMERS TO BE REPLACED BY PROPOSED POLEMOUNTED TRANSFORMERS.
3. WHERE OVERHEAD INFRASTRUCTURE IS NOT AVAILABLE, SUBMERSIBLE TRANSFORMERS TO BE INSTALLED.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 1:

Reference(s): **Tab 4, Schedule B17, Appendix 3, page 7, Table 1**

Please provide the annual non-coincident demands of the Downtown Core for each year from 2000 to 2010 inclusive. Please break out the demands by each of the five transformer stations; and for each transformer station please break-out the demands by rate class.

RESPONSE:

Annual historic non-coincident demands for 2000 to 2010 for the five transformer stations that supply the downtown core are summarized below. THESL is not able to further break out the demands by rate class for each station.

STATION	NON-COINCIDENT PEAK (MVA)											
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
CECIL	145	150	161	149	148	158	159	169	168	177	180	188
ESPLANADE	158	157	165	156	153	159	165	168	162	170	197	180
STRACHAN	104	104	115	115	117	110	121	118	109	121	118	137
TERAULEY	215	229	234	239	224	231	229	194	201	188	225	190
JOHN / WINDSOR	304	307	313	289	289	300	303	284	283	300	303	311
TOTAL PEAK DEMAND	926	947	988	948	931	958	977	933	922	956	1,023	1,006

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 2:

Reference(s): **Tab 4, Schedule B17, Appendix 3, page 7, Table 1**

Please provide the annual coincident demands of the Downtown Core for each year from 2000 to 2011 inclusive. Please break out the demands by each of the five transformer stations and for each transformer station please break out the demands by rate class.

RESPONSE:

Annual coincident demands for the five transformer stations that supply the downtown core have only been utilized since 2008. This information is summarized in the table below. THESL is not able to further break out the demands by rate class for each station.

STATION	COINCIDENT PEAK (MVA)			
	2008	2009	2010	2011
CECIL	164	176	181	187
ESPLANADE	164	169	176	180
STRACHAN	104	119	117	138
TERAULEY	194	188	185	190
JOHN/WINDSOR	277	295	303	311
TOTAL PEAK DEMAND	903	947	962	1,006

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 3:

Reference(s): **Tab 4, Schedule B17, Appendix 3, page 7, Table 1**

Please provide the forecast coincident demands of the Downtown Core for each year from 2012 to 2021. Please break out the demands by each of the five transformer stations and for each transformer station please break out the demands by rate class.

RESPONSE:

The forecast coincident demands for the five transformer stations that supply the downtown core have been reproduced in the table below, based on information provided in Tab 4, Schedule 17, page 10-11 as well as Tab 4, Schedule 17, Appendix 2 and 3. THESL is unable to break out the demands by rate class.

Station	Station Rating	Year										
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Cecil	224	182	189	196	199	203	207	212	216	220	224	229
Esplanade	198	175	173	177	182	187	192	196	199	204	208	212
Strachan	175	122	127	130	131	133	140	143	147	151	153	157
Terauley	240	199	205	211	215	220	225	229	234	238	243	248
Windsor	340	304	306	315	324	328	335	342	349	355	362	371
Total	1177	982	1000	1029	1051	1071	1099	1122	1145	1168	1190	1217

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 4:

Reference(s): **Tab 4, Schedule B17, Appendix 3, page 3**

Please provide a precise description of the service boundaries of each of the five downtown transformer stations, for example by listing the portions of the streets that constitute the boundaries between the service areas.

RESPONSE:

The following are the primary voltage boundaries between stations as shown in Tab 4, Schedule B17 Appendix 3 Figure 1. The nearest streets have been used to indicate the boundaries.

- Boundary between Cecil TS and Strachan TS: Dundas St W, Euclid Ave, and Queen St W
- Boundary between Strachan TS and Windsor TS: Spadina Ave
- Boundary between Windsor TS and Esplanade TS: Yonge St, Gardiner Expressway, and York St
- Boundary between Esplanade TS and Terauley TS: Church St and Adelaide St E
- Boundary between Windsor TS and Cecil TS: Richmond St W
- Boundary between Windsor TS and Terauley TS: Richmond St W, Bay St, and Adelaide St W

Station service boundaries are dynamic due to system modifications, and are therefore subject to change.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 5:

Reference(s): Tab 4, Schedule B17, Appendix 3, page 3

Please provide an Excel spreadsheet with the demands of each of the five downtown transformer stations for every five minute interval in 2011.

RESPONSE:

Please refer to the loading information provided in response to PP interrogatories 1 to 3 (Tab 6F, Schedules 9-1 to 9-3). Planning for capacity increases is based on peak load demands. Data of finer granularity (such as loading at five-minute intervals) has not been used in Appendix 3, nor is it relevant to the business case presented. Furthermore, THESL cannot release loading data using five-minute intervals as it could potentially indirectly reveal confidential customer information.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 6:

Reference(s): Tab 4, Schedule B17, Appendix 3, page 10, Table 4

Please provide all of the reports and analyses in Toronto Hydro's possession that justify its load forecasts for each of the downtown transformer stations.

RESPONSE:

Please refer to the following reports and analyses as justification of the load forecasts for each of the downtown transformer stations:

1) Load Growth – In Downtown Toronto Area (Tab 4, Schedule B17, Appendix 2)
2) Navigant Consulting: Downtown Toronto-Electric Supply Evaluation (Tab 4, Schedule B17, Appendix 3)
3) Excerpts from THESL's 2011 Load Forecast that are relevant to this production request: formed the basis for the information in the Bremner ICM application (attached as Appendix A)
4) Excerpts from THESL's 2012 Load Forecast that are relevant to this production request: an updated version of the 2011 load forecast (attached as Appendix B).

For the purposes of the Bremner TS ICM business case, the 2012 Load Forecast is not materially different from the 2011 Load Forecast.

Toronto Hydro-Electric System Limited
Spring 2011
Station Load Forecast

Document ID: THESL-Spring 2011_ Station_ Load_Forecast
Issue: 3rd
Reason for Issue: Initial Release
Effective Date: July 25, 2011

Executive Summary

This report presents a forecast of the peak demand, based upon the stated assumptions and methodology, of all transformer station buses supplying Toronto Hydro-Electric System Limited's (THESL) distribution system assets. The primary purpose is to evaluate station bus capacity adequacy.

This report focuses on the capacity starting at the transmission/distribution boundary. This report does not focus on transmission planning issues directly nor does it reflect transmission capacity limitations unless those were directly reflected in the bus capacity limits provided to us by Hydro One Networks Inc. (HONI).

The forecast reveals bus capacity adequacy issues in Central Toronto (downtown) and in the Manby TS Area and also in some Other Area Stations during the 10-year study period.

Central Toronto

The new Bremner TS is under construction. As planned to date, the first switchgear is to be in-service in 2013 and second switchgear is to be in-service in 2014. Each switchgear will have 72 MVA capacity and will provide needed capacity relief in Central Toronto Area. At the same time, System Reliability Planning Department has developed several load transfer projects to relieve heavily loaded buses in the area. However, two out of the five stations serving the central Toronto area will still have inadequate capacity during the next ten years. These two stations are Cecil and Esplanade. A schedule of capacity additions to meet demand requirements has been developed. In addition to above mentioned new Bremner TS, expansion of Esplanade TS is planned for 2019.

THESL has included the Bremner TS project in its rate filing applications. The initial capacity at the new Bremner TS is planned to be in-service in 2013. The need date for Bremner TS has been advanced to 2013 from 2017 to enable switchgear replacement at Windsor TS.

[redacted]

Conservation and Demand Management

The impact of Conservation and Demand Management initiatives where known and significant were included in this forecast.

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List of Tables

All tables are found in Appendix A

1 Introduction

Purpose

This report presents a forecast of the peak demand, based upon the stated assumptions and methodology, of all transformer station buses supplying Toronto Hydro-Electric System Limited's (THESL) distribution system assets. The primary purpose is to evaluate station bus capacity adequacy.

Background

THESL distributes to its customers the electricity it receives in bulk at 35 transformer stations. One of those stations is wholly owned by THESL. Hydro One Networks Inc. (HONI) owns the rest either in whole or in part. Therefore almost all station bus capacity issues and their resolution involve dialogue and agreement with HONI. This report provides needed information for those capacity issues to be resolved.

Limitations

The Independent Electricity System Operator (IESO) regularly assesses the reliability of the transmission system supplying the Greater Toronto Area (GTA). This report, however, was not prepared with the purpose of supporting the transmission planning issues directly nor does it reflect transmission capacity limitations unless those were directly reflected in the bus capacity limits provided to us by HONI. The resolution of the transmission capacity issue of central Toronto will require dedicated cooperation and special purpose investigations to be conducted collaboratively by all stakeholders.

Capital Planning

This forecast is one of many inputs into THESL's long-term capital planning process. The long-term asset plans will capture all recommendations and actions required as a result of this forecast and other inputs.

2 Forecasting Process and Assumptions

2.1 Forecasting Process

As the purpose of the forecast is to assess station bus capacity adequacy, the summer and winter maximum peak demands are forecast rather than monthly peak demands.

The process for calculating peak demands follows three steps:

a) Historical summer/winter peak demand for a bus is weather corrected,
b) New loads are added to the weather corrected demands according to the build-up formula, and
c) Growth rates are applied to obtain annual peak demand forecasts for the study period.

Where a station bus capacity is exceeded during the first five years of the study period, remedial action is proposed and then the forecast is repeated to include the remedial action.

The following alternatives are considered, in order of preference, to remedy the bus/station capacity shortfall:

1. Load transfer to another bus or station;
2. Upgrade of station bus capacity;
3. Upgrade of station transformer capacity;
4. Station expansion, new bus;
5. New station.

2.2 Models

2.2.1 Weather Sensitivity

THESL normalizes downtown station bus peak demands to a mean daily temperature of 27°C for the summer forecast. The summer forecast is the most restrictive. This temperature is the average of the recorded mean daily temperature of the days that the buses reached highest peak demand over the period of 1998 to 2008.

A linear regression model is used to calculate bus weather sensitivity (b) and intercept parameter (a) from historical daily peak load (Y) and daily mean temperature (X) observations. The mathematical equation is:

$$Y = bX + a$$

where

Y = the daily peak load (MVA)
b = the slope of the trend line (MVA/°C),
X = the daily mean temperature (°C), and
a = the y-axis intercept (MVA).

The daily station bus peak demand data is obtained from station revenue metering. Daily mean temperature data is obtained from Environment Canada's Monthly Meteorological Summary Report. Since extreme temperature-bad behavior is of interest, only data for the summer and winter months are used for the regression model. Data for the months of June, July and August are used for the calculation of bus summer-season sensitivity. Data for the months of December, January and February are used for bus winter-season sensitivity. Weekends and holidays are excluded from model data as they differ dramatically from the weekday loads.

If 'N' is the number of Y-X readings, then the value of 'b', bus weather sensitivity (MVA/ C°) can be found by using the Method of Least Squares, as follows:

$$b = \frac{N \times \left\{ \sum_{i}^{N} (X_i Y_i) \right\} - \left(\sum_{i}^{N} (X_i) \right) \left(\sum_{i}^{N} (Y_i) \right)}{N \times \left\{ \sum_{i}^{N} (X_i^2) \right\} - \left(\sum_{i}^{N} (X_i) \right)^2}$$

Using spreadsheet programs, bus weather sensitivity calculations and normalization of starting bus peak demands are performed.

2.2.2 Peak Demand Growth Rate

Bus load growth rates are determined using a Time-Trend model. The relationship between x and y in the Time-Trend model is exponential, taking the form $y = ab^x$. After taking natural logarithms of the equation it becomes:

$$\ln y = \ln a + x \ln b$$

Where 'ln a' and 'ln b' represent the constants in the equation. 'ln y' and 'x' now have a linear relationship and the Least Squares method can be applied. The equation can be simplified as:

$$Y = A + Bx$$

Where

A = 'ln a' as described before,
B = 'ln b' which is the slope of the trend line,
x = time (i.e.; 1,2,3,4 . . .), and
Y = the natural logarithm of bus summer/winter peak load (MVA).

The summer/winter monthly peak load data is obtained from station revenue metering. As with the weather sensitivity model in section 2.2.1, the extreme temperature-load behavior of the Time-Trend model is of interest. Data for the months of June, July and August are used for the calculation of bus summer peak load, and data for the months of December, January and February are used for bus winter peak load.

If 'N' is the number of data, then the value of 'B', which is the slope of the line, can be found by using the Method of Least Squares. The following equation is used to compute the slope 'B'.

$$B = \frac{N \times \left\{ \sum_{i}^{N} (x_i Y_i) \right\} - \left(\sum_{i}^{N} (x_i) \right) \left(\sum_{i}^{N} (Y_i) \right)}{N \times \left\{ \sum_{i}^{N} (x_i)^2 \right\} - \left(\sum_{i}^{N} (x_i) \right)^2}$$

The original exponential model $y=ab^x$ can be re-written as $y=a(1+g)^x$, where g is the annual growth rate. Thus, the bus percentage growth rate '**g**' is calculated using equation:

$$g = (e^{B} - 1) \times 100 \quad \%$$

First, historical peak demands are adjusted to account for load transfers and other non-growth related events during the past five to ten years. Then the growth rates are determined using the model above.

2.3 Assumptions

2.3.1 New Load Build-up

New customer load is included in the forecast only for known projects for which THESL has been approached for service connection estimates.

The following load build-up guidelines are used in absence of customer specific data:

Proposed Load	% Load Build Up		
	Year 1	Year 2	Year 3
Up to 0.5 MVA	100%		
0.6 MVA to 2 MVA	70%	30%	
Over 2 MVA	60%	20%	20%

Based upon past experience, not all projects materialize and those that do materialize usually overestimate their peak demand. Therefore prospective new customer peak demand estimates are reduced by 50% to achieve a more realistic peak demand estimate.

2.3.2 Load Growth Rate for New Loads

For new customer loads, a zero percent growth rate is used for the first two years of the forecast period.

2.3.3 Bus Capacity Limits

For 115kV-13.8kV stations, the bus capacity limit is reached when forecasted peak demand reaches 95% of the bus firm capacity.

For 230kV-27.6kV/13.8kV and 115kV-27.6kV stations, the bus capacity limit is reached when forecasted peak demand reaches 100% of the bus firm capacity.

2.3.4 Uptown Peak Demand Growth Rate

For stations that are outside of central Toronto, that is stations with secondary voltages of 27.6 kV or primary voltages of 230 kV, the peak demand growth model of 2.2.2 is not used and instead is replaced with a growth rate of 1%.

2.3.5 Extraneous Loads

Not all load supplied from stations within Toronto are for THESL. The following foreign utility loads have been included in the forecast for determining station capacity adequacy:

PowerStream (load supplied from Leslie TS, Finch TS, Fairchild TS),

Veridian (load supplied from Sheppard TS, Malvern TS),

Enersource (load supplied from Richview TS), and

OPG (load supplied from Manby TS).

2.3.6 Conservation and Demand Management (CDM)

The Ontario Power Authority and THESL have both developed and implemented complementary projects over the past few years.

The major program portfolios are:

1. Conservation
2. Demand Response
3. Distributed Energy

In the shorter term, where committed projects are known, the potential impact of the project is taken into account in the forecasts. Committed generation projects are easier to quantify, as their location and size are clear and potential contributions could be estimated from signed agreements. At this time, THESL takes into consideration new committed generation projects that are over 10MW in size when performing the forecast. Once the unit is in service, in absence of physical assurance of operation, the actual impact on the bus load is reflected in the actual historical bus load data and therefore it is accounted for in the forecast.

Where CDM projects are installed and commissioned, the actual impact on bus load is reflected in the actual historical bus load data, and therefore accounted for in the forecasts.

3 Demand Forecast

The forecasts may be found in Appendix A.

Peak Demand Forecast

Table A1 is a ten-year system coincident summer peak demand forecast of all buses.

Table A2 is a ten-year system coincident winter peak demand forecast of all buses.

Tables B, C and D summarize the proposed major station projects, load transfers and voltage conversions respectively.

Area Peak Demand Studies

Table E is a 25-year system coincident summer peak demand forecast of Manby TS and surrounding stations.

Table F is a 25-year system coincident summer peak demand forecast of Central Toronto transformer stations.

4 Analysis

[redacted]

4.2 Central Toronto Stations

Two out of the five stations serving central Toronto (the downtown) will have inadequate capacity to meet peak demand during the next ten years. These two stations are Cecil and Esplanade.

Increasing load density due to redevelopments in central Toronto has put heavy pressure on the Cecil, John/Windsor, Terauley, Strachan and Esplanade stations. Esplanade and Cecil will reach 95% station firm capacity in 2017 and 2020 respectively. As a group, the downtown stations will need new capacity expansion in order to continue to serve the downtown core needs.

A schedule of capacity additions to meet demand requirements has been developed. They are:

1. The new Bremner TS is under construction. The initial capacity at Bremner is planned to be in-service in 2013 and second switchgear is planned to be in-service in 2014.
2. Expansion of Esplanade TS is planned to add one new bus in 2019.
3. Cecil TS switchgear replacements are planned for 2017 and 2019.

Of the five central stations, only two have room for expansion: Strachan TS and Esplanade TS. Approximately 96 MVA may be added at Strachan TS while another 216 MVA (3 x 72 MVA) may be added to Esplanade. These two stations are respectively west and east of the Cecil, John/Windsor and Terauley group. The forecast indicates that 280 MVA of capacity will be required by the year 2035.

The Bremner TS project has been included in the 2010 EDR rate filing evidence and will be resubmitted in 2011. HONI and THESL have obtained land fronting on Bremner Ave, Rees St and Lakeshore Blvd W for the purpose of building a new station. This site is attractively located closer to Central Toronto than the Strachan and Esplanade stations. Design of the new Bremner TS is in progress. A new station with an ultimate capacity of 288 MVA installed in 4 steps of 72 MVA would permit new load demands to be met. Freed up capacity at existing stations would permit long term planned outages for station sustainment projects, the creation of inter-station transfer capability where warranted, and a reduction of the impact of a low-probability high-impact event at a station. It also keeps the expansion capability at Strachan and Esplanade stations intact. The new station plus the expansion capability at Strachan and Esplanade totals over 600 MVA and it would ensure central Toronto's needs will be met past 2035. The initial capacity of 72 MVA at the new Bremner TS is planned for 2013 in order to provide the capacity to facilitate switchgear replacement at Windsor TS. This is an advancement from 2017, the need date based upon the 95% load level criteria. The second switchgear is planned to be in-service in 2014. This second switchgear is required to support the additional loads from Water Front developments and to support the Downtown Contingency plan. The remaining two phases, each of 72MVA, are planned to be in-service following the usual 95% load trigger level, as described in Table F (Appendix A).

List of buses are requiring load relief for next ten years in Central Toronto Stations.

Cecil TS:
A7-8CE Bus requires load relief in 2016.
A5-6CE Bus requires load relief in 2019.
A3-4CE Bus requires load relief in 2020.

Esplanade TS:
A1-2X Bus requires load relief in 2015.
A1-2GD Bus requires load relief in 2017.

Strachan TS:
A1-2T Bus requires load relief in 2018 (trigged by winter load forecast report).
A3-4T Bus requires load relief in 2018.

Terauley TS:
A5-6A Bus requires load relief in 2015.
A1-2A Bus requires load relief in 2019.

Windsor TS:
A15-16WR Bus requires load relief in 2011.
A13-14WR Bus requires load relief in 2014.
A3-4WR Bus requires load relief in 2018.
A11-12WR Bus requires load relief in 2020.

[redacted]

[redacted]

5 Conclusions

Central Toronto Stations

Two out of the five stations serving central Toronto (the downtown) will have inadequate capacity to meet peak demand during the next ten years. These two stations are Esplanade and Cecil. As a group, the downtown stations will need capacity expansion.

Long term plans have been developed to deal with the inadequate bus capacity. They are:

1. New Bremner TS is under construction. The first switchgear is planned to be in-service in 2013 and the second switchgear is in 2014.
2. Expansion of Esplanade TS is planned for 2019.
3. Cecil TS switchgear replacements are planned for 2017 and 2019.

[redacted]

6 Recommendations

The following recommendations are made for station buses which would have inadequate capacity in the next five years.

Central Toronto Stations

1. Windsor TS: A15-16WR bus requires load transfer of 3 MVA to A11-12WR in 2011.
2. Windsor TS: A13-14WR bus requires load transfer of 16 MVA or more in 2014. It could be dealt with the new Bremner TS.
3. Terauley TS: A5-6A bus requires load transfer of 7 MVA or more to A3-4A in 2015.
4. Esplanade TS: A1-2X bus requires load transfer in 2015. Planners to note that expansion of Esplanade TS will take place in 2019.

[redacted]

Appendix A

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2011 10 YEARS SUMMER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2011 10 YEARS SUMMER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
BREMNER (115KV/13.8KV) TS															
A1-2BR			72	68					57	57	58	59	60	61	62
Total of all Buses			72	68					57	57	58	59	60	61	62
Surplus MVA								72	15	15	14	13	12	11	10
% Loading (Load/2010 Firm Cap)								0	79	79	81	82	83	85	86

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2011 10 YEARS SUMMER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CECIL (115KV/13.8KV) TS															
A1-2	46	44	46	44	32	31	31	32	32	33	34	34	35	36	36
A3-4	46	44	46	44	34	34	36	38	39	40	41	42	43	43	44
A5-6	72	68	72	68	54	55	59	61	62	63	64	66	67	68	70
A7-8	72	68	72	68	61	62	63	65	66	67	68	70	71	73	74
Total of all Buses	236	224	236	224	181	182	189	196	199	203	207	212	216	220	224
Surplus MVA					55	54	47	40	37	33	29	24	20	16	12
% Loading (Load/2010 Firm Cap)					77	77	80	83	84	86	88	90	92	93	95

Cecil TS: A3-4 Bus requires load relief in 2020

Cecil TS: A5-6 Bus requires load relief in 2019

Cecil TS: A7-8 Bus requires load relief in 2016

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2011 10 YEARS SUMMER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
[redacted]															
ESPLANADE (115KV/13.8KV) TS															
A1-2GD	69	66	69	66	64	58	58	58	60	63	65	67	68	69	71
A3-4GD (A5-6GD) (see note 3)	69	66	69	66	57	58	55	56	57	58	59	60	61	63	64
A1-2X	69	66	69	66	55	59	60	63	65	66	68	69	70	72	73
Total of all Buses	207	198	207	198	176	175	173	177	182	187	192	196	199	204	208
Surplus MVA					31	32	34	30	25	20	15	11	8	3	-1
% Loading (Load/2010 Firm Cap)					85	85	84	86	88	90	93	95	96	99	100
[redacted]															

Esplanade TS:
A1-2GD Bus requires load relief in 2017

Esplanade TS:
A1-2X Bus requires load relief in 2015

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2011 10 YEARS SUMMER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
[redacted]															

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2011 10 YEARS SUMMER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

[redacted]

9/27/2011

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2011 10 YEARS SUMMER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2011 10 YEARS SUMMER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
[redacted]															
STRACHAN (115KV/13.8KV) TS															
A1-2	56	53	56	53	29	40	43	44	45	46	47	48	49	50	51
A3-4	48	46	48	46	27	32	35	36	37	38	43	44	46	47	48
A5-6	40	38	40	38	31	20	19	20	21	21	21	22	22	23	23
A7-8	40	38	40	38	30	30	30	30	28	28	29	29	30	31	31
Total of all Buses	184	175	184	175	117	122	127	130	131	133	140	143	147	151	153
Surplus MVA					67	62	57	54	53	51	44	41	37	33	31
% Loading (Load/2010 Firm Cap)					64	66	69	71	71	72	76	78	80	82	83

Strachan TS:
A3-4 Bus requires load relief in 2018

*-Actual 2010 summer peaks

16- Bus load includes load supplied to Veridian (formerly Pickering Hydro)

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2011 10 YEARS SUMMER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
TERAULEY (115KV/13.8KV) TS															
A1-2	68	65	68	65	49	56	56	58	59	60	62	63	64	65	67
A3-4	72	68	72	68	40	44	49	51	52	53	54	55	57	58	59
A5-6	66	63	66	63	56	59	60	61	62	64	65	66	68	69	70
A9-10 (Formerly A7-8, see note 17)	55	52	55	52	40	40	40	41	42	43	44	45	45	46	47
Total of all Buses (see note 18)	240	240	240	240	185	199	205	211	215	220	225	229	234	238	243
Surplus MVA					55	41	35	29	25	20	15	11	6	2	-3
% Loading (Load/2010 Firm Cap)					77	83	85	88	90	92	94	95	98	99	101

Terauley TS:
A1-2 Bus requires load relief in 2019

Terauley TS:
A5-6 Bus requires load relief in 2015

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2011 10 YEARS SUMMER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
WINDSOR (115KV/13.8KV) TS															
A11-12	69	66	69	66	54	55	56	58	59	60	61	62	64	65	66
A13-14	41	39	41	39	34	34	34	35	48	49	50	51	52	53	55
A15-16	69	66	69	66	62	67	66	68	69	70	72	73	75	76	78
A17-18	49	47	49	47	47	42	42	43	22	22	23	23	23	24	24
A3-4	64	61	64	61	49	49	50	52	56	57	58	60	61	62	63
A5-6	64	61	64	61	57	57	58	59	13	13	13	14	14	14	14
Total of all Buses	356	340	356	340	303	304	306	315	267	271	277	283	289	294	300
Surplus MVA					53	52	50	41	89	85	79	73	67	62	56
% Loading (Load/2010 Firm Cap)					85	85	86	88	75	76	78	79	81	83	84

Windsor TS: A11-12 Bus requires load relief in 2020

Windsor TS: A15-16 Bus requires load relief in 2011

Windsor TS: A13-14 Bus requires load relief in 2014

Windsor TS: A3-4 Bus requires load relief in 2018

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2011 10 YEARS WINTER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2011 10 YEARS WINTER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
BREMNER (115KV/13.8KV) TS															
A1-2BR			72	68					57	57	58	59	60	61	62
Total of all Buses			72	68					57	57	58	59	60	61	62
Surplus MVA								72	15	15	14	13	12	11	10
% Loading (Load/2010 Firm Cap)								0	79	79	81	82	83	85	86

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2011 10 YEARS WINTER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CECIL (115KV/13.8KV) TS															
A1-2	46	44	46	44	17	17	17	18	18	18	19	19	19	20	20
A3-4	46	44	46	44	29	29	30	32	34	35	36	36	37	38	39
A5-6	72	68	72	68	41	43	47	49	50	51	52	53	54	55	56
A7-8	72	68	72	68	47	49	51	52	53	54	55	56	57	59	60
Total of all Buses	236	224	236	224	134	138	145	151	155	158	162	164	167	172	175
Surplus MVA					102	98	91	85	81	78	74	72	69	64	61
% Loading (Load/2010 Firm Cap)					57	58	61	64	66	67	69	69	71	73	74

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2011 10 YEARS WINTER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
[redacted]															
ESPLANADE (115KV/13.8KV) TS															
A1-2GD	72	68	72	68	50	48	46	46	47	50	51	53	54	55	56
A3-4GD (A5-6GD) (see note 3)	72	68	72	68	35	37	34	35	36	36	37	38	38	39	40
A1-2X	72	68	72	68	45	50	52	54	56	58	59	60	61	62	64
Total of all Buses	216	204	216	204	130	135	132	135	139	144	147	151	153	156	160
Surplus MVA					86	81	84	81	77	72	69	65	63	60	56
% Loading (Load/2010 Firm Cap)					60	63	61	63	64	67	68	70	71	72	74

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2011 10 YEARS WINTER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2011 10 YEARS WINTER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2011 10 YEARS WINTER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2011 10 YEARS WINTER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

[redacted]

STRACHAN (115KV/13.8KV) TS															
A1-2	56	53	56	53	31	43	47	48	49	50	51	52	53	54	55
A3-4	48	46	48	46	26	27	33	36	37	38	39	44	45	47	48
A5-6	48	46	48	46	26	15	14	15	15	15	16	16	16	17	17
A7-8	48	46	48	46	26	26	26	26	23	24	24	25	25	26	26
Total of all Buses	200	191	200	191	109	111	120	125	124	127	130	137	139	144	146
Surplus MVA					91	89	80	75	76	73	70	63	61	56	54
% Loading (Load/2010 Firm Cap)					55	56	60	63	62	64	65	69	70	72	73

Strachan TS:
A1-2 Bus requires load relief in 2018

Strachan TS:
A3-4 Bus requires load relief in 2019

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2011 10 YEARS WINTER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
TERAULEY (115KV/13.8KV) TS															
A1-2	72	68	72	68	42	46	46	48	49	50	51	52	53	54	55
A3-4	72	68	72	68	35	40	48	51	53	54	55	56	57	58	60
A5-6	66	63	66	63	42	42	43	44	45	46	47	48	49	50	51
A9-10 (Formerly A7-8, see note 17)	55	52	55	52	31	31	32	32	33	34	34	35	36	36	37
Total of all Buses (see note 18)	240	240	240	240	150	159	169	175	180	184	187	191	195	198	203
Surplus MVA					90	81	71	65	60	56	53	49	45	42	37
% Loading (Load/2010 Firm Cap)					63	66	70	73	75	77	78	80	81	83	85

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2011 10 YEARS WINTER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
WINDSOR (115KV/13.8KV) TS															
A11-12	72	68	72	68	50	53	55	57	58	59	61	62	63	64	66
A13-14	48	46	48	46	28	28	28	29	42	43	44	45	46	47	48
A15-16	72	68	72	68	47	52	51	51	52	53	54	55	56	58	59
A17-18	58	55	58	55	36	32	32	33	11	11	11	12	12	12	12
A3-4	64	61	64	61	38	38	40	42	45	46	47	48	49	50	51
A5-6	64	61	64	61	41	42	42	43	0	0	0	0	0	0	0
Total of all Buses	378	359	378	359	240	245	248	255	208	212	217	222	226	231	236
Surplus MVA					138	133	130	123	170	166	161	156	152	147	142
% Loading (Load/2010 Firm Cap)					63	65	66	67	55	56	57	59	60	61	62

Windsor TS:
A13-14 Bus requires load relief in 2018

[redacted]

TORONTO HYDRO-ELECTRIC SYSTEM
2011 LOAD FORECAST SUMMARY
MAJOR STATION PROJECTS

STATION	BUS	2010 FORECAST IN-SERVICE DATE	2011 FORECAST IN-SERVICE DATE	COMMENTS
[redacted]				
BREMNER TS	A1-2BR	Spring 2017	2013	Construct new building and install two (2) new transformers & new 72MVA A1-2BR bus
ESPLANADE TS	A3-4X	Spring 2020	Spring 2020	Expand existing building & install two (2) new transformers & new 72MVA A3-4X bus (Hydro One & Toronto Hydro)
CECIL TS	A1-2CE, A3-4CE	Spring 2023	Spring 2023	Upgrade T1 to 60/80/100MVA and A1-2CE, A3-4CE to 3000A (Hydro One & Toronto Hydro)
BREMNER TS	A3-4BR	Spring 2025	2014	Install new 72MVA A3-4BR bus
BREMNER TS	A5-6BR	Spring 2028	Spring 2028	Install two (2) new transformers & new 72MVA A5-6BR bus
BREMNER TS	A7-8BR	Spring 2030	Spring 2030	Install new 72MVA A7-8BR bus
STRACHAN TS	A1-2T	>2032	>2032	Installation & connection of new transformer T16 to the existing A1-2T Bus (Hydro One)
STRACHAN TS	A9-10T	>2032	>2032	Installation & connection of new transformer T16 to the new A9-10T Bus (Hydro One)
STRACHAN TS	A1-2T	>2032	>2032	Installation & connection of new transformer T17 to the existing A1-2T Bus (Hydro One)
STRACHAN TS	A9-10T	>2032	>2032	Installation & connection of new transformer T17 to the new A9-10T Bus (Hydro One)

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

TORONTO HYDRO-ELECTRIC SYSTEM
2011 CENTRAL TORONTO TS's
SUMMER LOAD FORECAST
(SYSTEM CO-INCIDENT PEAK - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR																									
	PRESENT		FUTURE																											
	100%	95%	100%	95%	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
BREMNER (115KV/13.8KV) TS																														
A1-2BR			72	68					57	57	58	59	60	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77
Total of all Buses			72	68					57	57	58	59	60	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77
Surplus MVA								72	15	15	14	13	12	11	10	9	8	7	6	5	4	3	2	1	0	-1	-2	-3	-4	-5
% Loading (Load/2010 Firm Cap)								0	79	79	81	82	83	85	86	88	89	90	92	93	94	96	97	99	100	101	103	104	106	107
CECIL (115KV/13.8KV) TS																														
A1-2	46	44	46	44	32	31	31	32	32	33	34	34	35	36	36	37	38	39	39	40	41	42	43	43	44	45	46	47	48	49
A3-4	46	44	46	44	34	34	36	38	39	40	41	42	43	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	60
A5-6	72	68	72	68	54	55	59	61	62	63	64	66	67	68	70	71	72	74	75	77	78	80	81	83	85	86	88	90	92	94
A7-8	72	68	72	68	61	62	63	65	66	67	68	70	71	73	74	76	77	79	80	82	83	85	87	89	90	92	94	96	98	100
Total of all Buses	236	224	236	224	181	182	189	196	199	203	207	212	216	220	224	229	233	239	242	248	252	258	263	268	273	278	284	290	296	303
Surplus MVA					55	54	47	40	37	33	29	24	20	16	12	7	3	-3	-6	-12	-16	-22	-27	-32	-37	-42	-48	-54	-60	-67
% Loading (Load/2010 Firm Cap)					77	77	80	83	84	86	88	90	92	93	95	97	99	101	103	105	107	109	111	114	116	118	120	123	125	128
ESPLANADE (115KV/13.8KV) TS																														
A1-2GD	69	66	69	66	64	58	58	58	60	63	65	67	68	69	71	72	74	75	77	78	80	81	83	85	86	88	90	92	93	95
A3-4 (Formerly A5-6)	69	66	69	66	57	58	55	56	57	58	59	60	61	63	64	65	66	68	69	71	72	73	75	76	78	79	81	83	84	86
A1-2X	69	66	69	66	55	59	60	63	65	66	68	69	70	72	73	75	76	78	79	81	82	84	86	87	89	91	93	95	96	98
Total of all Buses	207	198	207	198	176	175	173	177	182	187	192	196	199	204	208	212	216	221	225	230	234	238	244	248	253	258	264	270	273	279
Surplus MVA					31	32	34	30	25	20	15	11	8	3	-1	-5	-9	-14	-18	-23	-27	-31	-37	-41	-46	-51	-57	-63	-66	-72
% Loading (Load/2010 Firm Cap)					85	85	84	86	88	90	93	95	96	99	100	102	104	107	109	111	113	115	118	120	122	125	128	130	132	135
STRACHAN (115KV/13.8KV) TS																														
A1-2	56	53	56	53	29	40	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	59	60	61	62	63	65	66	67	69
A3-4	48	46	48	46	27	32	35	36	37	38	43	44	46	47	48	49	50	51	52	53	54	55	56	57	58	60	61	62	63	65
A5-6	40	38	40	38	31	20	19	20	21	21	21	22	22	23	23	24	24	25	25	26	26	27	27	28	28	29	29	30	30	31
A9-10 (Formerly A7-8)	40	38	40	38	30	30	30	30	28	28	29	29	30	31	31	32	32	33	34	34	35	36	37	37	38	39	40	40	41	42
Total of all Buses	184	175	184	175	117	122	127	130	131	133	140	143	147	151	153	157	159	163	166	169	172	177	180	183	186	191	195	198	201	207
Surplus MVA					67	62	57	54	53	51	44	41	37	33	31	27	25	21	18	15	12	7	4	1	-2	-7	-11	-14	-17	-23
% Loading (Load/2010 Firm Cap)					64	66	69	71	71	72	76	78	80	82	83	85	86	89	90	92	93	96	98	99	101	104	106	108	109	113
TERAULEY (115KV/13.8KV) TS																														
A1-2	68	65	68	65	49	56	56	58	59	60	62	63	64	65	67	68	69	71	72	74	75	76	78	80	81	83	84	86	88	90
A3-4	72	68	72	68	40	44	49	51	52	53	54	55	57	58	59	60	61	62	64	65	66	68	69	70	72	73	75	76	78	79
A5-6	66	63	66	63	56	59	60	61	62	64	65	66	68	69	70	72	73	75	76	78	79	81	82	84	86	87	89	91	93	95
A9-10 (Formerly A7-8)	55	52	55	52	40	40	40	41	42	43	44	45	45	46	47	48	49	50	51	52	53	54	55	56	58	59	60	61	62	64
Total of all Buses (see note 1)	240	240	240	240	185	199	205	211	215	220	225	229	234	238	243	248	252	258	263	269	273	279	284	290	297	302	308	314	321	328
Surplus MVA					55	41	35	29	25	20	15	11	6	2	-3	-8	-12	-18	-23	-29	-33	-39	-44	-50	-57	-62	-68	-74	-81	-88
% Loading (Load/2010 Firm Cap)					77	83	85	88	90	92	94	95	98	99	101	103	105	108	110	112	114	116	118	121	124	126	128	131	134	137

* - Actual 2010 summer peaks.

1 - Terauley TS's total bus capacity is 261MVA, but its FIRM capaciaty is limited to 240MVA due to Hydro One's 115kV Cecil-Terauley C5E & C7E circuits' rating.

TORONTO HYDRO-ELECTRIC SYSTEM
2011 CENTRAL TORONTO TS's
SUMMER LOAD FORECAST
(SYSTEM CO-INCIDENT PEAK - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR																									
	PRESENT		FUTURE																											
	100%	95%	100%	95%	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
WINDSOR (115KV/13.8KV) TS																														
A11-12	69	66	69	66	54	55	56	58	59	60	61	62	64	65	66	68	69	70	72	73	75	76	78	79	81	82	84	86	87	89
A13-14	41	39	41	39	34	34	34	35	48	49	50	51	52	53	55	56	57	58	59	60	61	63	64	65	66	68	69	71	72	73
A15-16	69	66	69	66	62	67	66	68	69	70	72	73	75	76	78	79	81	82	84	86	87	89	91	93	95	96	98	100	102	104
A17-18	49	47	49	47	47	42	42	43	22	22	23	23	23	24	24	25	25	26	26	27	27	28	29	29	30	30	31	32	32	33
A3-4	64	61	64	61	49	49	50	52	56	57	58	60	61	62	63	65	66	67	68	70	71	73	74	76	77	79	80	82	83	85
A5-6	64	61	64	61	57	57	58	59	13	13	13	14	14	14	14	15	15	15	16	16	16	17	17	17	18	18	18	19	19	19
Total of all Buses	356	340	356	340	303	304	306	315	267	271	277	283	289	294	300	308	313	318	325	332	337	346	353	359	367	373	380	390	395	403
Surplus MVA					53	52	50	41	89	85	79	73	67	62	56	48	43	38	31	24	19	10	3	-3	-11	-17	-24	-34	-39	-47
% Loading (Load/2010 Firm Cap)					85	85	86	88	75	76	78	79	81	83	84	87	88	89	91	93	95	97	99	101	103	105	107	110	111	113
Total of all Stations																														
Bus Total	1223	1177	1295	1245	962	982	1000	1029	1051	1071	1099	1122	1145	1168	1190	1217	1237	1264	1287	1315	1336	1367	1394	1419	1448	1475	1505	1537	1562	1597
Surplus MVA					261	241	223	194	172	152	124	101	78	55	33	6	-14	-41	-64	-92	-113	-144	-171	-196	-225	-252	-282	-314	-339	-374
% Loading (Load/2010 Firm Cap)					79	80	82	84	86	88	90	92	94	96	97	100	101	103	105	108	109	112	114	116	118	121	123	126	128	131
Total of all Stations																														
Future 100% FIRM Capacity								1295	1367						1439			1491					1563		1635					
Surplus MVA (Fut. FIRM Cap. - Load)					261	241	223	266	316	296	268	245	222	199	249	222	202	227	204	176	155	124	169	144	187	160	130	98	73	38
% Loading (Load/Fut. FIRM Cap.)					79	80	82	79	77	77	79	81	82	84	83	85	86	85	86	88	90	92	89	91	89	90	92	94	96	98

* - Actual 2010 summer peaks.

72MVA addition, A1-2BR - 2013

72MVA addition, A3-4BR - 2014

72MVA addition, A3-4X - 2020

52MVA addition, Cecil TS - 2023

72MVA addition, A5-6BR - 2028

72MVA addition, A7-8BR - 2030

Toronto Hydro-Electric System Limited
Spring 2012
Station Load Forecast

Document ID: THESL-Spring 2012_ Station_ Load_Forecast
Issue: 1st version
Reason for Issue: Initial Release
Issued Date: March 5, 2012

Executive Summary

This report presents a forecast of the peak demand, based upon the stated assumptions and methodology, of all transformer station buses supplying Toronto Hydro-Electric System Limited's (THESL) distribution system assets. The primary purpose is to evaluate station bus capacity adequacy.

This report focuses on the capacity starting at the transmission/distribution boundary. This report does not focus on transmission planning issues directly nor does it reflect transmission capacity limitations unless those were directly reflected in the bus capacity limits provided to THESL by Hydro One Networks Inc. (HONI).

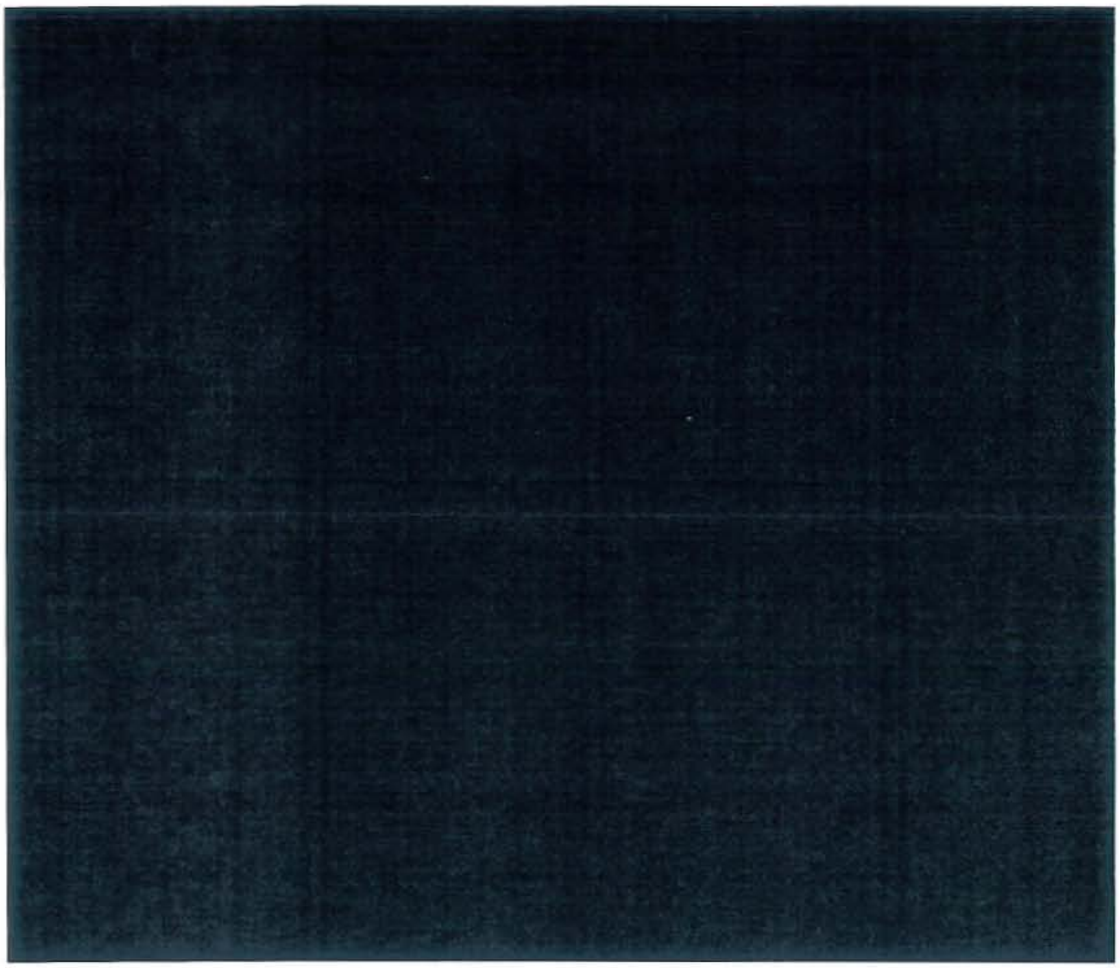
The forecast shows bus capacity adequacy in the Central Toronto (downtown) area, the Manby TS area and other areas' Station buses for the 10-year forecast period.

Central Toronto

THESL has included the Bremner TS project in its rate filing applications. The new Bremner TS is under construction. As planned to date, the first switchgear is to be in-service in 2014 and second switchgear is to be in-service in 2015. Each switchgear will have 72 MVA rating and will provide capacity relief for Central Toronto Area.

System Reliability Planning Department has also developed several load transfer projects to relieve heavily loaded buses at the Windsor and Esplanade stations. Based on load transfer plans, approximately 55 MVA load will be transferred to Bremner TS new A1-2 bus in 2014 and 39 MVA load will be transferred to Bremner TS new A3-4 bus in 2015.

In addition to the new Bremner TS, expansion of Esplanade TS is planned for 2020 and transformer upgrade in Cecil TS is planned for 2023. Based on current load forecast, the capacity additions at Bremner TS, Esplanade TS and Cecil TS will meet the load demand from Central Toronto Area for the next 16 years.



Caution and Disclaimer

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All tables are found in Appendix A

1 Introduction

1.1 Purpose

This report presents a forecast of the peak demand, based upon the stated assumptions and methodology, of all transformer station buses supplying Toronto Hydro-Electric System Limited's (THESL) distribution system assets. The primary purpose is to evaluate station bus capacity adequacy.

1.2 Background

THESL receives power in bulk at 35 transformer stations and distributes power to customers. One station, Cavanagh TS, is wholly owned by THESL. Hydro One Networks Inc. (HONI) owns the remaining 34 TS either in whole or in part. Therefore, all station bus capacity issues and resolutions require consultation and agreement with HONI. This report provides needed information for those capacity issues to be resolved.

1.3 Limitations

The Independent Electricity System Operator (IESO) regularly assesses the reliability of the transmission system supplying the Greater Toronto Area (GTA). This report, however, was not prepared with the purpose of supporting the transmission planning issues directly nor does it reflect transmission capacity limitations unless those were directly reflected in the bus capacity limits provided to THESL by HONI. The resolution of the transmission capacity issue of central Toronto will require dedicated cooperation and special purpose investigations to be conducted collaboratively by all stakeholders.

1.4 Capital Planning

This forecast is one of many inputs into THESL's long-term capital planning process. The long-term asset plans will capture all recommendations and actions required as a result of this forecast and other inputs.

2 Forecasting Process and Assumptions

2.1 Forecasting Process

As the purpose of the forecast is to assess station bus capacity adequacy, the summer and winter maximum peak demands are forecast rather than monthly peak demands.

The process for calculating peak demands follows three steps:

a) Historical summer/winter peak demand for a bus is weather corrected,
b) New loads are added to the weather corrected demands according to the build-up formula, and
c) Growth rates are applied to obtain annual peak demand forecasts for the study period.

Where a station bus capacity is exceeded during the first five years of the study period, remedial action is proposed and then the forecast is repeated to include the remedial action.

The following alternatives are considered, in order of preference, to remedy the bus/station capacity shortfall:

1. Load transfer to another bus or station;
2. Upgrade of station bus capacity;
3. Upgrade of station transformer capacity;
4. Station expansion, new bus;
5. New station.

2.2 Models

2.2.1 Weather Sensitivity

THESL normalizes downtown station bus peak demands to a mean daily temperature of 28.6°C for the summer forecast. The summer forecast is the most restrictive. This temperature is the average of the recorded mean daily temperature of the days that the buses reached highest peak demand over the period of 2000 to 2010.

A linear regression model is used to calculate bus weather sensitivity (b) and intercept parameter (a) from historical daily peak load (Y) and daily mean temperature (X) observations. The mathematical equation is:

$$Y = bX + a$$

where

Y = the daily peak load (MVA)
b = the slope of the trend line (MVA/°C),
X = the daily mean temperature (°C), and
a = the y-axis intercept (MVA).

The daily station bus peak demand data is obtained from station revenue metering. Daily mean temperature data is obtained from Environment Canada's Monthly Meteorological Summary Report. Since extreme temperature-bad behavior is of interest, only data for the summer and winter months are used for the regression model. Data for the months of June, July and August are used for the calculation of bus summer-season sensitivity. Data for the months of December, January and February are used for bus winter-season sensitivity. Weekends and holidays are excluded from model data as they differ dramatically from the weekday loads.

If 'N' is the number of Y-X readings, then the value of 'b', bus weather sensitivity (MVA/ C°) can be found by using the Method of Least Squares, as follows:

$$b = \frac{N \times \left\{ \sum_{i}^{N} (X_i Y_i) \right\} - \left(\sum_{i}^{N} (X_i) \right) \left(\sum_{i}^{N} (Y_i) \right)}{N \times \left\{ \sum_{i}^{N} (X_i^2) \right\} - \left(\sum_{i}^{N} (X_i) \right)^2}$$

Using spreadsheet programs, bus weather sensitivity calculations and normalization of starting bus peak demands are performed.

2.2.2 Peak Demand Growth Rate

Bus load growth rates are determined using a Time-Trend model. The relationship between x and y in the Time-Trend model is exponential, taking the form $y = ab^x$. After taking natural logarithms of the equation it becomes:

$$\ln y = \ln \mathrm{a} + x \ln \mathrm{b}$$

Where 'ln a' and 'ln b' represent the constants in the equation. 'ln y' and 'x' now have a linear relationship and the Least Squares method can be applied. The equation can be simplified as:

$$Y = A + Bx$$

Where

A = 'ln a' as described before,
B = 'ln b' which is the slope of the trend line,
x = time (i.e.; 1,2,3,4 . . .), and
Y = the natural logarithm of bus summer/winter peak load (MVA).

The summer/winter monthly peak load data is obtained from station revenue metering. As with the weather sensitivity model in section 2.2.1, the extreme temperature-load behavior of the Time-Trend model is of interest. Data for the months of June, July and August are used for the calculation of bus summer peak load, and data for the months of December, January and February are used for bus winter peak load.

If 'N' is the number of data, then the value of 'B', which is the slope of the line, can be found by using the Method of Least Squares. The following equation is used to compute the slope 'B'.

$$B = \frac{N \times \left\{\sum_{i}^{N}(x_i Y_i)\right\} - \left(\sum_{i}^{N}(x_i)\right)\left(\sum_{i}^{N}(Y_i)\right)}{N \times \left\{\sum_{i}^{N}(x_i)^2\right\} - \left(\sum_{i}^{N}(x_i)\right)^2}$$

The original exponential model $y=ab^x$ can be re-written as $y=a(1+g)^x$, where g is the annual growth rate. Thus, the bus percentage growth rate 'g' is calculated using equation:

$$g = (e^{B} - 1) \times 100 \quad \%$$

First, historical peak demands are adjusted to account for load transfers and other non-growth related events during the past five to ten years. Then the growth rates are determined using the model above.

2.3 Assumptions

2.3.1 New Load Build-up

New customer load is included in the forecast only for known projects for which THESL has been approached for service connection estimates.

The following load build-up guidelines are used in absence of customer specific data:

Proposed Load	% Load Build Up		
	Year 1	Year 2	Year 3
Up to 0.5 MVA	100%		
0.6 MVA to 2 MVA	70%	30%	
Over 2 MVA	60%	20%	20%

Based upon past experience, not all projects materialize and those that do materialize usually overestimate their peak demand. Therefore prospective new customer peak demand estimates are reduced by 50% to achieve a more realistic peak demand estimate.

2.3.2 Load Growth Rate for New Loads

For new customer loads, a zero percent growth rate is used for the first two years of the forecast period.

2.3.3 Bus Capacity Limits

For 115kV-13.8kV stations, the bus capacity limit is reached when forecasted peak demand reaches 95% of the bus firm capacity.

For 230kV-27.6kV/13.8kV and 115kV-27.6kV stations, the bus capacity limit is reached when forecasted peak demand reaches 100% of the bus firm capacity.

2.3.4 Extraneous Loads

Not all load supplied from stations within Toronto are for THESL. The following foreign utility loads have been included in the forecast for determining bus capacity adequacy:

PowerStream (load supplied from Leslie TS, Finch TS, Fairchild TS),

Veridian (load supplied from Sheppard TS, Malvern TS),

Enersource (load supplied from Richview TS), and

OPG (load supplied from Manby TS).

3 Demand Forecast

The load forecast tables are shown in Appendix A.

3.1 Peak Demand Forecast

Table A1 is a ten-year system coincident summer peak demand forecast of all buses.

Table A2 is a ten-year system coincident winter peak demand forecast of all buses.

Tables B, C and D summarize the proposed major station projects, load transfers and voltage conversions respectively.

3.2 Area Peak Demand Studies

Table E is a 25-year system coincident summer peak demand forecast of Manby TS and surrounding stations.

Table F is a 25-year system coincident summer peak demand forecast of Central Toronto transformer stations.

4 Analysis

[redacted]

4.2 Central Toronto Stations

Increasing load density due to redevelopments in central Toronto has put heavy pressure on the John/Windsor, Esplanade, Strachan, Cecil and Terauley stations. As a group, the downtown stations will need new capacity expansion in order to continue to serve the downtown core.

A schedule of capacity additions to meet demand requirements has been developed. They are:

1. The new Bremner TS is under construction. The initial capacity at Bremner TS is planned to be in-service in 2014 and second switchgear is planned to be in-service in 2015. Each of the switchgear will provide an additional 72 MVA capacity.

2. Expansion of Esplanade TS will add an additional new bus in 2020, which will provide 72 MVA additional capacity.
3. Transformer upgrade in Cecil TS will provide 52 MVA additional capacity in 2023.

The Bremner TS project has been updated and resubmitted in the 2012 ICM rate filing evidence. The new Bremner TS is under construction. A new station with an ultimate capacity of 288 MVA installed in 4 steps of 72 MVA each would permit new load demands to be met. Freed up capacity at existing stations would permit long term planned outages for station sustainment projects, the creation of inter-station transfer capability where warranted, and a reduction of the low-probability high-impact event at Windsor station.

The initial capacity of 72 MVA at the new Bremner TS is planned for 2014 in order to provide the capacity to facilitate switchgear replacement at Windsor TS. The second switchgear is planned to be in-service in 2015. The remaining two phases, each of 72MVA, are planned to be in-service following the usual 95% load trigger level, as described in Table F (Appendix A).

List of buses are requiring load relief for the next ten years in Central Toronto Stations.

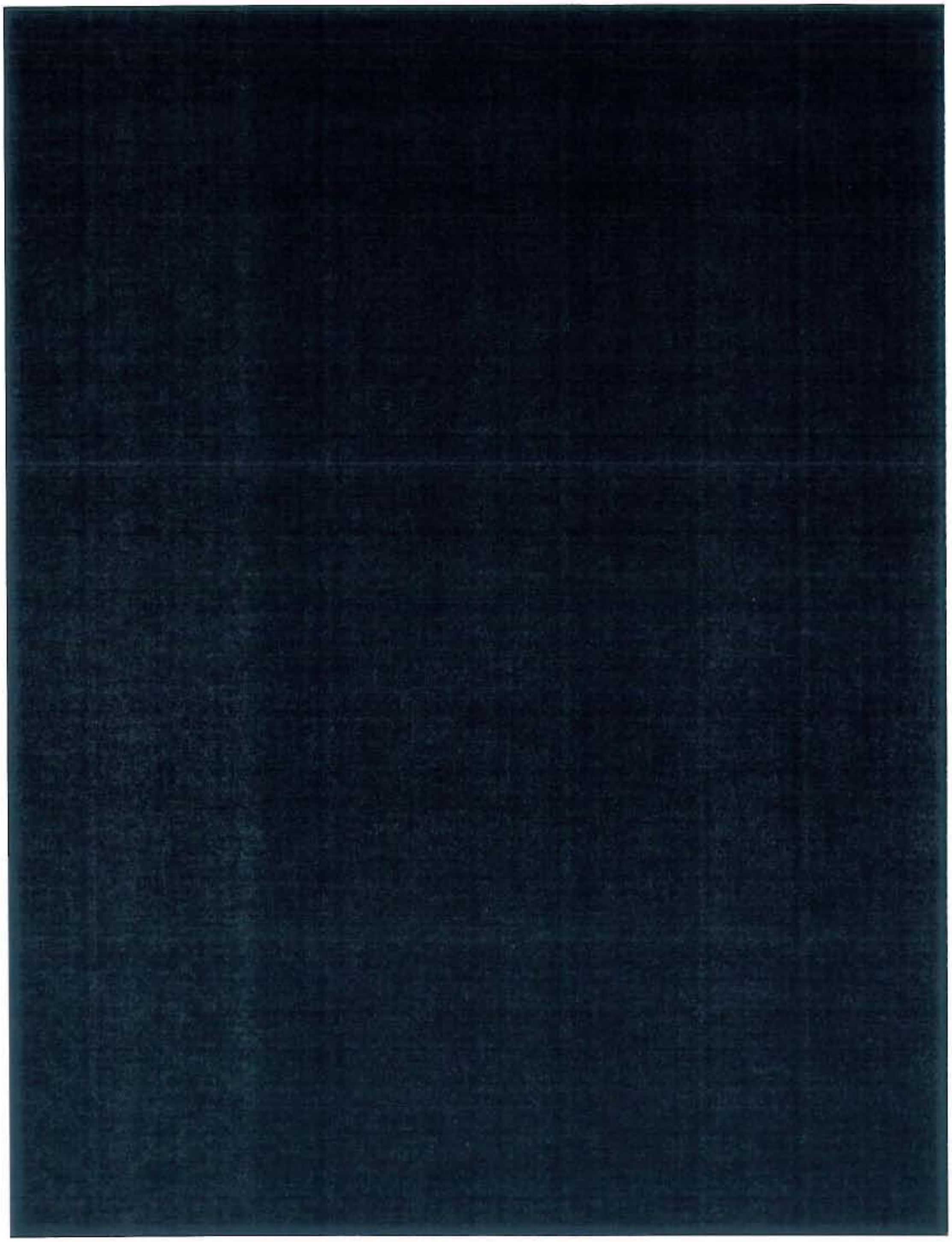
Esplanade (George & Duke) TS:
A1-2GD Bus requires load relief in 2012.

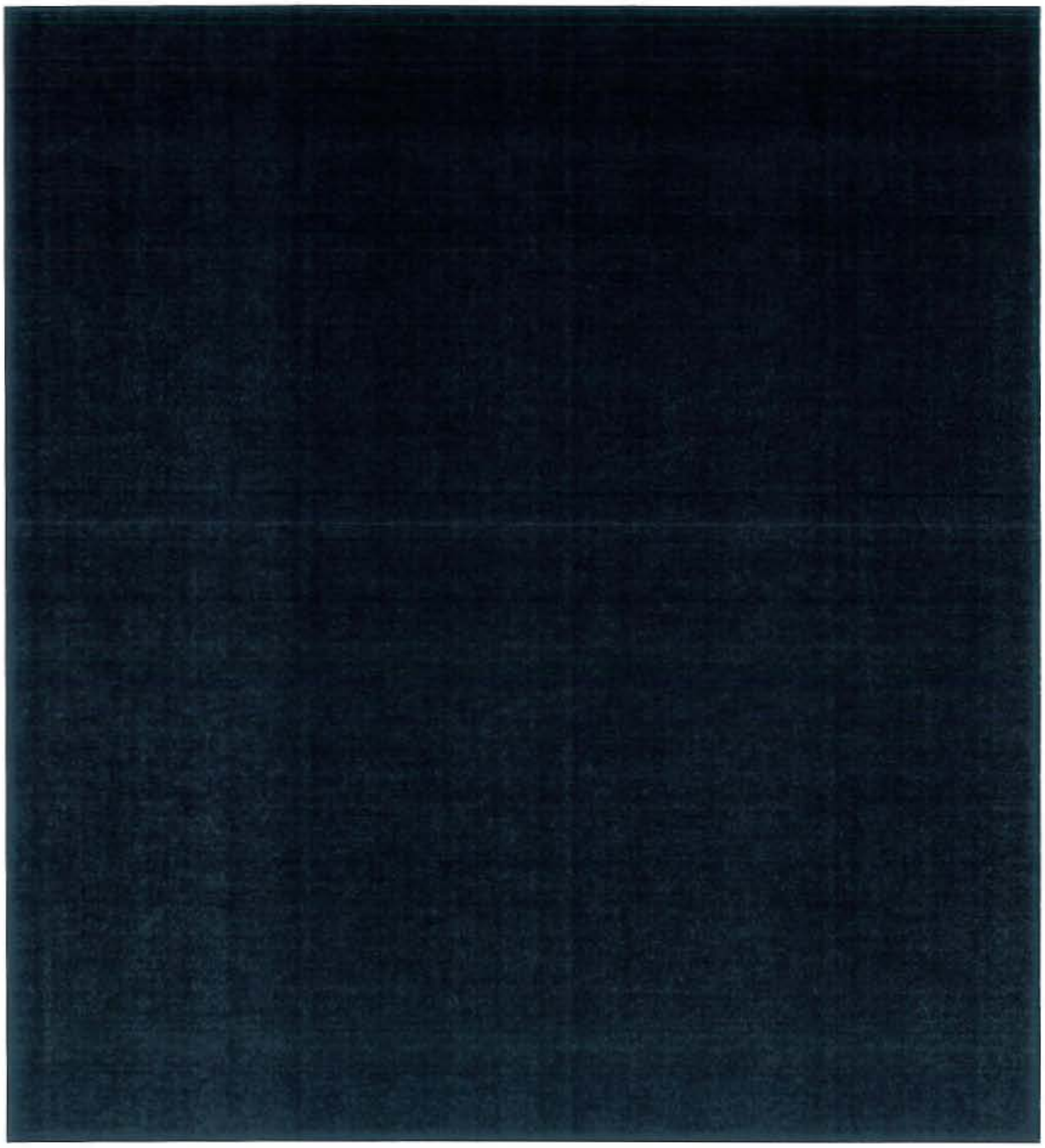
Windsor TS:
A13-14WR Bus requires load relief in 2013.
A17-18WR Bus requires load relief in 2014.

Strachan TS:
A5-6T Bus requires load relief in 2016.
A7-8T Bus requires load relief in 2018.
A1-2T Bus requires load relief in 2020.

Terauley TS:
A5-6A Bus requires load relief in 2019.

Cecil TS:
A7-8CE Bus requires load relief in 2019.
A3-4CE Bus requires load relief in 2020.
A5-6CE Bus requires load relief in 2021.





5 Recommendations

5.1 Recommendations on Distribution System

This load forecast recommends the following actions on the distribution system to relieve heavily loaded buses for the next five years:

Central Toronto Stations

1. Windsor TS: A13-14WR bus requires load transfer of 6 MVA or more in 2013. SRP to review the load transfer plans related to Windsor TS A13-14WR bus.
2. Windsor TS: A17-18WR bus requires load transfer of 3 MVA or more in 2014. SRP to review the load transfer plans related to Windsor TS A17-18WR bus.
3. Esplanade (George & Duke) TS: A1-2GD bus requires 5 MVA load transfer to bus A3-4GD in 2012.
4. Strachan TS: A5-6T bus requires load transfer of 5 MVA or more to bus A9-10T in 2016.

[redacted]

5.2 Recommendations on Transmission System

In addition to the recommendations for load transfer on THESL distribution system, this report also recommends the following actions which are related to HONI transmission system.

This load forecast recommends the following feasibility studies on transmission system to be carried out by HONI:

1. Perform feasibility study to install a second bus of 117 MVA at Runnymede TS.
2. Perform feasibility study to install a second bus of 192 MVA at Horner TS.
3. Perform feasibility study to install a second bus of 72 MVA at Esplanade TS.
4. Perform feasibility study to increase transformer capacity at Bridgman to increase (High Level) TS A5-6H to 72MVA bus.
5. Perform feasibility study to increase transformer size to supply 72MVA for Strachan TS A9-10T bus.
6. Replace CGE transformer (T4) at Ellesmere TS.
7. Replace CGE transformer (T3) at Leslie TS as soon as possible to lift load restriction since load restriction at this station cannot be met.
8. Perform feasibility study to increase capacity at Bathurst TS JQ bus to its maximum rating of 193 MVA (current rating is 158 MVA), limited by transformer T3 capacity.
9. Perform feasibility study to increase capacity at Dufferin TS or develop solution to address long term load growth.
10. Perform feasibility study to install an additional 112 MVA bus at Manby TS or develop solution to address long term load growth.
11. Perform feasibility study to increase capacity at Fairbank TS or develop solution to address long term load growth.

Appendix A

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2012 10 YEARS SUMMER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2012 10 YEARS SUMMER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2011*	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
BREMNER (115KV/13.8KV) TS															
A1-2BR (see note 1)			72	68				55	55	56	57	58	60	61	62
A3-4BR (see note 2)			72	68					39	39	40	41	41	42	43
Total of all Buses			144	136				55	94	95	97	99	101	103	105
Surplus MVA								17	50	49	47	45	43	41	39
% Loading (Load/Future Firm Cap)								76	65	66	67	69	70	72	73

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2012 10 YEARS SUMMER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2011*	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
CECIL (115KV/13.8KV) TS															
A1-2	46	44	46	44	32	31	31	31	32	32	33	34	34	35	36
A3-4	46	44	46	44	35	35	37	38	40	41	41	42	43	44	45
A5-6	72	68	72	68	57	57	57	59	60	61	62	64	65	66	68
A7-8	72	68	72	68	63	60	61	62	63	65	66	67	69	70	71
Total of all Buses	236	224	236	224	187	183	186	190	195	199	202	207	211	215	220
Surplus MVA					49	53	50	46	41	37	34	29	25	21	16
% Loading (Load/2011 Firm Cap)					79	78	79	81	83	84	86	88	89	91	93

Cecil TS:
A3-4 Bus requires load relief in 2020

Cecil TS:
A5-6 Bus requires load relief in 2021

Cecil TS:
A7-8 Bus requires load relief in 2019

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2012 10 YEARS SUMMER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2011*	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
[redacted]															
ESPLANADE (115KV/13.8KV) TS															
A1-2GD	69	66	69	66	68	67	68	70	68	69	70	72	73	75	76
A3-4GD (Formerly A5-6GD)	72	68	72	68	57	56	57	58	59	60	61	63	64	65	66
A1-2X	69	66	69	66	55	57	59	61	51	52	53	54	55	56	57
Total of all Buses	210	200	210	200	180	180	184	189	178	181	184	189	192	196	199
Surplus MVA					30	30	26	21	32	29	26	21	18	14	11
% Loading (Load/2011 Firm Cap)					86	86	88	90	85	86	88	90	91	93	95
[redacted]															

Esplanade TS:
A1-2GD Bus requires load relief in 2012

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2012 10 YEARS SUMMER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2012 10 YEARS SUMMER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2012 10 YEARS SUMMER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2012 10 YEARS SUMMER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

[redacted]

STRACHAN (115KV/13.8KV) TS															
A1-2	56	53	56	53	41	43	45	47	48	49	50	51	52	53	54
A9-10 (Formerly A3-4)	56	53	56	53	30	27	30	32	33	34	35	36	36	37	38
A5-6	40	38	40	38	33	31	34	36	37	38	38	39	40	41	42
A7-8	40	38	40	38	34	37	34	35	35	36	37	38	38	39	40
Total of all Buses	192	182	192	182	138	138	143	150	153	157	160	164	166	170	174
Surplus MVA					54	54	49	42	39	35	32	28	26	22	18
% Loading (Load/2011 Firm Cap)					72	72	74	78	80	82	83	85	86	89	91

Strachan TS:
A5-6 Bus requires load relief in 2016

Strachan TS:
A7-8 Bus requires load relief in 2018

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2012 10 YEARS SUMMER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2011*	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
TERAULEY (115KV/13.8KV) TS															
A1-2	68	65	68	65	48	48	49	50	51	52	53	54	55	56	57
A3-4	72	68	72	68	43	49	51	53	54	55	56	57	58	59	61
A5-6	66	63	66	63	58	56	56	58	59	60	61	62	64	65	66
A9-10 (Formerly A7-8)	55	52	55	52	41	40	40	40	41	42	43	44	45	46	46
Total of all Buses (see note 1)	240	240	240	240	190	193	196	201	205	209	213	217	222	226	230
Surplus MVA					50	47	44	39	35	31	27	23	18	14	10
% Loading (Load/2011 Firm Cap)					79	80	82	84	85	87	89	90	93	94	96

Terauley TS:
A5-6 Bus requires load relief in 2019

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2012 10 YEARS SUMMER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2011*	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
WINDSOR (115KV/13.8KV) TS															
A11-12	69	66	69	66	56	61	51	53	41	42	42	0	0	24	25
A13-14	41	39	41	39	37	37	43	44	45	46	47	48	49	50	51
A15-16	69	66	69	66	67	64	64	66	59	60	61	63	64	41	42
A17-18	49	47	49	47	44	42	42	48	49	50	50	52	53	54	55
A3-4	64	61	64	61	51	51	55	56	51	0	0	43	44	45	46
A5-6	64	61	64	61	56	55	61	0	0	52	53	54	55	57	58
Total of all Buses	356	340	356	340	311	310	316	267	245	250	253	260	265	271	277
Surplus MVA					45	46	40	89	111	106	103	96	91	85	79
% Loading (Load/2011 Firm Cap)					87	87	89	75	69	70	71	73	74	76	78

Windsor TS: A13-14 Bus requires load relief in 2013

Windsor TS: A17-18 Bus requires load relief in 2014

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2012 10 YEARS WINTER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2012 10 YEARS WINTER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2011*	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
BREMNER (115KV/13.8KV) TS															
A1-2BR			72	68				55	55	56	57	58	60	61	62
A3-4BR			72	68					39	40	41	41	42	43	44
Total of all Buses			144	136				55	94	96	98	99	102	104	106
Surplus MVA								17	50	48	46	45	42	40	38
% Loading (Load/2011 Firm Cap)								76	65	67	68	69	71	72	74

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2012 10 YEARS WINTER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2011*	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
CECIL (115KV/13.8KV) TS															
A1-2	46	44	46	44	18	18	18	18	18	19	19	19	20	20	21
A3-4	46	44	46	44	28	28	30	32	33	35	36	36	37	38	38
A5-6	72	68	72	68	41	43	44	45	46	47	48	49	50	51	52
A7-8	72	68	72	68	49	49	50	51	52	53	54	55	57	58	59
Total of all Buses	236	224	236	224	136	138	142	146	149	154	157	159	164	167	170
Surplus MVA					100	98	94	90	87	82	79	77	72	69	66
% Loading (Load/2011 Firm Cap)					58	58	60	62	63	65	67	67	69	71	72

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2012 10 YEARS WINTER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2011*	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
[redacted]															
ESPLANADE (115KV/13.8KV) TS															
A1-2GD	72	68	72	68	52	53	53	55	53	54	55	56	57	59	60
A3-4GD (Formerly A5-6GD)	72	68	72	68	43	45	46	47	48	49	50	51	52	53	54
A1-2X	72	68	72	68	43	45	49	52	53	43	43	44	45	46	47
Total of all Buses	216	204	216	204	138	143	148	154	154	146	148	151	154	158	161
Surplus MVA					78	73	68	62	62	70	68	65	62	58	55
% Loading (Load/2011 Firm Cap)					64	66	69	71	71	68	69	70	71	73	75
[redacted]															

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2012 10 YEARS WINTER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2012 10 YEARS WINTER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2012 10 YEARS WINTER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

[redacted]

STRACHAN (115KV/13.8KV) TS															
A1-2	56	53	56	53	36	41	42	44	45	47	48	49	50	51	52
A9-10 (Formerly A3-4)	56	53	56	53	27	29	28	30	32	32	33	34	34	35	36
A5-6	48	46	48	46	27	26	28	31	32	34	34	35	36	36	37
A7-8	48	46	48	46	26	25	31	28	29	29	30	30	31	32	32
Total of all Buses	208	198	208	198	116	121	129	133	138	142	145	148	151	154	157
Surplus MVA					92	87	79	75	70	66	63	60	57	54	51
% Loading (Load/2011 Firm Cap)					56	58	62	64	66	68	70	71	73	74	75

* Actual 2010/2011 winter peaks

1. Bus load includes load supplied to Veridian (formerly Pickering Hydro)

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2012 10 YEARS WINTER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2011*	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
TERAULEY (115KV/13.8KV) TS															
A1-2	72	68	72	68	44	45	45	46	47	48	49	50	51	52	53
A3-4	72	68	72	68	34	34	42	44	46	47	48	49	50	51	52
A5-6	66	63	66	63	43	44	44	45	46	47	47	48	49	50	51
A9-10 (Formerly A7-8)	55	52	55	52	31	31	31	32	32	33	34	34	35	36	36
Total of all Buses (see note 1)	240	240	240	240	152	154	162	167	171	175	178	181	185	189	192
Surplus MVA					88	86	78	73	69	65	62	59	55	51	48
% Loading (Load/2011 Firm Cap)					63	64	68	70	71	73	74	75	77	79	80

[redacted]

TORONTO HYDRO ELECTRIC SYSTEM LIMITED
2012 10 YEARS WINTER LOAD FORECAST
(SYSTEM COINCIDENT PEAKS - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR										
	PRESENT		FUTURE												
	100%	95%	100%	95%	2011*	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
WINDSOR (115KV/13.8KV) TS															
A11-12	72	68	72	68	50	52	46	48	56	38	39	0	0	21	21
A13-14	48	46	48	46	27	27	33	34	34	35	36	37	37	38	39
A15-16	72	68	72	68	53	52	52	53	48	47	48	48	49	26	27
A17-18	58	55	58	55	35	36	36	-9	41	42	43	44	44	45	46
A3-4	64	61	64	61	39	41	42	46	47	0	0	32	33	34	34
A5-6	64	61	64	61	42	43	50	39	0	42	43	43	44	45	46
Total of all Buses	378	359	378	359	246	251	259	211	226	204	209	204	207	209	213
Surplus MVA					132	127	119	167	152	174	169	174	171	169	165
% Loading (Load/2010 Firm Cap)					65	66	69	56	60	54	55	54	55	55	56

[redacted]

TORONTO HYDRO-ELECTRIC SYSTEM
2012 LOAD FORECAST SUMMARY
MAJOR STATION PROJECTS

STATION	BUS	2011 FORECAST IN-SERVICE DATE	2012 FORECAST IN-SERVICE DATE	COMMENTS
[redacted]				
BREMNER TS	A1-2BR	2013	2014	Construct new building and install two (2) new transformers & new 72MVA A1-2BR bus
BREMNER TS	A3-4BR	2014	2015	Install new 72MVA A3-4BR bus
[redacted]				
ESPLANADE TS	A3-4X	Spring 2020	Spring 2020	Expand existing building & install two (2) new transformers & new 72MVA A3-4X bus (Hydro One & Toronto Hydro)
CECIL TS	A1-2CE, A3-4CE	Spring 2023	Spring 2023	Upgrade T1 to 60/80/100MVA and A1-2CE, A3-4CE to 3000A (Hydro One & Toronto Hydro)
BREMNER TS	A5-6BR	Spring 2028	Spring 2028	Install two (2) new transformers & new 72MVA A5-6BR bus
BREMNER TS	A7-8BR	Spring 2030	Spring 2030	Install new 72MVA A7-8BR bus
STRACHAN TS	A1-2T	>2032	>2032	Installation & connection of new transformer T16 to the existing A1-2T Bus (Hydro One)
STRACHAN TS	A9-10T	>2032	>2032	Installation & connection of new transformer T16 to the new A9-10T Bus (Hydro One)
STRACHAN TS	A1-2T	>2032	>2032	Installation & connection of new transformer T17 to the existing A1-2T Bus (Hydro One)
STRACHAN TS	A9-10T	>2032	>2032	Installation & connection of new transformer T17 to the new A9-10T Bus (Hydro One)

[redacted]

[redacted]

[redacted]

[redacted]

TORONTO HYDRO-ELECTRIC SYSTEM
2012 CENTRAL TORONTO TS's
SUMMER LOAD FORECAST
(SYSTEM CO-INCIDENT PEAK - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR																									
	PRESENT		FUTURE																											
	100%	95%	100%	95%	2011*	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
BREMNER (115KV/13.8KV) TS																														
A1-2BR			72	68				55	55	56	57	58	60	61	62	63	64	66	67	68	70	71	73	74	76	77	79	80	82	83
A3-4BR			72	68					39	39	40	41	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58
Total of all Buses			144	136				55	94	95	97	99	101	103	105	107	109	112	114	116	119	121	124	126	129	131	134	136	139	141
Surplus MVA								17	50	49	47	45	43	41	39	37	35	32	30	28	25	23	20	18	15	13	10	8	5	3
% Loading (Load/2011 Firm Cap)								76	65	66	67	69	70	72	73	74	76	78	79	81	83	84	86	88	90	91	93	94	97	98
CECIL (115KV/13.8KV) TS																														
A1-2	46	44	46	44	32	31	31	31	32	32	33	34	34	35	36	37	37	38	39	40	40	41	42	43	44	44	45	46	47	48
A3-4	46	44	46	44	35	35	37	38	40	41	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60
A5-6	72	68	72	68	57	57	57	59	60	61	62	64	65	66	68	69	70	72	73	75	76	78	79	81	82	84	86	87	89	91
A7-8	72	68	72	68	63	60	61	62	63	65	66	67	69	70	71	73	74	76	77	79	80	82	84	85	87	89	91	92	94	96
Total of all Buses	236	224	236	224	187	183	186	190	195	199	202	207	211	215	220	225	228	234	238	244	247	253	258	263	268	273	279	283	289	295
Surplus MVA					49	53	50	46	41	37	34	29	25	21	16	11	8	2	-2	-8	-11	-17	-22	-27	-32	-37	-43	-47	-53	-59
% Loading (Load/2011 Firm Cap)					79	78	79	81	83	84	86	88	89	91	93	95	97	99	101	103	105	107	109	111	114	116	118	120	122	125
ESPLANADE (115KV/13.8KV) TS																														
A1-2GD	69	66	69	66	68	67	68	70	68	69	70	72	73	75	76	78	79	81	83	84	86	88	89	91	93	95	97	99	101	103
A3-4GD (Formerly A5-6)	72	68	72	68	57	56	57	58	59	60	61	63	64	65	66	68	69	71	72	73	75	76	78	79	81	83	84	86	88	89
A1-2X	69	66	69	66	55	57	59	61	51	52	53	54	55	56	57	59	60	61	62	63	65	66	67	69	70	71	73	74	76	77
Total of all Buses	210	200	210	200	180	180	184	189	178	181	184	189	192	196	199	205	208	213	217	220	226	230	234	239	244	249	254	259	265	269
Surplus MVA					30	30	26	21	32	29	26	21	18	14	11	5	2	-3	-7	-10	-16	-20	-24	-29	-34	-39	-44	-49	-55	-59
% Loading (Load/2011 Firm Cap)					86	86	88	90	85	86	88	90	91	93	95	98	99	101	103	105	108	110	111	114	116	119	121	123	126	128
STRACHAN (115KV/13.8KV) TS																														
A1-2	56	53	56	53	41	43	45	47	48	49	50	51	52	53	54	55	56	57	58	60	61	62	63	65	66	67	69	70	71	73
A9-10 (Formerly A3-4)	56	53	56	53	30	27	30	32	33	34	35	36	36	37	38	38	39	40	41	42	42	43	44	45	46	47	48	49	50	51
A5-6	40	38	40	38	33	31	34	36	37	38	38	39	40	41	42	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56
A7-8	40	38	40	38	34	37	34	35	35	36	37	38	38	39	40	41	41	42	43	44	45	46	47	48	49	50	51	52	53	54
Total of all Buses	192	182	192	182	138	138	143	150	153	157	160	164	166	170	174	176	179	183	187	192	195	199	203	208	212	216	221	225	229	234
Surplus MVA					54	54	49	42	39	35	32	28	26	22	18	16	13	9	5	0	-3	-7	-11	-16	-20	-24	-29	-33	-37	-42
% Loading (Load/2011 Firm Cap)					72	72	74	78	80	82	83	85	86	89	91	92	93	95	97	100	102	104	106	108	110	113	115	117	119	122
TERAULEY (115KV/13.8KV) TS																														
A1-2	68	65	68	65	48	48	49	50	51	52	53	54	55	56	57	58	60	61	62	63	64	66	67	68	70	71	73	74	75	77
A3-4	72	68	72	68	43	49	51	53	54	55	56	57	58	59	61	62	63	64	66	67	68	70	71	72	74	75	77	78	80	82
A5-6	66	63	66	63	58	56	56	58	59	60	61	62	64	65	66	67	69	70	72	73	74	76	77	79	81	82	84	86	87	89
A9-10 (Formerly A7-8)	55	52	55	52	41	40	40	40	41	42	43	44	45	46	46	47	48	49	50	51	52	53	54	55	57	58	59	60	61	62
Total of all Buses (see note 1)	240	240	240	240	190	193	196	201	205	209	213	217	222	226	230	234	240	244	250	254	258	265	269	274	282	286	293	298	303	310
Surplus MVA					50	47	44	39	35	31	27	23	18	14	10	6	0	-4	-10	-14	-18	-25	-29	-34	-42	-46	-53	-58	-63	-70
% Loading (Load/2011 Firm Cap)					79	80	82	84	85	87	89	90	93	94	96	98	100	102	104	106	108	110	112	114	118	119	122	124	126	129

* Actual 2011 summer peaks.

1. Terauley TS's total bus capacity is 261MVA, but its FIRM capaciaty is limited to 240MVA due to Hydro One's 115kV Cecil-Terauley C5E & C7E circuits' rating.

TORONTO HYDRO-ELECTRIC SYSTEM
2012 CENTRAL TORONTO TS's
SUMMER LOAD FORECAST
(SYSTEM CO-INCIDENT PEAK - MVA)

STATION / BUS	FIRM CAPACITY(MVA)				YEAR																									
	PRESENT		FUTURE																											
	100%	95%	100%	95%	2011*	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
WINDSOR (115KV/13.8KV) TS																														
A11-12	69	66	69	66	56	61	51	53	41	42	42	0	0	24	25	25	26	26	27	27	28	29	29	30	30	31	31	32	33	33
A13-14	41	39	41	39	37	37	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	61	62	63	64	66	67	68
A15-16	69	66	69	66	67	64	64	66	59	60	61	63	64	41	42	43	44	44	45	46	47	48	49	50	51	52	53	54	55	56
A17-18	49	47	49	47	44	42	42	48	49	50	50	52	53	54	55	56	57	58	59	60	62	63	64	65	67	68	69	71	72	74
A3-4	64	61	64	61	51	51	55	56	51	0	0	43	44	45	46	47	48	49	49	50	51	53	54	55	56	57	58	59	60	62
A5-6	64	61	64	61	56	55	61	0	0	52	53	54	55	57	58	59	60	61	62	64	65	66	68	69	70	72	73	75	76	78
Total of all Buses	356	340	356	340	311	310	316	267	245	250	253	260	265	271	277	282	288	292	297	303	310	317	323	330	336	343	348	357	363	371
Surplus MVA					45	46	40	89	111	106	103	96	91	85	79	74	68	64	59	53	46	39	33	26	20	13	8	-1	-7	-15
% Loading (Load/2011 Firm Cap)					87	87	89	75	69	70	71	73	74	76	78	79	81	82	83	85	87	89	91	93	94	96	98	100	102	104
Total of all Stations																														
Bus Total	1234	1186	1378	1322	1006	1004	1025	1052	1070	1091	1109	1136	1157	1181	1205	1229	1252	1278	1303	1329	1355	1385	1411	1440	1471	1498	1529	1558	1588	1620
Surplus MVA					228	230	209	254	308	287	269	242	221	197	173	149	126	100	75	49	23	-7	-33	-62	-93	-120	-151	-180	-210	-242
% Loading (Load/2011 Firm Cap)					82	81	83	81	78	79	80	82	84	86	87	89	91	93	95	96	98	101	102	104	107	109	111	113	115	118
Total of all Stations																														
Future 100% FIRM Capacity								1306	1378						1450			1502					1574		1646					
Surplus MVA (Fut. FIRM Cap. - Load)					228	230	209	254	308	287	269	242	221	197	245	221	198	226	201	175	149	119	165	136	177	150	119	90	60	28
% Loading (Load/Fut. FIRM Cap.)					82	81	83	81	78	79	80	82	84	86	83	85	86	85	87	88	90	92	90	91	89	91	93	95	96	98

* Actual 2011 summer peaks.

72MVA addition, A1-2BR - 2014
72MVA addition, A3-4BR - 2015
72MVA addition, A3-4X - 2020
52MVA addition, Cecil TS - 2023
72MVA addition, A7-8BR - 2028
72MVA addition, A9-10BR - 2030

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 7:

Reference(s): **Reference: Tab 4, Schedule B17, Appendix 3, page 10, Table 4**

Has Toronto Hydro estimated the potential for incremental cost-effective energy efficiency and demand response options to reduce the demands of the downtown transformer stations between 2012 and 2026? If yes, please provide these estimates for each year from 2012 to 2026 inclusive and please break out the results by the service areas of each of the five transformer stations and for each transformer station please break out the demands by rate class. Please also provide the reports and analyses that support your estimates.

RESPONSE:

No, THESL has not developed an estimate of additional incremental energy efficiency and demand response options for the area served by the five downtown transformer stations. THESL's projections of the impact of energy efficiency and demand response activities are limited to province wide programs funded by the OPA until the end of 2014, as there is currently no mechanism for funding incremental energy efficiency and demand response programs on a localized basis. The estimated impact of the current OPA-funded programs is shown in Tab 4, Schedule B17, Appendix3, Table 2 (page 8).

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 8:

Reference(s): **Tab 4, Schedule B17, Appendix 3, page 17**

According to the Navigant Business Case Analysis:

> "The results of the study indicated significant technical potential for DG in Toronto, but amounts likely to be installed as uncertain. Estimates of the potential market penetration for customer-connected distributed generation in Central and Downtown Toronto ranged from 140 MW in the medium term to more than 550 MW in the long-term….
>
> One of the key findings of these studies is the difficulty of siting DG in dense downtown load areas, particularly on secondary grid networks….. The ability to install rotating devices (e.g., synchronous generators) is limited by fault current limits, and by the likely de-sensitization of network protectors, which are not designed to accommodate generators."

After Hydro One has completed its short-circuit upgrades at its Leaside, Hearn and Manby Transformer Stations, how many megawatts (MW) of natural gas-fired generation capacity will it be technically possible to install in the Downtown Core? Please break out this estimate according to the service areas of each of the five downtown transformer stations.

RESPONSE:

From a distribution system perspective, technical constraints are based on either short circuit levels (fault current), thermal capacity, or reverse power flow. The distribution system limits currently are Windsor TS (53 MW DG), Terauley TS (43 MW DG), Cecil TS (30 MW DG), Esplanade TS (19 MW DG) and Strachan TS (29 MW DG). This

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

totals 174 MW of synchronous DG as an area limit, ignoring any upstream transmission (Hydro One) constraints.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 9:

Reference(s): Tab 4, Schedule B17, Appendix 3, page 17

Please describe Toronto Hydro's programs, budgets and timetables to increase the amount of natural gas-fired generation capacity that can be installed in the Downtown Core.

Please quantify the incremental amount of natural gas-fired generation capacity (MW) that will be able to be installed in the Downtown Core in each year between 2012 and 2021 as a result of Toronto Hydro's actions.

Please break out your incremental capacity estimates by year and for the service areas of each of the five downtown transformer stations.

RESPONSE:

While THESL has no incentive programs to increase DG capacity in the downtown core, it does have a dedicated interconnections team which supports requests for new generation capacity, consistent with the Distribution System Code and other IESO and OEB requirements. THESL expects to prepare a GEA Plan submission to the OEB which aims to enable renewable generation and development of its smart grid.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 10:

Reference(s): **Tab 4, Schedule B17, Appendix 3, pages 10 & 17**

According to the Navigant Business Case Analysis:

> "The results of the DG study indicate there is considerable uncertainty that customers will install DG in an amount sufficient to back up Windsor or to defer station capacity needed to serve downtown Toronto."

Please provide your estimates of the amount of the incremental natural gas-fired generation capacity that would be needed, in each year from 2017 to 2026 inclusive, to back up Windsor and defer station capacity needed to serve downtown Toronto.

RESPONSE:

The rationale for Bremner TS is primarily based on reliability and capacity.

1) Reliability:

   Windsor TS is a six-bus arrangement, each typically with a 69MVA capacity, with heavy loading on each bus reaching 85% station capacity in 2011. The required firm incremental DG needed to support one of these buses is estimated at 86 MW (assuming a PF=1.0) to allow a 25% reserve margin for DG outages. This 86 MW DG would potentially allow switchgear upgrades at Windsor to address reliability issues with a multi-year program.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

2) Capacity:

Bremner TS load is forecast to reach 116 MVA by 2026 and would require a further 145 MW DG to satisfy capacity due to area growth (using a 25% reserve and assuming a PF=1.0).

In total, there is expected to be a need for 86 MW (for reliability) and 145 MW (for capacity), or a total of 231 MW of new firm DG capacity tied directly to the Windsor TS bus. The fault capacity of the upstream system would need to accommodate approximately six times this value, or 1,386 MVA, which will not be available even after Leaside/Manby/ Hearn upgrades.

In addition, a DG solution in such a dense urban environment would likely create substantial air/noise emissions and would likely not provide the inherent reliability of paired transmission circuits.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 11:

Reference(s): **Tab 4, Schedule B17, Appendix 3, page 17**

Please describe Toronto Hydro's actions to persuade the Ontario Power Authority to contract for natural gas-fired distributed generation capacity to back up Windsor and to defer the need for additional transformer station capacity to serve downtown Toronto.

Please provide copies of all your correspondence with the OPA on this issue.

RESPONSE:

THESL is not directly advocating that the OPA contract for DG to back up Windsor TS. Work has been initiated on the Toronto Regional Plan, which involves the OPA, IESO, THESL and Hydro One. THESL expects that the Toronto Regional Plan will examine transmission, generation and conservation options. Results are expected to be available in mid-2013.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 12:

Reference(s): **Tab 4, Schedule B17, Appendix 3, page 17**

Would Toronto Hydro be willing to own and operate natural gas-fired generation capacity in downtown Toronto to back up Windsor and to defer the need for new transformer station capacity, if the Ontario Energy Board were to permit the inclusion of these assets in its rate base? If no, please explain why not.

RESPONSE:

THESL cannot provide a categorical response (i.e., 'yes' or 'no') because the question as posed is hypothetical and does not specify an adequate level of detail concerning other important factors which would bear on the decision. THESL has not previously considered this question because the arrangement is not permitted under current rules. If the hypothetical arrangement were to become permitted under changed rules, THESL would need to consider several other contingent factors including siting and financial feasibility, risks, and the extent to which generation capacity would defer the need for transformer station capacity, before it could come to a position on the proposal. Any further comment at this time would be purely speculative.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 13:

Reference(s): Tab 4, Schedule B17, Appendix 3, page 17

Has Toronto Hydro had any discussions with the City of Toronto regarding the City of Toronto owning such generation, with Toronto Hydro being responsible for operation and maintenance?

Have there been any similar discussions held with Enwave? If yes, please provide copies of all of your correspondence with the City of Toronto and/or Enwave on this issue.

RESPONSE:

THESL has not had discussions with the City of Toronto regarding the City owning gas-fired generation. Over the past decade, THESL has had exploratory discussions with Enwave regarding gas-fired generation opportunities in Toronto, but is not aware of any correspondence on this subject.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 14:

Reference(s): **Tab 4, Schedule B17, Appendix 3, page 11**

According to the Navigant Business Case Analysis:

> "The greatest outage risk to customers in downtown Toronto is a catastrophic outage, such as the loss of multiple transmission supply lines…" (see Tab 4, Schedule B17, Appendix 3, page 11)

According to the Ontario Power Authority's Integrated Power System Plan:

> "An extreme event resulting in a Leaside station loss would result in the isolation of the Leaside system from the rest of the network for potentially several days….This leaves about 300 MW of load that would be unsupplied and rotating outages for this load would be required." (see EB-2007-0707, Exhibit E, Schedule 5, page 21)

Please fully describe Toronto Hydro's programs and budgets to eliminate or mitigate the risk of unsupplied load in Toronto in the event of the loss of Hydro One's Leaside Transformer Station.

RESPONSE:

The risk of unsupplied load from Bremner TS will be mitigated by having transmission line connections from both the West at John TS and from the East at Esplanade TS. There will also be redundant transformers and a high level of bus inter-connectivity at the station.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

Leaside TS is a Hydro One-owned station separate and distinct from Bremner TS. THESL does not have programs designed to eliminate or mitigate risks impacting Hydro One-owned facilities, but does routinely cooperate with Hydro One, the OPA, and the IESO in developing solutions to electricity supply issues affecting the Toronto area.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 15:

Reference(s): **Tab 4, Schedule B17, Appendix 3, page 11**

Please provide your best estimate of the number of megawatts (MW) of diesel back-up generating capacity in the downtown core.

Please provide a break-out of your estimate according to the service areas of each of the five downtown transformer stations.

RESPONSE:

Based on discussions with industry suppliers and building owners, THESL estimates that approximately 150 MW of diesel back-up generation capacity exists in the downtown core. A break-out by service area of each of the downtown transformer stations is not available.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 16:

Reference(s): **Tab 4, Schedule B17, Appendix 3, pages 15 & 16**

Please state the number of peaksaver and peaksaver plus customers in the service areas of each of the five downtown transformer stations in 2011 and during the summer of 2012.

Please state the days during 2011 and 2012 when these customers were curtailed and please provide for each day the resulting reductions in the demands of

a) peaksaver; and
b) peaksaver plus customers

for each of the five downtown transformer stations.

RESPONSE:

The estimated number of ***peaksaver*** customers in the service areas of the five downtown transformer stations is detailed below. The ***peaksaverPlus*** program has only recently (September 2012) started, as THESL was awaiting ESA approval to commence installation of the equipment.

Transformer Station	Total Number of *peaksaver* Customers as of 2012
Cecil	234
Esplanade	186
Strachan	466
Terauley	25
Windsor	34
DOWNTOWN TOTALS	945

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

The ***peaksaver*** events in 2011 and 2012 are detailed below:

Event Day	Transformer Station	OPA-Assigned Reduction (kW)	THESL Actual Reductions (kW)
Jul-21-2011	Cecil	131	168
	Esplanade	104	134
	Strachan	261	336
	Terauley	14	18
	Windsor	19	24
DOWNTOWN TOTALS		529	680
Jun-20-2012	Cecil	131	176
	Esplanade	104	140
	Strachan	261	350
	Terauley	14	19
	Windsor	19	26
DOWNTOWN TOTALS		529	709
Jul-06-2012	Cecil	131	164
	Esplanade	104	130
	Strachan	261	326
	Terauley	14	18
	Windsor	19	24
DOWNTOWN TOTALS		529	662

Note:

The OPA credited reductions are based on provincial averages, as compared to THESL values which are based on measured actuals.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 17:

Reference(s): Tab 4, Schedule B17, Appendix 3, pages 15 & 16

Please state the potential number of peaksaver and peaksaver plus customers in the service areas of each of the five downtown transformer stations.

RESPONSE:

THESL has an expected growth in the total number of residential demand response (RDR) customers (***peaksaver*** and ***peaksaverPlus***) customers of 25% by the end of 2014. As THESL does not have specific growth information at the transformer level, the data below has been extrapolated from this growth target for information purposes. The total number of potential RDR customers was determined by data analysis of single family residences that have air conditioning in the areas served by the five transformers.

Transformer Station	Total Number of Existing RDR Customers	Total Number of Potential RDR Customers	THESL Forecasted New RDR Customers by End of 2014	THESL Forecasted RDR Customers by End of 2014
Cecil	234	919	59	293
Esplanade	186	720	46	232
Strachan	466	1,837	118	584
Terauley	25	99	6	31
Windsor	34	124	8	42
DOWNTOWN TOTALS	945	3,700	238	1,183

Please note that the ***peaksaver*** program ended in August 2011 and was replaced by the ***peaksaverPlus*** program going forward.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 18:

Reference(s): Tab 4, Schedule B17, Appendix 3, pages 15 & 16

Please provide a break-out of the number of the Ontario Power Authority's ("OPA") non-residential demand response program participants (e.g., DR1, DR2, DR3) in the service areas of each of the five downtown transformer stations in 2011 and the summer of 2012.

Please state the days during 2011 and 2012 when these customers were curtailed and please provide for each day the resulting reductions in demand for each of the five downtown transformer stations.

RESPONSE:

Information regarding specific DR-3 participants is not available to THESL due to contractual obligations between the aggregators and participants. There has been no DR1 and DR2 program participation in THESL's service territory.

DR-3 was activated on the following days in 2011:
May 31, June 6, June 7, June 8, July 11, July 21, July 22, August 2, August 4, November 21, and November 22.

To date, DR-3 has been activated on the following days in 2012:
June 20, June 21, July 17, September 5, and September 6.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 19:

Reference(s): Tab 4, Schedule B17, Appendix 3, pages 15 & 16

Has Toronto Hydro requested funding from the OPA for incremental conservation and demand management programs to defer the need for new transformer station capacity in downtown Toronto?

If yes, please provide copies of all your correspondence with the OPA on this issue.

If no, please explain why not.

RESPONSE:

No. The OPA only funds programs that address provincial conservation demand reduction targets. These programs are available to all local distribution companies and are by their nature not designed to address local distribution issues and constraints.

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 20:

Reference(s): **Tab 4, Schedule B17, Appendix 3, pages 15 & 16**

According to the Navigant Business Case Analysis:

> "Equally important is the compelling need to change out obsolete and heavily loaded switchgear busses at Windsor. One of the primary reasons new station capacity is needed downtown is to provide back-up support while switchgear is sequentially removed and upgraded at Windsor. Several of the busses at Windsor will soon be overloaded. Table 5 presents Windsor bus load forecast, indicating overloads by 2014. Because of the grid network configuration and load location, further balancing of load among the busses is difficult." (pages 10 & 11)
>
> "Current Conservation and Demand Management (CDM) programs will not defer the need for additional station capacity in downtown Toronto. Accelerated efforts and targeted CDM also will not materially defer the need for station capacity in downtown Toronto. A large DG unit with firm capability could defer the need for new capacity; however, there is no indication at this time that firm DG in amounts needed to meet capacity deficits will be installed to prior to need dates, nor does it provide the back-up needed to replace switchgear at Windsor." (page 29)

According to Table 4 of the Navigant Business Case Analysis, the peak demand at Windsor in 2011 was 304 MW. How long would it take to replace a switchgear bus at Windsor? How many MW of capacity would be lost while a switchgear bus is being replaced? How many MW of conservation and demand management or distributed generation is needed to provide back-up when a switchgear bus at Windsor is replaced?

RESPONSES TO POLLUTION PROBE INTERROGATORIES ON ISSUE 2.2

RESPONSE:

A switchgear replacement project such as the planned replacement of A5-6 at Windsor TS could span up to three years. This would include all engineering, procurement, construction and commissioning processes. The entire capacity of the existing bus would be lost during replacement. For a Windsor TS bus, this is 72MVA. THESL does not accept the premise of the question that conservation and demand management or distributed generation could provide back-up when a switchgear bus at Windsor TS is replaced. In theory, at least 72MVA of firm, highly reliable capacity would need to be installed locally to support the replacement of a Windsor TS bus.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 10:

Reference(s): none provided

Please provide the Applicant's 2010, 2011 and 2012 SAIDI, SAIFI and CAIDI numbers.

RESPONSE:

Please see the response in AMPCO 5 part a) (Tab 6F, Schedule 2-5).

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 11:

Reference(s): EB-2010-0142 Ex. D/6/1/p.16

With respect to the 2011 capital budget contained in Table 2, please expand the table to include the following columns:

a) Revised 2011 Test Year budgeted amount incorporating the Settlement Agreement approved by the Board

RESPONSE:

a) The OEB has historically approved overall total amounts for capital expenditures; it has not divided that amount between particular capital portfolios. As a result, the 2011 Test Year budget cannot be displayed in the form requested; the assignment of the Settlement Agreement to THESL's capital budget categories would not reflect the OEB's decision. For 2011 the approved capital expenditure funding was $378.8M.

b) 2011 actual year end actuals

RESPONSE:

b) See table below:

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

	2011 Actual
OPERATIONAL INVESTMENTS	
Grid System Investments	
Underground System	99.0
Overhead System	39.3
Network System	4.8
Stations	18.2
Total Grid System Investments	161.4
Reactive Work	28.6
Customer Connections	58.2
Customer Capital Contribution	(29.8)
Externally Initiated Plant Relocations	7.8
Capital Contributions to HONI	27.8
Engineering Capital	23.6
AFUDC	5.2
Other	(4.2)
Total Distribution Plant Capital	278.6
CORPORATE OPERATIONAL INVESTMENTS	
Fleet &Equipment Services	11.8
Facilities	25.3
Other	-
Total Corporate Operational Investments	37.1
CUSTOMER SERVICES	
Wholesale Metering	-
Smart Metering	10.1
Suite Metering	10.2
Other	0.0
Total CUSTOMER SERVICES	20.3
Total INFORMATION TECHNOLOGY	32.4
Total OPERATIONAL INVESTMENTS	368.4
CRITICAL ISSUES	
Standardization	44.6
Downtown Contingency	4.7
FESI / WPF	19.3
Stations System Enhancements	4.7
Secondary Upgrade	3.9
Total CRITICAL ISSUES	77.1
TOTAL CAPITAL	445.5

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 12:

Reference(s): none provided

Please confirm that Underground Infrastructure and Cable project category (Schedule B1-B3) are equivalent to the 'Underground Direct Buried' and 'Underground Rehabilitation' categories contained in Table 2, Ex. D1, Tab7, Schedule 1, Page 16 of pre-filled evidence in EB-2010-0142.

RESPONSE:

Not confirmed. The Underground Infrastructure and Cable project category (Schedule B1-B3) is not equivalent to the 'Underground Direct Buried' and 'Underground Rehabilitation' categories contained in Table 2, Exhibit D1, Tab7, Schedule 1, Page 16 of pre-filled evidence in EB-2010-0142. The table below compares the items included in each application.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

Item	EB-2010-142 UG Direct Buried and UG Rehabilitation	EB-2012-0064 UG Infrastructure and Cable
Replacement of direct buried cable (with cable in concrete-encased ducts) and connected assets	X	X
Replacement of cable in duct and connected assets	X	
Replacement of air-insulated switchgear	X	X
Replacement of Paper Insulated Lead Covered (PILC) cable	X	X
UG load management improvement	X	
Handwell upgrades		X
URD system rebuilds	X	
Rear lot conversions	X	

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 13:

Reference(s): Tab 4/B

How does the Applicant define and calculate projected 'risk cost'?

RESPONSE:

As discussed in the Revised Manager's Summary (Tab 2, Appendix 4, pages 3-4), the projected risk cost represents the costs to both THESL and customers if an asset fails weighted by its probability of failure. THESL will incur the cost of replacing the asset including any additional costs of replacing it on a reactive, rather than planned, basis. Customers will incur costs from the outage that will result from the failure of a particular asset, given its function and location on the distribution system and its typical failure mode. The probability of failure is the product of a Hazard Distribution Function (HDF) for the given asset, which represents the conditional probability of asset failing from the remaining population that has survived up until that time. The HDF is based on asset age and condition.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 14:

Reference(s): Tab 4/B

Please provide and explain all assumptions required for the Applicant's calculations of Present Value of Project Net cost in 2015.

RESPONSE:

The Project Net Cost is calculated by taking into consideration various costs and benefits associated with executing a project. Major assumptions considered when calculating the Project Net Cost include:

- Age and/or condition of assets, captured from Health Index Calculator
- Failure probability, based upon age and/or condition of asset
- Direct Costs of asset replacement, including material units (MU) and labour units (LU) associated with each respective asset type or sub-type
- Customer Interruption Costs (Event Cost of $30 per kVA, Duration Cost of $15 per kVA-hour) are utilized as part of Optimal Intervention Timing, Sacrificed Life and Excess Risk calculations
- Corporate Discount Rate of 6.06% is applied as part of Present Value of Project Net Cost in 2015

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 15:

Reference(s): Tab 4/B

For each project (and project segment), please provide a chart that shows from 2008 to 2014, how much has the Applicant has spent or is seeking to spend, on like or similar projects.

RESPONSE:

The projects and project segments in THESL's present application cannot be directly compared with capital portfolios set out in previous applications. Please see THESL's response to SEC interrogatory 6 (Tab 6E, Schedule 10-6).

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 16:

Reference(s): **Tab 4/B1/p.2-3**

Please rank the jobs listed in Table 1 by priority. Please provide an explanation of the methodology the Applicant used to do.

RESPONSE:

Table 1 below lists the 34 jobs by priority. The jobs were first given a rank in each of the following:

1) The total number of interruptions due to primary cable failures experienced by the feeder(s) in 2010 and 2011.
2) The number of interruptions due to primary cable failures experienced by the feeder(s) in 2011 only.
3) The number of sustained outages experienced by the feeder(s) in 2011.

The three rankings for each feeder were then added to make one ranking, resulting in the priority list in Table 1.

This prioritization emphasizes jobs on feeders with poor reliability due to recent primary cable failures.

Prioritized	Job Title
1	Underground Rehabilitation of Feeder SCNA502M22
2	Underground Rehabilitation of Feeder SCNAE5-1M29
3	Underground Rehabilitation of Feeder SCNAR26M34
4	Underground Rehabilitation of Feeder SCNA47M14

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

Prioritized	Job Title
5	Underground Rehabilitation of Feeder NY51M6
6	Underground Rehabilitation of Feeder NY80M8
7	Underground Rehabilitation of Feeder NY80M30
8	Underground Rehabilitation of Feeder SCNA47M13
9	Underground Rehabilitation of Feeder NY55M8
10	Underground Rehabilitation of Feeder SCNT47M1
11	Underground Rehabilitation of Feeder NY55M23
12	Underground Rehabilitation of Feeder SCNT63M4
13	Underground Rehabilitation of Feeder NY80M29
14	Underground Rehabilitation of Feeder SCNAH9M23
15	Underground Rehabilitation of Feeder NY51M8
16	Underground Rehabilitation of Feeders NY85M1, NY85M9 and NYSS58F1
17	Underground Rehabilitation of Feeder SCNAH9M30
18	Underground Rehabilitation of Feeder NY85M4
19	Underground Rehabilitation of Feeder NY51M24
20	Underground Rehabilitation of Feeder NY80M2
21	Underground Rehabilitation of Feeder NY53M25
22	Underground Rehabilitation of Feeder SCNA47M17
23	Underground Rehabilitation of Feeder SCNA502M21
24	Underground Rehabilitation of Feeder NY51M7
25	Underground Rehabilitation of Feeder SCNT63M12
26	Underground Rehabilitation of Feeder NY51M3
27	Underground Rehabilitation of Feeder NY85M24
28	Underground Rehabilitation of Feeder NY85M6
29	Underground Rehabilitation of Feeder SCNAE5-2M3
30	Underground Rehabilitation of Feeder SCNT63M8
31	Underground Rehabilitation of Feeder SCNT47M3
32	Underground Rehabilitation of Feeder NY85M7
33	Underground Rehabilitation of Feeder NY80M9

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

Prioritized	Job Title
34	Underground Rehabilitation of Feeder YK35M10

As mentioned in lines 9-11 of Tab 4, Schedule B1, Page 2, the jobs in Table 1 are listed by the number of unplanned sustained outages experienced by the feeder in 2011 (with the exception of the last job in the table because it addresses a number of feeders).

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 17:

Reference(s): **Tab 4/B1/p.3**

Please expand Table 1 to include:

a. Estimated cost per year
b. Unplanned sustained outages for 2010
c. Unplanned sustained outages for 2011
d. Unplanned sustained outages year to date

RESPONSE:

The requested information is provided in the attached table in Appendix A.

Job #	Job Title	Year	Estimated Cost ($M)	Estimated Cost per year ($M)			Unplanned Sustained Outages		
				2012	2013	2014	2010	2011	Jan 1 2012 - Aug 31 2012
1	Underground Rehabilitation of Feeder NY80M29	2012, 2013	$2.90	2.47	0.43		7	15	6
2	Underground Rehabilitation of Feeder SCNAR26M34	2012, 2013, 2014	$5.52	0.47	3.46	1.60	7	12	2
3	Underground Rehabilitation of Feeder NY55M8	2012	$2.49	2.49			10	12	4
4	Underground Rehabilitation of Feeder YK35M10	2012	$2.14	2.14			6	11	11
5	Underground Rehabilitation of Feeder SCNT63M4	2014	$3.16			3.16	3	10	2
6	Underground Rehabilitation of Feeder SCNA47M14	2012, 2013	$4.43	2.77	1.66		6	10	4
7	Underground Rehabilitation of Feeder NY51M6	2012, 2013	$2.54	0.66	1.84		10	10	5
8	Underground Rehabilitation of Feeder NY80M8	2014	$9.51			9.51	7	8	4
9	Underground Rehabilitation of Feeder NY85M6	2014	$2.01			2.01	3	8	1
10	Underground Rehabilitation of Feeder NY51M8	2013, 2014	$1.58		1.26	0.32	7	8	9
11	Underground Rehabilitation of Feeder SCNA502M22	2012, 2013, 2014	$2.96	0.35	2.36	0.25	6	7	2
12	Underground Rehabilitation of Feeder SCNAH9M30	2013, 2014	$3.56		0.81	2.75	11	7	11
13	Underground Rehabilitation of Feeder NY85M4	2013, 2014	$8.27		4.96	3.31	4	7	2
14	Underground Rehabilitation of Feeder SCNA47M13	2013, 2014	$4.91	0.98	2.61	1.32	6	6	5
15	Underground Rehabilitation of Feeder NY80M2	2013	$1.63		1.63		7	6	4
16	Underground Rehabilitation of Feeder NY51M7	2013	$1.40		1.40		9	6	3
17	Underground Rehabilitation of Feeder NY51M24	2013, 2014	$5.64		4.97	0.67	6	6	5
18	Underground Rehabilitation of Feeder NY80M30	2012	$8.95	8.95			13	6	4
19	Underground Rehabilitation of Feeder NY55M23	2014	$2.24			2.24	8	6	8
20	Underground Rehabilitation of Feeder NY85M24	2014	$2.03			2.03	3	6	5
21	Underground Rehabilitation of Feeder SCNAE5-2M3	2013	$1.51		1.51		6	6	9
22	Underground Rehabilitation of Feeder NY85M7	2014	$13.83			13.83	4	6	4
23	Underground Rehabilitation of Feeder SCNT63M12	2012, 2013, 2014	$11.14	6.10	2.42	2.62	9	5	3
24	Underground Rehabilitation of Feeder SCNT63M8	2013, 2014	$7.59		5.34	2.25	4	5	5
25	Underground Rehabilitation of Feeder SCNAE5-1M29	2012, 2013	$3.91	2.28	1.63		5	5	8
26	Underground Rehabilitation of Feeder NY53M25	2012, 2013	$3.44	2.40	1.05		6	5	4
27	Underground Rehabilitation of Feeder NY80M9	2014	$2.21			2.21	3	5	4
28	Underground Rehabilitation of Feeder SCNT47M3	2012, 2013, 2014	$20.44	10.45	6.78	3.22	12	4	3
29	Underground Rehabilitation of Feeder SCNAH9M23	2014	$2.71			2.71	4	4	3
30	Underground Rehabilitation of Feeder NY51M3	2013, 2014	$3.54		0.43	3.10	7	4	2
31	Underground Rehabilitation of Feeder SCNA47M17	2013, 2014	$5.70		0.89	4.82	12	3	2

Job #	Job Title	Year	Estimated Cost ($M)	Estimated Cost per year ($M)			Unplanned Sustained Outages		
				2012	2013	2014	2010	2011	Jan 1 2012 - Aug 31 2012
32	Underground Rehabilitation of Feeder SCNA502M21	2013, 2014	$3.44		0.88	2.55	3	2	1
33	Underground Rehabilitation of Feeder SCNT47M1	2012, 2013, 2014	$14.91	3.06	3.42	8.43	7	2	0
34	Underground Rehabilitation of Feeders NY85M1, NY85M9 and NYSS58F1	2012, 2013	$2.66	1.00	1.66		24	16	9

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 18:

Reference(s): **Tab 4/B1/p.5**

Please provide the year-to-date number interruptions attributed to direct buried cable failures.

RESPONSE:

The number of sustained interruptions attributed to direct buried cable failures from January 1, 2012, to August 31, 2012, is 89.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 19:

Reference(s): **Tab 4/B1/p.5**

Please provide the year-to-date number of Air-Insulated failures of Pad-Mounted switches.

RESPONSE:

There were 22 air-insulated pad-mounted switchgear failures between January 1, 2012, and August 31, 2012.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 20:

Reference(s): **Tab 4/B6/p.37**

With respect to the Rear Lot Construction Segment:

a) Please provide a projected cost of Option 3.

b) Please provide the projected cost of each option over the life of asset.

RESPONSE:

a) and b)

Please see the response to EP interrogatory 39 (Tab 6F, Schedule 7-39). Note that COO represents the Cost of Ownership and COST represents the project costs.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 21:

Reference(s): Tab 4, B17

With respect to the Bremner TS project:

a) What is the projected in-service date of the Bremner TS?

RESPONSE:

a) The current projected in-service date of the Bremner TS is Q4 2014.

b) The Applicant has asked a number of interrogatories regarding the Bremner TS station in HONI Transmission's 2013-2014 Rate Application (EB-2012-0031). Please place the answers to those interrogatories on the record in this proceeding when they become available.

RESPONSE:

b) Please see Appendix A.

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #1 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1/Tab 2/Sch 2/ p41 lines 12, 13; p42 lines 2, 3; p 40 Fig 14, 15

a) Please explain why Hydro One considers its strategy of maintaining 25% of its underground transmission cable population in fair/poor condition over the next 10 years to be an appropriate long term strategy.
b) Please compare the forced outage frequency of underground transmission cables with the CEA benchmark for forced outage frequency of underground transmission cables. Please plot it onto the data of Figure 14. If the CEA benchmark is not available, please compare to another comparable benchmark for forced outage frequency of underground transmission cables. Please state the relative performance of Hydro One to the benchmark.
c) Please compare the forced outage duration of underground transmission cables with the CEA benchmark for forced outage duration of underground transmission cables. Please plot it onto the data of Figure 15. If the CEA benchmark is not available, please compare to another comparable benchmark for forced outage duration of underground transmission cables. Please state the relative performance of Hydro One to the benchmark.

Response

a) Hydro One believes its strategy in the long term management of the transmission underground cables to be appropriate. As per Exhibit C1, Tab 2, Schedule 2 page 41 Figure 16, the cable circuits currently rated as poor condition will be replaced under ISD# S62 of this application. Those cables that remain are considered to be in varying states of fair condition, and will be considered for replacement over approximately the next 10 years. Condition of the cable system is an important factor, but not the only factor considered for cable replacement. Refer to Exhibit C1, Tab 2, Schedule 2, pages 34–43 for further details on the sustainment of transmission underground cables.

b) The forced outage frequency for Hydro One cables versus CEA is shown in the table below. The presentation of cable performance below is a different basis from Figure 14 due to the event data structure in the CEA study. As can be seen from the table below, Hydro One's frequency of occurrences per 100km-yr is nearly twice that of the CEA average.

Cable Performance
Hydro One and All Canada-wide Cable Statistics from 2007 to 2011
Cable-Related

#	Voltage Class kV	Hydro One		All Canada	
		Frequency occ per 100 km.yr	Unavailability % per 100 km.yr	Frequency occ per 100 km.yr	Unavailability % per 100 km.yr
	110 - 299 (pool)	1.24	8.917	0.7	4.26

c) The underground cable unavailability for Hydro One versus CEA is shown in the table in part b) above. The presentation of cable performance above is a different basis from Figure 15 due to the event data structure in the CEA study. As can be seen from the table, Hydro One's unavailability is approximately twice that of the CEA average. However, this is primarily as a result of the outages associated with the two underground cable circuits that are being replaced during the test years of this application (refer to Exhibit D1, Tab 3, Schedule 2, Page 70, ISD# S62).

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #2 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit D1-3-3/Appendix A/Table 4/Item #D17

a) Please explain why the customer capital contribution for Bremner TS constitutes 100% of the gross total cost. What assumptions underpin this conclusion?

Response

a) Hydro One has calculated the capital cost contributions based on the incremental load forecast provided by THESL. The discounted cash flow (DCF) analysis showed that a 100% capital contribution is required as there was insufficient incremental load growth to offset this cost, and this was conveyed to THESL.

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #3 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit D2/Tab 2/Sch 3/ p74

a) Please explain the impact of the Bremner TS line connection on the current transfer capability between John TS and Esplanade TS. In Hydro One's response, please indicate how 115kV transfer capability will be maintained.

Response

a) The through transfer capability between John TS and Esplanade TS will be reduced by the amount of load on Bremner TS. The only way to maintain existing transfer capability, during such transfer scenarios, is to move the Bremner TS load to other transformer stations in Toronto via the THESL distribution network.

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #4 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit D2/Tab 2/Sch 3/ p74

a) Please provide a detailed cost breakdown of the $60M gross cost for building the Bremner TS line connection.

Response

a) As mentioned in Exhibit D2, Tab 2, Schedule 3, ISD #D17 the project is in a preliminary stage and Hydro One is working with THESL to finalize the scope.

The $60M gross cost for the work is based on the preliminary scope discussed with THESL and budgetary costs for equipment and installation is as follows:

i) Station: Gas Insulated Switchgear (GIS) (230kV rated, operated at 115kV) ~ $30M
ii) Cables: Four 115kV circuits (230kV rated, operated at 115kV) ~ $15M
iii) Protections: ~ $5M
iv) Other costs (interest/overhead/contingencies): ~ $10M

Hydro One will be advising THESL of the detailed project costs when the project scope is finalized, the preliminary engineering and estimating work are complete, and the tender bids for outsourced work have been reviewed.

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #5 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit D2/Tab 2/Sch 3/ p74

a) Has Hydro One considered any alternate designs for the Bremner TS line connection project? If so, please identify any alternative designs that have been considered, and the status of those alternatives.

Response

a) Yes, Hydro One did suggest to THESL potential alternatives for Bremner TS and its line connection. The alternatives were as follows:

- Build station facilities at Esplanade TS and connect to the John to Esplanade 115kV circuits.
- Build station facilities at Bremner TS and install 115kV underground cables between Bremner TS and Esplanade TS.
- Build station facilities at Bremner TS and install 115kV underground cables between Bremner TS and John TS.
- Install low voltage switchgear facilities at Bremner TS and install transformers at another location.

These alternatives were discussed with THESL but THESL indicated that the current Bremner proposal better meets their timeline needs.

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #6 List 1

Issue 12 **Are the proposed 2013 and 2014 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit D1/Tab 3/Sch 1/Table 1, Table 2, Table 3

a) Please indicate the amount of the historic, bridge and test year amounts for Sustaining, Development, Operations, and Shared Services Capital that were spent and will be spent within the municipal boundaries of Toronto in each of Tables I, 2 and 3.

Response

Sustaining and Development Capital expenditures within the municipal boundaries of Toronto are provided in Table 1 below. The 2011 and 2012 Capital expenditures within the municipal boundaries of Toronto against the Board approved amounts are provided in Tables 2 and 3 respectively. Shared Services and Operations Capital is related to expenditures to support the general functioning of the business and operation of the transmission system. No specific expenditures are made for any particular municipality and therefore determination of what was spent in support of the assets within Toronto is not practical.

Table 1
Transmission Capital Expenditures in Toronto ($ Millions)

Capital Category	Historic			Bridge	Test	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Sustaining	47.4	66.2	71.8	71.2	139.9	133.3
Development	18.7	16.2	26.6	64.3	100.1	41.2
Total	**66.1**	**82.4**	**98.4**	**135.5**	**240.0**	**174.5**

Table 2
2011 Capital Expenditures within Toronto – Actual vs. Board Approved ($Millions)

Capital Category	2011 Board Approved*	2011 Actuals	Variance
Sustaining	108.7	71.8	-36.9
Development	111.9	26.6	-85.3
Total	**220.6**	**98.4**	**-122.2**

*Amounts shown as Board Approved include the projects within the municipal boundaries of Toronto from the EB-2010-0002 proceeding.

Table 3
2012 Capital Expenditures within Toronto – Actual vs. Board Approved ($Millions)

Capital Category	2012 Board Approved*	2012 Bridge Forecast	Variance
Sustaining	105.7	71.2	-34.5
Development	79.4	64.3	-15.1
Total	**185.1**	**135.5**	**-49.6**

*Amounts shown as Board Approved include the projects within the municipal boundaries of Toronto from the EB-2010-0002 proceeding.

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #7 List 1

Issue 12 **Are the proposed 2013 and 2014 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

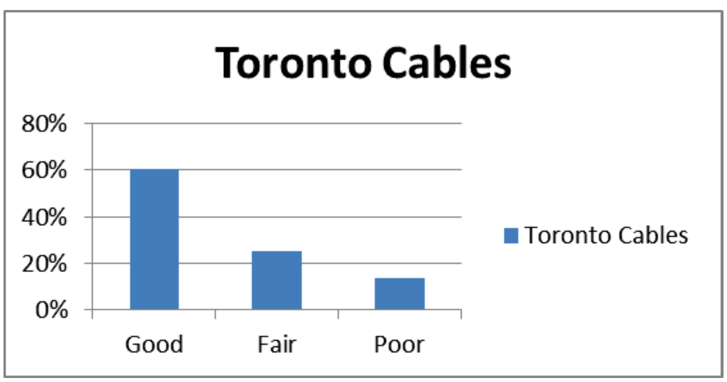
Ref: Exhibit Cl/Tab 2/Sch 2/ p34 1ines 16-18; p41 Fig 16

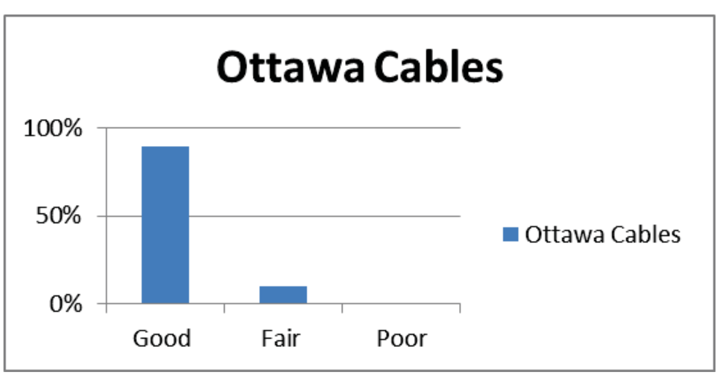
a) Please state what percentage of Hydro One's overall underground transmission cable population is in Toronto, Ottawa and Hamilton, respectively.
b) Please plot the cable health by category (as shown in Figure 16) for each of the cable populations in Toronto, Ottawa and Hamilton.
c) Please describe the planned cable replacement rate and cable investment strategy for each of Toronto, Ottawa and Hamilton.

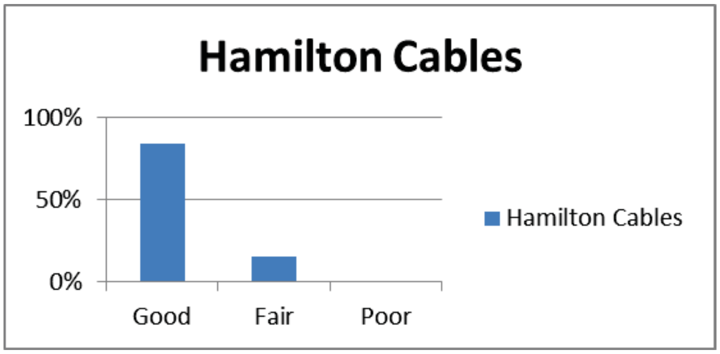
Response

a) The percentage of Hydro One’s overall underground transmission cable population in Toronto, Ottawa and Hamilton are 55%, 13% and 10% respectively.

b) The requested graphs are shown below:







c) Hydro One's underground cable investment strategy is a provincial strategy.

Capital investments, such as the work covered under ISD# S62 from this application, are proposed when cable sections are approaching end of life. Investment decisions are based on several factors including condition, reliability and customer impact, consideration to equipment design considerations, operating history, and considerations to health, safety and environmental factors. Underground cable sections are monitored on a regular basis, and replacement projects are proposed as required based on these factors.

The proposed rate of replacement for 2012-2014 is an average of 3.7 kilometers per year based on the number of kilometers being addressed by the specific project. It is expected that on-going renewal of the provincial underground cables will be required beyond the test years.

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #8 List 1

Issue 12 **Are the proposed 2013 and 2014 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1/Tab 2/Sch 2 p40 Fig 14, Fig 15; p34 lines 16-17; p70 Fig 30, Fig 31

a) Please prepare a chart comparing the forced outage frequency of underground transmission cables for the period 2002 to 2011 (from Figure 14) with the forced outage frequency of line conductors for the period 2002 to 2011 (from Figure 30).
b) Please prepare a chart comparing the forced outage duration of underground transmission cables for the period 2002 to 2011 (from Figure 15) with the forced outage duration of line conductors for the period 2002 to 2011 (from Figure 31).
c) Please explain what Hydro One believes to be the appropriate relative performance of underground cables to line conductors in order to achieve "a high degree of reliability" for underground cables *as* stated in line 17 of p34?
d) What level of cable replacement would be required so that the forced outage frequency and forced outage duration of underground cables would be three and (separately) ten times better than that of line conductors?

Response

a & b)

In reference to parts a), and b), the question relates performance of an underground transmission cable system to a subcomponent of overhead transmission lines. Such a comparison would be misleading. Overhead transmission lines are composed of numerous sub-components (e.g. insulators, structures, shieldwire, hardware) each of which plays a role in their forced outage frequency and duration performance. Underground cable systems are composed of different subcomponents such as conductors, insulation, cable sheath, bushings, oil pressurization systems, etc.

The table below presents a direct comparison between the performance of Hydro One's 115/230 kV underground cable system to the 115/230 kV overhead line system from 2007 to 2011. The comparison demonstrates a higher level of performance for underground cables with fewer forced outages relative to overhead lines. Based on the Unavailability measure, the duration of forced outages on underground cables is typically greater relative to overhead lines. Approximately 90 % of the contribution to the unavailability of the underground cables was attributed to the two circuits that are being replaced within this application during the test years due to recurring oil leaks (refer to Exhibit D1, Tab 3, Schedule 2, Page 70 ISD# S62).

HV Cable and Overhead Line Forced Outage Performance

Hydro One-Owned Cable & Overhead Line Performance 2007 - 2011

Momentary and Sustained Outages

Voltage Class kV	HV Cable		Overhead Line	
	Frequency (#occ / yr /cct)	Unavailability (hr / yr / cct)	Frequency (#occ / yr /cct)	Unavailability (hr / yr / cct)
115 & 230 kV	0.54	64.9	1.3	19.3

c) Generally, underground cables are exposed to different conditions than those which challenge overhead transmission lines. For example, overhead transmission lines are frequently challenged by weather conditions while underground cables are more sheltered from weather effects. As a result, underground cables would be expected to perform better than overhead lines, thereby achieving "a high degree of reliability" for underground cables as stated on page 34 of the referenced exhibit.

d) Currently the frequency performance from 2007 to 2011 of our underground system is approximately 2.5 times better than the overhead system. Duration performance is more than 3 times worse than the overhead system. The performance of the underground system is expected to improve once the two cable circuits are replaced under this application (as per Exhibit D1, Tab 3, Schedule 2, page 70 ISD# S62), as approximately 90% of the contribution to underground cable unavailability is attributed to these two circuits.

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #9 List 1

Issue 12 **Are the proposed 2013 and 2014 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?**

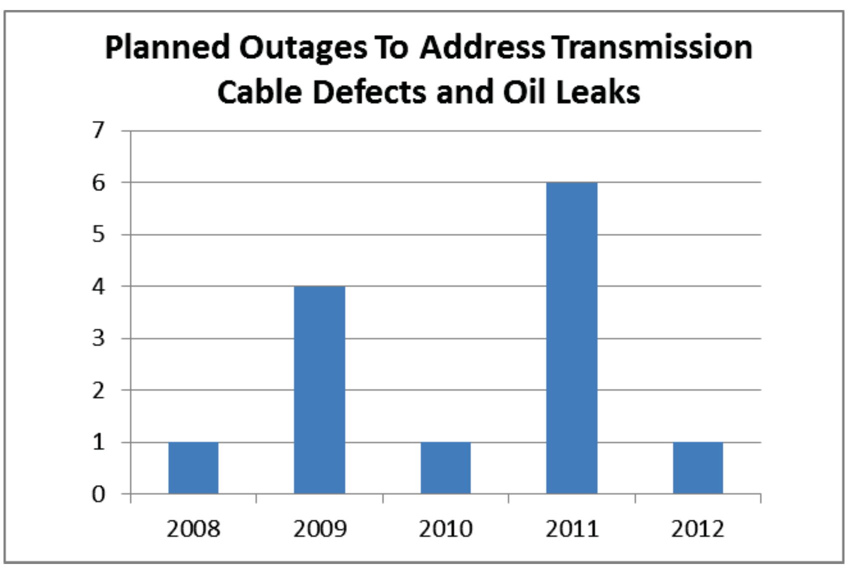
Interrogatory

Ref: Exhibit Cl/Tab 2/Sch 2/ p41 lines 1-4

a) Please plot, for HONI's entire underground transmission cable population, the number of defects and cable leaks that were addressed in planned outages from 2002 to 2011.
b) Please state if defects and cable leaks that did not lead to forced outages are considered as main factors in driving cable replacement. Please explain the reason why or why not.

Response

a) The graph below depicts the number of planned outages taken by year to address oil leaks and other defects on the entire underground cable population dating back to 2008. Outages taken for preventative maintenance activities and other program replacement work are not included. These details are not available prior to 2008.



b) Defects and cable leaks that do not lead to forced outages are considered and can be factors in driving cable replacement, in addition to other factors that are considered as described in the referenced exhibit. These are considered because depending on the number and severity of these defects/leaks they may be indicative of cable deterioration and impending problems with the cables, which could eventually lead to forced outages.

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #10 List 1

Issue 12 Are the proposed 2013 and 2014 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Interrogatory

Ref: Exhibit C1/Tab 2/Sch 2/ p41 lines 13-15

a) Please state the relative weight of circuit criticality, maintenance costs, forced outage frequency and environmental risks in making cable replacement decisions.
b) Please explain if the type of customer load (i.e., Residential, commercial, industrial), or the presence of public service customers (i.e., Hospitals) is used in determining circuit criticality?
c) Does Hydro One, in its current process, consider factors such as extent of high voltage and or distribution voltage back-up facilities, amount of load at risk, or length of time customers will remain in a single contingency state when making cable replacement decisions? If Hydro One does consider such factors, please explain how it does.

Response

a) Hydro One uses a health index assessment to evaluate its cable inventory. A risk analysis is also performed associated with reliability or criticality (including size of customer load), environment and economic impacts including maintenance costs. The result of this analysis is then used to determine the need for underground cable replacements.

b) The total customer load on a circuit and availability of backup supply are used in determining circuit criticality. Hydro One also works with its customers to understand their needs regarding their customers and takes these into consideration in making investment decisions.

c) Hydro One considers the risks of replacements of all assets including high voltage cables. This is done through our system design, investment planning process, assessment of project and construction alternatives and outage planning processes.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 22:

Reference(s): **Tab 4/B18**

At the current time, which projects are THESL legally required to pay a capital contribution to HONI for?

RESPONSE:

THESL is legally required to make a capital contribution once an engineering study agreement or a Connection and Cost Recovery Agreement (CCRA) is signed with Hydro One. The table below lists the referenced capital projects in which THESL is currently under a legal obligation to pay a capital contribution to Hydro One and the nature of that obligation.

Project Title	Legal Obligation
Leaside-Birch Transmission Reinforcement	CCRA Signed
Wiltshire TS switchgear replacements and engineering studies	CCRA Signed
Strachan TS A7-8 switchgear replacements and engineering studies	CCRA Signed

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 23:

Reference(s): Tab 4/B21

With respect to Externally – Initiated Plant Relocations and Expansions:

a) [p.4] Please breakdown each job into a) relocation costs and b) expansion costs.

RESPONSE:

a)

Job Title	Agency	Total Estimated Project Cost ($M)	Project Breakdown			
			Relocation (%)	Expansion (%)	Relocation ($M)	Expansion ($M)
Queens Quay Rebuild Phase 1	Waterfront Toronto	$4.67	13%	87%	$0.60	$4.07
Queens Quay Rebuild Phase 2	Waterfront Toronto	$5.30	11%	89%	$0.60	$4.70
Queens Quay Rebuild Phase 3	Waterfront Toronto	$3.42	18%	82%	$0.60	$2.82
Queens Quay Rebuild Phase 4	Waterfront Toronto	$12.43	22%	78%	$2.70	$9.73
Queens Quay Rebuild Phase 5	Waterfront Toronto	$7.98	13%	87%	$1.00	$6.98

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

Job Title	Agency	Total Estimated Project Cost	Project Breakdown			
		($M)	Relocation (%)	Expansion (%)	Relocation ($M)	Expansion ($M)
Metrolinx West of Hwy 27	GO Transit	$0.23	100%	0%	$0.23	$0.00
GTS Bridge – Hwy 27	GO Transit	$0.14	100%	0%	$0.14	$0.00
Weston Tunnel	GO Transit	$0.47	100%	0%	$0.47	$0.00
Martin Grove Bridge	GO Transit	$0.12	100%	0%	$0.12	$0.00
Black Creek and Weston UG Reinstatement	GO Transit	$0.09	100%	0%	$0.09	$0.00
GO Strachan UG Crossing Civil	GO Transit	$0.26	100%	0%	$0.26	$0.00
GO Strachan UG Crossing Civil	GO Transit	$0.13	100%	0%	$0.13	$0.00
Strachan Electrical Relocation Part 1	GO Transit	$1.98	100%	0%	$1.98	$0.00
Strachan Electrical Relocation Part 2	GO Transit	$1.73	100%	0%	$1.73	$0.00

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

Job Title	Agency	Total Estimated Project Cost	Project Breakdown			
		($M)	Relocation (%)	Expansion (%)	Relocation ($M)	Expansion ($M)
Strachan Electrical Relocation Part 3	GO Transit	$1.34	100%	0%	$1.34	$0.00
Strachan Electrical Relocation Part 4	GO Transit	$0.92	100%	0%	$0.92	$0.00
Keele St and Hwy 401-PH2-Tunnelling Under Hwy 401	MTO	$1.69	100%	0%	$1.69	$0.00
Eglinton Ramp Onto Hwy 427	MTO	$0.24	100%	0%	$0.24	$0.00
Dunn Ave Directional Drilling	City of Toronto	$0.72	100%	0%	$0.72	$0.00
Dundas Street Overhead to Underground Phase 1 - Design	City of Toronto	$0.64	100%	0%	$0.64	$0.00
Dundas Street Overhead to Underground Phase 2	City of Toronto	$8.77	100%	0%	$8.77	$0.00

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

Job Title	**Agency**	**Total Estimated Project Cost**	**Project Breakdown**			
		($M)	**Relocation (%)**	**Expansion (%)**	**Relocation ($M)**	**Expansion ($M)**
Dundas Street Overhead to Underground Phase 3	City of Toronto	$8.01	100%	0%	$8.01	$0.00
North West PATH Addition Phase 1	City of Toronto	$1.62	95%	5%	$1.54	$0.08
North West PATH Addition Phase 2	City of Toronto	$1.38	90%	10%	$1.24	$0.14
Front Street Streetscape Improvement	City of Toronto	$0.52	100%	0%	$0.52	$0.00
Beecroft OH Reconfiguration	City of Toronto	$1.07	100%	0%	$1.07	$0.00
Lawrence Avenue Relocation	City of Toronto	$0.15	100%	0%	$0.15	$0.00

b) Have any of the requesting Agencies/Governments made official requests to date? If so, for which projects?

b) Yes. Official requests have been made for all projects.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

c) Between 2008 and 2010, how many externally – initiated plant relocations and expansions jobs (and there costs) were i) budgeted and ii) actual incurred in the year budgeted.

RESPONSE:

c)

Year	Number of Projects Budgeted	Amount Budgeted ($M)	Number of Projects Completed in Budget Year	Actual Costs Incurred in Budgeted Year ($M)
2008	7	2.97	2	0.73
2009	0	0	1	2.24
2010	17	3.57	7	3.18

Note: Projects typically require 12-18 months to complete.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 24:

Reference(s): **Tab 4/B22**

Does the Applicant believe that any of its Grid Solutions projects could be considered Smart Grid in nature? If so, which ones?

RESPONSE:

Pursuant to THESL's letter dated October 5, 2012, THESL has withdrawn the Grid Solutions project (Tab 4, Schedule B-22) from this application.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 25:

Reference(s): Tab 4/B22/p.3

With respect to the Community Energy Storage project:

a) Please provide a copy of all contracts, MOUs and agreements between THESL and any consortium member individually, or as a group.

b) Please detail all material differences between this project and the Community Energy Storage project proposed, and later withdrawn, in EB-2010-0142.

RESPONSE:

Pursuant to THESL's letter dated October 5, 2012, THESL has withdrawn the Grid Solutions project (Tab 4, Schedule B-22) from this application.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 26:

Reference(s): Tab 4/B5

With respect to the Power System Engineering, Inc. report, *ICM Businesses Cases – Summary Report*, dated May 8, 2012. Please provide the terms of reference and all instructions provided to Power Engineering, Inc. regarding the undertaking and preparation of their report.

RESPONSE:

THESL does not understand the relevance of this question. Pursuant to rule 13A.03(c) of the OEB's *Rules of Practice and Procedure*, Power System Engineering, Inc. set out in its report the instructions provided to it by THESL in respect of the above-noted report. Please see Tab 4, Schedule D4, at page 2 in particular.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 27:

Reference(s): **Tab 4/D5**

With respect to the Navigant Report, *Independent Assessment of Toronto Hydro Business Cases*, dated May 8, 2012:

a) Please provide the terms of reference and all instructions provided to Navigant Consulting Ltd. regarding the undertaking and preparation of their report.

RESPONSE:

a) THESL does not understand the relevance of this question. Pursuant to rule 13A.03(c) of the OEB's *Rules of Practice and Procedure*, Navigant Consulting Ltd. set out in its report the instructions provided to it by THESL in respect of the above-noted report. Please see Tab 4, Schedule D5, at pages 5-6 in particular.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 20:

Reference(s): **Tab 2, page 2, lines 7-8**

a) Please provide the 2006-2011 values for the Board's three reliability performance measures. For each year, please break down each of the reliability performance measures so as to separate out the impact of upstream outages (e,g., outages on HON's facilities). Please also separate out the impact of equipment outages due to equipment failure as opposed to external events such as lighting, traffic accidents, etc.

RESPONSE:

a)

System Level Reliability Measures (Excluding MEDs[1])

	2006	2007	2008	2009	2010	2011
SAIDI	1.24	1.35	1.24	1.38	1.29	1.43
SAIFI	2.06	2.01	1.76	1.64	1.77	1.62
CAIDI	0.60	0.67	0.70	0.84	0.73	0.88

System Level Reliability Measures (Excluding Loss of Supply and MEDs)

	2006	2007	2008	2009	2010	2011
SAIDI	1.17	1.25	1.24	1.24	1.18	1.38
SAIFI	1.84	1.77	1.69	1.49	1.53	1.48
CAIDI	0.63	0.71	0.73	0.83	0.77	0.93

[1] "Major Event Days" as defined by the IEEE 1366.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

Defective Equipment-Related Reliability Measures (Excluding MEDs)

	2006	2007	2008	2009	2010	2011
SAIDI	0.58	0.71	0.66	0.69	0.49	0.59
SAIFI	0.84	0.85	0.87	0.75	0.70	0.62
CAIDI	0.70	0.84	0.75	0.91	0.70	0.95

b) How does THESL's reliability performance compare with that of the of the other electricity distributors in its IRM cohort?

RESPONSE:

b) Please see table below for a comparison between THESL and other distributors within the IRM cohort. The list of distributors were taken from the "Third Generation Incentive Regulation Stretch Factor Updates for 2012 (EB-2011-0387)" document. While THESL's reliability indicators are below (i.e., better than) the cohort, it is important to understand that utilities identified in the IRM Cohort are significantly smaller in size, making THESL an outlier in the sample. As well, the utilities operate under different business conditions. THESL serves the largest urban centre in Canada. The nature of its service area, including the presence of numerous large businesses and the inherent difficulties in acquiring real estate, result in more demanding requirements for plant undergrounding, system reliability, and safety procedures.

THESL does not consider these statistics as indicating that THESL's reliability is currently at an acceptable level. THESL has not and does not consider its current reliability results to be "good". Average reliability statistics mask reliability

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

degradations in specific locations that are essential to address. In addition, THESL notes that over short intervals, reliability statistics can fluctuate according to short term influences such as the severity of weather and changes in the amount of work being done on the system.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

	2006			2007			2008			2009			2010			2011		
	SAIFI	SAIDI	CAIDI	SAIFI	SAIDI	CAIDI	SAIFI	SAIDI	CAIDI	SAIFI	SAIDI	CAIDI	SAIFI	SAIDI	CAIDI	SAIFI	SAIDI	CAIDI
Algoma Power Inc	NA	NA	NA	NA	NA	NA	NA	NA	NA	3.42	9.86	2.88	4.58	16.65	3.64	6.55	13.69	2.09
Brant County Power Inc	1.58	2.54	1.61	2.64	2.95	1.11	1.34	1.81	1.35	1.15	1.42	1.24	2.59	2.89	1.11	1.53	2.19	1.43
Centre Wellington Hydro Ltd	0.66	0.69	1.04	0.07	0.1	1.4	0.63	0.61	0.97	0.88	1.29	1.48	1.67	2.18	1.3	1.9	3.67	1.93
Collus Power Corp.	0.65	1.15	1.76	4.56	2.23	0.49	NA	NA	NA	1.75	1.87	1.07	1.03	1.1	1.07	0.96	1.35	1.41
EnWin Utilities Ltd	2.2	1.39	0.63	2.11	1.2	0.57	2.75	1.34	0.49	1.18	0.55	0.47	1.81	0.99	0.55	2.72	2.48	0.91
Erie Thames Powerlines Corp	0.62	1.14	1.86	2.09	3.16	1.51	1.63	6.08	3.73	0.62	1.91	3.09	4.83	11.21	2.32	2.04	4.45	2.18
Port Colborne Power	5.86	14.77	2.52	4.95	3.57	0.72	1.62	1.79	1.11	1.17	1.07	0.92	1.74	1.69	0.97	2.2	3.59	1.63
Toronto Hydro Electric System Ltd	2.17	1.57	0.72	2.27	1.95	0.86	1.76	1.24	0.7	1.86	2.9	1.56	1.95	1.66	0.85	1.62	1.43	0.88
Wellington North Power Inc	0.02	0.04	1.84	0.33	0.32	0.97	2.79	4.77	1.71	1.52	4.06	2.66	2.22	0	0	0.47	1.02	2.18
West Perth Power	NA	NA	NA	2.25	3.54	1.57	5.36	28.11	5.25	4.55	10.83	2.38	0.64	1.11	1.75	NA	NA	NA

Values taken from Annual Electricity Yearbook.

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INTERROGATORY 21:

Reference(s): Tab 2, page 17, lines 20-21

a) Please provide a schedule which indicates which of the five "considerations" apply to each project and thereby (in THESL's view) make it essential and non-discretionary.

RESPONSE:

a) Please see THESL's response to SEC interrogatory 9 (Tab 6E, Schedule 10-9).

b) For those projects where reliability degradation is a consideration, please indicate whether the issue is existing degradation or imminent degradation. If the latter, please indicate the timeframe involved.

RESPONSE:

b) Underground Infrastructure, Overhead Infrastructure, Rear Lot, PILC Piece-out and Leakers, Network Vault and roofs, SMD-20 fuses, SCADAMATE R1, Fibertops, ATS & RPB, Stations, Downtown Contingency and Bremner TS have all shown signs of existing degradation. Box Construction shows signs of imminent degradation. Specifying a timeframe as to when reliability will degrade is difficult as there is no real means of predicting when assets will fail. However, THESL has determined that many of the assets in question have passed their useful life, suggesting that the likelihood of asset failures will increase in the near future.

c) For those projects where capacity shortages are a consideration, please indicate whether the issue is an existing or an imminent capacity shortage. If the later,

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please indicate the timeframe over which the capacity shortage is expected to occur.

RESPONSE:

c) The table below lists major projects which are primarily driven by capacity constraints. Please refer to Tab 4, Schedule B18 for more details.

Job	Project	Capacity Need	Comments
Leaside-Birch Transmission Reinforcement	HONI Contributions	Existing	Constraints on HONI transmission lines servicing Toronto
Leaside-Birch Transmission Reinforcement	HONI Contributions	Existing	Constraints on HONI transmission lines servicing Toronto
Bremner TS Capital Contribution	HONI Contributions	2014	Refer to Bremner TS business case
Bremner TS Capital Contribution	HONI Contributions	2014	Refer to Bremner TS business case
Bremner TS Capital Contribution	HONI Contributions	2014	Refer to Bremner TS business case
Malvern TS 2 new CBs HONI Capital Contribution Agreement	HONI Contributions	Existing	Needed to reduce average feeder loading, support nearby stations and facilitate new customer connections
Malvern TS 2 new CBs HONI Engineering Study	HONI Contributions	Existing	Needed to reduce average feeder loading, support nearby stations and facilitate new customer connections

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Job	Project	Capacity Need	Comments
Horner TS 2nd bus expansion HONI Engineering study	HONI Contributions	Existing	To support overloading at Manby TS
Runnymede TS 2nd bus expansion HONI Engineering study	HONI Contributions	Existing	Potential customers are already being diverted to other stations due to capacity constraints.
Esplanade TS 2nd bus expansion HONI Engineering study	HONI Contributions	2021	Expected redevelopment of West Don Lands, East Bayfront and waterfront revitalization may push date sooner
Bridgman/High Level transformers upgrade HONI Engineering study	HONI Contributions	Existing	New connections have been restricted due to capacity constraints at this station
Bremner Project (not including capital contributions to HONI)	Bremner TS	2014	Refer to Bremner TS business case
Bremner Project (not including capital contributions to HONI)	Bremner TS	2014	Refer to Bremner TS business case
Bremner Project (not including capital contributions to HONI)	Bremner TS	2014	Refer to Bremner TS business case

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INTERROGATORY 22:

Reference(s): **Tab 2, page 17**
Tab 2, Appendix 4

a) Appendix 4, page 6 (lines 7-16) suggest that an approach similar to that outlined for the Feeder Investment Model is applies a wide range of asset in order to determine the optimal timing for re-investment. Please indicate which of the ICM projects are subjected to this analysis.

RESPONSE:

a) The following ICM projects are subject to the analysis where an approach similar to FIM is applied to a wide range of assets to determine the optimal timing for re-investment:

- Station Power Transformers
- Municipal Substation Switchgear Replacement
- Transformer Station Switchgear
- Station Circuit Breakers
- Fibertop Network Units
- Overhead Infrastructure
- Underground Infrastructure
- PILC
- Box Construction
- Rear Lot Construction
- Scadamate R1
- Feeder Automation

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b) Tab 2 (page 17) lists five considerations based on which a project can be viewed as "non-discretionary". If a project qualifies for imminent implementation based on the Avoided Risk Analysis (per Appendix 4) is this sufficient for it to be viewed as "non-discretionary"?

RESPONSE:

b) No. In a situation of "like for like" replacement, avoided risk cost show the benefits of undertaking a project in 2012 rather than in 2015. This goes to the prudence of undertaking the project rather than its non-discretionary character.

c) If the response to part (b) is yes, which of the five criteria/considerations listed on page 17 does such a circumstance fall under?

RESPONSE:

c) Not applicable.

d) If the response to part (b) is yes, please identify those proposed projects/segments (per Tab 4, Appendix A, Schedule 1) where this is the sole basis for the project/segment being considered as "non-discretionary".

RESPONSE:

d) Not applicable.

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INTERROGATORY 23:

Reference(s): Tab 2, page 18, lines 20-27 and page 19, lines 6-18

a) Does the OHSAS 18001 Standard provide explicit direction as to where on the hierarchy of controls a Company should be (at a minimum) with respect to specific safety hazards? If yes, please provide a schedule that identifies those projects justified (all or in part) on safety considerations and indicate i) where THESL currently is with respect to this minimum standard and ii) where THESL will be after the completion of the projects.

RESPONSE:

a) No, the OHSAS 18001 standard does not provide explicit direction as to where a Company should be on the hierarchy of controls.

b) Does replacing equipment that is not functioning at an "acceptable current standard" eliminate all residual safety risk? If so, please explain how, given that the equipment may still be subject to failure.

RESPONSE:

b) No, it does not. All electrical equipment operating at high voltages is inherently dangerous and residual safety risk is not generally eliminated by the installation of new equipment. However, specific risks stemming from specific factors, such as the presence of lead or asbestos, can be eliminated by the installation of new equipment.

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INTERROGATORY 24:

Reference(s): Tab 2, page 14, lines 17-23

Preamble:

THESL states that "prudency" [sic] is defined as the achievement of or approach to the lowest reasonable life cycle cost consistent with all other constraints.

a) Does THESL consider year over year bill impacts to be an element of the "public acceptability" constraint noted in the text? If not, why not?

RESPONSE:

a) The statement referred to is as follows:

"Prudence is defined as the achievement of or approach to the lowest reasonable life cycle cost consistent with all other constraints, including for example safety of equipment, compliance with standards including accepted standards of good utility practice, public acceptability, and the reliability and adequacy of the distribution system."

THESL regards 'bill impacts' as being important, but logically separate from the attribute of prudence. The term 'public acceptability' in THESL's definition of prudence refers to the physical character of the project per se, including aesthetic attributes, siting, environmental impacts, etc. The costs for a needed project could be prudent and still create bill impacts that might be opposed by some parties.

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INTERROGATORY 25:

Reference(s): Tab 2, page 20, lines 7-12

In its EB-200B-0205 Part II Decision (page 14) on Oshawa PUC the Board determined that:

> *With respect to the proposed feeder, in its reply submission OPUCN states that at page 25 of/he Supplementary Report contemplates that "the application would substantiate the need for incremental capital due to drivers that are non-discretionary in the control of the distributor's management such as: life-cycle replacement of aging distribution assets; ". That quote is found in the July 14, 2008 Board Report, not the Supplementary Report issued on September 17, 2008. More importantly, the above quotation is the Board's reference of Board staffs proposal to the May 6, 2008 stakeholder meeting. This is not where the Board settled on this matter in either the July 14, 2008 report or the September 17, 2008 report, the latter containing the framework and the details of filing under the incremental capital module. The Board's articulation of what should govem the incremental capital module is as the Board has set out in this decision above.*

a) Please confirm that THESL's proposal to include spending for the replacement of obsolete and failing plant in its ICM request is not consistent with the purpose of the ICM as outlined in the Board's Decision regarding Oshawa PUC? If THESL disagrees, please fully explain why.

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RESPONSE:

a) THESL does not confirm VECC's assertion that THESL's proposal to replace its failing plant is not consistent with the purpose of the ICM. As detailed throughout THESL's evidence, THESL believes that all the work proposed in this application is essential to maintaining the safety and reliability of the distribution system and THESL has no other options currently available to fund this capital work except through the ICM mechanism.

As is also detailed in THESL's application – including the Revised Manager's Summary and the ICM evidence, Tab 4 of its pre-filed evidence and throughout its answers to interrogatories – THESL has sought to prepare this application in accordance with the relevant ICM materials and has taken into consideration the OEB's past decisions in respect of other distributors' ICM applications. Regarding the guidance that THESL has gained from these past decisions, including the above-referenced Oshawa PUC decision, please see THESL's response to VECC interrogatory 12 (Tab 6E, Schedule 11-5).

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INTERROGATORY 26:

Reference(s): **Tab 2, page 23, Table 3**

a) Were each of the 2012 projects/jobs proposed in the current Application included in THESL's EB-2011-0144 Application?

RESPONSE:

a) No. Please see THESL's response to OEB Staff interrogatory 26d (Tab 6F, Schedule 1-26, part d).

b) For any projects that were not included in the earlier Application, please explain what change in circumstances has led to their inclusion in the current Application.

RESPONSE:

b) As described in THESL's response to SEC interrogatory 6 (Tab 6E, Schedule 10-6), the capital portfolios used in previous applications are fundamentally incomparable with the projects and segments into which work is divided in this application. While the projects in this application cannot be directly compared with previous capital portfolios, THESL can confirm that the following projects are comprised of jobs that were not included in EB-2011-0144:

1) **PILC – Piece Outs and Leakers**

As described in THESL's response to SEC interrogatory 6 (Tab 6E, Schedule 10-6), this application approaches PILC cable differently than the previous application. Whereas the previous application contemplated replacement of failing or overloaded PILC cable with larger 500 MCM XLPE cables, the jobs

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in this application target a specific damaged portion of leaking cable or cables requiring piecing out.

2) **SMD-20 Fuses**

SMD-20 fuses were found to have a defect within the polymer body, causing the insulator to potentially break in half during operation. This defect was only discovered in late 2011, subsequent to the filing of the filing of THESL's application in EB-2011-0144.

c) For those projects/jobs that were included in the earlier Application, please provide a schedule that indicates where in the earlier Application the description of the project/job and the (then) proposed spending can be found.

RESPONSE:

c) Please see THESL's response to SEC interrogatory 6 (Tab 6E, Schedule 10-6).

d) Please provide a schedule that lists all such projects/jobs (per part (c)) and compares the currently proposed spending for 2012 with that proposed in EB-2011-0144.

RESPONSE:

d) Please see THESL's response to SEC interrogatory 6 (Tab 6E, Schedule 10-6).

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INTERROGATORY 27:

Reference(s): **Tab 2, Appendix 4, pages 3 -5 Supplemental Report of the Board (EB-2007-0673), Appendix B, page VII**

a) Does the Risk Cost associated with the existing asset include the ongoing maintenance costs as well as any additional maintenance costs associated with repairing the assets when/if they fail?

RESPONSE:

a) As maintenance costs are typically the same between the existing asset to be replaced and the new asset to be installed, these costs are not included within the business case as they would cancel each other out. There are only two specific business cases – rear lot and box construction conversion – where a maintenance savings are identified between the existing assets to be replaced and the new assets to be installed. Under these instances, the differing maintenance costs are identified as an "ongoing cost" within the cost of ownership for the existing and new assets. The risk cost of the existing asset does include the cost of emergency repairs should an asset failure take place.

b) To the extent earlier replacement is justified on the basis of lower risk costs are there not O&M savings accruing to THESL as compared to the non-early replacement case? If not, please explain why.

RESPONSE:

b) Typically, when performing like-for-like replacement of assets, there is no difference in maintenance policy to the assets in question, and therefore no change in

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maintenance costs. In the case of non-in-kind replacement projects, where existing infrastructure is replaced with new infrastructure with new configurations and designs, there may be maintenance savings achieved. For instance, there is typically a savings in maintenance costs achieved with rear lot conversion, as tree trimming activities no longer need to be performed. Similarly, there is a savings in maintenance costs achieved for box construction conversion, as maintenance to the corresponding 4kV municipal stations assets will no longer be required once these assets can be decommissioned.

c) Given that such savings represent a source of funds, how are they accounted for in the determination of the ICM requirements – as directed in the Supplemental Report of the Board?

RESPONSE:

c) The avoided maintenance costs are small in the context of the overall capital spend contained in this application and thus do not represent a significant source of funds.

d) For each of the Segments that utilize a Business Case Evaluation which relies on Avoided Risk cost analysis to support the investment decision, please identify the O&M costs avoided over the 2012-2014 period.

RESPONSE:

d) THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response to this interrogatory, such that providing a response now would

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not materially assist the OEB or intervenors. THESL accordingly defers its response to this interrogatory until after its forthcoming evidentiary update.

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INTERROGATORY 28:

Reference(s): **Tab 2, Appendix 4, page 3**

Preamble:

THESL states that it bases the magnitude of an outage on the peak load interrupted due to the fact that most outages occur in the peak period.

a) Please explain how the "cost of a failure" is determined from the magnitude (i.e. kW) of the outage. If THESL is using estimates of customer outage costs, please provide the relevant sources.

RESPONSE:

a) Please see the response to OEB Staff interrogatory 27 (Tab 6F, Schedule 1-27).

b) Based on the most recent 24 months, how many outages (due to equipment failure) occurred in the peak period and what was the average duration of such outages?

RESPONSE:

b) Over the last 24-month period, a total of 841 outages have occurred within the peak loading period as defined by the current time-of-use regulations within the Province of Ontario. Within that same 24-month period, a total of 1,293 equipment failures took place. Therefore, 65% of outages occur during peak loading times, with an average duration of 3.86 hours.

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c) If most outages occur in the peak period, why not use the average load in the peak period as a measure of the magnitude of the outage?

RESPONSE:

c) When determining the full "cost of a failure" with respect to a particular asset, the asset peak load is used as a proxy to represent the quantities of connected customers that would be impacted by the resulting outage. In this instance, asset peak loading is used as it accurately quantifies the criticality of the customer outage by factoring in the class of customer (residential, commercial, industrial) and accounting for bulk metered multi-residential accounts. In essence, the peak load is used as a representation of the customers connected and the load they may have been needed during the outage.

This value is also available at the individual asset level, which is the level of granularity that is required in order to develop the provided business case evaluations. The "average load in the peak period" is not available at the individual asset level, and therefore cannot be used to develop the provided business case evaluations.

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INTERROGATORY 29:

Reference(s): Tab 2, Appendix 4, page 4

a) Please explain how non-asset related failure costs are included in the risk costs. In particular, do they tend to increase risk costs and therefore lead to an earlier intervention year?

RESPONSE:

a) Non-Asset Risk (NAR) is an additional risk formulated through a study of outages that were not due to equipment failure i.e., they were non-asset related (for instance, animal contact, lightning, adverse weather, vegetation, etc.). The information on past failures is obtained from ten years worth of historical outage data.

Should an asset be replaced in a like-for-like manner, there will be no adjustment with respect to the overall risk costs due to non-asset-related risks, as these risks are applicable to both the existing and new assets respectively. On the other hand, should an asset be replaced in a non-in-kind manner, where the new asset is installed in a new configuration or where new technologies are deployed to the existing assets such that outage duration times are decreased, this will result in an adjustment in regards to the non-asset-related risk, and therefore an adjustment to the overall risk cost.

b) As an extreme example, if the utility <u>knew</u> an asset (whether old or new) was going to need to be replaced sometime over the next three years due to a non-asset related event, would this reduce the likelihood of intervention (i.e., pro-active replacement) during this period?

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RESPONSE:

b) As the non-asset-related risks are identical between the existing asset and new asset, absent any change to configuration, it is just as likely for the non-asset-related event in question to impact the existing asset or the new asset alike. Therefore, these non-asset-related risks do not adjust the overall risks to the assets in question.

c) More generally, how does the FIM analysis account for the fact that early intervention/replacement also means that subsequent failures due to non-asset related events (e.g., weather, human interference, vegetation, etc.) during the intervening will result in having to replace the newer asset as opposed to the older asset which would have been in place without such an intervention?

RESPONSE:

c) The FIM analysis can account for this fact by comparing the non-asset-related risks between the existing and new assets. An in-kind intervention, which involves the replacement of an existing asset with a new asset of the same type and under the same configuration, would have unchanged non-asset risks. In order to mitigate this non-asset risk, a non-in-kind intervention is necessary, in which the new asset is installed in a new configuration or design standard. Examples of this include conversion from existing overhead rear lot construction to underground front lot construction where the new assets will not be exposed to same levels of non-asset risks (animal contact, lightning, adverse weather, vegetation, etc.).

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INTERROGATORY 30:

Reference(s): **Tab 2, Appendix 4, pages 4**

a) Figure 3 is somewhat illegible. Please provide an improved copy with a legible explanation of the various components.

RESPONSE:

a) Please note Figure 1 below:

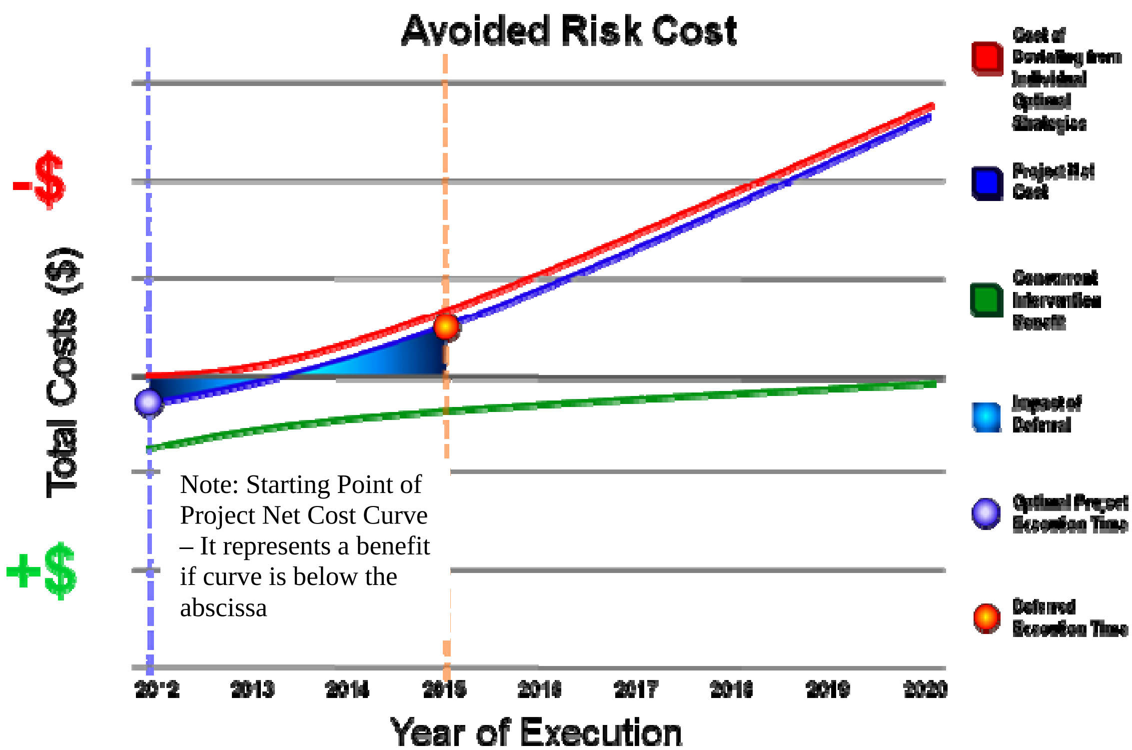

Figure 1 – Avoided Cost Calculation

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In-kind replacement projects are evaluated by calculating the ‘avoided risk’ of executing the project immediately in 2012 as opposed to delaying it until 2015. In order to calculate the avoided risk of performing a project in 2012 as opposed to 2015, the various costs and benefits associated with executing a project in a particular year are taken into account.

In essence, the benefit of performing the project, termed ‘Project Net Cost’ is calculated year by year moving forward from the current year. Further details of the Project Net Cost value are explained in part (c) below.

b) Does valuation of early replacement also take into account the risk costs (both asset and non-asset related) associated with the new asset and include these as part of the overall “cost” of early replacement? If so, how?

RESPONSE:

b) Valuation of proactive replacement does take into account the risk costs associated with the new asset. In order to determine the optimal intervention timing of the existing asset, the analysis must begin with the new asset, as illustrated in Figure 2. The new assets’ capital and risk costs are annualized across the life cycle of the asset. The total of these annualized costs produces the life cycle cost, or total operating cost of the asset. The lowest point on this life cycle cost curve represents the Equivalent Annualized Cost (EAC), which is then cross-referenced to the existing assets’ risk cost curve. It is through this cross-referencing that the Optimal Intervention Timing is determined for the existing asset. Therefore, both the annualized capital and risk costs of the new asset will impact the optimal intervention timing result of the existing asset.

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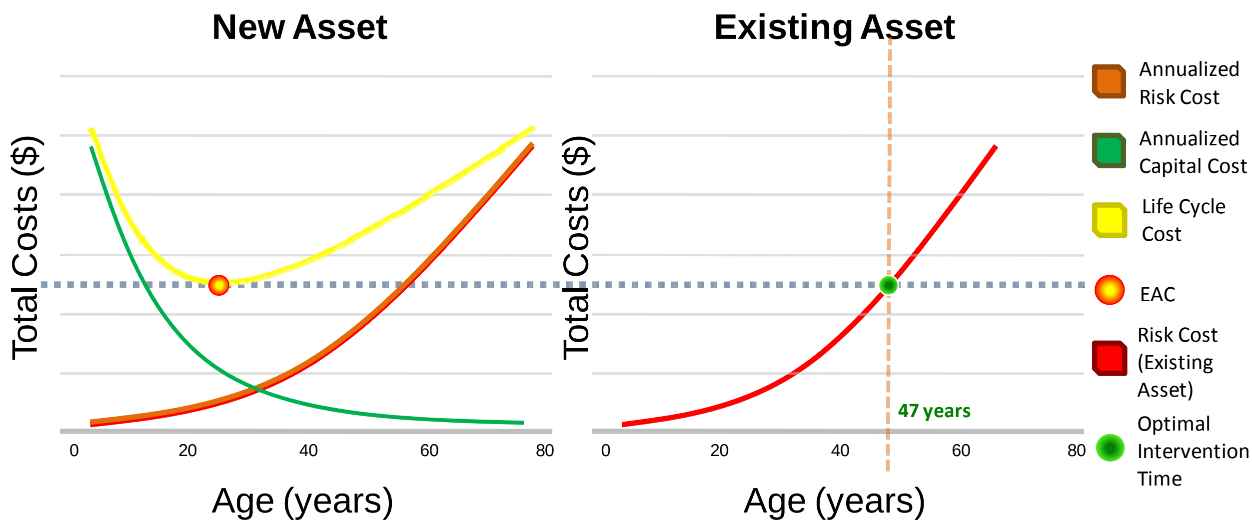

Figure 2 – Optimal Intervention Timing Result for Existing Asset

c) If possible, please illustrate the overall way the analysis in Figure 3 works using an illustrative example that shows how all the relevant costs (including the cost of the new asset, the asset-related and non-asset related risk costs (for the new and the existing asset) and the sacrificed life values) are taken into account and incorporated into the evaluation.

RESPONSE:

c) As described in the response to part (b) and illustrated in Figure 2, each existing asset will receive an optimal intervention timing result, based upon the life cycle analysis that is performed. It should be noted that for the example in Figure 2, should the asset be replaced prior to the 47 year optimal intervention time, a certain portion of its economic life would be sacrificed. The amount of 'life' that is forfeited by performing the replacement before the asset's optimal replacement time, in dollars, is

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the ‘sacrificed life’ of the asset. However, should the asset be replaced after it’s optimal intervention time, the asset will incur ‘excess estimated risk’, that is, risks that are not economically warranted. These two concepts are illustrated in Figures 3 and 4 respectively.

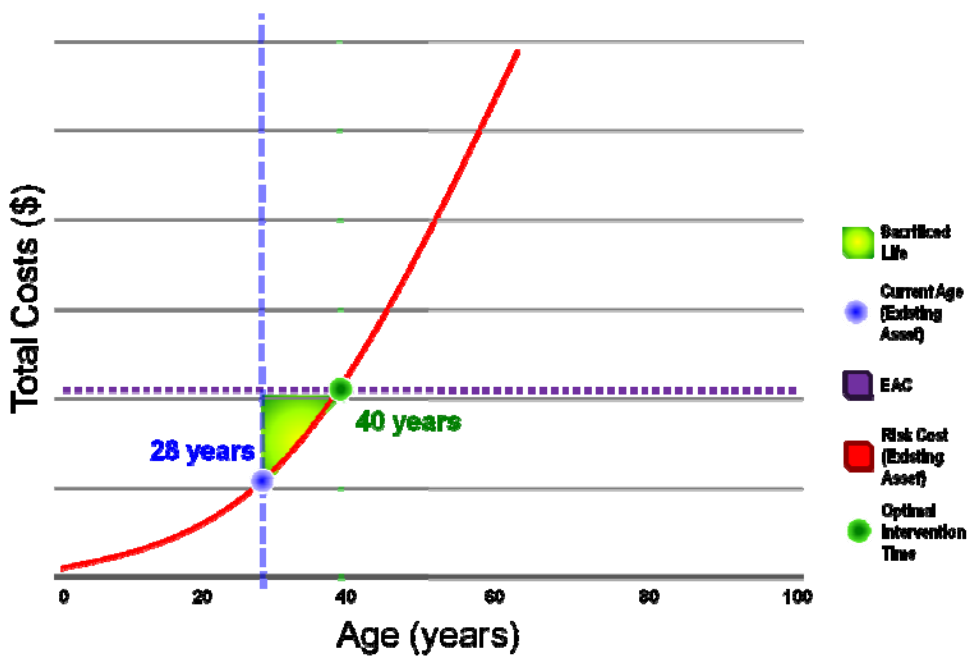

Figure 3 – Sacrificed Life

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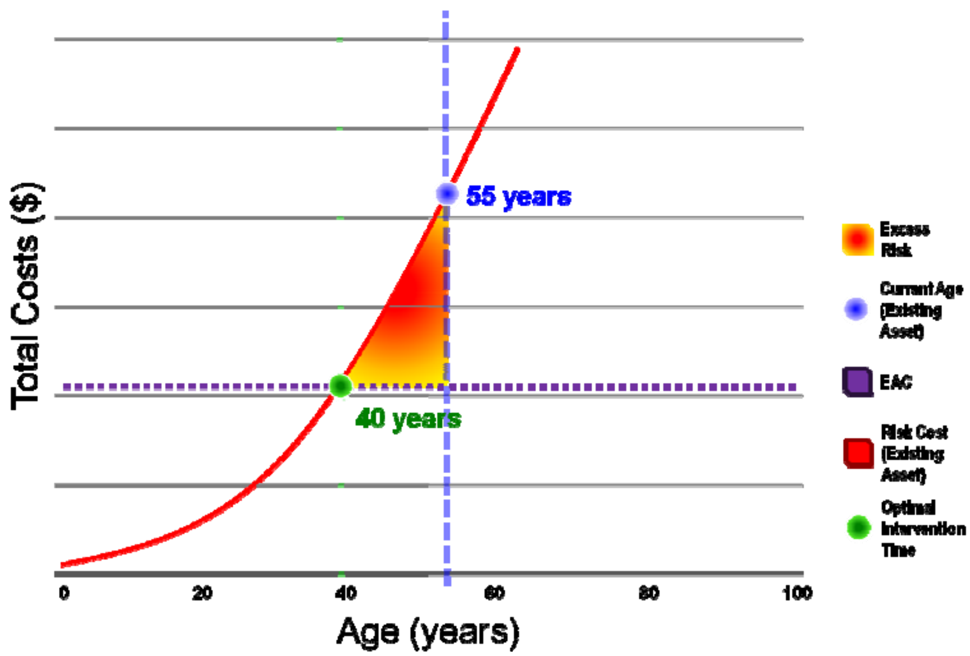

Figure 4 – Excess Risk

When executing asset replacements as a project, assets within the project may be before, at, or beyond their optimal replacement time, thus some assets will have sacrificed economic life and others will have incurred excess risk. The cumulative sacrificed life and excess risk of the assets involved becomes a cost against the project, which is illustrated by the red curve in Figure 1.

The benefits of the project stem from the fact that there are a number of savings attained by performing multiple asset replacements together as opposed to an individual basis. These concurrent intervention benefits include factors such as equipment rentals, transportation of crew and material, excavations, and road moratoriums. Taking the sum of the costs and benefits, year by year, provides the

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Net Project Benefit, the blue curve in Figure 1. Note that the curves in Figure 1 are plotted with time, in years, as the abscissa and the total costs as the ordinate. As such, the minimum point of this curve provides the highest Net Project Benefit and defines the optimal year to execute the specific project.

The effectiveness of the project can be measured by calculating the total "avoided cost" of executing this work immediately in 2012, as opposed to waiting until 2015. In order to calculate the avoided cost, the Project Net Cost in 2012 is subtracted from the present value of the Project Net Cost from 2015. Both the benefits and costs that are seen by waiting until 2015 are captured with this approach. An example of this avoided cost is shaded in blue in Figure 1.

Since the optimal year is the lowest point in Figure 1, when this avoided cost is calculated as a positive value, it means that estimated risk costs for the project assets in 2015 will exceed the estimated risks that exist today in 2012. By performing the work immediately as opposed to waiting until 2015, we can eliminate these estimated risks. Therefore, these avoided costs represent the benefits of the in-kind project execution.

Note that non-asset-related risks are not applied as part of in-kind replacement project evaluations, where the Avoided Risk Cost is calculated, since these risks will exist before and after the project is executed. These non-asset-related risks are only applied to non-in-kind replacement projects, where these risks may be either reduced or completely eliminated due to the installation of new assets under a completely new configuration or design, or where new technologies are deployed to existing assets in order to reduce outage durations.

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INTERROGATORY 31:

Reference(s): Tab 4, Schedule B1, page 2

a) As of 2006 how many kilometers of direct burled cable did THESL have?

RESPONSE:

a) As the end of year 2006, there were 1,358 conductor kilometres of direct buried cable in the system.

b) Please provide a schedule that sets out the kilometers of direct buried cable that were replaced each year between 2007 and 2011.

RESPONSE:

b) Please see the response to AMPCO interrogatory 10 e (Tab 6F, Schedule 2-10, part e).

c) Was all of this direct buried cable replaced with cable in concrete-encased ducts and, if not, why not?

RESPONSE:

c) In planned projects since 2007, all direct buried cables were replaced with cable in concrete-encased ducts. However, in emergency repairs, direct buried cables are usually replaced with direct buried cables because replacing the failed direct buried cable with cable in concrete-encased ducts would significantly lengthen the outage duration.

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d) Over the same 2007-2011 period, was there any replacement of air-insulated pad-mounted switchgear units? If so, were they all replaced with SF6-insulated pad-mounted switch gear units and, if not, why not?

RESPONSE:

d) Yes, air-insulated pad-mounted switchgear units were replaced over this period. Not all air-insulated pad-mounted switchgear units were replaced with SF_6-insulated pad-mounted switchgear units when repairs were made on a reactive basis. During emergency repairs, replacement air-insulated pad-mounted switchgear units were installed when installing SF_6-insulated pad-mounted switchgear would have significantly prolonged the outage. In some cases this was because the existing cable was not long enough to allow for the connection to SF_6-insulated pad-mounted switchgear units, which require longer cable than air-insulated pad-mounted switchgear units in order to make the proper terminations.

e) Based on the timing of the jobs set out in Table 1, how many kilometers of direct buried cable will be replaced in each year 2012-2014?

RESPONSE:

e) THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response to this interrogatory, such that providing a response now would not materially assist the OEB or intervenors. THESL accordingly defers its response to this part until after its forthcoming evidentiary update.

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INTERROGATORY 32:

Reference(s): Tab 4, Schedule B1, pages 4 -5

a) Over the period 2007-2011 what has been the annual capital spending on the replacement of direct buried cable and air-insulated pad-mounted switchgear units?

RESPONSE:

a) Table 1 below provides the annual capital spending for the "Underground Direct Buried" and "Underground Rehabilitation" portfolios for 2008 through 2011.

Table 1: Annual spending on underground projects ($ millions)

Year	2007	2008	2009	2010	2011
Underground Direct Buried	$33.00	$23.80	$31.90	$42.40	$47.00
Underground Rehabilitation	$35.70	$38.20	$36.70	$69.10	$52.10

The "Underground Direct Buried" portfolio represents direct buried cable replacements. It also includes replacement of air-insulated pad-mounted switches and submersible transformers, as these are sometimes replaced in direct buried cable replacement projects.

The "Underground Rehabilitation" portfolio is for underground capital work that is not related to direct buried cable, such as replacement of primary cable in concrete-encased ducts, and may also include air-insulated pad-mounted switch replacements.

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INTERROGATORY 33:

Reference(s): Tab 4, Schedule B1, pages 9-109

Preamble:

The referenced pages describe 34 separate underground asset replacement projects.

a) Please provide a single schedule that sets out the historical reliability performance (2007-2011) for each of the 34 feeders. Please also include in the schedule the number of unplanned sustained outages in each year by feeder.

RESPONSE:

a) Table 1 in Appendix A, attached, provides the requested information.

b) Please identify the 5 worst performing direct buried feeders that are not scheduled for rehabilitation/replacement during this period and identify the historical reliability performance of each (2007-2011).

RESPONSE:

b) The WPF program (described in Tab 4, Schedule C1, Pages 3-5) methodology was utilized to identify the five worst performing feeders that are not scheduled for rehabilitation or rebuild in 2012, 2013 and 2014. These five feeders and the historical reliability performance of each are illustrated in Table 2 in Appendix A. Note that all these feeders have direct buried cable portions, but they are not solely comprised of direct buried cable.

Table 1

Job #	Feeder Name	Unplanned Sustained Outages					Historical Reliability Performance 2007		Historical Reliability Performance 2008		Historical Reliability Performance 2009		Historical Reliability Performance 2010		Historical Reliability Performance 2011	
		2007	2008	2009	2010	2011	CI	CHI	CI	CHI	CI	CHI	CI	CHI	CI	CHI
1	NY80M29	11	13	14	7	15	8294	9781.4	10000	1829.4	10473	3704.4	2430	1631.4	8255	2294.1
2	SCNAR26M34	3	8	7	7	12	1687	3982.4	3592	8995.2	1183	7220.9	9101	5567.4	7560	14615.7
3	NY55M8	9	7	9	10	12	4388	1548.6	7595	21434.9	15626	6944.5	6227	3920.1	10734	8972.8
4	YK35M10	8	11	12	6	11	13452	5959.8	12575	4410.0	12687	4099.1	3289	548.4	17593	2332.9
5	SCNT63M4	14	2	2	3	10	12452	9976.0	1504	3899.0	397	131.1	230	648.8	28124	22101.8
6	SCNA47M14	9	6	8	6	10	6026	4910.7	3924	1226.2	4076	3364.7	14227	7657.6	11491	7586.0
7	NY51M6	6	6	6	10	10	201	594.0	3015	2851.5	7099	6992.4	5131	2937.5	5408	8757.6
8	NY80M8	6	4	6	7	8	2036	1006.0	4010	1002.7	4622	5143.6	4616	3768.3	3004	2975.2
9	NY85M6	4	3	1	3	8	753	370.1	118	217.0	576	38.4	1831	782.2	5833	12279.2
10	NY51M8	7	6	2	7	8	3179	481.9	5601	1154.2	6124	2786.9	2277	2634.0	2480	460.9
11	SCNA502M22	6	1	6	6	7	27672	1755.8	3705	4775.5	19233	11978.6	7957	4184.7	20126	7458.2
12	SCNAH9M30	6	7	6	11	7	80	356.6	5139	3820.8	8147	8174.7	6796	9441.2	2461	3238.7
13	NY85M4	7	4	2	4	7	2243	1185.8	3261	470.1	524	129.1	26	84.1	2862	6235.2
14	SCNA47M13	6	8	6	6	6	8142	2355.0	5692	2919.2	4889	2652.9	10328	11820.5	17600	12499.5
15	NY80M2	5	6	4	7	6	21400	1176.4	4228	1898.7	2050	394.5	7966	5441.0	2809	1354.4
16	NY51M7	9	12	11	9	6	4744	2243.7	14020	5422.4	5466	1782.7	9764	3676.3	3126	1728.4
17	NY51M24	4	6	11	6	6	2086	2757.4	5141	2156.1	4337	3518.4	6265	5409.8	270	942.0
18	NY80M30	5	8	14	13	6	460	647.0	7916	1695.7	7419	5809.5	9370	4961.8	442	255.7
19	NY55M23	3	3	6	8	6	3485	3904.9	37	120.1	115	455.1	6533	1367.2	3170	914.9
20	NY85M24	8	4	3	3	6	4271	5339.0	6324	5005.1	2726	1321.5	62	52.1	4793	3023.6
21	SCNAE5-2M3	3	5	5	6	6	3607	6725.1	4391	4697.6	174	447.6	297	1376.3	2374	757.7
22	NY85M7	3	4	2	4	6	169	431.0	2871	1248.0	1228	1415.1	3414	772.7	85	35.8
23	SCNT63M12	11	8	9	9	5	23815	22638.4	985	2658.3	4968	6925.4	1459	5414.3	18772	31571.0
24	SCNT63M8	10	7	6	4	5	15468	6657.7	6986	3533.3	11495	5276.3	227	658.5	5313	5879.2
25	SCNAE5-1M29	5	2	6	5	5	1477	119.2	2955	494.0	1934	3827.0	8032	4101.2	2676	1952.3
26	NY53M25	13	3	11	6	5	21402	6421.1	260	854.4	19054	10647.6	563	1167.2	1393	919.9
27	NY80M9	2	6	10	3	5	104	203.6	1721	1292.7	3666	1662.2	141	422.6	927	816.7
28	SCNT47M3	18	14	21	12	4	54593	20824.6	20841	8681.3	47262	21607.5	102883	45728.6	12750	8963.5
29	SCNAH9M23	8	3	2	4	4	4217	2527.4	397	757.2	1963	432.5	1163	134.8	10042	7207.5
30	NY51M3	4	3	1	7	4	2103	2722.5	259	265.9	150	454.2	4500	1420.2	1638	3012.8
31	SCNA47M17	15	11	6	12	3	17982	6314.2	9360	10051.7	7260	1916.2	7740	3305.4	3303	665.4
32	SCNA502M21	6	10	3	3	2	3893	1750.0	13067	12822.7	7099	941.1	4814	1534.0	8992	6298.1
33	SCNT47M1	6	12	9	7	2	26818	5632.0	14377	8393.7	6436	3492.6	11039	7162.5	2151	142.6
34	NY85M1	8	8	5	6	6	2997	755.7	5596	3031.3	178	374.7	341	1837.1	9883	3059.2
34	NY85M9	5	3	1	9	4	170	753.6	1731	1472.2	1553	155.3	1789	367.3	608	2710.4
34	NYSS58F1	8	10	6	9	6	888	870.1	678	2151.9	460	1295.3	1229	1175.6	240	832.1

Table 2

Feeder Name	Unplanned Sustained Outages					Historical Reliability Performance 2007		Historical Reliability Performance 2008		Historical Reliability Performance 2009		Historical Reliability Performance 2010		Historical Reliability Performance 2011	
	2007	2008	2009	2010	2011	CI	CHI	CI	CHI	CI	CHI	CI	CHI	CI	CHI
SCNT47M7	5	3	3	1	5	13067	17917	6735	3324	424	930	2660	107	6876	4231
SCNT63M6	9	7	4	1	1	11888	1558	11625	2846	6990	550	2381	3170	5899	8596
SCXGF3	2	5	4	1	6	3283	3710	2958	7841	2192	2378	15	40	4724	9112
SCNAR43M27	4	0	3	2	4	2937	2743	0	0	183	1520	15	20	465	819
NY51M21	7	10	9	18	3	13288	12934	2569	1124	15491	36582	9953	7414	70	184

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INTERROGATORY 34:

Reference(s): Tab 4, Schedule B1, pages 115-117

a) What evidence does THESL have that the increase in outages in 2011 is indicative of a future trend in increasing failures as opposed to a one year aberration in reliability performance?

RESPONSE:

a) As shown in Figure 1 in the response to AMPCO interrogatory 9 (b) (Tab 6F, Schedule 2-9), the number of interruptions attributed to direct buried cable has shown a slightly decreasing trend. However, the total length of direct buried cable in THESL's distribution system also has been decreasing since 2007, when THESL began replacing direct buried cable. As a result, the number of interruptions (due to direct buried cable) per km of direct buried cable remaining in the system has been increasing. This is illustrated in Figure 1, below.

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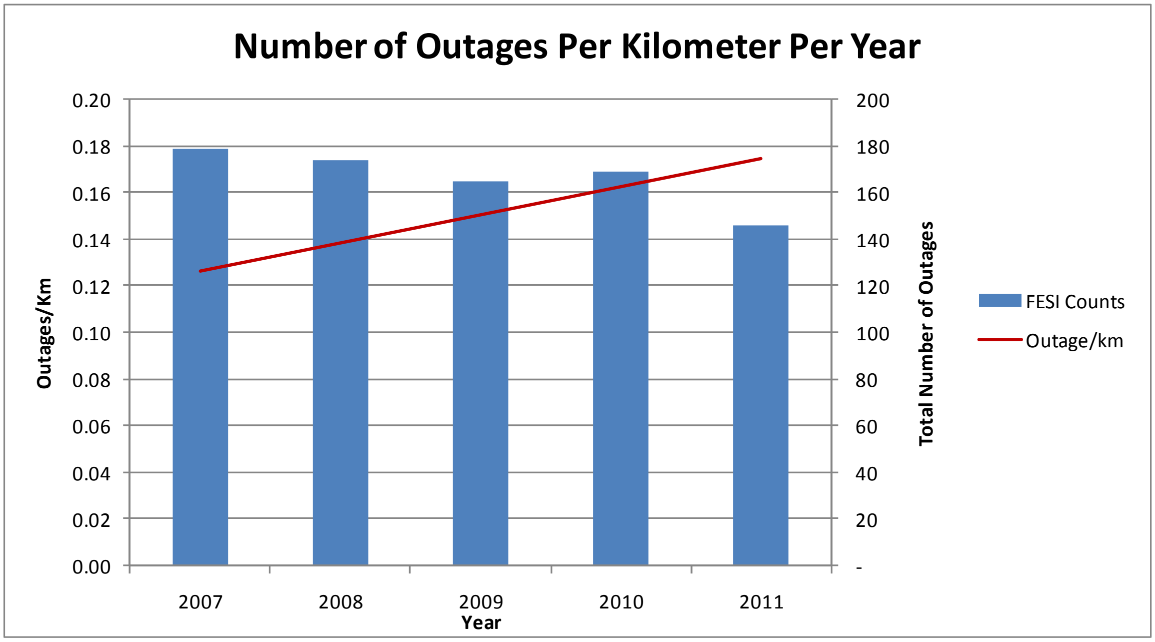

Figure 1: Number of interruptions per km of direct buried cable

The increasing trend of number interruptions (due to direct buried cable) per km of direct buried cable supports the view that the 2011 results referenced in the question are not a "one-year aberration" and that direct buried cable replacements must continue.

b) Please update Figures 42-45 to include the first six months of 2012.

RESPONSE:

b) Figures 2, 3 and 4 below are, respectively, updated versions of Figures 42, 44 and 45 in Tab 4, Schedule B1, Pages 116-117. Data for the first six months of 2012 has been added to each figure. A corrected and updated version of Figure 43 is presented in response to AMPCO interrogatory 9 (b) (Tab 6F, Schedule 2-9, part b).

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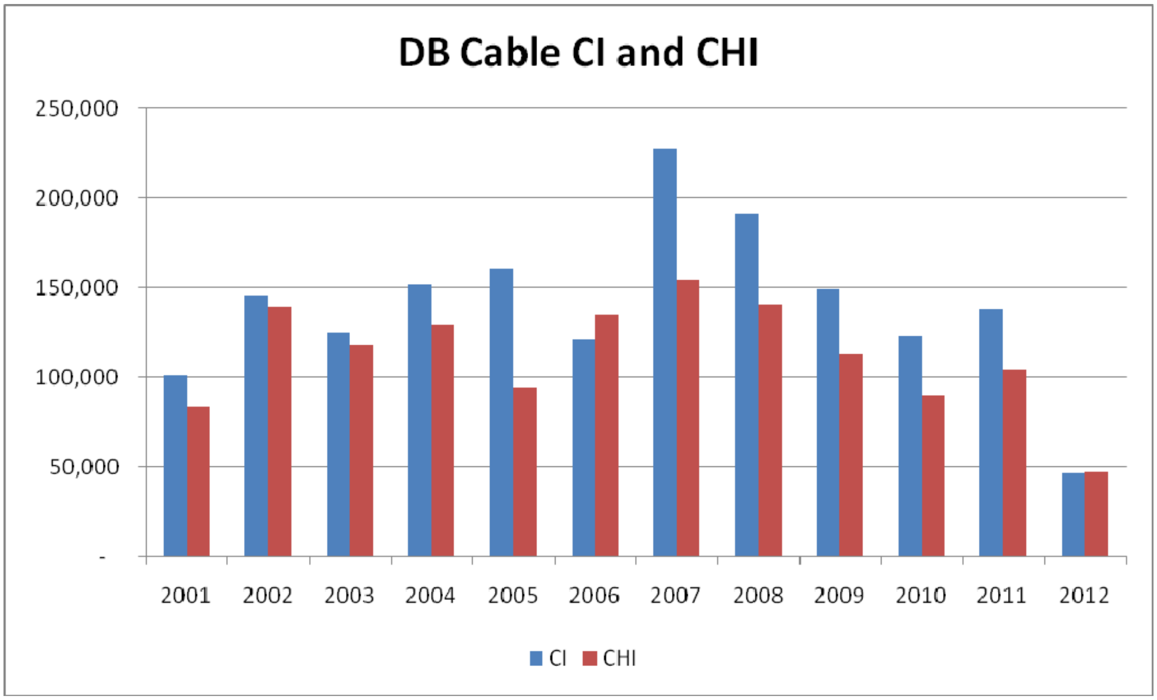

Figure 2: Customer Interruptions (CI) and Customer Hours Interrupted (CHI) due to interruptions attributed to direct buried cable.

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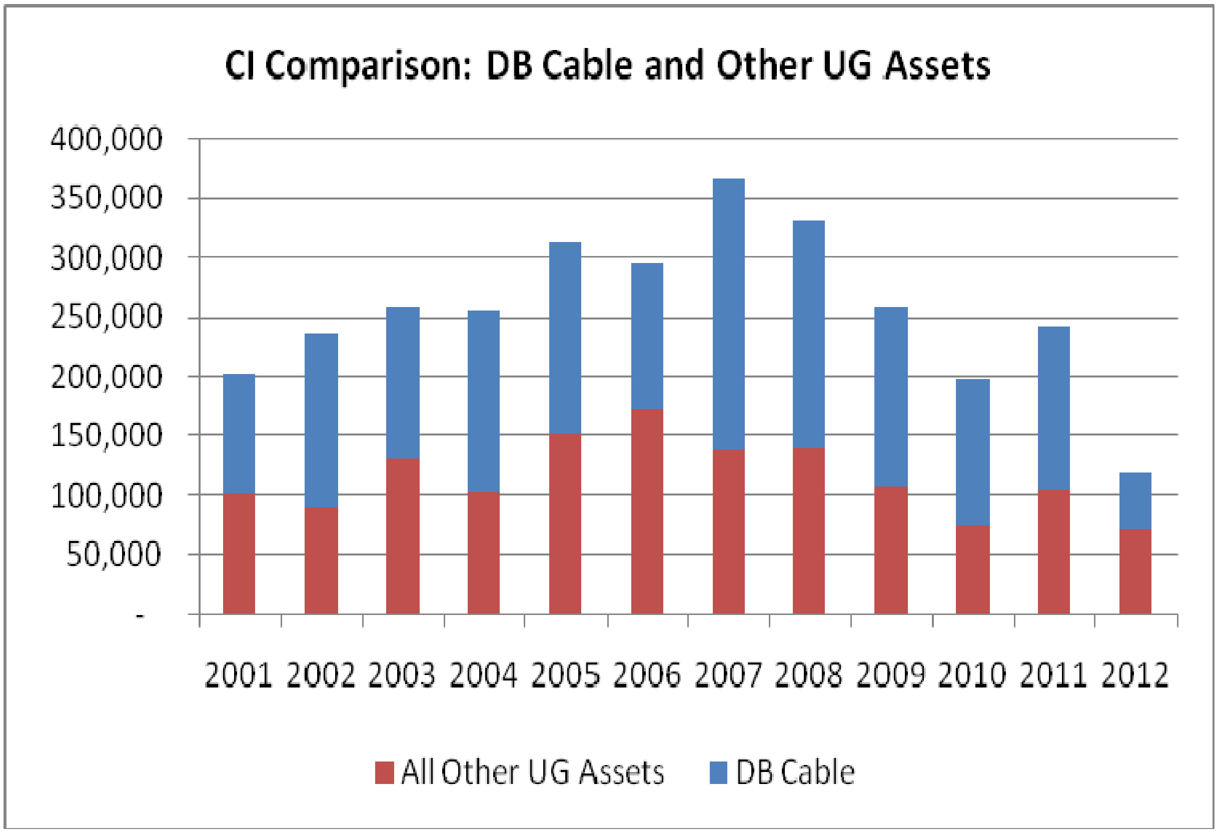

Figure 3: Customer Interruptions (CI) due to interruptions attributed to direct buried cable versus all other underground assets.

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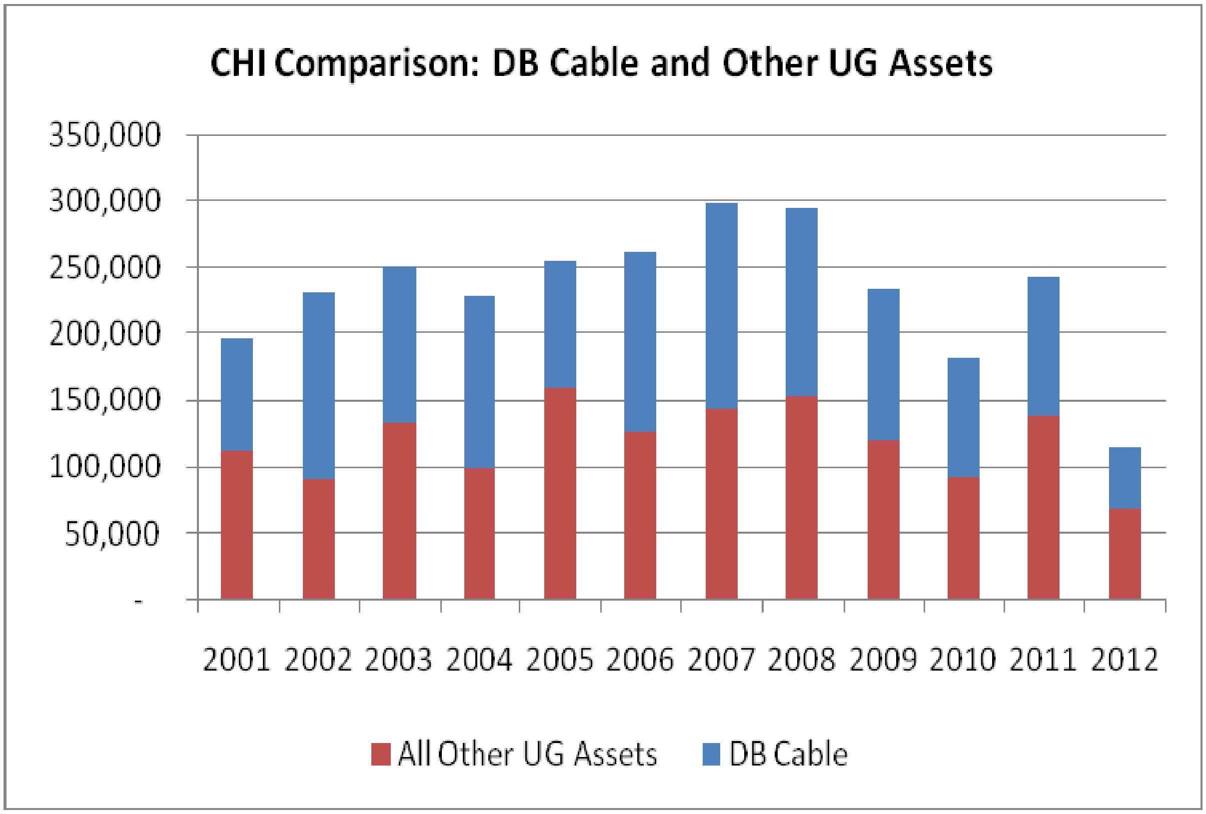

Figure 4: Customer Hours Interrupted (CHI) due to interruptions attributed to direct buried cable versus all other undergound assets.

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INTERROGATORY 35:

Reference(s): **Tab 4, Schedule B1, pages 192-194**

a) Has THESL undertaken any analysis to determine the level of confidence and/or confidence interval associated with the "optimal intervention time" derived by its BCE process?

RESPONSE:

a) As part of the development and enhancement processes for the Feeder Investment Model (FIM), in-field testing and evaluations are performed to ensure that:

   i) All inputs used as part of the risk calculation process, including asset class identification, age, condition and nameplate data are accurate;
   ii) The optimal intervention timing results produced are accurately aligned to the qualitative drivers and rationale for project execution; and
   iii) The business case results produced, including Net Present Value (NPV) results, are accurately aligned to the qualitative drivers and rationale for project execution.

b) If yes, please indicate the analyses that were performed and the results.

RESPONSE:

b) As discussed in (a), in-field testing and evaluations are performed to ensure that accurate risk calculation, optimal intervention timing and business case results are produced. The following actions are executed where testing and evaluations indicate that further investigations are required:

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i) Where in-field testing indicates that data within the modelling does not align to what is being captured from the field, improvements are immediately recommended and initiated to those respective source systems to ensure that data quality is improved.

ii) Where optimal intervention timing or business case evaluation results do not align to the qualitative results that are produced, the FIM is closely examined and compared to these qualitative results to ensure that all appropriate justifications (asset performance, costing data, etc) are being accurately assessed within the modelling in order to ensure accurate alignment is in place. Where re-alignment is necessary, this is captured as part of ongoing improvements and enhancements within the FIM. As new data and information becomes available, the FIM is routinely enhanced to ensure alignment and accuracy.

c) If no, does THESL acknowledge that there is some uncertainty associated with the various inputs to the BCE process which in turn will lead to some uncertainty in term of the results?

RESPONSE:

c) Results produced by the Feeder Investment Model (FIM) represent only a portion of the complete business case evaluation and scope packaging procedure, where both qualitative and quantitative measures are utilized in order to initiate and justify a capital project. Therefore, when utilized within a business case, FIM results are compared to the qualifying project drivers to ensure that alignment exists. If it is shown that the FIM is not capturing the "full" benefits or over quantifying the

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benefits associated with a project, appropriate enhancements to the FIM are executed to ensure that a more robust and accurate quantification results can be produced.

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INTERROGATORY 36:

Reference(s): Tab 4, Schedule B1, pages 196-197

a) Please provide a schedule that sets out the Avoided Risk cost results (similar to Table 1) for each of the 34 "jobs".

RESPONSE:

a) Please see Table 1 for Avoided Risk Cost results for all 34 jobs. Please note that the Avoided Estimated Risk Cost has been revised to correct an error in the evidence. In calculating the present value of the 2015 figure, THESL inadvertently applied both an annual discount rate to the years 2013, 2014 and 2015 and an overall rate to the 2015 figure. This response also corrects Table 1 on page 197 of Tab 4, Schedule B1 where the 2012 and 2015 numbers were transposed and given the wrong sign.

Table 1 – Avoided Risk Cost Results (Estimated Costs)

Job #	Job Feeder Name	Job Cost ($M)	PV (2015 Project Net Cost) ($M)	2012 Project Net Cost ($M)	Avoided Risk Cost ($M)
1	NY80M29	$2.90	$4.87	-$5.31	$10.18
2	SCNAR26M34	$5.52	$1.95	-$8.63	$10.58
3	NY55M8	$2.49	$1.51	$2.05	-$0.54
4	NY35M10	$2.14	$1.31	$1.28	$0.03
5	SCNT63M4	$3.16	-$3.89	-$10.41	$6.52
6	SCNA47M14	$4.43	-$0.41	-$0.05	-$0.36
7	NY51M6	$2.54	$0.35	-$5.42	$5.77
8	NY80M8	$9.51	$6.90	$8.53	-$1.63
9	NY85M6	$2.01	$9.66	$0.19	$9.47

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Job #	Job Feeder Name	Job Cost ($M)	PV (2015 Project Net Cost) ($M)	2012 Project Net Cost ($M)	Avoided Risk Cost ($M)
10	NY51M8	$1.58	$1.73	$2.12	-$0.39
11	SCNA502M22	$2.96	-$1.80	-$0.76	-$1.05
12	SCNAH9M30	$3.56	$3.77	$4.08	-$0.31
13	NY85M4	$8.27	$0.40	-$8.24	$8.64
14	SCNA47M13	$4.91	$1.72	$2.22	-$0.51
15	NY80M2	$1.63	-$6.10	-$7.86	$1.77
16	NY51M7	$1.40	$0.94	$1.29	-$0.35
17	NY51M24	$5.64	-$5.13	-$13.70	$8.57
18	NY80M30	$8.95	-$5.68	-$7.53	$1.85
19	NY55M23	$2.24	$2.21	$2.78	-$0.58
20	NY85M24	$2.03	-$1.84	-$3.01	$1.17
21	SCNAE5-2M3	$1.51	$2.12	$0.90	$1.22
22	NY85M7	$13.83	$5.91	$7.78	-$1.87
23	SCNT63M12	$11.14	-$30.76	-$44.06	$13.30
24	SCNT63M8	$7.59	-$6.38	-$14.12	$7.74
25	SCNAE5-1M29	$3.91	-$0.04	-$3.79	$3.75
26	NY53M25	$3.44	-$7.67	-$10.06	$2.39
27	NY80M9	$2.21	$0.96	$2.17	-$1.22
28	SCNT47M3	$20.44	-$19.46	-$24.90	$5.44
29	SCNAH9M23	$2.71	$5.65	-$3.45	$9.10
30	NY51M3	$3.54	$2.71	$3.28	-$0.56
31	SCNA47M17	$5.70	-$12.01	-$28.32	$16.30
32	SCNA502M21	$3.44	-$10.63	-$19.25	$8.62
33	SCNT47M1	$14.91	-$96.48	-$176.66	$80.17
34	NY85M1	$2.66	$6.71	$1.24	$5.47
Total		$174.90	-$146.92	-$355.59	**$208.68**

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b) Please provide the detailed calculations related to Feeder NY80M29 (i.e. the first job described).

RESPONSE:

b) The detailed calculations associated with Feeder NY80M29 as shown below in Tables 2 and 3.

Table 2 – Avoided Risk Cost Results Summary for NY80M29

Job #	Job Feeder Name	Job Cost ($M)	PV(2015 Cost of Deviating from Optimal Intervention) ($M)	2012 Cost of Deviating from Optimal Intervention ($M)	2012 Concurrent Intervention Benefit ($M)	PV(2015 Net Project Benefit) ($M)	2012 Net Project Benefit ($M)	PV(2015 Project Net Cost) ($M)	2012 Project Net Cost ($M)	Avoided Risk Cost ($M)
1	NY80M29	$2.90	$31.58	$26.56	$2.12	$26.71	$31.87	$4.87	-$5.31	$10.18

In-kind replacement projects are evaluated by calculating the ‘avoided risk’ of executing the project immediately in 2012 as opposed to delaying it until 2015. In order to calculate the avoided risk of performing a project in 2012 as opposed to 2015, the various costs and benefits associated with executing a project in a particular year is taken into account.

When executing asset replacements as a project, assets within the project may be before, at, or beyond their optimal replacement time, thus some assets will have sacrificed economic life and others will have incurred excess risk. The cumulative sacrificed life and excess risk of the assets involved becomes a cost against the project, which is

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combined under the variable "Cost of Deviating from Optimal Intervention," which is provided in Table 2 for both 2012 and 2015 (as a present value).

Table 3 illustrates the Cost of Deviation from Optimal Intervention for each of the assets replaced in Job #1 related to feeder NY80M29. All estimated costs in the table below are in dollars.

Table 3 – Cost of Deviation from Optimal Intervention for Assets in NY80M29

Job #	Asset Identifier	PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal($)
1	1220945	$435,078	$0
1	1220973	$435,078	$0
1	1220977	$435,078	$0
1	1663897	$52,679	$0
1	1663912	$52,679	$0
1	1663913	$52,679	$0
1	1663914	$52,679	$0
1	1663916	$52,679	$0
1	1663917	$52,679	$0
1	1664118	$1,576	$6,921
1	1664125	$163,836	$0
1	1664129	$19	$166
1	1664130	$337	$578
1	1664135	$2,083	$0
1	1664137	$2,083	$0
1	1664140	$2,644	$8,451
1	1668984	$1,431,005	$1,732,237
1	1669875	$1,521,660	$1,819,485
1	1669998	$1,364,303	$1,658,837

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Job #	Asset Identifier	PV (2015 Cost of Deviation from	2012 Cost of Deviation from
1	1670719	$46,204	$55,752
1	1671188	$48,648	$58,277
1	1674243	$1,521,756	$1,819,569
1	1677369	$32,625	$40,071
1	1677489	$32,032	$39,570
1	1677719	$678,864	$818,153
1	1678294	$8,954,146	$0
1	1679831	$49,022	$61,002
1	1681035	$8,216	$10,240
1	1681091	$780,114	$1,053,342
1	1681625	$630,658	$769,813
1	1682884	$44,494	$71,878
1	1683264	$59,286	$71,197
1	1684124	$532,232	$674,560
1	1684299	$44,071	$61,018
1	1684514	$13,541	$21,320
1	1685237	$49,505	$69,168
1	1685395	$2,227	$9,808
1	1685429	$33,651	$40,954
1	1686536	$611,292	$751,168
1	1686654	$57,326	$68,584
1	1687572	$47,240	$60,253
1	1687896	$54,101	$66,390
1	1688276	$37,763	$51,216
1	1689030	$51,054	$70,845
1	1689756	$32,080	$83,234
1	1690012	$57,321	$68,580
1	1690803	$44,064	$60,552
1	1691454	$35,289	$70,387

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Job #	Asset Identifier	PV (2015 Cost of Deviation from	2012 Cost of Deviation from
1	1691700	$14,244	$23,983
1	1692530	$33,495	$40,818
1	1693007	$75,355	$107,598
1	1694495	$568,386	$709,696
1	1696463	$36,042	$43,084
1	1696730	$556,621	$698,286
1	1696837	$630,457	$769,621
1	1696879	$52,814	$65,226
1	1697487	$624,377	$763,770
1	1697780	$561,867	$703,377
1	1698337	$12,553	$15,052
1	1698962	$50,114	$69,468
1	1699002	$33,742	$45,255
1	1699390	$31,895	$39,456
1	1699440	$504,717	$647,698
1	1701088	$402,475	$546,619
1	1702196	$59,313	$71,220
1	1703019	$34,116	$41,359
1	1703233	$47,244	$60,256
1	1704753	$539,001	$681,159
1	1705289	$35,477	$69,603
1	1707179	$43,708	$70,448
1	1707717	$36,319	$49,270
1	1707781	$8,040	$9,634
1	1707986	$428,641	$572,698
1	1708647	$1,001,519	$1,795,983
1	1708690	$54,576	$79,312
1	1711166	$484,796	$628,161
1	1711521	$14,841	$25,755

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Job #	Asset Identifier	PV (2015 Cost of Deviation from	2012 Cost of Deviation from
1	1712331	$0	$13,910
1	1712609	$718,793	$987,814
1	1713025	$52,471	$77,600
1	1750232	$2,388	$5,565
1	1750323	$6,323	$10,516
1	1750324	$8,750	$0
1	1750383	$8,698	$0
1	1750392	$6,991	$0
1	1750393	$6,991	$0
1	1750394	$6,991	$0
1	1750395	$6,991	$0
1	1750396	$6,991	$0
1	1750397	$5,487	$9,540
1	1750398	$1,157	$4,165
1	1750399	$1,157	$4,165
1	1750400	$13,757	$0
1	1750401	$12,864	$0
1	1750402	$2,158	$0
1	1750429	$6,016	$9,296
1	1750430	$7,999	$0
1	1750453	$2,158	$0
1	1750464	$16,657	$0
1	1750465	$2,223	$0
1	1750466	$1,844	$0
1	1750467	$1,844	$0
1	1750468	$16,657	$0
1	1750469	$2,158	$0
1	1750470	$1,844	$0
1	1750474	$1,207	$2,925

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Job #	Asset Identifier	PV (2015 Cost of Deviation from	2012 Cost of Deviation from
1	1750482	$34,535	$48,274
1	1750483	$1,957	$4,090
1	1750485	$16,657	$0
1	1750493	$18,184	$0
1	7771333	$57,595	$68,852
1	7774903	$57,290	$68,553
1	28044440	$666,760	$817,052
1	28135725	$34,843	$41,995
1	28135727	$33,306	$40,656
1	28732105	$59,673	$71,529
1	28732401	$57,362	$68,615
1	28732408	$57,308	$68,568
1	28732413	$57,362	$68,615
1	28732414	$50,695	$62,510
1	28732490	$52,434	$64,087
1	28732493	$57,371	$68,623
1	28825900	$560,804	$702,341
1	28826000	$523,793	$666,333
1	28826002	$507,108	$650,035
1	28839006	$33,807	$41,090
1	30378202	$33,825	$41,105
Total		$31,578,658	$26,555,860

c) For purposes of the analysis what was the assumed cost to customers of an outage and what was the basis for this value?

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RESPONSE:

c) Please see the responses to OEB Staff interrogatories 27 (b) and (c) (Tab 6F, Schedule1-27).

d) How sensitive are the results to the value used for the cost to customers of an outage? How would the results change if the customer cost of an outage was reduced by 30%?

RESPONSE:

d) Please see Table 4 below for the Avoided Risk Cost results with the 30% reduction in both customer interruption event and duration costs for each of the 34 jobs listed in the ICM UG Infrastructure Business Case.

Table 4 – Estimated Avoided Risk Cost results with 30% Reduction in Customer Interruption Cost

Job #	Job Feeder Name	Job Cost	PV(Project Net Cost 2015)	Project Net Cost 2012	Avoided Risk Cost
1	NY80M29	$2.90	$3.34	-$3.60	$6.95
2	SCNAR26M34	$5.52	$1.99	-$5.10	$7.09
3	NY55M8	$2.49	$1.39	$1.90	-$0.50
4	NY35M10	$2.14	$1.24	$1.32	-$0.08
5	SCNT63M4	$3.16	-$3.52	-$7.90	$4.38
6	SCNA47M14	$4.43	$0.17	$0.64	-$0.46
7	NY51M6	$2.54	$0.03	-$3.88	$3.91
8	NY80M8	$9.51	$6.79	$8.38	-$1.59

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Job #	Job Feeder Name	Job Cost	PV(Project Net Cost 2015)	Project Net Cost 2012	Avoided Risk Cost
9	NY85M6	$2.01	$6.89	$0.36	$6.53
10	NY51M8	$1.58	$1.49	$1.84	-$0.35
11	SCNA502M22	$2.96	-$1.13	-$0.25	-$0.89
12	SCNAH9M30	$3.56	$3.11	$3.50	-$0.39
13	NY85M4	$8.27	$0.08	-$5.60	$5.67
14	SCNA47M13	$4.91	$1.82	$2.42	-$0.60
15	NY80M2	$1.63	-$4.70	-$5.85	$1.15
16	NY51M7	$1.40	$0.94	$1.25	-$0.31
17	NY51M24	$5.64	-$3.47	-$9.17	$5.70
18	NY80M30	$8.95	-$2.59	-$3.04	$0.45
19	NY55M23	$2.24	$2.01	$2.51	-$0.51
20	NY85M24	$2.03	-$1.74	-$2.46	$0.72
21	SCNAE5-2M3	$1.51	$1.56	$0.77	$0.79
22	NY85M7	$13.83	$6.61	$8.58	-$1.97
23	SCNT63M12	$11.14	-$22.26	-$30.96	$8.70
24	SCNT63M8	$7.59	-$4.10	-$9.13	$5.03
25	SCNAE5-1M29	$3.91	-$0.21	-$2.64	$2.44
26	NY53M25	$3.44	-$5.34	-$6.86	$1.51
27	NY80M9	$2.21	$1.02	$1.99	-$0.97
28	SCNT47M3	$20.44	-$11.93	-$14.66	$2.73
29	SCNAH9M23	$2.71	$3.95	-$2.29	$6.24
30	NY51M3	$3.54	$2.51	$3.10	-$0.59
31	SCNA47M17	$5.70	-$8.12	-$19.26	$11.13
32	SCNA502M21	$3.44	-$7.44	-$13.29	$5.85
33	SCNT47M1	$14.91	-$66.05	-$121.43	$55.38
34	NY85M1	$2.66	$4.99	$1.28	$3.70
Total		$174.90	-$90.67	-$227.51	**$136.84**

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e) How sensitive are the results to the use of average peak period load as opposed to the peak period as the basis for establishing the impact of an outage on customers?

RESPONSE:

e) Please refer to the response to VECC interrogatory 28 (c) (Tab 6F, Schedule 11-28, part c). The "average load in the peak period" is not available at the individual asset level.

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INTERROGATORY 37:

Reference(s): **Tab 4, Schedule B2, pages 1-2**

a) Given that the issues identified with PILC cable have existed since 1990, please provide a schedule that sets out the annual capital spending on PILC cable over the period 2007-2011 and the kilometers of PILC cable replaced each year.

RESPONSE:

a) The table below highlights the capital spending (rounded to nearest $1,000) and kilometres of PILC cable replaced pertaining only to piecing out congested cable chambers and repairing leaking PILC cable from 2007 to 2011.

	2007	2008	2009	2010	2011
Capital Spending	$0	$799,000	$234,000	$732,000	$344,000
Kilometres of PILC cable replaced	0.0	9.7	9.6	11.5	7.7

Note that as per Appendix A in reference document Tab 4, Schedule B2, page 29, the average piece out or leaker PILC segment is 0.157km.

b) Please provide a similar schedule for the period 2011-2014 based on THESL's proposed spending.

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RESPONSE:

b) THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response to this interrogatory, such that providing a response now would not materially assist the OEB or intervenors. THESL accordingly defers its response to this part until after its forthcoming evidentiary update.

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INTERROGATORY 38:

Reference(s): **Tab 4, Schedule B2, pages 4 -5; 15 and 18-24**

a) What was the basis for choosing the jobs/feeders listed in Table 3 over other existing PILC cables on THESL's system?

RESPONSE:

a) The locations of projects outlined in Table 3 were chosen based on site surveys performed by THESL field crews. Each location was determined to have PILC cables with either leakers or piece-outs required in one or more cable chambers. Note that the entire PILC feeder of interest will not be replaced, but rather only the sections that have leakers or require piece-outs.

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INTERROGATORY 39:

Reference(s): **Tab 4, Schedule B2, page 25**

a) Please confirm that the principle reason Option 1 is more costly than Option 4 is due to the reduced productivity associated with repairs that are made on a reactive as opposed to planned/proactive basis.

RESPONSE:

a) Option 1 is more costly than Option 4 due mainly to the precautions that THESL crews must take to safely perform work in cable chambers with piece-outs needed and leakers present. These precautions include using mirrors to work around the problem and de-energizing the affected feeder by switching customers to their standby feeder, which generally causes the work at the cable chamber to take twice as long when compared to a working in a cable chamber not requiring piece-outs and with no leakers.

b) Is there any economic justification for completing the proactive replacement in three years as opposed to say four or five years? If so, please provide.

RESPONSE:

b) In this ICM case, the emphasis is on worker safety. A near miss from a damaged PILC cable on December 15, 2011 exemplifies the on-going safety concerns that require rapid repair of all PILC cable that is leaking or requires piecing out. Figure 15 on Tab 4, Schedule B2, page 25 supports THESL's view that these potential hazards must be removed from the system quickly. THESL has not attempted to economically justify this project based on the cost of potential injuries to its workers.

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Using the same economic justification shown in Tab 4, Schedule B2, Appendix A for Option 1, however, there is a NPV savings of **$2.1M** by performing the project in three years as opposed to five. Again, this is because of the additional precautions needed to work around damaged PILC cable, including the cost required to de-energize the affected feeder by switching customers to their standby feeder and the additional environmental cost from processing water in cable chambers that contain oil from leaking PILC cables. It does not consider the costs of potential additional injuries.

As the PILC cable asset base is rapidly reaching its end of life, THESL expects to experience more problems from damaged PILC cable. Delay in fixing the current issues will only increase potential safety and operational risks going forward.

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INTERROGATORY 40:

Reference(s): Tab 4, Schedule B3, page 1

a) Please clarify whether the reference to there being 11,700 handwells on the THESL system includes or excludes the 5,600 that were replaced between 2009 and 2011.

RESPONSE:

a) The 11,700 includes the 5,600.

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INTERROGATORY 41:

Reference(s): Tab 4, Schedule B3, page 9 and page 13

a) Why does this project need to be completed over the next 3 years as opposed to a shorter period of time (e.g. 2 years) or a longer period of time (e.g. 4 or 5 years)?

RESPONSE:

a) For the reasons provided in the evidence (Tab 4, Schedule B3, pages 2 and 9 to 12), THESL should complete this project as soon as practical to protect the public from the potential risk of electric shocks (also referred to as contact voltage) through preventive and proactive measures. If the project is not implemented to its full extent, the risk of contact voltage will continue to be present until the work can be completed. THESL completed almost 5,600 handwells between 2010 and 2011. Based on this experience, THESL has planned to continue the work rate achieved in 2011 so that most handwells would be replaced by the end of 2014.

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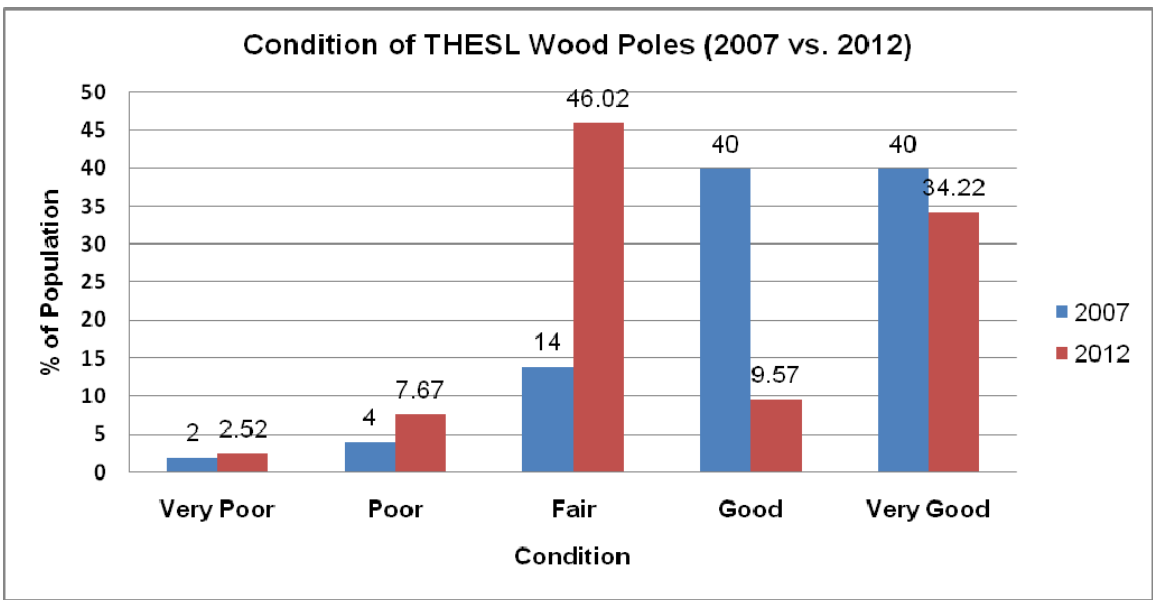
INTERROGATORY 42:

Reference(s): **Tab 4, Schedule B4, pages 1 and 30**

a) Please contrast the Health Index results noted at lines 19-22 and on page 30 with the condition of THESL's wood poles in 2007.

RESPONSE:

a) Below is a graph comparing the results of the 2007 ACA Audit to the 2012 ACA Audit for wood poles.



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INTERROGATORY 43:

Reference(s): Tab 4, Schedule B4, page 16

a) Please provide the details supporting the results reported in Table 1.

RESPONSE:

a) Please refer to THESL's response to VECC interrogatory 51 (Tab 6F, Schedule 11-51).

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INTERROGATORY 44:

Reference(s): Tab 4, Schedule B4, page 31

a) Please explain why the number of poles scheduled for replacement in 2013 is more than double that in either 2012 or 2014.

RESPONSE:

a) As shown on page 11 of Tab 4, Schedule B4, the amount of total overhead infrastructure spending proposed for 2013 is approximately 180% of the proposed 2012 spending and more than 260% of the proposed 2014 spending. Thus even if the proportion of wood pole replacement contained in each year's jobs were identical, the number of wood poles replaced in 2013 would be close to double the 2012 number and substantially more than double the 2014 number. In reality, however, the proportion of wood pole replacements contained in each year's jobs is not identical because the jobs are designed to efficiently address areas with significant numbers of overhead asset types identified as requiring replacement (see Tab 4, Schedule B4, pages 9-10). This approach results in some jobs including more wood poles and other jobs including fewer.

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INTERROGATORY 45:

Reference(s): Tab 4, Schedule B4, page 37

a) Please confirm that non-CSP transformers account for the remaining 90.8% of all overhead transformers. If not, what percentage do they account for?

RESPONSE:

a) The remaining 90.8% of all overhead transformers are non-CSP transformers.

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INTERROGATORY 46:

Reference(s): **Tab 4, Schedule B4, pages 44-46**

a) Is the use of the 75% factor (page 44, line 11) standard industry practice? If so, please indicate what other Ontario distributors use this approach.

RESPONSE:

a) No. THESL is not aware of a percentage loading factor which is considered standard industry practice.

b) What is the basis for the assumption that bus load will grow at 1% annually? Please contrast this value with that used in the calculation of the lCM threshold value in the current Application.

RESPONSE:

b) The 27.6 kV bus load growth rate assumption of 1% originated from a time-trend model using historical peak demand values between 2001 and 2011. Historical peak demand values are based on summer and winter monthly peak loading, which are corrected for weather sensitivity. In addition, these values are also adjusted to account for load transfers, new customer loads (known projects approached for service connection), extraneous station bus loads for foreign utilities, and committed CDM projects. It was determined that the average growth rate among the 27.6 KV station buses was 1%.

In contrast, the load growth assumption used in the Board's ICM threshold calculations, as defined by the Board, reflects the change in annual system energy

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sales between the last approved load forecast and the previous year's actual load. This change in energy sales: 1) does not directly include peak load; 2) is a system-wide value; and 3) is measured over two years only.

c) What is the historic base year used to establish the starting point for the application of the 1% bus load growth assumption?

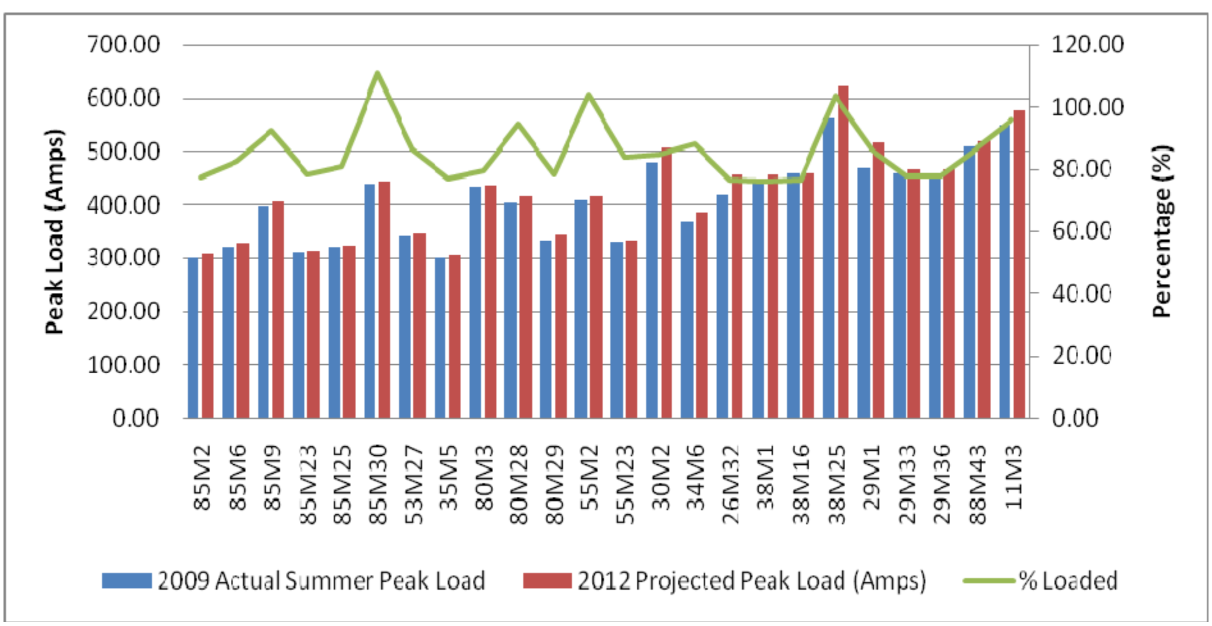
RESPONSE:

c) The historic base year that was used to establish the starting point for the application of the 1% bus load growth rate is 2001.

d) Please re-do Figure 30 using actual loadings for each feeder.

RESPONSE:

d) Below is the revised Figure 30 using actual loadings for each feeder.



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INTERROGATORY 47:

Reference(s): **Tab 4, Schedule B1, pages 82-83**

a) In THESL's view, does the avoided risk cost analysis demonstrate that the Overhead Infrastructure Segment is "non-discretionary"?

RESPONSE:

a) No, the avoided risk cost demonstrates the prudence of the preferred replacement strategy.

b) If not, what is the basis for THESL's position that this Segment is non-discretionary?

RESPONSE:

b) The basis for THESL's position that the Overhead Infrastructure segment is non-discretionary is explained in Tab 2, from page 16, line 26 to page 17, line 21 and on Tab 4, Schedule B4, pages 11-13 (general overview), pages 17-28 (wood poles), pages 32-40 (CSP transformers), pages 43-53 (conductor), pages 58-75 (porcelain overhead switches) and pages 77-81 (porcelain hardware).

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INTERROGATORY 48:

Reference(s): Tab 4, Schedule B4, page 94, lines 18-23

a) Please indicate what range of HI score is considered to indicate very poor condition.

RESPONSE:

a) Assets with an HI score between zero (0) and thirty (30) are categorized as very poor in the asset condition assessment.

b) Please clarify whether each of the 83 poles had an average HI score of 15 or whether the average across all 83 was 15. If the latter, what was the range of scores for the 83 poles?

RESPONSE:

b) Due to a data transposition, the evidence was in error. Corrected evidence will be provided. Please also see question c) below. The average HI score across all 83 poles was 28, not the 15 stated in the evidence. HI scores of these poles ranged from a minimum of 15 to a maximum of 45.

c) Please provide a similar clarification for the 192 poles reported to have an average HI score of 28 in 2011.

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RESPONSE:

c) Please see also response b) above. The average HI score across all 192 poles was 15, not the 28 stated in the evidence. The HI scores of these poles ranged from a minimum of zero to a maximum of 58.

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INTERROGATORY 49:

Reference(s): Tab 4, Schedule B4, page 152

a) Please explain what makes the Worst Performing Feeder Overhead Rebuilds "non-discretionary"?

RESPONSE:

a) The work taking place on Worst Performing Feeders is non-discretionary for the reasons listed in Tab 4, Schedule B4, pages 11-13. In particular, these feeders have faced significant reliability degradation and thus any further deferral of this work will likely result in continued deterioration of the plant and poor reliability for the customers served by them.

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INTERROGATORY 50:

Reference(s): **Tab 4, Schedule B4, page 159**

a) Please explain what makes the Replacement of Non-Standard Equipment and Overload Transformers “non-discretionary”?

RESPONSE:

a) The replacement of non-standard equipment such as porcelain switches/hardware is non-discretionary for the reasons that it addresses safety and reliability issues that are associated with such equipment. With respect to safety, the failure modes associated with the equipment can create potential risks for THESL crews and the public. Only by beginning to eliminate these equipment types can THESL begin to reduce these potential risks. In terms of reliability, overhead equipment accounts for 69 percent of the Customer Interruptions (CI) and 58 percent of Customer Hours Interrupted (CHI) of the total Overhead Equipment failures in 2011. Overhead switches, insulators, and lightning arrestor failures have increasingly contributed to system outage levels.

The replacement of overloaded transformers as part of specific jobs is non-discretionary because it would be imprudent to allow them to fail and incur extra costs and inconvenience to customers if replaced on reactive basis.

In general, the reasons why replacement of overhead infrastructure is non-discretionary are provided at Tab 4, Schedule B4, pages 11-13. With regard to the particular equipment addressed by the job described in the reference provided with the question, the replacement of wood poles is non-discretionary for the reasons provided at Tab 4, Schedule B4, pages 17-28; the replacement of CSP transformers

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for the reasons provided at pages 32-40; the replacement of porcelain switches for the reasons provide at pages 58-75, and porcelain hardware for the reasons provided at pages 77-81.

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INTERROGATORY 51:

Reference(s): Tab 4, Schedule B4, pages 15 and 175-180

a) Please provide the Individual Avoided Estimated Risk Cost for each of the asset being replaced (similar to Table 1).

RESPONSE:

a) Estimated Avoided Risk Cost is the difference between the Project Net Costs in 2015 and 2012, both in terms of present values. The Project Net Cost can be broken down into two components, namely Cost of Deviation from Optimal Strategy and Concurrent Intervention Benefit. The Cost of Deviation from Optimal Strategy is calculated on asset level, but the Concurrent Intervention Benefit can only be calculated on the project level.

Table 1 below illustrates the per asset class breakdown of the Costs of Deviating from Optimal Strategy. It also shows the overall project Concurrent Intervention Benefits to calculate the Estimated Avoided Risk Cost. Please note that the Estimated Avoided Risk Cost has been revised to correct an error in the evidence. In calculating the present value of the 2015 figure, THESL inadvertently applied both an annual discount rate to the years 2013, 2014 and 2015 and an overall rate to the 2015 figure. This response also corrects Table 1 on page 180 of Tab 4, Schedule B4. Also please note that in Table 1 below underground assets are also listed, as these are replaced linearly within overhead projects.

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Table 1: Estimated Avoided Risk Cost Breakdown per Asset Class

	PV of 2015	2012	PV of (2015) - (2012)
Asset Type	Cost of Deviating from Optimal Strategy		
Overhead Switch	$32,790,379.42	$1,704,126.13	$31,086,253.29
Overhead Transformer	$13,574,894.94	$8,557,800.16	$5,017,094.78
Poles	$139,891,850.71	$61,815,650.64	$78,076,200.08
Underground Cable	$99,332,580.66	$120,868,710.90	-$21,536,130.24
Underground Switch	$5,730,230.55	$18,483.23	$5,711,747.32
Underground Transformer	$1,142,446.48	$1,551,062.86	-$408,616.38
Total Cost of Deviating from Individual Optimal Strategies	**$292,462,382.76**	**$194,515,833.93**	**$97,946,548.84**
Concurrent Intervention Benefit	**$70,338,914.28**	**$83,917,111.92**	**-$13,578,197.64**
Project Net Cost (Total Cost of Deviating from Optimal Strategies - Concurrent Intervention Benefit)	**$222,123,468.48**	**$110,598,722.01**	**$111,524,746.47**
Estimated Avoided Risk Cost			**$111,524,746.47**

b) How sensitive are the results to the value used for the cost to customers of an outage? How would the results change if the customer cost of an outage was reduced by 30%?

RESPONSE:

b) If the customer cost of an outage was reduced by 30%, the Estimated Avoided Risk Cost would decrease to $104,090,293.

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c) How sensitive are the results to the use of average peak period load as opposed to the peak period as the basis for establishing the impact of an outage on customers?

RESPONSE:

c) The "average load in the peak period" is not available at the individual asset level. Therefore, THESL is unable to determine the difference in results between those obtained using asset level peak loads and the results that would be obtained using "average load in the peak period."

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INTERROGATORY 52:

Reference(s): Tab 4, Schedule B5, page 2 and pages 11-16

a) When did EUSR rule 129 come into effect?

RESPONSE:

a) EUSR rule 129 was first cited in the Occupation Health and Safety Act in August 2004. Prior to that date (and for decades prior to 2004), the same limits of approach existed for Ontario Hydro, and were considered the standard for all utilities to follow.

b) Which of the factors listed on page 2 and discussed on pages 11-16 1ead to this Segment being non-discretionary within the 2012-2014 period? Please explain why.

RESPONSE:

b) Please see the response to AMPCO interrogatory 34 (Tab 6F, Schedule 2-34).

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INTERROGATORY 53:

Reference(s): Tab 4, Schedule B5, page 22

a) Please explain how THESL established the number of "Assets Presently Projected to Fail by Year of Conversion" for each Feeder.

RESPONSE:

a) 'Assets Presently Projected to Fail by Year of Conversion' for each feeder was established using THESL's Feeder Investment Model (FIM). FIM provides a probability of failure for each asset for a given feeder for a given year, and then sums those probabilities to estimate the number of assets projected to fail for that year. If a project is to be executed in 2014 for example, then the projected failures for 2012, 2013 and 2014 were summed in this table. If a project is to be executed in 2012 for example, then only projected failures for 2012 were included.

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INTERROGATORY 54:

Reference(s): Tab 4, Schedule 85, pages 6-7, 25 and 35

a) Is THESL's plan to i) decommission the Hazelwood MS per page 25 or ii) convert the Station as per page 35?

RESPONSE:

a) THESL's plan is to decommission Hazelwood MS after all associated feeder load has been converted from 4kV to 13.8kV.

b) If the former, does this Segment include any allowance for the cost of decommissioning Hazelwood MS as discussed on page 25? If no, why not?

RESPONSE:

b) The cost of decommissioning Hazelwood MS was not included. The high level estimate for station decommissioning work is relatively small at ~$50k. However, potential savings from spare parts inventory from station equipment deemed in reusable condition (which avoids purchasing legacy spares) could potentially offset the station decommissioning cost to some degree. As result, station decommissioning costs were not included.

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INTERROGATORY 55:

Reference(s): Tab 4, Schedule B5, Section V (Description of Work)

a) For many of the jobs, the stated objective is to prepare the MS for conversion from 4.16kV to 13.8kV. When will these conversions actually occur? If within the 2012-2014 period, where are the decommissioning costs reflected?

RESPONSE:

a) "Conversion" from 4kV to 13.8kV refers to the 4kV feeders themselves, rather than the 4kV municipal stations (MS). Once all 4kV feeders from a given MS are converted to 13.8kV, the MS will no longer have any load and can be de-energized/decommissioned. Assuming all projects in this portfolio will be executed, the following stations will have no load and will be ready for de-energization and eventual decommissioning by the following years:

- Hazelwood MS – 2012
- College MS – 2013
- Keele & St Clair – 2013
- Merton MS – 2014
- Millwood MS – 2014
- Dufferin MS – 2014

The cost of decommissioning the stations was not included. The high level estimate for station decommissioning cost is relatively small at ~$50k per station. However, potential savings from spare parts inventory from station equipment deemed in reusable condition (which avoids purchasing legacy spares) could potentially offset

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the station decommissioning cost to some degree. As result, station decommissioning costs were not included.

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INTERROGATORY 56:

Reference(s): Tab 4, Schedule B5, Appendix J

a) With respect to Section 5.1, how does the analysis account for the cost of decommissioning the existing MS in assessing the cost of converting to the new 13.8 kV overhead system?

RESPONSE:

a) The analysis for 5.1 takes into account costs associated with converting feeders from 4kV to 13.8kV, but not the cost of decommissioning the stations. The high level estimate for station decommissioning cost is relatively small at ~$50k per station. However, potential savings from spare parts inventory from station equipment deemed in reusable condition (which avoids purchasing legacy spares) could potentially offset the station decommissioning cost to some degree. As result, station decommissioning costs were not included

b) Please provide the individual Avoided Estimated Risk Cost for each of the asset being replaced (similar to Table 1).

RESPONSE:

b) Avoided estimated risk cost for assets can be calculated for projects where there is a 'like-for-like' replacement. Because the box construction feeders are being converted to standard 13.8kV overhead construction type as opposed to an equivalent 4kV box construction type, the projects are considered 'non-in-kind' (not 'like-for-like'). As a result, the requested avoided estimated risk cost for each asset being replaced cannot be obtained.

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c) What is the impact on the Net Benefit calculations for each "job' if the cost of customer outages is reduced by 30%?

RESPONSE:

c) Some of the 'jobs' have feeders from multiple stations (e.g., X11452 converts sections of B1MR and B2MD and X12129 converts sections of B3MD and B2MR) and some feeders are converted in sections by multiple projects (e.g., sections of B1MR is converted in projects X11452 and X12143).

Because savings from station decommissioning and line losses contribute to the overall business case for box construction, these additional benefits are not easily quantified when performing business case evaluations (BCE's) by individual 'jobs', especially on the examples given above. It is for this reason why a single BCE was done for all the 'jobs'.

When the cost of customer outages was reduced by 30%, the overall NPV for all box construction projects remains positive at $2,887,483.

d) What is the estimated value ($) of the reduction in losses for each year 2012-2014 as a result of undertaking the proposed jobs?

RESPONSE:

d) The estimated dollar value of the reduction in losses for each year is presented below. The estimates were prepared assuming that stations will be de-energized by the end of the year. For example, if Hazelwood MS is de-energized in 2012, savings from line losses will be realized from 2013 onward.

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2013 – $48,315 (only Hazelwood MS load considered, 3.4MVA total)
2014 – $161,999 (College and Keele & St Clair MS loads considered, 8MVA total)
2015 – $629,920 (Merton, Millwood, Dufferin MS loads and partial load of Junction and Dupont MS loads included, 32.93MVA total)

Note that savings continue over time. If no other conversion projects were to be completed after 2015, there would be $629,920 in loss reductions realized annually when compared to the system in 2012 with no conversions.

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INTERROGATORY 57:

Reference(s): **Tab 4, Schedule B6, pages 5 and 9**

a) What are the reductions in O&M cost for each year 2012-2014 as a result of removing the rear lot service in the targeted areas and moving to underground service?

RESPONSE:

a) THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response to this interrogatory, such that providing a response now would not materially assist the OEB or intervenors. THESL accordingly defers its response to this interrogatory until after its forthcoming evidentiary update.

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INTERROGATORY 58:

Reference(s): **Tab 4, Schedule B7, page 2**

a) Why would it not be appropriate to record the cost of replacing the switches in a variance account (along with any compensation received) and refund/recover the net difference from customers at the time of rebasing?

RESPONSE:

a) THESL believes that the suggestion above will effectively be achieved through the anticipated operation of the true-up mechanism. THESL will record any compensation received from the supplier as a negative capital cost (similar to a capital contribution) which would then be reflected in the determination of the final approved ratebase and revenue requirement. The earlier characterization of any supplier compensation as a 'revenue offset' was erroneous.

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INTERROGATORY 59:

Reference(s): **Tab 4, Schedule B7, Appendix J**

a) What is the customer interruption cost (i.e., $/kWh) used in the analysis and what is it based on?

RESPONSE:

a) Please see the response to OEB Staff interrogatory 27 (Tab 6F, Schedule 1-27) for a description of the customer interruption cost and its basis. In this case, only the "Duration Cost" component was considered because SMD-20 switches will only be used once an outage event has already taken place. Therefore, in this business case the customer interruption cost represents only the extension of the outage duration by two hours due to the failure of the SMD-20 switch.

b) What is the impact on the Project PV if customer interruption costs are reduced by 30%?

RESPONSE:

b) Reducing the Customer Interruption Costs (CICs) by 30% (from $15/kVA-hr to $10.50/kVA-hr) will cause the Overall Cost of Ownership (COO_{N-E}) to decline from $17,051,833 to $11,936,283, while the Project Cost is estimated and fixed at $8,943,549. Thus, as per the formula outlined below:

- **Project PV = COO_{N-E} – Project Cost** (Page 33 in Reference)

Project PV will be reduced from: $8,108,283 to $2,992,733, which represents a reduction of 63.1%.

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INTERROGATORY 60:

Reference(s): Tab 4, Schedule B8, pages 2-3

a) When did THESL first institute the revised work practices outlined at the bottom of page 2/top of page 3 and were such practices reflected in THESL's approved 2011 revenue requirement?

RESPONSE:

a) The revised work practice for SCADA-Mate R1 was determined in April 2011 following the instructions noted in Tab 4, Schedule B8, Appendix 2, page 21. Given this timing, this practice was not reflected in the 2011 revenue requirement.

b) Given that the problem is the result of a design flaw why is there no recourse to the supplier/manufacturer to provide compensation?

RESPONSE:

b) As stated in the response to OEB Staff interrogatory 42 (b) (Tab F6, Schedule 1-42, part 42), "No compensation has been established at this time."

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INTERROGATORY 61:

Reference(s): **Tab 4, Schedule B8, pages 29-30**

a) Please provide the detailed calculations underlying the $0.28 M Project Net Cost in 2012 and the $46.14M PV of the Project Net Cost in 2015.

RESPONSE:

a) The Project Net Cost is calculated by taking into consideration all the costs and benefits associated with executing the project. The table below lists all the SCADAMATE R1 switches that need to be replaced and the breakdown of the Project Net Cost per job in years 2012 to 2015. The Project Net Cost in the table has been revised to correct an error in the evidence. In calculating the present value of the 2015 figure, THESL inadvertently applied both an annual discount rate to the years 2013, 2014 and 2015 and an overall rate to the 2015 figure. This response also corrects Table 1 on page 30 of Tab 4, Schedule B8.

At the time of the project execution, some assets may be before their optimal intervention time which will have sacrificed economic life. Also some assets may be after their optimal intervention time which will have incurred excess risk. Additionally there may be benefits associated with the project considering multiple asset replacements together as a part of the overall project. However, in this instance, the benefits would not be applicable as the project consists of pre-determined assets being replaced all over the system. Therefore, in this project, the total Project Net Cost is directly proportional to the total costs including sacrificed life and excess risk.

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Example 1): The job that is highlighted in yellow (OSC2938) has an optimal intervention time of 0 (i.e., in year 2012). This means that if the asset was to be replaced in 2012, the cost for that job would be a value of '0' as it would incur neither sacrificed life cost nor excess risk cost. On the contrary, if the project was to be postponed to a later year, the excess risk cost would be incurred in the subsequent years.

Example 2): The job that is highlighted in blue (OSC58792), has an optimal intervention time of 1 (i.e., in year 2013). This means that if the asset was to be replaced in 2012, the cost for that job would be the cost of sacrificed life (one-year worth of sacrificed life in this case). The $0.28 M Project Net Cost in 2012 is the accumulation of the cost of all the jobs in 2012. The 2015 net cost is similar to 2012 and is just an accumulation of all the job costs in 2015. The cost is then expressed in the Present value (2012).

		COST OF DEVIATING FROM OPTIMAL STRATEGY (REPLACEMENT)			
Location	Optimal Intervention Timing	2012	PV (2013)	PV (2014)	PV (2015)
Project Net Cost		$283,933	$18,348,930	$36,607,173	$55,045,980
OSC40880	0	$0	$96,203	$192,709	$289,325
OSC33911	0	$0	$22,940	$46,986	$72,027
OSC65977	0	$0	$133,533	$265,491	$395,742
OSC69882	0	$0	$133,533	$265,491	$395,742
OSC9416	0	$0	$38,145	$76,622	$115,333
OSC38192	0	$0	$297,985	$588,702	$872,160
OSC5813	0	$0	$244,667	$483,404	$716,216
OSC3206	0	$0	$103,545	$206,562	$308,899
OSC2938	0	$0	$134,626	$269,514	$404,408

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		COST OF DEVIATING FROM OPTIMAL STRATEGY (REPLACEMENT)			
Location	Optimal Intervention Timing	2012	PV (2013)	PV (2014)	PV (2015)
Project Net Cost		$283,933	$18,348,930	$36,607,173	$55,045,980
OSC85939	0	$0	$91,746	$183,800	$275,975
OSC52727	0	$0	$423,841	$838,532	$1,243,991
OSC54003	0	$0	$36,410	$73,607	$111,472
OSC38413	0	$0	$302,003	$596,635	$883,909
OSC62574	0	$0	$16,761	$37,532	$62,246
OSC63584	0	$0	$1,069	$3,248	$6,478
OSC4133	0	$0	$4,190,149	$8,546,891	$13,056,183
OSC67950	0	$0	$18,762	$39,168	$61,093
OSC71749	0	$0	$18,874	$38,340	$58,321
OSC55255	0	$0	$28,199	$58,106	$89,571
OSC85025	0	$0	$15,024	$29,963	$44,792
OSC58792	1	$1,160	$0	$730	$2,364
OSC5742	0	$0	$475,173	$941,785	$1,399,608
OSC5839	0	$0	$25,256	$50,959	$77,029
OSC39293	0	$0	$123,141	$244,263	$363,290
OSC26527	0	$0	$91,716	$181,987	$270,750
S175	0	$0	$391,653	$776,304	$1,153,764
OSC84468	0	$0	$24,209	$51,743	$82,429
OSC41616	0	$0	$206,211	$406,916	$602,162
OSC91960	0	$0	$28,716	$74,366	$138,814
OSC4665	0	$0	$9,038	$20,014	$32,827
OSC453	0	$0	$128,540	$255,861	$381,814
OSC3723	0	$0	$416,076	$821,911	$1,217,528
OSC47348	0	$0	$83,274	$168,252	$254,680
OSC4367	0	$0	$31,724	$65,101	$99,978
OSC52633	0	$0	$12,740	$26,479	$41,132

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		COST OF DEVIATING FROM OPTIMAL STRATEGY (REPLACEMENT)			
Location	Optimal Intervention Timing	2012	PV (2013)	PV (2014)	PV (2015)
Project Net Cost		$283,933	$18,348,930	$36,607,173	$55,045,980
OSC26044	0	$0	$127,449	$252,310	$374,540
OSC55748	0	$0	$127,092	$252,699	$376,694
OSC15961	0	$0	$13,971	$30,347	$49,002
OSC6674	0	$0	$48,254	$95,847	$142,734
OSC85412	0	$0	$57,921	$119,260	$183,749
OSC7147	0	$0	$135,115	$269,441	$402,788
OSC27716	0	$0	$76,285	$152,264	$227,817
OSC8616	0	$0	$84,264	$229,054	$444,780
OSC40834	0	$0	$99,517	$198,539	$296,920
OSC89248	1	$699	$0	$399	$1,312
OSC70655	0	$0	$489	$2,188	$5,067
OSC5722	0	$0	$154,820	$305,962	$453,419
OSC1019	0	$0	$16,774	$36,209	$58,166
OSC50296	2	$2,325	$899	$0	$57
OSC81817	0	$0	$43,584	$89,443	$137,373
OSC87281	0	$0	$8,397	$18,011	$28,759
OSC93009	10	$48,692	$40,328	$32,688	$25,810
OSC38185	0	$0	$39,614	$79,559	$119,737
OSC7699	0	$0	$41,515	$82,991	$124,351
OSC28922	0	$0	$217,836	$431,908	$642,097
OSC66704	0	$0	$14,406	$29,872	$46,306
OSC1256	11	$15,542	$12,640	$10,098	$7,893
OSC36717	8	$32,644	$25,578	$19,375	$14,040
OSC63516	0	$0	$181,438	$358,053	$529,883
OSC11208	0	$0	$67,473	$133,939	$199,348
OSC75064	0	$0	$51,391	$102,065	$151,976

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		COST OF DEVIATING FROM OPTIMAL STRATEGY (REPLACEMENT)			
Location	Optimal Intervention Timing	2012	PV (2013)	PV (2014)	PV (2015)
Project Net Cost		$283,933	$18,348,930	$36,607,173	$55,045,980
OSC957	0	$0	$426,177	$844,708	$1,255,387
OSC57370	0	$0	$43,296	$85,680	$127,139
OSC2160	0	$0	$2,696	$6,686	$11,899
OSC1563	0	$0	$35,944	$73,326	$111,993
OSC50833	0	$0	$63,622	$126,047	$187,246
OSC70606	0	$0	$29,131	$60,004	$92,469
OSC68048	0	$0	$18,889	$39,127	$60,597
OSC60779	0	$0	$95,231	$190,003	$284,173
OSC47319	0	$0	$29,529	$84,797	$170,154
OSC3400	0	$0	$221,136	$439,465	$654,790
OSC7003	0	$0	$36,942	$76,405	$118,192
OSC41954	0	$0	$45,690	$107,753	$186,921
OSC25127	0	$0	$21,720	$44,900	$69,414
OSC30940	0	$0	$221,256	$437,170	$647,743
OSC11099	0	$0	$15,352	$32,130	$50,226
OSC30494	0	$0	$1,259,870	$2,485,019	$3,675,836
OSC66380	0	$0	$154,761	$308,567	$461,206
OSC863	0	$0	$27,609	$56,445	$86,382
OSC42017	0	$0	$24,876	$51,331	$79,231
OSC63339	0	$0	$91,565	$181,688	$270,307
OSC66329	0	$0	$131,386	$260,602	$387,568
OSC92350	0	$0	$2,380	$5,264	$8,609
OSC48880	0	$0	$102,618	$202,858	$300,712
OSC57194	3	$2,837	$1,480	$544	$0
OSC70474	0	$0	$77,724	$154,643	$230,670
OSC55277	0	$0	$161,888	$321,805	$479,598

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		COST OF DEVIATING FROM OPTIMAL STRATEGY (REPLACEMENT)			
Location	Optimal Intervention Timing	2012	PV (2013)	PV (2014)	PV (2015)
Project Net Cost		$283,933	$18,348,930	$36,607,173	$55,045,980
OSC41917	0	$0	$33,486	$69,330	$107,350
OSC7171	0	$0	$23,609	$48,601	$74,850
OSC97424	0	$0	$44,975	$98,374	$160,076
OSC8681	0	$0	$40,364	$83,349	$128,751
OSC51687	0	$0	$359,050	$709,295	$1,050,752
OSC64242	0	$0	$255,440	$510,971	$766,137
OSC829	0	$0	$8,011	$17,488	$28,343
OSC16303	0	$0	$277,668	$549,432	$815,228
OSC42077	0	$0	$16,761	$37,532	$62,246
S244	0	$0	$4,009	$9,451	$16,249
OSC84659	0	$0	$136,375	$273,011	$409,647
OSC56394	7	$3,904	$3,011	$2,207	$1,509
OSC33856	2	$2,579	$859	$0	$779
OSC99632	0	$0	$7,550	$18,745	$33,511
OSC5999	0	$0	$74,999	$148,554	$220,635
OSC648	1	$2,064	$0	$2,005	$6,038
OSC34189	0	$0	$146,742	$291,724	$434,806
OSC11625	0	$0	$4,657	$10,061	$16,153
OSC22629	0	$0	$212,302	$419,486	$621,553
OSC29927	0	$0	$139,650	$275,999	$409,043
OSC59905	0	$0	$168,426	$335,782	$501,839
OSC28943	0	$0	$111,296	$222,000	$331,952
OSC45715	0	$0	$21,720	$44,900	$69,414
OSC48803	24	$50,801	$45,816	$41,160	$36,823
OSC36939	0	$0	$18,874	$38,340	$58,321
OSC72267	0	$0	$22,178	$45,833	$70,838

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		COST OF DEVIATING FROM OPTIMAL STRATEGY (REPLACEMENT)			
Location	Optimal Intervention Timing	2012	PV (2013)	PV (2014)	PV (2015)
Project Net Cost		$283,933	$18,348,930	$36,607,173	$55,045,980
OSC10238	0	$0	$184,478	$365,809	$543,889
OSC7256	0	$0	$46,011	$93,188	$141,374
OSC17629	0	$0	$23,932	$48,684	$74,158
OSC4127	0	$0	$10,426	$22,023	$34,704
OSC10293	0	$0	$17,827	$36,836	$56,923
OSC7414	8	$36,707	$28,947	$22,080	$16,126
OSC56295	0	$0	$138,568	$275,490	$410,632
OSC56542	0	$0	$48,254	$95,847	$142,734
OSC658	0	$0	$38,043	$78,657	$121,643
OSC77275	0	$0	$15,867	$32,963	$51,183
OSC29264	0	$0	$37,234	$76,301	$117,029
OSC8977	0	$0	$33,554	$66,557	$98,983
OSC36646	0	$0	$2,217	$5,419	$9,555
OSC43407	0	$0	$17,731	$37,054	$57,850
OSC91394	0	$0	$171,004	$337,925	$500,759
OSC67394	0	$0	$56,050	$111,299	$165,701
OSC52383	0	$0	$14,640	$31,422	$50,235
OSC8250	0	$0	$4,712	$12,509	$23,322
OSC80158	0	$0	$18,889	$39,127	$60,597
OSC1518	0	$0	$216,789	$429,834	$639,015
OSC97120	8	$36,013	$27,985	$20,944	$14,914
OSC15450	0	$0	$27,909	$55,673	$83,247
OSC94501	0	$0	$23,853	$49,098	$75,607
OSC38300	0	$0	$12,520	$27,311	$44,253
OSC99384	0	$0	$23,118	$46,878	$71,192
OSC35496	0	$0	$18,136	$37,589	$58,249

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		COST OF DEVIATING FROM OPTIMAL STRATEGY (REPLACEMENT)			
Location	Optimal Intervention Timing	2012	PV (2013)	PV (2014)	PV (2015)
Project Net Cost		$283,933	$18,348,930	$36,607,173	$55,045,980
OSC21136	0	$0	$125,781	$249,496	$371,065
OSC4311	9	$47,965	$38,975	$30,821	$23,557
OSC22666	0	$0	$29,469	$60,517	$92,997
OSC264	0	$0	$120,573	$238,707	$354,364
OSC42204	0	$0	$46,871	$93,351	$139,379
OSC9989	0	$0	$47,333	$94,269	$140,745
OSC57969	0	$0	$80,670	$159,774	$237,278
OSC2437	0	$0	$80,091	$159,344	$237,670
OSC35169	0	$0	$254,503	$502,829	$744,984
OSC58853	0	$0	$352,179	$701,687	$1,048,088
OSC24013	0	$0	$37,220	$76,273	$116,985
OSL11400	0	$0	$108,159	$216,312	$324,272
OSC45246	0	$0	$165,284	$326,189	$482,751

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INTERROGATORY 62:

Reference(s): **Tab 4, Schedule B9, page 5**

a) If the load has been displaced and the vaults no longer used, why do the Category 1 vaults present safety issues for THESL crews?

RESPONSE:

a) As these vaults are generally located beneath sidewalks in the downtown core, the main potential safety risks from vaults no longer in use is that to the public. However, these vaults still contain de-energized oil-filled transformers and lead covered cables which need to be routinely inspected by THESL crews to ensure that they are not leaking or causing an environmental hazard. As a result, THESL crews will require entry into the vault (and be subject to the same safety concerns as poor condition operational vaults) until these vaults are permanently decommissioned.

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INTERROGATORY 63:

Reference(s): Tab 4, Schedule B9, page 12

a) Within the ACA, in general, on what basis is the determination made that an asset needs to be replaced within one year and thereby warrants a "very poor" rating? Is this based on the expectation that the asset will fail within one year and, if so, what probability of failure is required to meet this criterion?

RESPONSE:

a) The Asset Condition Assessment (ACA) utilizes a multi-criteria analysis, including maintenance records and life-grade assessment, to estimate the condition of assets and group assets into one of five conditions: Very Poor, Poor, Fair, Good, or Very Good. A 'very poor' asset condition indicates extensive, serious deterioration, and dictates that the vault must be replaced or rebuilt immediately. A 'poor' asset condition indicates widespread serious deterioration, and suggests that a process to replace or rebuild the asset be initiated. An asset that is expected to fail within one year would have a probability of failure of 50% or higher.

b) In the specific case of network vaults what would trigger the need to replace within the next year?

RESPONSE:

b) As outlined in Tab 4, Schedule B9, the replacement of network vaults is a time consuming process that requires, among other things, the relocation of plant, the establishment of temporary alternative supplies to existing customers, the completed of detailed civil and electrical designs, the approval of permits, and carries with it

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unique restrictions on when work can be completed. As vaults identified as 'poor' or 'very poor' trigger the need for replacement within the next one to three years, it is necessary to begin the replacement work immediately to complete it within that timeframe. Otherwise, vaults currently categorized as poor would be at critical risk of failure (in a few years time) before any work on their replacement has commenced.

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INTERROGATORY 64:

Reference(s): **Tab 4, Schedule B10, pages 2 (lines 6-9) and 30-33**

a) What are the annual avoided O&M costs over the 2012-2014 period due to the proposed replacement of the 187 Fibretop Network Units?

RESPONSE:

a) Replacing Fibertop Network Units would eliminate the need for specific additional cleaning of Fibertop protectors. In 2012, $33,281 was budgeted to clean 168 units. If 61 network units are replaced in each of 2012 and 2013, the cleaning budget is forecast to be $21,197 in 2013 for 107 units and $9,113 in 2014 for 46 units. In total, $36,252 is expected to be avoided over 2012-2014.

In addition there maybe costs associated with restoration during a reactive replacement. If a catastrophic failure were to occur then there would be significant costs associated with the restoration, cleanup and outage to customers. However these costs are variable and not quantified here.

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INTERROGATORY 65:

Reference(s): **Tab 4, Schedule B10, page 33**

a) Please provide the detailed calculations underlying the $0.3M Project Net Cost in 2012 and the $31.6M PV of the Project Net Cost in 2015.

RESPONSE:

a) The Project Net Cost is calculated by taking into consideration all the costs and benefits associated with executing the project. The table below lists all the Fibertop Network Protector Units that need to be replaced and the breakdown of the Project Net Cost per job in years 2012 to 2015. The Project Net Cost in the table has been revised to correct an error in the evidence. In calculating the present value of the 2015 figure, THESL inadvertently applied both an annual discount rate to the years 2013, 2014 and 2015 and an overall rate to the 2015 figure. This response also corrects Table 1 on page 33 of Tab 4, Schedule B10.

At the time of the project execution, some assets may be before their optimal intervention time which will have sacrificed economic life. Also some assets may be after their optimal intervention time which will have incurred excess risk. Additionally there may be benefits associated with the project considering multiple asset replacements together as a part of the overall project. However, in this instance, the benefits would not be applicable as the project consists of pre-determined assets being replaced all over the system. Therefore, in this project, the total Project Net Cost is directly proportional to the total costs including sacrificed life and excess risk. **Example 1):** The job that is highlighted in yellow (Equipment Number: 472529) has an optimal intervention time of 0 (i.e. in year 2012). This means that if the asset was

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to be replaced in 2012, the cost for that job would be a value of '0' as it would incur neither sacrificed life cost nor excess risk cost. On the contrary, if the project was to be postponed to a later year, the excess risk cost would be incurred in the subsequent years.

Example 2): The job that is highlighted in blue (Equipment Number: 3351), has an optimal intervention time of 1 (i.e. in year 2013). This means that if the asset was to be replaced in 2012, the cost for that job would be the cost of sacrificed life (one-year worth of sacrificed life in this case).

$0.3 M Project Net Cost in 2012 is the accumulation of the cost of all the jobs in 2012. The 2015 net cost is similar to 2012 and is just an accumulation of all the job costs in 2015. The cost is then expressed in the Present value (2012).

		COST OF DEVIATING FROM OPTIMAL STRATEGY (REPLACEMENT)			
Equipment Number	Optimal Intervention Timing	2012	PV (2013)	PV (2014)	PV (2015)
Project Net Cost		$305,879	$12,935,720	$25,397,061	$37,677,765
472350	0	$0	$376,550	$748,567	$1,115,709
473653	0	$0	$233,621	$461,494	$683,633
473218	0	$0	$207,299	$409,521	$606,673
472818	0	$0	$230,092	$456,253	$678,358
472675	0	$0	$229,894	$455,676	$677,233
472529	0	$0	$177,203	$349,906	$518,128
8633	0	$0	$172,057	$339,663	$502,844
473356	0	$0	$161,075	$317,839	$470,328
473374	0	$0	$160,872	$317,364	$469,519

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		COST OF DEVIATING FROM OPTIMAL STRATEGY (REPLACEMENT)			
Equipment Number	Optimal Intervention Timing	2012	PV (2013)	PV (2014)	PV (2015)
Project Net Cost		$305,879	$12,935,720	$25,397,061	$37,677,765
473395	0	$0	$150,688	$297,426	$440,243
473267	0	$0	$150,688	$297,426	$440,243
473614	0	$0	$150,244	$296,551	$438,947
473624	0	$0	$150,244	$296,551	$438,947
472525	0	$0	$195,365	$387,653	$576,734
472526	0	$0	$195,365	$387,653	$576,734
473316	0	$0	$146,495	$289,302	$428,436
473569	0	$0	$143,745	$285,230	$424,359
472543	0	$0	$137,232	$272,989	$407,128
473278	0	$0	$129,784	$256,257	$379,433
473581	0	$0	$122,659	$242,537	$359,619
472457	0	$0	$122,435	$242,169	$359,181
472530	0	$0	$118,802	$234,589	$347,372
472752	0	$0	$117,899	$233,279	$346,113
472857	0	$0	$116,537	$229,896	$340,108
3312	0	$0	$116,189	$229,975	$341,326
472967	0	$0	$113,659	$224,972	$333,907
473615	0	$0	$111,388	$220,336	$326,826
473868	0	$0	$109,152	$215,919	$320,280
472345	0	$0	$139,169	$276,497	$411,865
472601	0	$0	$101,799	$201,450	$298,928
473804	0	$0	$101,053	$199,977	$296,747
473195	0	$0	$100,971	$208,416	$321,926
473647	0	$0	$93,030	$183,838	$272,422
3346	0	$0	$104,145	$206,410	$306,743

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		COST OF DEVIATING FROM OPTIMAL STRATEGY (REPLACEMENT)			
Equipment Number	Optimal Intervention Timing	2012	PV (2013)	PV (2014)	PV (2015)
Project Net Cost		$305,879	$12,935,720	$25,397,061	$37,677,765
473067	0	$0	$123,066	$244,930	$365,452
473394	0	$0	$90,603	$179,795	$267,513
472508	0	$0	$90,206	$178,535	$264,959
473213	0	$0	$88,079	$174,064	$257,952
473099	0	$0	$84,948	$168,196	$249,716
473771	0	$0	$82,682	$163,608	$242,755
473858	0	$0	$82,682	$163,608	$242,755
473802	0	$0	$79,558	$157,484	$233,754
473712	0	$0	$74,323	$147,814	$220,395
472290	0	$0	$73,945	$147,064	$219,279
473346	0	$0	$72,592	$144,039	$214,291
473668	0	$0	$96,370	$191,142	$284,255
473239	0	$0	$95,876	$190,015	$282,369
1903	0	$0	$70,641	$139,681	$207,111
472779	0	$0	$69,652	$138,693	$207,037
473772	0	$0	$69,423	$138,237	$206,358
473393	0	$0	$67,513	$133,767	$198,730
472705	0	$0	$66,986	$133,393	$199,140
472491	0	$0	$66,972	$133,366	$199,100
3218	0	$0	$66,949	$133,320	$199,032
472394	0	$0	$87,309	$173,425	$258,273
472395	0	$0	$87,309	$173,425	$258,273
72605	0	$0	$65,049	$129,545	$193,407
472762	0	$0	$64,494	$128,442	$191,762
472631	0	$0	$64,494	$128,442	$191,762

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		COST OF DEVIATING FROM OPTIMAL STRATEGY (REPLACEMENT)			
Equipment Number	Optimal Intervention Timing	2012	PV (2013)	PV (2014)	PV (2015)
Project Net Cost		$305,879	$12,935,720	$25,397,061	$37,677,765
472691	0	$0	$64,486	$128,426	$191,740
472739	0	$0	$85,856	$170,545	$253,992
472758	0	$0	$85,856	$170,545	$253,992
473091	0	$0	$64,195	$126,813	$187,855
473188	0	$0	$64,195	$126,813	$187,855
473317	0	$0	$71,488	$142,295	$212,336
473851	0	$0	$71,224	$141,770	$211,555
472325	0	$0	$83,490	$165,933	$247,248
473816	0	$0	$83,438	$165,403	$245,849
472768	0	$0	$83,359	$165,673	$246,861
#N/A	0	$0	$69,005	$137,440	$205,218
3345	0	$0	$68,992	$137,415	$205,181
472326	0	$0	$81,711	$162,746	$243,002
473752	0	$0	$68,952	$137,334	$205,061
473854	0	$0	$68,952	$137,334	$205,061
473280	0	$0	$60,751	$121,004	$180,680
8634	0	$0	$60,669	$120,839	$180,435
472466	0	$0	$68,254	$135,949	$202,997
472650	0	$0	$60,065	$119,573	$178,451
472622	0	$0	$79,500	$158,096	$235,706
473369	0	$0	$79,222	$157,545	$234,886
473231	0	$0	$79,222	$157,545	$234,886
472434	0	$0	$66,378	$132,220	$197,441
3285	0	$0	$58,206	$115,315	$171,300
472632	0	$0	$57,696	$114,088	$169,165

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		COST OF DEVIATING FROM OPTIMAL STRATEGY (REPLACEMENT)			
Equipment Number	Optimal Intervention Timing	2012	PV (2013)	PV (2014)	PV (2015)
Project Net Cost		$305,879	$12,935,720	$25,397,061	$37,677,765
472714	0	$0	$57,696	$114,088	$169,165
72604	0	$0	$57,514	$114,570	$171,095
473481	0	$0	$64,494	$128,477	$191,863
472695	0	$0	$56,909	$113,367	$169,302
472784	0	$0	$56,909	$113,367	$169,302
473662	0	$0	$56,883	$113,315	$169,225
9202	0	$0	$53,834	$106,560	$158,162
473582	0	$0	$69,607	$138,613	$206,933
3547	0	$0	$69,278	$137,813	$205,529
473565	0	$0	$51,621	$102,222	$151,784
1912	0	$0	$67,252	$134,014	$200,194
1911	0	$0	$67,252	$134,014	$200,194
473823	0	$0	$56,524	$112,636	$168,262
473342	0	$0	$56,383	$112,357	$167,845
473114	0	$0	$66,800	$132,965	$198,416
473719	0	$0	$56,356	$112,303	$167,766
473663	0	$0	$49,905	$98,864	$146,855
473430	0	$0	$49,296	$98,128	$146,437
473271	0	$0	$64,981	$129,287	$192,842
473459	0	$0	$64,981	$129,287	$192,842
72597	0	$0	$64,865	$129,270	$193,126
473756	0	$0	$54,370	$108,294	$161,701
3238	0	$0	$53,489	$106,670	$159,466
3239	0	$0	$53,489	$106,670	$159,466
473765	0	$0	$47,276	$94,068	$140,321

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		COST OF DEVIATING FROM OPTIMAL STRATEGY (REPLACEMENT)			
Equipment Number	Optimal Intervention Timing	2012	PV (2013)	PV (2014)	PV (2015)
Project Net Cost		$305,879	$12,935,720	$25,397,061	$37,677,765
473766	0	$0	$47,276	$94,068	$140,321
3505	0	$0	$53,187	$105,627	$157,275
3504	0	$0	$53,187	$105,627	$157,275
#N/A	0	$0	$51,498	$102,649	$153,381
472935	0	$0	$44,488	$88,684	$132,525
472945	0	$0	$44,488	$88,684	$132,525
473043	0	$0	$57,966	$115,560	$172,699
472506	0	$0	$42,790	$85,259	$127,350
473065	0	$0	$41,689	$82,981	$123,826
473605	0	$0	$40,683	$81,122	$121,258
473348	0	$0	$40,468	$80,695	$120,622
473126	0	$0	$45,369	$89,990	$133,832
473479	0	$0	$43,869	$87,489	$130,792
473371	0	$0	$42,585	$84,885	$126,840
473109	0	$0	$41,563	$82,529	$122,861
473791	0	$0	$48,677	$97,099	$145,192
3359	0	$0	$48,537	$96,822	$144,779
3361	0	$0	$48,537	$96,822	$144,779
473124	0	$0	$40,284	$80,363	$120,175
472254	0	$0	$38,230	$76,149	$113,705
472571	0	$0	$32,736	$65,251	$97,498
472357	0	$0	$39,995	$79,847	$119,487
3288	0	$0	$32,808	$65,507	$98,040
473184	0	$0	$30,570	$61,002	$91,245
473184	0	$0	$30,570	$61,002	$91,245

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		COST OF DEVIATING FROM OPTIMAL STRATEGY (REPLACEMENT)			
Equipment Number	Optimal Intervention Timing	2012	PV (2013)	PV (2014)	PV (2015)
Project Net Cost		$305,879	$12,935,720	$25,397,061	$37,677,765
473747	0	$0	$26,555	$53,035	$79,391
473714	0	$0	$22,019	$44,163	$66,380
472656	0	$0	$24,520	$49,889	$76,006
472494	0	$0	$22,818	$45,711	$68,625
472495	0	$0	$22,818	$45,711	$68,625
473030	0	$0	$21,709	$43,476	$65,250
3351	1	$2,679	$0	$1,682	$5,848
473544	0	$0	$1,471	$3,175	$5,086
473618	0	$0	$1,123	$2,539	$4,220
473552	0	$0	$1,123	$2,539	$4,220
3444	0	$0	$1,025	$2,326	$3,875
72594	0	$0	$412	$1,067	$1,942
473488	0	$0	$385	$1,093	$2,091
1703	3	$1,964	$1,018	$372	$0
473277	8	$9,132	$6,963	$5,138	$3,630
472419	6	$6,057	$4,187	$2,703	$1,571
3278	5	$4,857	$3,156	$1,851	$911
472421	7	$7,868	$5,710	$3,948	$2,548
473545	6	$7,235	$5,129	$3,425	$2,090
473644	6	$7,235	$5,129	$3,425	$2,090
473806	6	$7,235	$5,129	$3,425	$2,090
473848	6	$7,235	$5,129	$3,425	$2,090
473551	5	$6,050	$4,092	$2,540	$1,362
472896	8	$11,102	$8,498	$6,301	$4,479
473638	11	$16,133	$13,044	$10,362	$8,058

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		COST OF DEVIATING FROM OPTIMAL STRATEGY (REPLACEMENT)			
Equipment Number	Optimal Intervention Timing	2012	PV (2013)	PV (2014)	PV (2015)
Project Net Cost		$305,879	$12,935,720	$25,397,061	$37,677,765
473324	11	$16,133	$13,044	$10,362	$8,058
473144	12	$18,166	$14,906	$12,055	$9,580
473252	12	$18,166	$14,906	$12,055	$9,580
472414	4	$3,159	$1,896	$967	$344
#N/A	6	$6,539	$4,685	$3,172	$1,972
472727	5	$3,847	$2,560	$1,555	$807
72596	9	$10,785	$8,432	$6,425	$4,738
72595	9	$10,713	$8,370	$6,373	$4,694
2521	9	$11,298	$8,887	$6,823	$5,078
157234	14	$42,481	$36,463	$30,929	$25,881
181010	10	$34,796	$28,702	$23,146	$18,158
181012	10	$35,016	$28,921	$23,360	$18,364
473865	0	$0	$73,998	$147,168	$219,435
473524	0	$0	$81,875	$162,600	$242,109
473292	0	$0	$88,450	$175,855	$262,129
472789	0	$0	$64,486	$128,426	$191,740
473878	0	$0	$83,490	$165,933	$247,248
3354	0	$0	$60,585	$120,673	$180,187
12776	0	$0	$57,140	$113,826	$169,986
473306	0	$0	$76,155	$151,537	$226,061
3274	0	$0	$61,533	$122,590	$183,093
472913	0	$0	$66,131	$131,758	$196,792
472573	0	$0	$56,476	$112,541	$168,119
472572	0	$0	$56,476	$112,541	$168,119
473813	0	$0	$65,984	$131,493	$196,439

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		COST OF DEVIATING FROM OPTIMAL STRATEGY (REPLACEMENT)			
Equipment Number	Optimal Intervention Timing	2012	PV (2013)	PV (2014)	PV (2015)
Project Net Cost		$305,879	$12,935,720	$25,397,061	$37,677,765
473738	0	$0	$65,984	$131,493	$196,439
472269	0	$0	$44,477	$88,661	$132,491
2172	0	$0	$43,250	$86,223	$128,858

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INTERROGATORY 66:

Reference(s): Tab 4, Schedule B11, pages 1 and 9

a) What conditions would lead to the conclusion that an asset needs to be replaced within one year?

RESPONSE:

a) For an asset to require replacement in one year the asset must be showing signs of extensive deterioration, be at end-of-life, have the potential for major failure, and/or be damaged beyond repair. The urgency to replace within one year would be emphasized if the damage or deterioration is to components that relate to the primary functions of the asset.

b) For purposes of the annual ACA are all ATS and RPB assets individually assessed or just a sample?

RESPONSE:

b) All ATS and RPB assets are individually assessed.

c) If based on a sample, how were then units proposed for replacement in 2012-2014 selected?

RESPONSE:

c) Please see response to part b) above. ATS and RPB units proposed for replacement in 2012-2014 were selected based on the severity of the asset condition.

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INTERROGATORY 67:

Reference(s): **Tab 4, Schedule B11, page 23**

a) Under the Base Case why are there no costs shown for year 2 (presumably 2013)?

RESPONSE:

a) The Base Case for ATS replacements uses the asset condition assessment's assumptions for remaining life. A very poor asset is expected to fail in one year; a poor asset will fail in three years. If no proactive intervention occurs then ten assets are projected to fail in Year 1 and 20 will fail by Year 3; hence there are no costs associated with Year 2.

b) What is the source of the $15/kWh value used for customer interruption costs?

RESPONSE:

b) The $15/kVA-hour value was developed with consultants, who have worked with other utilities in establishing similar parameters. Reliability valuation studies, such as those from Roy Billinton, were used to aid in the development of these parameters, which are applied to quantify power interruptions to all types of customers. Please refer to the response to OEB Staff interrogatory 27 (Tab 6F, Schedule 1-27) for a detailed explanation as to how this value is applied.

c) What would be the impact on the ATS & RPB analysis if the customer outage costs were reduced by 30%?

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RESPONSE:

c) A reduction of customer outage costs by 30% would reduce the present value of the base case to $12,051,154, a reduction of $617,087. Under this assumption, the proactive replacement option is still more favourable by $1,637,969.

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INTERROGATORY 68:

Reference(s): Tab 4, Schedule B12, page 1

a) How many power transformers has THESL replaced in each of the past four years (2008-2011)?

RESPONSE:

a) Please see the table below:

	2008	2009	2010	2011
Number of Power Transformers Replaced	5	3	4	7

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INTERROGATORY 69:

Reference(s): Tab 4, Schedule B12, page 16

a) What are the annual savings in maintenance costs over the period 2012-2014 due to the replacement of these 12 transformers?

RESPONSE:

a) THESL cannot quantify the annual savings in maintenance costs for 2012 to 2014 for the 12 transformers proposed for replacement. THESL anticipates that the said savings are minimal because the maintenance program for a new transformer is generally the same as that for an older transformer. The following are some explanations for the anticipated savings:

- less frequent oil sampling after the replacement of a transformers if the unit was being sampled more often than once every two years, and
- reactive or emergency maintenance work (which is generally more costly than planned work) is less likely required for a new transformer.

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INTERROGATORY 70:

Reference(s): Tab 4, Schedule B12, page 53

a) Please provide the detailed calculations underlying the $0.0658 M Project Net Cost in 2012 and the $66.635 M PV of the Project Net Cost in 2015.

RESPONSE:

a) Please note that the estimated Project Net Cost in the table below has been revised to correct an error in the evidence. In calculating the present value of the 2015 figure, THESL inadvertently applied both an annual discount rate to the years 2013, 2014 and 2015 and an overall rate to the 2015 figure. This response also corrects Table 1 on page 53 of Tab 4, Schedule B12.

The Project Net Cost is calculated by taking into consideration all the costs and benefits associated with executing the project. The table below lists all the Stations Power Transformers that need to be replaced and the breakdown of the Project Net Cost per job in years 2012 to 2015.

At the time of project execution, some asset replacements may be ahead of their optimal intervention time which will result in sacrificed economic life. Also some assets replacements may be later than their optimal intervention time which will have incurred excess risk. Additionally there may be benefits associated with the project considering multiple asset replacements together as a part of the linear project. However, in this instance, the benefits would not be applicable as the project consists of pre-determined assets being replaced all over the system. Therefore, in this

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project, the total Project Net Cost is directly proportional to the total costs including sacrificed life and excess risk.

The following examples are provided:

Example 1): The job that is highlighted in yellow (Equipment Number: 2434) has an optimal intervention time of 0 (i.e., in year 2012). This means that if the asset was to be replaced in 2012, the cost for that job would be a value of ‘0’ as it would incur neither sacrificed life cost nor excess risk cost. On the contrary, if the project was to be postponed to a later year, the excess risk cost would be incurred in the subsequent years.

Example 2): The job that is highlighted in blue (Equipment Number: 2404), has an optimal intervention time of 1 (i.e., in year 2013). This means that if the asset was to be replaced in 2012, the cost for that job would be the cost of sacrificed life (one-year worth of sacrificed life in this case).

$0.144M Project Net Cost in 2012 is the accumulation of the cost of all the jobs in 2012. The 2015 net cost is similar to 2012 and is just an accumulation of all the job costs in 2015. The cost is then expressed in the Present value (2012), which results in $66.1M.

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		COST OF DEVIATING FROM OPTIMAL STRATEGY (REPLACEMENT)			
Location	Optimal Intervention Timing	2012	2013 (PV)	2014 (PV)	2015 (PV)
Project Net Cost		$144,454	$27,195,297	$53,428,453	$78,857,232
2404	1	$1,754	$0	$1,420	$4,259
2434	0	$0	$4,632	$10,869	$18,557
2780	0	$0	$51,960	$103,951	$155,853
2817	21	$118,727	$104,331	$91,257	$79,416
3148	0	$0	$179,583	$355,847	$528,702
2407	0	$0	$21,964	$44,331	$67,007
2823	7	$23,974	$17,809	$12,693	$8,539
2468	0	$0	$16,958	$34,734	$53,216
2477	0	$0	$29,332	$58,623	$87,808
2043	0	$0	$10,874,440	$21,372,553	$31,504,545
2476	0	$0	$22,201	$44,619	$67,180
2159	0	$0	$15,872,087	$31,297,555	$46,282,151

Please note the error correction discussed in part a) above.

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INTERROGATORY 71:

Reference(s): **Tab 4, Schedule B13.1, pages 1 (lines 6-7) and 4 (lines 5-7)**

a) What are the annual savings in maintenance costs over the period 2012-2014 due to the proposed replacement of Municipal Substation Switchgear?

RESPONSE:

a) Municipal station switchgear preventive maintenance activities are primarily focussed on the circuit breaker maintenance within the switchgear assemblies. These activities are performed on a multi-year cycle. The preventive maintenance costs of an entire cycle have been calculated and annualized. Based on the evidence filed, upon completion of all the identified replacements, the annual savings (the difference between annualized maintenance of the existing breakers and the new breakers) is approximately $5,980, per year.

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INTERROGATORY 72:

Reference(s): **Tab 4, Schedule B13.1, page 22**

a) Please explain how the $16.88 M in project costs is factored into the analysis summarized in Table 1.

b) Please provide the detailed calculations underlying the $2.155 M Project Net Cost in 2012 and the $2.355 M PV of the Project Net Cost in 2015.

RESPONSE:

a) and b)

Please note that the estimated Project Net Cost in the table below has been revised to correct an error in the evidence. In calculating the present value of the 2015 figure, THESL inadvertently applied both an annual discount rate to the years 2013, 2014 and 2015 and an overall rate to the 2015 figure. This response also corrects Table 1 on page 22 of Tab 4, Schedule B13.1.

The sum of the "Replacement Cost" column in the table below equals the total projects costs ($16.88M), minus any costs associated with distribution support work (such as station egress cable replacements or load transfers).

The Project Net Cost is calculated by taking into consideration all the costs and benefits associated with executing the project. The table below lists all the Municipal Station Switchgears that need to be replaced and the breakdown of the Project Net Cost per job in years 2012 to 2015.

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At the time of project execution, some asset replacements may be ahead of their optimal intervention time which will result in sacrificed economic life. Also some assets replacements may be later than their optimal intervention time which will have incurred excess risk. Additionally there may be benefits associated with the project considering multiple asset replacements together as a part of the linear project. However, in this instance, the benefits would not be applicable as the project consists of pre-determined assets being replaced all over the system. Therefore, in this project, the total Project Net Cost is directly proportional to the total costs including sacrificed life and excess risk.

The following examples are provided:

Example 1): The job that is highlighted in yellow (Location: vMCS_25) has an optimal intervention time of 0 (i.e., in year 2012). This means that if the asset was to be replaced in 2012, the cost for that job would be a value of '0' as it would incur neither sacrificed life cost nor excess risk cost. On the contrary, if the project was to be postponed to a later year, the excess risk cost would be incurred in the subsequent years.

Example 2): The job that is highlighted in blue (Location: vMCS_24), has an optimal intervention time of 1 (i.e., in year 2013). This means that if the asset was to be replaced in 2012, the cost for that job would be the cost of sacrificed life (one-year worth of sacrificed life in this case).

$2.155 M Project Net Cost in 2012 is the accumulation of the cost of all the jobs in 2012. The 2015 net cost is similar to 2012 and is just an accumulation of all the job costs in 2015. The cost is then expressed in the Present value (2012).

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			COST OF DEVIATING FROM OPTIMAL STRATEGY (REPLACEMENT)			
Location	Replacement Cost	Optimal Intervention Timing	2012	2013 (PV)	2014 (PV)	2015 (PV)
		Project Net Cost	$2,155,459	$2,331,951	$2,557,005	$2,809,649
vMCS_24	$4,082,048	1	$31,853	$0	$3,787	$23,985
vMCS_25	$974,374	0	$0	$91,412	$182,573	$273,295
vMCS_26	$580,732	8	$38,938	$29,524	$21,644	$15,169
vMCS_27	$580,732	12	$69,654	$57,397	$46,659	$37,321
vMCS_28	$1,251,965	0	$0	$50,315	$101,670	$153,841
vMCS_29	$574,041	19	$129,327	$112,372	$97,093	$83,367
vMCS_31	$589,435	0	$0	$152,830	$303,708	$452,479
vMCS_32	$984,848	0	$0	$96,114	$191,711	$286,616
vMCS_33	$615,527	40	$306,488	$280,379	$256,196	$233,813
vMCS_34	$615,237	47	$378,586	$350,227	$323,797	$299,174
vMCS_35	$1,095,435	43	$622,164	$574,076	$529,327	$487,703
vMCS_36	$859,719	43	$578,449	$537,305	$498,839	$462,885

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c) What would be the impact on the results presented in Table 1 if the customer outage costs were reduced by 30%?

RESPONSE:

c) If the customer outage costs were reduced by 30%, the figures in Table 1 in evidenced referenced will be as follows:

Present Value of Project Net Cost in 2015
(PV(PROJECTNET_COST(2015)) = **$2.938**

Project Net Cost in 2012
(PROJECTNET_COST(2012)) = **$3.027**

Avoided Estimated Risk Cost
(PV(PROJECTNET_COST(2015)) – PROJECTNET_COST(2012)) **= -$0.088**

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INTERROGATORY 73:

Reference(s): **Tab 4, Schedule B13.2, page 1 (lines 11-12) and page 6 (lines 9-10)**

a) What are the annual savings in O&M costs over the period 2012-2014 due to the proposed replacement of Transformer Station Switchgear?

RESPONSE:

a) Transformer station switchgear preventive maintenance activities are primarily focussed on the circuit breaker maintenance within the switchgear assemblies. These activities are performed on a multi-year cycle. The preventive maintenance costs of an entire cycle have been calculated and annualized. Based on the evidence filed, upon completion of all the identified replacements, the annual savings (the difference between annualized maintenance of the existing breakers and the new breakers) are forecast to be $15,125, per year.

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INTERROGATORY 74:

Reference(s): Tab 4, Schedule B13.1, page 5

a) Please explain why the cost of replacement will be 50% more if done on an emergency basis.

RESPONSE:

a) THESL assumes that the evidence reference intended is Tab 4, Schedule B13.2, page 5.

The estimated 50 percent is based on past experience. A number of factors contribute to the increase in the cost if the replacement is done on an emergency basis. The incremental costs may include overtime costs for crews and increased material/ equipment procurement costs if the switchgear replacement must be expedited.

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INTERROGATORY 75:

Reference(s): **Tab 4, Schedule B13.2, page 34**

a) Please explain how the $41.53 M in project costs is factored into the analysis summarized in Table 1.

b) Please provide the detailed calculations underlying the $0.0298 M Project Net Cost in 2012 and the $35.235 M PV of the Project Net Cost in 2015.

RESPONSE:

a) and b)

Please note that the Project Net Cost in the table below has been revised to correct an error in the evidence. In calculating the present value of the 2015 figure, THESL inadvertently applied both an annual discount rate to the years 2013, 2014 and 2015 and an overall rate to the 2015 figure. This response also corrects Table 1 on page 34 of Tab 4, Schedule B13.2.

The sum of the “Replacement Cost” column in the table below equals the total projects costs ($41.53M), minus any costs associated with distribution support work (primarily load transfers).

The Project Net Cost is calculated by taking into consideration all the costs and benefits associated with executing the project. The table below lists all the Transformer Station Switchgears that need to be replaced and the breakdown of the Project Net Cost per job in years 2012 to 2015.

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At the time of project execution, some asset replacements may be ahead of their optimal intervention time which will result in sacrificed economic life. Also some assets replacements may be later than their optimal intervention time which will have incurred excess risk. Additionally there may be benefits associated with the project considering multiple asset replacements together as a part of the linear project. However, in this instance, the benefits would not be applicable as the project consists of pre-determined assets being replaced all over the system. Therefore, in this project, the total Project Net Cost is directly proportional to the total costs including sacrificed life and excess risk.

The following examples are provided:

Example 1): The job that is highlighted in yellow (Equipment Number: 10038) has an optimal intervention time of 0 (i.e., in year 2012). This means that if the asset was to be replaced in 2012, the cost for that job would be a value of '0' as it would incur neither sacrificed life cost nor excess risk cost. On the contrary, if the project was to be postponed to a later year, the excess risk cost would be incurred in the subsequent years.

Example 2): The job that is highlighted in blue (Equipment Number: 10035) has an optimal intervention time of 1 (i.e., in year 2013). This means that if the asset was to be replaced in 2012, the cost for that job would be the cost of sacrificed life (one-year worth of sacrificed life in this case).

$0.0298 M Project Net Cost in 2012 is the accumulation of the cost of all the jobs in 2012. The 2015 net cost is similar to 2012 and is just an accumulation of the total job costs. The cost is then expressed in the Present Value (2012).

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			COST OF DEVIATING FROM OPTIMAL STRATEGY (REPLACEMENT)			
Location	Replacement Cost	Optimal Intervention Timing	2012	2013 (PV)	2014 (PV)	2015 (PV)
		Project Net Cost	$29,777	$14,259,461	$28,272,384	$42,036,846
10035	$7,238,013	1	$29,777	$0	$14,511	$49,062
10038	$2,120,742	0	$0	$1,573,888	$3,130,890	$4,669,310
10083	$8,407,503	0	$0	$3,718,930	$7,366,593	$10,941,308
10088	$7,301,911	0	$0	$2,978,823	$5,897,990	$8,756,345
10089	$7,671,800	0	$0	$3,157,453	$6,251,546	$9,281,065
10097	$8,409,807	0	$0	$2,830,367	$5,610,855	$8,339,756

c) What would be the impact on the results presented in Table 1 if the customer outage costs were reduced by 30%?

c) If the customer outage costs were reduced by 30%, the figures in Table 1 in the evidence referenced will be as follows:

Present Value of Project Net Cost in 2015
(PV(PROJECTNET_COST(2015)) = **$28.128**

Project Net Cost in 2012
(PROJECTNET_COST(2012)) = **$0.594**

Avoided Estimated Risk Cost
(PV(PROJECTNET_COST(2015)) – PROJECTNET_COST(2012)) **= $27.533**

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INTERROGATORY 76:

Reference(s): **Tab 4, Schedule B14, pages 2 (lines 14-15) and 11 (lines 7-8)**

a) What are the anticipated annual O&M savings over the 2012-2014 period associated with the proposed replacement of the oil circuit breakers?

RESPONSE:

a) Preventive maintenance activities are performed on a multi-year cycle. The preventive maintenance costs of an entire cycle have been calculated and annualized. Based on the evidence filed, upon completion of all the identified replacements, the annual savings (the difference between annualized maintenance of the existing breakers and the replacement breakers) is $11,880, per year (total).

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INTERROGATORY 77:

Reference(s): **Tab 4, Schedule B14, pages 5 and 33-34**

a) What are the relative costs of using vacuum vs. SF_6 breakers?

RESPONSE:

a) The overall costs of using vacuum circuit breakers and those of using SF_6 circuit breakers are approximately equal.

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INTERROGATORY 78:

Reference(s): **Tab 4, Schedule B14, page 7**

a) Please explain how the oil circuit breaker replacement plan is also driven by the impact on station capacity and operational flexibility.

RESPONSE:

a) The statement "The KSO circuit breaker replacement plan is also driven by the impact on station supply capacity and operational flexibility" that was included in the business case is in error. This program involves like-for-like replacements and does not address any issues related to station capacity or operational flexibility. The primary driver for this program is the mitigation of the risk associated with the failure of any of these breakers.

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INTERROGATORY 79:

Reference(s): Tab 4, Schedule B14, page 35

a) Please provide the Health Index for each of the circuit breakers included in the replacement plan.

RESPONSE:

a) As identified in the 2012 Asset Condition Assessment Audit report from Kinectrics (Tab 4, Schedule D), the majority of oil KSO breakers (approximately 70%) do not have health index scores. THESL is working to close this gap and to review health index formulations for this asset class in general. Where available, health index has been considered to prioritize replacements, along with field inspection results and impact of failure. The primary drivers for this work, as described in the business case, are condition (health index if available, field inspection results, etc.), age, and the high impact collateral damage should a failure occur. The available health indices of breakers selected for replacement are provided below.

Breaker	**Health Index**
80M1	63
80M3	69
80M5	63
85M1	59
85M4	59
85M2	64

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INTERROGATORY 80:

Reference(s): Tab 4, Schedule B14, page 43

a) Please explain how the $3.83 M in project costs is factored into the analysis summarized in Table 1.

b) Please provide the detailed calculations underlying the $0.157 M Project Net Cost in 2012 and the $2.784 M PV of the Project Net Cost in 2015.

RESPONSE:

a) and b)

Please note that the estimated Project Net Cost in the table below has been revised to correct an error in the evidence. In calculating the present value of the 2015 figure, THESL inadvertently applied both an annual discount rate to the years 2013, 2014 and 2015 and an overall rate to the 2015 figure. This response also corrects Table 1 on page 43 of Tab 4, Schedule B14.

The sum of the "Replacement Cost" column in the table shown in response to (b) equals the total projects costs ($3.83M).

The Project Net Cost is calculated by taking into consideration all the costs and benefits associated with executing the project. The table below lists all the Stations Circuit Breakers that need to be replaced and the breakdown of the Project Net Cost per job in years 2012 to 2015.

At the time of the project execution, some asset replacements may be ahead of their optimal intervention time which will result in sacrificed economic life. Also some assets

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assets replacements may be later than their optimal intervention time which will have incurred excess risk. Additionally there may be benefits associated with the project considering multiple asset replacements together as a part of the linear project. However, However, in this instance, the benefits would not be applicable as the project consists of of pre-determined assets being replaced all over the system. Therefore, in this project, project, the total Project Net Cost is directly proportional to the total costs including sacrificed life and excess risk.

The following examples are provided:

Example 1): The job that is highlighted in yellow (Location: 158851) has an optimal intervention time of 0 (i.e., in year 2012). This means that if the asset was to be replaced replaced in 2012, the cost for that job would be a value of ‘0’ as it would incur neither sacrificed life cost nor excess risk cost. On the contrary, if the project was to be postponed to a later year, the excess risk cost would be incurred in the subsequent years. years.

Example 2): The job that is highlighted in blue (Location: 31992), has an optimalintervention time of 8 (i.e., in year 2020). This means that if the asset was to be replaced in 2020, the cost for that job would be the cost of sacrificed life (eight-year worth of sacrificed life in this case).

$0.157 M Project Net Cost in 2012 is the accumulation of the cost of all the jobs in 2012. The 2015 net cost is similar to 2012 and is just an accumulation of all the job costs in 2015. The cost is then expressed in the Present value (2012), which results in $3.339M.

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			COST OF DEVIATING FROM OPTIMAL STRATEGY (REPLACEMENT)			
Location	Replacement Cost	Optimal Intervention Timing	2012	2013 (PV)	2014 (PV)	2015 (PV)
		Project Net Cost	$157,174	$1,227,344	$2,288,708	$3,339,792
158851	$215,003	0	$0	$5,664	$11,763	$18,243
158855	$215,003	0	$0	$5,628	$11,717	$18,211
31990	$192,823	14	$32,405	$27,279	$22,733	$18,726
31992	$192,823	8	$13,605	$10,308	$7,549	$5,282
31993	$215,661	26	$72,317	$64,522	$57,397	$50,894
31994	$215,661	12	$28,293	$23,282	$18,892	$15,077
32001	$192,759	0	$0	$13,032	$26,275	$39,679
32002	$204,519	0	$0	$11,348	$22,967	$34,805
32004	$68,376	0	$0	$19,989	$39,759	$59,286
32005	$68,376	0	$0	$19,509	$38,813	$57,889
32011	$204,519	0	$0	$1,096	$2,657	$4,637
32022	$194,236	0	$0	$131,286	$261,485	$390,430
32033	$193,449	0	$0	$66,914	$133,555	$199,813
32038	$195,782	0	$0	$117,649	$234,399	$350,096
32041	$197,284	5	$10,553	$7,118	$4,402	$2,345
32042	$194,572	0	$0	$268,784	$532,769	$791,819
32044	$194,904	0	$0	$161,970	$321,258	$477,761
32046	$68,376	0	$0	$14,347	$28,625	$42,808
32047	$194,081	0	$0	$835	$2,141	$3,872
32054	$195,395	0	$0	$250,401	$496,367	$737,768
32283	$215,003	0	$0	$6,384	$13,185	$20,350

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c) What would be the impact on the results presented in Table 1 if the customer outage costs were reduced by 30%?

RESPONSE:

c) If the customer outage costs were reduced by 30%, the figures in Table 1 in the evidence referenced will be as follows:

Present Value of Project Net Cost in 2015
(PV(PROJECTNET_COST(2015)) = $ 2.368

Project Net Cost in 2012
(PROJECTNET_COST(2012)) = $ .334

Avoided Estimated Risk Cost
(PV(PROJECTNET_COST(2015)) – PROJECTNET_COST(2012)) = $ 2.034

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INTERROGATORY 81:

Reference(s): Tab 4, Schedule B15, page 2

a) Please explain why some segments lack redundancy if that is the normal design.

RESPONSE:

a) Normally, SONET systems that require a high degree of reliability are installed with an ample amount of redundancy. At the time THESL's SONET system was originally installed, such levels of redundancy were not incorporated throughout the entire system. Instead, radial designs were employed in some parts of the system. This system functioned well until, over time, failures started to become more frequent due to normal aging of components and collateral damage from occasional failures of distribution system equipment (due to incidents such as vault fires, or pole fires that occurred where fibre optic cable is installed).

b) For how long has this "lack of redundancy issue" existed?

RESPONSE:

b) The issue of lack of redundancy become an issue in approximately the past three years as the existing components have degraded due to age or damage.

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INTERROGATORY 82:

Reference(s): Tab 4, Schedule B15, pages 19-20

a) What is the basis for the $15 per kVA/hour/customer outage cost?

RESPONSE:

a) Please refer to THESL's response to OEB Staff interrogatory 27 (Tab 6F, Schedule 1-27).

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INTERROGATORY 83:

Reference(s): Tab 4, Schedule B16, page 1

a) Please explain what is meant by the statement – "None of the proposed work is included in existing rates".

RESPONSE:

a) This statement means that the proposed projects are incremental to the OEB-approved revenue requirement for 2011 rates.

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INTERROGATORY 84:

Reference(s): Tab 4, Schedule B16, page 2 and pages 9-14

a) Given that the issues are related to the radial design employed in downtown Toronto, why has this project not been undertaken previous to now?

RESPONSE:

a) In the past Hydro One and Toronto Hydro had young transmission equipment, station equipment and stations buildings that had little history of major lengthy outages and the need for this redundancy was not evident.

b) More specifically, what has critically changed that makes the risks unacceptable now and the project non-discretionary (as opposed to previous years when the work was not done and the risks were accepted)?

RESPONSE:

b) More recently, aging transmission equipment, station equipment and stations, combined with ever-increasing loads, have created the need for this project. A number of recent widespread and long duration station outages, such as that at the Dufferin Station, are identified in Table 4 of the reference. These have provided data showing risk is increasing. As a result of this increased risk, station to station load transfer facilities projects now evaluate as high priority.

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INTERROGATORY 85:

Reference(s): Tab 4, Schedule B16, page[s] 10-11

a) What is the basis for the $30/kW outage event cost used in addition to the $15/kWh outage duration cost?

RESPONSE:

a) Please refer to THESL's response to OEB Staff interrogatory 27 (Tab 6F, Schedule 1-27).

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INTERROGATORY 86:

Reference(s): Tab 4, Schedule B17, pages 2 and 10

a) Please provide a schedule that sets out THESL's historic load levels and projected loads through 2014 as filed in EB-2011-0144.

RESPONSE:

a) The schedule requested, which showed detailed THESL's system-wide load forecast for the purposes of determining rates, was originally contained in EB-2011-0144, Exhibit K1, Tab 1, Schedule 1 of THESL's EB-2011-0144 filing. It has been provided below:

Table 1: Total Load Growth Revenues and Customer

Year	Total Normalized GWh	Total Normalized MVA	Total Distribution Revenue ($M)	Total Customers
2007 Actual	26,371.10	43,809.50	$428.20	679,327
2008 Actual	26,201.00	43,559.20	$472.40	684,143
2009 Actual	25,608.80	42,828.10	$475.60	689,399
2010 Actual	25,608.00	43,268.90	$519.30	696,729
2011 Bridge	25,363.30	43,042.00	$556.00	706,052
2012 Test	25,341.00	43,124.40	$571.40	714,466
2013 Test	25,119.10	42,914.00	$639.50	724,600
2014 Test	24,944.40	42,775.80	$712.80	735,054

b) Please reconcile this forecast with the statement in the current application regarding "foreseeable load growth in the downtown core".

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

RESPONSE:

b) The two forecasts are not directly comparable. The statement concerning "foreseeable load growth in the downtown core" is used in reference to the urgent need for Bremner TS. It refers to a load projection specifically for the downtown core (please refer to Tab 4, Schedule B17, page 10, Table 2 for the exact forecast). The load forecast referred to in the EB-2011-0144 was a system-wide load forecast derived for the purpose of establishing distribution rates. The two forecasts are not comparable for three primary reasons:

1) The system-wide load forecast will not necessarily match the load forecast at any specific location in Toronto. The projections for the system-wide load forecast at the time of the EB-2011-0144 filing should not imply that certain sections of the city would not experience higher than average, or even a high rate, of growth.
2) The 'total normalized MVA' contained in Table 1 is the sum of each year's monthly demand measurements for demand-billable customers only. The load forecast for the downtown core is calculated in terms of 'total peak MVA', which represents the annual coincident peak demand for the five downtown transformer stations. Even if measured at the station level, a decline in 'total normalized MVA' (demand-billable MVA) is not indicative of an overall decline in peak demand.
3) Energy consumption, as represented by the "total normalized GWh" in Table 1 was not a consideration in the Bremner TS analysis as a decline in normalized GWh (energy consumption) does not drive a concomitant decline in peak demand.

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INTERROGATORY 87:

Reference(s): Tab 4, Schedule B17, pages 4-5 and 30

a) Please confirm that the Brenner TS is expected to be in-service Q3 of 2014.

RESPONSE:

a) The originally anticipated in-service date for Bremner TS was Q3 2014, but it currently appears more likely that the project will be in service in Q4 2014. This date is based on the same sequence of events, but anticipates that construction will begin in January 2013.

b) Does THESL include spending on the Bremner TS in its ICM-based revenue requirement calculations for years prior to the station's in-service date? If yes, please explain why.

RESPONSE:

b) Yes, THESL includes spending on the Bremner TS in its ICM-based revenue requirement calculations for years prior to the station's in-service date. THESL understands that this is in accordance with the ICM filing guidelines, and that the true up process will resolve the matter of when the assets go into service.

c) What is the impact on the annual ICM rate-riders, if the spending on Brenner (plus capitalized interest) is only included in the rate rider calculations once the station is in-service.

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RESPONSE:

c) THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response to this interrogatory, such that providing a response now would not materially assist the OEB or intervenors. THESL accordingly defers its response to this part until after its forthcoming evidentiary update.

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INTERROGATORY 88:

Reference(s): Tab 4, Schedule B17, page 35

a) Please provide a schedule that contrasts the current project cost ($134.5 M) with the total forecast costs as filed in previous rate applications. In each case, please provide references as to where in the earlier Application the cost can be found.

b) Please explain any material (>5%) changes in total costs.

RESPONSE:

a) and b)

Please see table below.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

Year	Location	Cost ($million)	Increase from previous application	Reason for increase
2009	EB-2009-0139, Exhibit D1, Tab 9, Schedule 6, Page 5, Table 1	95.5	N/A	
2010	EB-2010-0142, Exhibit D1, Tab 9, Schedule 6, Page 5, Table 1	108.2	12.7	Costs in the 2009 application were entirely based on 2009 prices. In the 2010 application, costs were revised based on escalated figures.
2011	EB-2011-0144, Exhibit D1, Tab 10, Schedule 4, Page 4, Table 2	129.5	21.3	Costs increased from 2010 due to an increase in anticipated station construction costs and the addition of the Bremner cable tunnel. The cable tunnel was previously captured in the Capital Contribution to HONI, but was transitioned to THESL's scope of work in 2011.
2012	EB-2012-0064,Tab 4, Schedule B17, Page 33, Table 10	134.5	5.0	

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 89:

Reference(s): Tab 4, Schedule B18, page 2

a) If not included in the individual project details, break down the contribution between that required to support engineering studies and that required to support the cost of actual construction work for each project.

RESPONSE:

a) A breakdown of costs is provided below.

Job	Component	Estimated Cost ($M)
Wiltshire TS switchgear replacements	Capital Contribution	6.00
	Engineering Study	0.24
Strachan TS switchgear replacements	Capital Contribution	6.00
	Engineering Study	0.14
Windsor TS switchgear replacements	Capital Contribution	3.00
	Engineering Study	0.10
Duplex TS switchgear replacements	Capital Contribution	3.00
	Engineering Study	0.70
Malvern TS switchgear replacement	Capital Contribution	1.28
	Engineering Study	0.02
Leslie TS switchgear replacement	Capital Contribution	0.15
	Engineering Study	0.30

Note: For Wiltshire TS, the engineering studies cost includes $0.1M for a study of upgrading HONI transformers supplying the A1-2 bus.

b) Does THESL normally capitalize or expense the cost of engineering studies related to planning its own facilities?

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

RESPONSE:

b) THESL capitalizes studies related to projects that have already been deemed feasible, and for which the studies provide future benefit to the project in terms of design and/or construction. THESL expenses engineering studies that are to determine feasibility.

c) For capital contributions that THESL receives from its customers for its capital projects, are they included in rate base when received or when the project is declared in-service?

RESPONSE:

c) THESL recognizes capital contributions from customers for its capital projects in ratebase when the project is declared in-service. For further clarity, capital contributions are not 'included' in rate base; capital contributions from customers are deducted from the total capital cost of a project in order to arrive at the portion of the capital cost eligible for inclusion in ratebase.

d) Please indicate the in-service date for each of the projects set out in Table 1.

RESPONSE:

d) Estimated service dates are listed below. The dates below are preliminary estimates that have not been confirmed with HONI, with the exception of the Leaside-Birch project, for which HONI has a scheduled completion date of 2014.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

Job	Estimated In Service Date(s)
Bremner TS Capital Contribution	2014
Leaside-Birch Transmission Reinforcement	2014
Wiltshire TS switchgear replacements and engineering studies	2013 (A3-4), 2015 (A5-6)
Strachan TS switchgear replacements and engineering studies	2014 (A7-8), 2015 (A5-6)
Windsor TS switchgear replacement and engineering Study	2014
Duplex TS A5-6 switchgear replacement and engineering study	2014
Malvern TS 2 new CBs and engineering study	2013
Leslie TS switchgear replacement and engineering Study	2013
Horner TS second bus expansion engineering study	TBD[1]
Runnymede TS second bus expansion engineering study	TBD[1]
Bridgman TS transformer upgrade engineering study	TBD[1]
Esplanade TS second bus expansion engineering study	TBD[1]

[1] As these jobs currently include only engineering studies, THESL is not able to provide in-service dates.

e) For purposes of determining the annual ICM rate riders, has THESL included the capital contributions starting the year they are received or the year the related project is declared in-service? If the former, please explain why.

RESPONSE:

e) THESL's interpretation of the Board's ICM mechanism is that all forecast capital spending, including capital contributions made by THESL, are to be included in the ICM rate adder calculations. To the extent that actual in-service dates of capital turn out not to be in the year the adder was calculated for, the true-up on rebasing at the next cost of service will account for these variances.

Panel: Parts a) and d) Capital Projects
Panel: Parts b), c) and e) Rates and Revenue Requirement

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 90:

Reference(s): Tab 4, Schedule B19, pages 2-3

a) Please explain more fully why this project is considered to be non-discretionary (i.e., must be done now).

RESPONSE:

a) Feeder Automation is non-discretionary on the basis that it introduces a new technology into the system that will significantly reduce the impact of trunk related outages on targeted at risk feeders. This is explained in greater detail as demonstrated on Tab 4, Schedule B19, page 3 to 4, in the section "Why the Project is Needed Now", and on Tab 4, Schedule B19, page 13 to 18, in the section "Need".

b) Has THESL used FA to improve the reliability in specific areas over the past 5 years (2007-2011)? If not, why not? If yes, please provide a schedule setting out the annual spending.

RESPONSE:

b) Yes, THESL used FA to improve the reliability in specific areas. The summary of spending on FA in previous years is shown below:

Project	Year	Location	Status	Cost
Feeder Automation Pilot Project	2010	Fairbanks TS and Bathurst TS	Online Oct. 2010	$3,597,479

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

c) In THESL's view does a favourable Benefit/Cost ratio demonstrate that a project is prudent or that it is non-discretionary or does it demonstrate both?

RESPONSE:

c) By itself a positive Benefit/Cost ratio supports the prudence of a proposed project, not its non-discretionary character. However, as explained in the Manager's Summary at page 17, where alternative timings or stagings of a project would generate materially different costs, THESL considers it non-discretionary to pursue the lower cost alternative, assuming that all requirements are met.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 91:

Reference(s): Tab 4, Schedule B19, pages 123-124

a) What is the customer outage cost used in the BCEs?

RESPONSE:

a) THESL has adopted the use of a $30/kVA (peak load) customer interruption cost value to represent the first period of the outage and a $15/kVA/hour (peak load) customer interruption cost value to represent the second period of the outage. Please also refer to THESL's response to OEB Staff interrogatory 27 (Tab 6F, Schedule 1-27).

b) How would the results presented in Tables D.1 – D.6 change if the value of customer outages was reduced by 30%.

RESPONSE:

a) If the customer outage costs were reduced by 30%, the information in Tables D.1 – D.6 will be as follows:

D1. Overall Projects (Estimated Costs)

Project Location	Project Cost Allocated ($)	Project Net Benefit	Option Benefit/Cost Ratio
Etobicoke Grid	$3,042,223	$163,988,707	53.90
North York Grid	$2,537,530	$119,425,005	47.06
Scarborough Grid	$25,919,699	$1,963,989,747	76.77

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1 **D2. Scarborough 2012**

Project Location	Project Cost Allocated ($)	Project Net Benefit	Option Benefit/Cost Ratio
Cavanagh TS and Agincourt TS	$7,820,666	$1,020,899,644	131.54

2 **D3. Etobicoke**

Project Location	Project Cost Allocated ($)	Project Net Benefit	Option Benefit/Cost Ratio
Horner TS and Manby TS	$3,042,223	$163,988,707	53.90

3 **D4. North York**

Project Location	Project Cost Allocated ($)	Project Net Benefit	Option Benefit/Cost Ratio
Fairchild TS	$2,537,530	$119,425,005	47.06

4 **D5. Scarborough 2013**

Project Location	Project Cost Allocated ($)	Project Net Benefit	Option Benefit/Cost Ratio
Cavanagh TS to Agincourt TS	$10,722,785	$426,538,898	40.78

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1 **D6. Scarborough 2014**

Project Location	Project Cost Allocated ($)	Project Net Benefit	Option Benefit/Cost Ratio
Scarborough East T.S.	$7,376,248	$516,551,205	71.03

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 92:

Reference(s): **Tab 4, Schedule B20, page 3**

a) Please provide a schedule that sets out THESL's approved and actual capital spending on Metering for the years 2009-2011.

RESPONSE:

a) The below table provides the actual capital spending on metering for 2009 to 2011. Note, the Board has historically only approved overall total amounts for capital expenditures, hence there are no values specifically approved for metering.

	2009 Actual	2010 Actual	2011 Actual
Total METERING	5.6	8.8	20.3

b) What is the basis for THESL's statement that the costs are not covered by PCI funded rates?

RESPONSE:

b) Metering is included in the application as an ICM project and is not included in projects funded through the PCI component of capital, as indicated at Tab 4, Schedule E1.2.

c) Please explain why the plan calls for 67 wholesale metering upgrades over the three year period 2012-2014 (roughly 22 per year) but only 69 (<10 per year) over the seven period 2015-2021.

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RESPONSE:

c) Over the next three years Toronto Hydro has commitments with the IESO and HONI to bring HONI's remaining Metering Supply Points (MSP) to compliance with the current IESO Wholesale Market Rules and Standards. HONI will then transfer the MSP responsibilities to THESL. For the 2015-2021 period, wholesale metering upgrades will follow the process outlined in the response to OEB Staff interrogatory 62 (Tab 6F, Schedule 1-62).

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 93:

Reference(s): **Tab 4, Schedule B21, pages 17-18**

a) Are the $33.80 M and $43.30 M values simply the expected capital costs for the two projects or has the higher value been adjusted/discounted for the time value of money based on the fact some the spending will occur in "future years"?

RESPONSE:

a) The $33.80M and $43.30M values are the NPV of the expected capital costs for the two alternative projects.

b) If simply a dollar cost comparison, please restate both values on an NPV basis.

RESPONSE:

b) Both values are stated in 2012 dollars.

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INTERROGATORY 94:

Reference(s): **Tab 4, Schedule B21, page 23**

a) How certain is THESL that each of these projects will proceed on the currently stated time lines.

RESPONSE:

a) Based on information currently available, THESL's degree of certainty that each of these projects will proceed on the currently stated time lines, on a scale of certain, less certain, and uncertain, is as follows:
   - GO Transit – Certain
   - Ministry of Transportation – Certain
   - City of Toronto – Less certain

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 95:

Reference(s): **Tab 4, Schedule B22, pages 7-9**

a) When did THESL first start installing Transformer Monitors and Power Line Monitors?

b) To date, how frequently does THESL currently collect and analyze the data from these sources?

c) What are the anticipated annual O&M savings from the Grid Analytics Project?

RESPONSE:

a) to c)

Pursuant to THESL's letter dated October 5, 2012, THESL has withdrawn the Grid Solutions project (Tab 4, Schedule B-22) from this application.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 96:

Reference(s): Tab 4, Schedule B22, page 13

a) Is the CES project considered to be a Smart Grid initiative? If not, why not?

b) Does THESL have an approved Green Energy Plan? If yes, is the CES project part of this plan?

RESPONSE:

a) and b)

Pursuant to THESL's letter dated October 5, 2012, THESL has withdrawn the Grid Solutions project (Tab 4, Schedule B-22) from this application.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 97:

Reference(s): Tab 4, Schedule B22, pages 16-17

a) Does THESL expect that it would be able to sell the CES system for the noted market value? If not, why is a benefit/cost ratio calculated using this value appropriate?

RESPONSE:

a) Pursuant to THESL's letter dated October 5, 2012, THESL has withdrawn the Grid Solutions project (Tab 4, Schedule B-22) from this application.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 98:

Reference(s): Tab 4, Schedule B22, page 21

a) Are CES systems able to react fast enough to changing system conditions (e.g. availability of renewable generation) to address the issues listed on pages 14-15?

RESPONSE:

a) Pursuant to THESL's letter dated October 5, 2012, THESL has withdrawn the Grid Solutions project (Tab 4, Schedule B-22) from this application.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 99:

Reference(s): **Tab 4, Schedule B22, page 23**

a) Please explain why the expenditures related to the Solutions Development Centre are considered capital costs as opposed to O&M?

RESPONSE:

a) Pursuant to THESL's letter dated October 5, 2012, THESL has withdrawn the Grid Solutions project (Tab 4, Schedule B-22) from this application.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 100:

Reference(s): Tab 4, Schedule B22, pages 28-29

a) Please explain why this project is considered non-discretionary.

RESPONSE:

a) Pursuant to THESL's letter dated October 5, 2012, THESL has withdrawn the Grid Solutions project (Tab 4, Schedule B-22) from this application.

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INTERROGATORY 101:

Reference(s): **Tab 4, Schedule C1, page 2**

a) Please explain how the costs associated with Engineering Capital are accounted for and recovered. For example, are they treated as part of capitalized overheads or are they tracked and capitalized on a project specific basis. Also does the treatment of these costs change under MIFRS?

RESPONSE:

a) Please see the response in Board Staff interrogatory 67 part a (Tab 6F, Schedule 1-67, part a). The treatment of these costs does not change under MIFRS.

b) When does THESL plan on adopting MIFRS? Will this have any effect on the capital spending costs for 2012-2014 as set out in Tab 4, Schedule A?

RESPONSE:

b) THESL is not planning on adopting MIFRS at this time. Effective January 1, 2012, THESL adopted USGAAP for external financial reporting and securities filing purposes. THESL's parent company, Toronto Hydro Corporation, reported its first two quarters of 2012 under US GAAP and filed all the required public documentation with the securities regulator.

THESL stated in its application for a request for a USGAAP deferral account (EB-2012-0079), that it intends to seek approval to transition to USGAAP for regulatory account purposes in its next cost of service application. (THESL's request for the deferral account was granted by the OEB on June 7, 2012).

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THESL notes that it believes that the capitalization policy it uses under USGAAP meets the requirements of the MIFRS capitalization policy. THESL changed its capitalization policy in 2011 to ensure consistency between USGAAP and MIFRS. Accordingly, there was no impact on the capital spending costs for 2012-2014 as set out in Tab 4, Schedule A.

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INTERROGATORY 102:

Reference(s): Tab 4, Schedule C1, page 2

Preamble:

The Application states that "The (engineering capital) amounts are solely for projects within the Incremental Capital Module (ICM) materiality threshold. The proposed ICM projects above the threshold have all their required capital funding included within their proposed budgets"

a) Please provide a schedule that sets out which projects are within the ICM materiality threshold and which projects are above the threshold.

RESPONSE:

a) Tab 4, Schedules E1.2, E2.2, and E3.2 show which ICM projects are included in the ICM revenue requirement and which fall under the threshold value, using the OEB's Standard ICM Methodology.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 103:

Reference(s): Tab 4, Schedule C1, page 3

a) Given the other projects that THESL is seeking ICM funding for (see particularly Schedules B1 and B4) why is additional funding for the WPF program considered to be non-discretionary?

RESPONSE:

a) The WPF program is intended to improve THESL's overall service reliability by improving service for customers supplied from poorly performing feeders. THESL considers the program non-discretionary based on need as it directly addresses existing reliability issues. Other projects, such as Underground Infrastructure (discussed in Schedule B1) and Overhead Infrastructure (discussed in Schedule B4) are likewise non-discretionary for reasons that are discussed in their business cases. Please also refer to Tab 2, pages 16 to 18 and response to SEC interrogatory 9 (Tab 6F, Schedule 10-9).

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 104:

Reference(s): Tab 4, Schedule C1, page 5

a) What are the expected annual revenues (at 2011 rates) from the new customers that THESL expects to connect in 2012, 2013 and 2014 respectively?

RESPONSE:

a) The table in the attached Appendix A, applies the approved 2011 rates to the 2012-2014 forecasts of customers and loads as filed in EB-2011-0144. The incremental revenue in each year will reflect the customer additions and load impacts. The load impacts for the new customers cannot be separated from the overall load forecast for the customer classes.

		Billing Units				Rates	Distribution Revenue @ 2011 Rates				Revenues from additional customers/loads		
		2011 Actual	2012 Forecast	2013 Forecast	2014 Forecast	2011 Board Approved	2011 Actual	2012 Forecast	2013 Forecast	2014 Forecast	2012 Forecast	2013 Forecast	2014 Forecast
Residential													
Customer Charge	Cust	624,649	633,121	642,696	652,539	18.25	$138,698,105	$140,579,242	$142,705,291	$144,890,847	$1,881,137	$2,126,049	$2,185,556
Distribution Charge	kWh	5,172,584,993	5,037,295,612	4,972,246,073	4,922,867,613	0.01520	$78,623,292	$76,566,893	$75,578,140	$74,827,588	-$2,056,399	-$988,753	-$750,553
											$0	$0	$0
General Service <50 kW											$0	$0	$0
Customer Charge	Cust	66,681	65,907	65,892	65,880	24.30	$19,714,238	$19,485,405	$19,480,970	$19,477,422	-$228,833	-$4,435	-$3,548
Distribution Charge	kWh	2,085,458,504	2,071,525,044	2,022,696,172	1,970,977,793	0.02247	$46,860,253	$46,547,168	$45,449,983	$44,287,871	-$313,085	-$1,097,185	-$1,162,112
											$0	$0	$0
General Service 50-999 kW											$0	$0	$0
Customer Charge	Cust	12,845	13,776	14,350	14,973	35.56	$5,557,346	$5,960,140	$6,208,480	$6,478,019	$402,794	$248,339	$269,539
Distribution Charge	kVA	26,844,224	26,934,430	27,031,733	27,179,325	5.5956	$152,295,781	$152,807,549	$153,359,581	$154,196,920	$511,768	$552,032	$837,339
											$0	$0	$0
General Service 1000-4999 kW											$0	$0	$0
Customer Charge	Cust	503	505	505	505	686.46	$4,201,021	$4,217,725	$4,217,725	$4,217,725	$16,704	$0	$0
Distribution Charge	kVA	10,611,793	10,637,920	10,464,411	10,297,773	4.4497	$47,875,117	$47,992,990	$47,210,204	$46,458,418	$117,872	-$782,785	-$751,786
											$0	$0	$0
Large Users											$0	$0	$0
Customer Charge	Cust	50	50	50	50	3009.11	$1,830,542	$1,830,542	$1,830,542	$1,830,542	$0	$0	$0
Distribution Charge	kVA	5,441,751	5,229,315	5,094,881	4,975,479	4.7406	$26,155,459	$25,134,396	$24,488,250	$23,914,351	-$1,021,062	-$646,146	-$573,899
											$0	$0	$0
Streetlighting											$0	$0	$0
Customer Charge	Conn	163,071	163,159	163,303	163,399	1.30	$2,579,240	$2,580,632	$2,582,909	$2,584,428	$1,392	$2,278	$1,518
Distribution Charge	kVA	322,481	322,725	322,977	323,229	28.7248	$9,391,867	$9,398,964	$9,406,303	$9,413,642	$7,097	$7,339	$7,339
											$0	$0	$0
Unmetered Scattered Load											$0	$0	$0
Customer Charge	Cust	1,113	1,107	1,107	1,107	4.84	$65,543	$65,188	$65,188	$65,188	-$356	$0	$0
Distribution Charge	kWh	42,758,509	52,097,299	52,097,299	52,097,299	0.06070	$2,595,441	$3,162,306	$3,162,306	$3,162,306	$566,865	$0	$0
Connection Charge	Conn	12,499	12,323	12,323	12,323	0.49	$74,515	$73,466	$73,466	$73,466	-$1,049	$0	$0
											$0	$0	$0
Total Distribution Revenue							$536,517,759	$536,402,604	$535,819,337	$535,878,731	-$115,155	-$583,268	$59,394

Notes:
1) Revenues adjusted for days of service
2) Competitive Sector Multi-Unit Residential class is included in Residential Class above
3) Does not include Transformer Allowance
4) Customers are mid-year
5) Forecast of customer and loads from EB-2011-0144

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 105:

Reference(s): Tab 4, Schedule C1, page 6

a) Please provide a summary of reactive capital spending for the years 2007-2011 using the same format as Table 5.

RESPONSE:

a) A summary of Reactive Capital expenditures for the years 2007-2011 is presented below in Table 1. THESL is not able to breakdown the reactive capital spending for the year 2007 using the same format in Table 5 due to a change in the categorization of capital work which took place in 2008.

Table 1: Reactive Capital Summary ($ millions)

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual
Underground Assets		11.2	9.4	12.9	17.6
Overhead Assets		7.6	10.7	11.7	10.7
Stations Assets		0.5	0.6	0.5	0.3
Metering Assets	-	-	-	-	-
Total	15.6	19.3	20.7	25.1	28.6

b) Given the extensive request that THESL is making for incremental capital over the 2012-2014 period aimed at replacing aging/deteriorating assets, why is it reasonable to assume that future reactive capital requirements will reflect trends in spending over the past 5 years (lines 12-13)?

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RESPONSE:

b) Incremental capital projects that were filed under ICM are limited to those that meet the Incremental Capital Module criteria set by the OEB (e.g., discrete, over the materiality threshold, non-discretionary, and prudent). THESL's request for incremental capital over the 2012-2014 period does not meet all its capital needs. There are other necessary capital projects to address ageing and unreliable assets that do not meet the ICM criteria, and were therefore not filed as Incremental Capital. As a result, such projects will have to compete with other capital projects for PCI funds. Given the limited size of the budget, many projects will ultimately be deferred to future years in order to target available funds to higher priority projects. The deferral of necessary work will leave the system vulnerable to unexpected failures, which must be addressed through Reactive Capital.

In addition, reactive capital addresses failures on the distribution system that arise from many causes in addition to defective equipment failures. A significant portion of reactive capital addresses failures not related to defective equipment.

Given the size THESL's distribution system and large number of assets approaching or already past their end of useful life, it is certain that equipment failures will continue to occur on THESL's system. These failures will have to be addressed on reactive basis in order to restore power to customer and mitigate safety concerns from the public. The increasing trend in reactive spending over the past few years shown in response to part a) illustrates this need.

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INTERROGATORY 106:

Reference(s): Tab 4, Schedule C1, pages 7-9

a) What was the level of funding for "Continuing Projects and Emerging Issues" that was approved by the OEB for THESL's 2011 rates?

RESPONSE:

a) In EB-2010-0142, the OEB-approved 2011 capital expenditures for THESL of $378.8 million on a total basis. The OEB did not specify the level of funding for the category of Continuing Projects and Emerging Issues.

b) What are the "continuing projects from 2011 into 2012"?

RESPONSE:

b) Please see the response to OEB Staff interrogatory 71 (Tab 6F, Schedule 1-71).

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INTERROGATORY 107:

Reference(s): **Tab 4, Schedule C2, page 1**

a) Please explain what the 2011 Carryover Projects are.

RESPONSE:

a) As stated in the evidence, the 2011 Carryover Projects are projects which were previously approved for 2011 which THESL will complete in 2012. The projects and their respective costs are provided in THESL's response to AMPCO interrogatory 30 (Tab 6F, Schedule 2-30).

b) Why are there no carryover projects for subsequent years?

RESPONSE:

b) For work subsequent to the 2011 Carryover Projects, THESL does not plan any carry over projects.

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INTERROGATORY 108:

Reference(s): **Tab 4, Schedule C3, page 1**

a) What is the annual salvage value associated with the vehicles THESL proposes to replace each year?

RESPONSE:

a) Vehicle salvage values are heavily influenced by a number of factors inclusive of, but not limited to: vehicle age, brand, drivetrain, exterior and interior condition, mechanical condition, mileage, and current re-sale/salvage market for current vehicle type. The forecast annual salvage values associated with the vehicles proposed for replacement are:

- 2012 – 1% to 4% of purchase budget
- 2013 – 2% of purchase budget
- 2014 – 2% to 6% of purchase budget

b) How many of the vehicles listed for replacement in 2012 has THESL already replaced?

RESPONSE:

b) THESL has purchased all replacement vehicles listed in Table 1 except for the 11 cube vans. Requests for Purchase (RFPs) for the 11 cube vans have been circulated to vendors and returned to THESL.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 109:

Reference(s): Tab 4, Schedule D4, page 11

a) Please confirm that Power System's Engineering characterizes THESL's business case methodology as looking at the economic merits of undertaking project considering both costs incurred by the utility and outage cost incurred by customers.

RESPONSE:

a) Yes, we can confirm this general characterization. Power System Engineering, Inc. ("PSE") concluded that THESL's business case evaluation methodology considered the costs incurred by the utility and outage costs incurred by customers. It should be noted, however, that other considerations may apply in some cases: regulatory, safety, operational, or other concerns.

As an illustration of a summary for THESL's methodology, the business case evaluation ("BCE") titled "ICM Project-Overhead Infrastructure and Equipment: Box Construction Segment" states that:

> **The business case evaluation (BCE) process involves the calculation of the net benefit of a capital project which requires comparing the ongoing annualized cost of an asset against the quantified risk cost associated with its failure**, which is calculated based upon the assets' probability of failure and the impact of their failure.

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> Calculation of the probability of failure relies on the assets' Hazard Distribution Function ("HDF"), which represents a conditional probability of an asset failing from the remaining population that has survived up until that time. These functions are validated either directly by THESL or through the assistance of asset life studies from third-party consultants. **The impacts of failure are then quantified by accounting for the direct costs associated with the materials and labour required to replace an asset upon failure, as well as the indirect costs. These indirect costs would include the costs of customer interruptions**, emergency repairs and asset replacements.

(See EB-2012-0064, Tab 4, Schedule B5, Appendix J: "Box Construction Business Case Evaluation (BCE) Process" (bolded emphasis added).)

PSE characterized THESL's BCE evaluation process in its "ICM Business Cases—Summary Report" as follows:

> PSE examined ten reliability-driven business cases prepared by THESL. In these cases, THESL typically presents a preferred solution along with one or more alternatives, and then compares the net present value ("NPV") of the preferred solution to the alternative. These NPV calculations incorporate customer interruption costs, asset probability of failure, and other cost and benefit items to estimate a risk-based cost of ownership. Project costs and cost of ownership are evaluated to determine if project funding is in the public interest, or if an alternative approach is more suitable.

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(See PSE's Summary Report, EB-2012-0064, Tab 4, Schedule D4, p. 13 (internal footnote omitted).)

b) Please confirm that it does not characterize THESL's business case methodology as determining whether or not a project must be done. If it does, please explain how.

RESPONSE:

b) Based on the assumptions, economic models, and results identified in the business cases reviewed by PSE, the projects are intended to mitigate the risk of higher costs and lower reliability associated with the continued operation of aged and deteriorated facilities. As such, the projects "must" be done in order for THSEL to act in the best interest of both existing and future ratepayers. For example, in the BCE titled "ICM Project – Underground Infrastructure and Cable Paper Insulated Lead Covered (PILC) Cable: Piece Outs and Leakers Segment," THESL evaluated the total present costs of four options:

1) Deferral of Repair and Replacement Activities [status quo, repair as needed]
2) De-energize Feeders within Cable Chamber during work activities
3) Repair or Replace Leakers and Cables Requiring Piece Outs when performing Emergency Work
4) Proactively Repair or Replace the Affected Cables

(See EB-2012-0064, Tab 4, Schedule B2, Appendix A, pp. 29-33.) THESL calculated and compared the total present costs of these four options. THESL concluded that Option 4 had the lowest total present cost. Each present cost

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calculation made assumptions about expected useful life, costs of various operations, and other figures.

Based on the input of accurate assumptions and sound methodology, it follows that THESL "must" choose the option (out of those studied) that presents the lowest total present cost—if it wants to minimize the costs to current and future ratepayers (i.e., if it wants to optimize rates vs. reliability levels for ratepayers).

There could be other situations in which minimizing costs current and future ratepayers is not the sole goal, and in those cases it would not be fair to say that THESL must choose the option with the lowest total present cost. For example, safety concerns or regulatory requirements could be considered in addition to total present cost.

In summary, THESL's business case methodology attempts to balance a variety of factors to determine what must be done by the utility to act in the best interests of its customers.

c) Did Power System Engineering review the appropriateness of the customer outage costs used by THESL in its analyses? If yes, specifically where can this assessment be found?

RESPONSE:

c) No, PSE's review of THESL's business cases did not include the source or appropriateness of costs applied in the economic models. Rather, our review focused

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

on the type of economic models used and the overall approach for choosing the best option, from the ratepayer perspective, out of those considered.

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INTERROGATORY 110:

Reference(s): Tab 4, Schedule D5, pages 1-3

a) Does the Navigant review find THESL has demonstrated that any/all of the projects are non-discretionary? If yes, please provide the specific references to such findings.

RESPONSE:

a) Navigant's review only addresses projects in its report titled "Independent Assessment of Toronto Hydro Business Cases," dated May 8, 2012. Navigant made a determination that each project assessed in the report should be deemed non-discretionary. Specific references to support these findings can be found in responses to Questions 1 through 6 in the Executive Summary of the report.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.3

INTERROGATORY 75:

Reference(s): **T2/p. 3 and 9**

In the first reference, THESL states that:

> "THESL proposes ICM projects for a three-year period, severable into three successive one-year rate periods, each with its own ICM rate adder."

In the second reference, THESL justifies its proposed approach on the basis that:

> "It is not possible for THESL to conduct this overall process effectively and effectively and efficiently without a long term planning horizon of at least 24 to 36 months. Without assurance of funding, THESL cannot enter into stable arrangements with contractors or plan for stability of its own workforce; it cannot plan customer engagement activities around its construction program; and it cannot obtain permits for or coordinate its construction programs with the municipality or other utilities."

a) **Please state whether there are any circumstances specific to THESL that would justify a departure from the Board's established practices regarding the approval of ICM projects on a year-by-year basis.**

RESPONSE:

a) While THESL appreciates that the OEB has historically granted ICM funding to distributors on a year-by-year basis and THESL is the first distributor to seek multi-year funding, THESL is not aware of any specific policy statement or finding of the OEB that applications for ICM funding are to be limited to a single year. Below,

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THESL discusses the particular circumstances that occasioned its current three year application.

1. The large utility capital jobs typically take more than 12 months to execute from planning through design to construction.
2. Job execution is more efficiently managed when jobs are scheduled to commence throughout a given year.
3. Multi-year work programs allow THESL Contractor firms to offer lower unit costs because they can more efficiently manage their labour, overhead support and material and service needs.
4. Multi-year decisions provide certainty of funding that allows THESL to negotiate better material costs with vendors through volume commitments.
5. Utility jobs often represent phases of a larger overall initiative to build or rebuild electrical plant in a large geographic area, which can span several years and requires multi-year planning certainty.
6. A one-year rate decision runs the risk, after having set expectations with the customers affected by a job, that the job may not be completed in the timeframe promised if funding is not secured for subsequent years. This situation can leave customers frustrated.

b) Given that THESL is the only distributor to date to have requested a three-year approval of this kind, please state whether or not THESL has had any discussions with other distributors in terms of how they deal with the issues referenced above. If yes, please state the results. If not, please explain why not and why THESL believes that other distributors appear able to manage these factors in the absence of three-year rate approvals.

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RESPONSE:

b) THESL does not believe that all "other distributors appear able to manage these factors in the absence of three-year rate approvals." THESL has not had recorded individual discussions with other distributors on these specific issues but understands based on participation in industry groups that many utilities have similar concerns and support the concept of multi-year capital planning.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES ON ISSUE 2.3

INTERROGATORY 35:

Reference(s): Tab 2, page 7

a) Please identify the proposed capital projects that span one year only.

RESPONSE:

a) As shown in Tab 4, Schedule A, Appendix 1, all capital projects require capital expenditures in all three years covered by the application. Consequently, all capital projects span the three-year period of the application.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 2.3

INTERROGATORY 53:

Reference(s): Managers Summary Tab 2, Page 7 and Page 22, Figure 1

a) Under THESL's proposal, how will over/under/ CAPEX be handled e.g. rate base closed each year or rolled over with a final accounting/disposition in 2015? Please explain in detail and cite references to Board Guidelines and/or other Board Decisions in your answer.

RESPONSE:

a) Based on Section 2.2.6 of the IRM Filing Requirements, THESL understands that ICM capital spending would not be recognized in ratebase directly until THESL's next rebasing, and that the purpose of the ICM rate adders is to provide interim funding as a proxy revenue requirement for approved ICM expenditures. While THESL awaits direction from the OEB regarding specifics, THESL anticipates that at a high level if ICM spending takes place across multiple years, at the time of rebasing the OEB will review historical spending, determine the corresponding amount to be added to ratebase, and dispose of any variances between the final approved revenue requirement and the actual revenue generated by the ICM rate adders.

b) Is there a series (2012, 2013, 2014) of successive CAPEX/Rate Base Deferral/Variance Accounts proposed? (Not in evidence). If not, please explain why this would not work.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 2.3

RESPONSE:

b) Chapter 3, Section 2.2.7 of the OEB's Filing Requirements for Electricity Transmission and Distribution Applications describes the accounting treatment for approved ICM capital expenditures and revenues from ICM rate adders. In summary, ICM amounts (expenditures and recoveries) are to be recorded in Account 1508, Other Regulatory Assets, and are anticipated to be reviewed and disposed of at the next Cost of Service filing.

c) How will Ratepayers be protected from over/under CAPEX spending during the IRM/ICM period?

RESPONSE:

c) Ratepayers will be protected through the operation of the post-ICM review and true up mechanism. The OEB has indicated that all variances from forecast ICM expenditures will be subject to review. Actual spending will be reviewed for acceptability and the final approved, actual expenditures will form the basis of the corresponding allowed revenue requirement. Variances between the final allowed revenue requirement and the actual ICM rate adder revenue would then be disposed by the OEB.

d) How will ratepayers avoid a major true-up in 2015?

RESPONSE:

d) THESL believes that this proceeding will afford the opportunity for the OEB to prospectively establish reasonably accurate ICM rate adders such that any variances

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 2.3

between final approved ICM revenue requirements and the actual ICM rate adder revenue would not be expected to be large.

e) Please explain why an alternative treatment based on three separate CAPEX/ Rate base years with *no carryover* would not work and is not appropriate.

RESPONSE:

e) The meaning of the phrase 'no carryover' is not clear in this context. ICM capital expenditures are by their nature related to ratebase, which persists across years and therefore carries over. If in the alternative the question is meant to suggest that the true up and reconciliation process could be conducted annually, THESL understands that this would be contrary to OEB policy, which is that reconciliation is to occur at rebasing. THESL's next rebasing is anticipated for 2015 rates.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.3

INTERROGATORY 28:

Reference(s): none provided

Has the Applicant begun any of the projects to date? If so, please provide details.

RESPONSE:

Yes.

THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response to the details sought in this interrogatory, such that providing a response now would not materially assist the OEB or intervenors. THESL accordingly defers its response to this interrogatory until after its forthcoming evidentiary update.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.3

INTERROGATORY 29:

Reference(s): none provided

How does an implementation date of January 1, 2013 affect the schedule of projects and the cost impacts for 2012, 2013 and 2014?

RESPONSE:

The date of rate implementation by itself would not affect the schedule of projects. However, the date of the OEB decision on the acceptability of the projects for ICM funding, and the content of the decision itself, will have a direct influence on what jobs are included within projects in each year.

THESL believes that the ICM rate adders can be established by the OEB without reference to the date at which base rates became interim. Please also see THESL's response to OEB Staff interrogatory 11 (Tab 6B, Schedule 1-11).

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.3

INTERROGATORY 111:

Reference(s): **Tab 2, pages 7 and 15**
Tab 4, Schedule A, Appendix 1, page 1

a) With reference to Tab 2, page 15 are each of the 10 areas listed under "Projects" considered to be a project for purposes of establishing spending envelopes or are each of the 22 areas listed under "Segments" considered to be a project for such purposes per Tab 2, page 7, lines 29-30?

RESPONSE:

In most cases project segments are constitutive of the projects, except for those projects with a single segment. While THESL has submitted its ICM application with ten specific "projects", it is prepared to manage and report as deemed appropriate by the OEB, including by project segment.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.3

INTERROGATORY 112:

Reference(s): **Tab 2, page 8, lines 19-30**
Tab 4, Schedule A, Appendix 1, page 1
EB-2009-0139, Exhibit D1, Tab 8, Schedule 10, Appendix A

a) Please provide a table that breaks down THESL's actual capital spending for the years 2009-2011 using the same project/segment designations as in the Tab 4 reference.

RESPONSE:

a) It is not possible to perform the comparison requested by this interrogatory. Please see THESL's response to SEC interrogatory 6 (Tab 6E, Schedule 10-6).

b) Please restate spending projections provided for 2012-2014 in EB-2009-0139 using the same project/segment designations as in the Tab 4 reference and contrast with the current proposed spending.

RESPONSE:

b) THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response to this interrogatory, such that providing a response now would not materially assist the OEB or intervenors. THESL accordingly defers its response to this part until after its forthcoming evidentiary update.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.3

c) With respect to the response to part (b), please explain any material (>10%) variances (by project/segment category) between the total projected spending over the three years per EB-2009-0139 and that projected for the three years in the current Application.

RESPONSE:

c) For the reasons set out in part b) above, THESL defers its response to this part until after its forthcoming evidentiary update

d) Please provide a schedule that for the two-year period 2010-2011 contrasts the actual spending by project/segment with that projected in EB-2009-0139.

RESPONSE:

d) The table below shows THESL's historical spend from 2010 to 2011. Note that THESL's actual capital work program was not tracked in the manner presented in EB-2009-0139, Exhibit D1, Tab 8, Schedule 10, Appendix A.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.3

	2010 Actual	2011 Actual
OPERATIONAL INVESTMENTS		
Grid System Investments		
Underground System	111.6	99.0
Overhead System	31.7	39.3
Network System	7.4	4.8
Stations	17.0	18.2
Total Grid System Investments	167.7	161.4
Reactive Work	25.1	28.6
Customer Connections	42.6	58.2
Customer Capital Contribution	(26.6)	(29.8)
Externally Initiated Plant Relocations	-	7.8
Capital Contributions to HONI	1.1	27.8
Engineering Capital	34.5	23.6
AFUDC	3.5	5.2
Other	12.3	(4.2)
Total Distribution Plant Capital	260.3	278.6
CORPORATE OPERATIONAL INVESTMENTS		
Fleet &Equipment Services	10.6	11.8
Facilities	12.1	25.3
Other	-	-
Total Corporate Operational Investments	22.7	37.1
CUSTOMER SERVICES		
Wholesale Metering	1.8	-
Smart Metering	0.4	10.1
Suite Metering	6.4	10.2
Other	0.2	0.0
Total CUSTOMER SERVICES	8.8	20.3
Total INFORMATION TECHNOLOGY	33.0	32.4
Total OPERATIONAL INVESTMENTS	324.7	368.4
CRITICAL ISSUES		
Standardization	30.2	44.6
Downtown Contingency	1.1	4.7
FESI / WPF	16.7	19.3
Stations System Enhancements	5.8	4.7
Secondary Upgrade	2.6	3.9
Total CRITICAL ISSUES	56.4	77.1
TOTAL CAPITAL	381.1	445.5

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.3

e) With respect to the response to part (d), please explain any material (>10%) variances (by project/segment category) between the total projected spending over the two years per EB-2009-0139 and the actual spending.

RESPONSE:

e) As noted in response (d) above, THESL actual capital work program was not tracked in the manner presented in EB-2009-0139, Exhibit D1, Tab 8, Schedule 10, Appendix A.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.4

INTERROGATORY 76:

Reference(s): T2/pp. 10-11

It is stated that:

> "In this application, THESL follows the standard Board-approved approach for the calculation of ICM revenue requirements and rate adders. THESL also offers for the consideration of the Board an alternative to the standard treatment of the ICM threshold, and the practice of exempting ICM-approved capital expenditures from the application of the half-year rule, except in the year immediately preceding rebasing. THESL observes that this alternative approach provides for rate mitigation as it could result in lower cumulative revenue requirements over the three proposed years."

a) Please state whether or not THESL's use of the word "could" in the above reference implies that THESL believes there are circumstances wherein the adoption of THESL's proposal by the Board might result in higher revenue requirements. If so, please explain what such circumstances would be. If not, please clarify the use of this term.

RESPONSE:

a) As detailed in the Manager's Summary (Aug 8 update), and at Appendix 3 to the Manager's Summary (Aug 8 update), if the combined ICM capital approved by the OEB for both 2012 and 2013 is less than $228 million under the OEB Standard ICM approach, the ICM revenue requirement would be higher using THESL's approach. This is because the alternate approach includes revenue requirement for the 20% deadband, which historically has been disallowed from entering the ICM revenue

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.4

requirement. Offsetting this is the fact that the Standard approach would grant full year capital recognition (in 2012 and 2013 in THESL's case), which creates a greater revenue requirement than the usual half year approach to capital recognition. The effect of full year capital recognition grows directly in proportion to the allowed amount of ICM capital, and past a certain threshold ($228 million) more than offsets the revenue requirement reduction related to the deadband capital. Approved amounts below that threshold produce a lower revenue requirement using the Standard approach.

b) Please state whether there are any circumstances specific to THESL that would justify a departure from the Board's established practices regarding the ICM.

RESPONSE:

b) As described in the Revised Manager's Summary, THESL's alternative revenue requirement suggestion is premised on a concern for its ratepayers. The level of THESL's proposed ICM expenditures, in total and by individual year, is significantly higher than that of other ICM applications, and if approved by the OEB, the alternate approach is expected to significantly mitigate the rate impact of THESL's capital expenditures.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.4

INTERROGATORY 77:

Reference(s): **T2/p. 11**

The second part of THESL's proposed modification discussed in the preceding interrogatory is stated as:

> "The ICM rate adders would be calculated for each year based on the average incremental ICM investment in that year (i.e., the approved ICM expenditure above the modified ICM threshold), calculated using the half year rule."

a) Please state the impact of the proposed use of the half year rule when calculating the rate adders on the anticipated surplus or deficit returned to or recovered from customers in 2015 upon rebasing relative to the standard methodology.

RESPONSE:

a) As demonstrated in Table 1 of the Managers Summary, the rate adders calculated applying THESL's proposed methodology would recover a lower amount over the three years than rate riders calculated using the OEB's standard methodology. THESL believes that the amount recovered under the alternative methodology is likely to more closely match the actual Revenue Requirement upon review by the OEB at the time of rebasing, and therefore the surplus or deficit to be cleared to customers is likely to be smaller than it would be otherwise.

b) Please expand Table 1 incorporating additional years to demonstrate the comparative impacts of the standard and alternative methodologies once rebasing has occurred and in subsequent years.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.4

RESPONSE:

b) THESL believes that once rebasing occurs, there would be no residual or ongoing differential impact on ratebase or revenue requirement in 2015 or beyond arising from the choice of rate adder determination methodology during the ICM period. THESL's accounting recognition of the assets and associated depreciation would not vary between the two methodologies; the difference is limited to revenue requirement attributed to the assets during the ICM period. Upon OEB approval at rebasing, the same net book value of the ICM assets, including the deadband assets, would be recognized in ratebase regardless of the revenue requirement determination methodology used during the ICM period.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.4

INTERROGATORY 78:

Reference(s): **T2/p. 11 and *Chapter 3 of the Filing Requirements For Electricity Transmission and Distribution Applications*, p 8, Section 2.2.3**

It is stated in the first reference that:

> "Under the Board's standard ICM model, THESL understands that funding is available for approved projects over the calculated materiality threshold. In years that do not immediately precede rebasing, the half-year rule is used in calculating the ICM adder so as to avoid creating a structural deficiency."

The second reference states that:

> "The Board's general guidance on the application of the half-year rule is provided in the Supplemental Report. In this report the Board determined that the half-year rule should not apply so as not build a deficiency for the subsequent years of the IRM plan term. In a subsequent decision with respect to the application of the half-year rule in the context of an ICM, the Board decided that the half-year rule would apply in the final year of the IRM plan term (EB-2010-0130, Guelph Hydro Electric Systems Inc., Decision and Order, p. 15). The Board has adopted this as a clarification to the policy on ICM."

Please clarify whether or not in THESL's view its understanding quoted in the first reference is in conformity with the Board policy outlined in the second reference.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.4

RESPONSE:

Yes, it is. The provided reference on page 11 of the Manager's Summary contained a typographical error and should have read "the half-year rule is <u>not</u> used in calculating the ICM adder so as to avoid creating a structural deficiency".

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.4

INTERROGATORY 79:

Reference(s): **T2/p. 12**

It is stated that:

> "Under the assumptions noted above and in the explanatory notes to the revised Appendix 3, THESL has calculated that if the approved ICM amount under the Standard Approach for 2012 and 2013 combined exceeds $228.2 million, then the standard ICM model would produce a windfall (i.e surplus revenue requirement), which THESL does not seek and would regard as an unintended outcome. The derivation of this amount is given in the revised Appendix 3 to this Manager's Summary."

a) With respect to the windfall referenced above, please specify the amount that THESL is referring to and why THESL believes that this amount is a windfall.

RESPONSE:

a) The amount of the potential windfall is dependent on the level of ICM capital approved by the OEB as well as its timing across the three year period.

However, THESL stated at page 13 of the Manager's Summary that if the OEB approves THESL's application as filed, the difference in revenue requirements across the three years would be approximately $27.7 million, based on results from the OEB ICM run under the standard versus alternate scenarios. Also as noted in the Manager's Summary, THESL considers this to be a significant opportunity for rate mitigation.

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THESL regards the potential surplus revenue requirement as a windfall because it would effectively over-compensate THESL for OEB approved capital expenditures actually made. Generally, the half year rule is employed as an approximate measure of average (incremental) capital in the test period and THESL does not seek to be compensated for capital not forecast to be invested by THESL in the relevant period.

Conversely ratepayers experience a windfall if THESL is not compensated for OEB approved capital expenditures due to the operation of the deadband.

THESL's suggestion is that both parties be kept whole by striking rates based on capital expenditures approved by the OEB; THESL should not be under- or over-compensated, and ratepayers should pay neither less nor more than the revenue requirement attracted by the approved capital expenditures.

b) Please state whether or not THESL is arguing that there is a limitation in the Board's ICM model, or whether there is instead something specific to THESL's application that is causing the model to produce results which THESL believes the Board would not consider appropriate. In either case, please provide a detailed explanation.

RESPONSE:

b) THESL does not assert that there is a 'limitation' in the ICM model. THESL does observe though that there are features of both the ICM model and THESL's ICM application that bear on this question.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.4

There are two contrary factors within the ICM model affecting the determination of the ICM revenue requirement. The first is the exclusion of deadband capital from the calculation of the ICM revenue requirement. The Supplemental Report of the Board on 3GIRM (EB-2007-0673) stated at page 33:

> "Certain participants suggested that there should be a dead band added to the calculated materiality threshold to prevent marginal applications. The suggested levels ranged from adding 10 percent to 50 percent to the calculated percentage thresholds. The Board finds merit in the suggestion of adding a dead band. However, a high adder may be unreasonably prohibitive for distributors genuinely in need of incremental CAPEX during the term of 3rd Generation IR, as it would connote a regime that is not related to revenue requirement considerations. The Board is satisfied that a 20 percent adder is sufficient at this time."

THESL calculates at the revised Appendix 3 to the Manager's Summary that the exclusion of the deadband amount ($27.8 million for THESL) produces a cumulative foregone revenue requirement of approximately $12 million over the ICM period.

The second factor is that the half year rule is not applied to ICM capital in years prior to the year immediately before rebasing. Section 2.2.3 of the IRM Filing Requirements states that "the Board determined that the half-year rule should not apply so as not to build a deficiency for the subsequent years of the IRM plan term".

In a given year the deadband amount remains fixed together with the associated foregone revenue requirement. The effect of applying the 'full year' rule varies according to the amount of ICM capital approved. In previous ICM applications, it

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.4

may be that the effect of the deadband exclusion outweighed the effect of the full year rule; however, in THESL's case the proposed ICM amounts are large, absolutely and relatively, and it is possible that the OEB would approve amounts large enough so that the effect of the full year rule would outweigh the effect of the excluded deadband capital. This type of outcome may not have been apparent or possible in previous ICM applications.

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INTERROGATORY 80:

Reference(s): T2/p. 13, Table 1 and T2/App.3

The first reference shows a total 2012 to 2014 revenue requirement difference between the standard methodology and THESL's proposed alternative methodology of $27.7 million.

It is unclear how the tables presented in Appendix 3 relate to Table 1 as the $27.7 million total difference does not appear to be replicated in Appendix 3.

a) Please reconcile the numbers in Table 1 of the first reference with Appendix 3.

RESPONSE:

a) Table 1 in the first reference demonstrates the annual difference between the ICM revenue requirement using the Board's standard ICM models (with the threshold and no-half year rule) and using a modified ICM model (removing the threshold and applying the half year rule to the annual Capex amounts). Table 3 in the second reference was intended to be illustrative of the differences between the two methodologies, and did not use the same precisions of inputs as the former (see for example the notes on assumed depreciation and revenue requirement attraction on page 5 of the updated and corrected Tab 2, Appendix 3 evidence).

b) Please provide a breakdown of the $27.7 million revenue requirement difference shown in Table 1 between the two modifications proposed by THESL which underlie this proposal (i.e. the removal of the dead band factor and calculation of the ICM rate adders using the half year rule.)

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.4

RESPONSE:

b) The $27.7M shown in Table 1 is the sum of ICM revenue requirement difference for each of the three years of the application. The removal of the deadband from the threshold calculation serves to increase the Revenue Requirement over the Standard model by approximately $6M over the three years. The application of the half-year rule to the capital spent in the first two years of the ICM serves to reduce the Revenue Requirement over the three years, as compared with the Standard model, by approximately $34M.

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INTERROGATORY 19:

Reference(s): Tab 2/p. 18

The evidence states that THESL has retained external consultants to provide independent analysis and opinion on its Business cases for its proposed ICM projects and its AM methodologies. Were the consulting contracts obtained through an RFP process? If not, why not? If so, please provide the RFPs, the responses from those retained, and the Terms of Reference for each study. What was the cost of each of the studies and how are those costs to be recovered?

RESPONSE:

The consulting contracts were not obtained through an RFP process. As set out below, the consultant retained in each case was uniquely qualified to provide the service required:

1. Having conducted a full Asset Condition Assessment ("ACA") of THESL in 2006, Kinectrics Inc. was uniquely qualified to audit changes in THESL's processes and procedures as well as its updated ACA results.
2. Having assisted THESL in developing its Feeder Investment Model methodology in 2007, BIS Consulting, LLC was uniquely qualified to assess THESL's current practices in respect of this model.
3. Navigant Consulting, Inc. and Power System Engineering, Inc. are industry leaders with distinct substantive experience and expertise in electricity distribution and asset management. At the time these consultants were retained, the only other comparable service provider, METSCO Inc., was unavailable to assist THESL on this matter. Consequently, Navigant Consulting, Inc. and Power

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System Engineering, Inc. were uniquely qualified to perform the services required.

The amount of the studies' costs is commercially-sensitive confidential information. Concurrent with this response, THESL has filed this information on a confidential basis, pursuant to the OEB's Practice Direction on Confidential Filings.

The recovery of these costs, if any, would be through the general OM&A envelope approved by the OEB at the time of THESL's 2011 rebasing.

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INTERROGATORY 20:

Reference(s): Tab 2/p. 20

The evidence states that "Because smart meters were installed in large numbers over a short interval, their replacement pattern will exhibit the same characteristic: a sharp peak in activity, rather than a smooth and uniform pattern of activity." Is THESL including the replacement of smart meters in it 2012-2013 capital program? If so please explain the details of the replacement and the annual expenditures?

RESPONSE:

The replacement of smart meters is not included in THESL's 2012-2013 capital program.

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INTERROGATORY 21:

Reference(s): **Tab 2/p. 23**

Please provide a detailed explanation as to how THESL reduced its capital budget for 2012 from $590 million in 2012 (as per EB-2011-0144) to $448.7 million. In the previous application THESL indicated that the planned investments ($590 million for 2012) were required to maintain the adequacy, reliability and quality of electricity distribution service to THESL's customers (D1/T8/S1). Why are there now $141.3 million less required expenditures to maintain adequacy, reliability and the quality of distribution service?

RESPONSE:

Please refer to THESL's response to OEB Staff interrogatory 16 (Tab 6E, Schedule 1-16).

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INTERROGATORY 22:

Reference(s): **Tab 2/p. 22 Tab 4/Schedule A/Appendix 1**

THESL has set out the cost estimates for each of the proposed projects for the three year period. Assuming that the Board approved the projects and the costs as proposed, what is THESL's proposal for rebasing? What happens if THESL spends more on each project or less than the forecast? Is THESL's proposal for the Board to determine the allowed amount for each project? Please explain how a true-up mechanism would work.

RESPONSE:

With respect to rebasing, THESL has not made specific proposals in this application. THESL intends to adhere to OEB guidelines concerning rebasing in effect at the time THESL is rebased.

THESL understands that the true-up mechanism will be defined by the OEB. THESL expects that the OEB's examination of actual ICM spending at the time of the true-up will take into account over- or under-spending on each project, consider the reasons for such variances, determine the allowable amount of actual ICM capital spending, and determine a corresponding allowed revenue requirement. That allowed revenue requirement would then be compared to the actual ICM rate adder revenue and any variance would be disposed. Should the OEB consider it advisable, THESL will develop the true-up method to be used in consultation with OEB Staff and Intervenors.

Please also see responses to CCC interrogatory 4 (Tab 6B, Schedule 6-4) and OEB Staff interrogatory 22a (Tab 6E, Schedule 1-22, part a).

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 2.4

INTERROGATORY 54:

Reference(s): **Managers Summary Tab 2, Appendix 3, pages 2 & 3**

a) Please provide an Active Excel spreadsheet corresponding to calculations in Appendix 3.

RESPONSE:

a) THESL's response is based on the revised Appendix 3 to the Manager's Summary, filed 2012 August 8.

b) Please list all input assumptions and data sources for each line of calculation (e.g. cost of capital, DRR and Depreciation).

RESPONSE:

b) In addition to the excel versions of the models, please also refer to the Notes to the Revised Appendix 3 to the Managers Summary. The logic and input assumptions of the spreadsheet are given within the spreadsheet. On page 2 of the revised Appendix 3, the quantities denoted as 'solution variables' were determined using the excel goal seek function so as to equalize the revenue requirements as between the Standard and Alternate approaches.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 2.4

INTERROGATORY 55:

Reference(s): **Tab 3, Appendix 3, Schedule C1.2, Sheet 19 and equivalent Sheets for 2013 (C2.2) and 2014 (C3.2)**

a) Please provide sheet 19 and similar <u>Residential</u> schedules in Active Excel Spreadsheet format and consolidate the base and 3 IRM years into one schedule and spreadsheet.

RESPONSE:

a) VECC has advised that its reference to Sheet 19 in this interrogatory is incorrect. The correct reference is Tab 3, Schedule C1.2 (and C2.2 and C3.3).

THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response to this interrogatory, such that providing a response now would not materially assist the OEB or intervenors. THESL accordingly defers this request until after its forthcoming evidentiary update.

b) Confirm that Sheet 19 is based on the Board Approved <u>Average</u> 2011 Rate base.

RESPONSE:

b) The distribution rates shown as "current", are THESL's 2011 OEB-approved rates. These rates were based on OEB-approved 2011 rate base, which is an average of opening and closing balances. The rates shown for 2012 through 2014 are based on

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 2.4

the OEB's IRM and ICM models, as filed by THESL in Tab 3, Schedules C1.1, C2.1, and C3.1, and Tab 3 Schedules E1.1, E2.1, and E3.1.

c) If not, also provide a spreadsheet version with the average 2011 rate base. Please list all assumptions and sources of data for each line.

RESPONSE:

c) Please see the response in part b).

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.4

INTERROGATORY 113:

Reference(s): Tab 2, pages 11-12 and Appendices 2 & 3

a) Please confirm that the calculations on page 3 of Appendix 3 illustrate the revenue requirement impact of $89.022 M annual capital spending under the Board's ICM module where the threshold has been calculated as $27.8 M and the resulting qualifying amount is $61.222 M annually. If not, please provide such a calculation.

RESPONSE:

a) The question refers to the originally filed Appendix 3 which has been withdrawn and replaced with a revised version.

b) Please provide a similar calculation of the revenue requirement impact of $89.022 M of annual capital spending based on THESL's proposal to i) eliminate the 20% dead band and ii) apply the ½ year rule in the year the capital is spent.

RESPONSE:

b) Please refer to the revised version of Appendix 3, which performs the requested calculation for an arbitrary level of capital expenditures equalling $50 million. Since $89.022 million is also under the cross over point of $114 million under the standard approach, the result is qualitatively the same as for the $50 million level.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.4

INTERROGATORY 114:

Reference(s): **Tab 2, page 12, lines 5-7**

a) Please provide a schedule that sets out THESL's approved 2011 revenue requirement, rate base and resulting ROE and contrasts these values with its actual result for 2011.

RESPONSE:

a) Please see the table below

	FY11	
	Approved	Actual
Gross Fixed Assets (Avg)	$ 4,358.0	$ 4,393.7
Accumulated Amortization (Avg)	$ (2,356.5)	$ (2,354.1)
Net Fixed Assets (Avg)	$ 2,001.5	$ 2,039.7
Working Capital Allowance	$ 296.7	$ 313.6
Rate Base	$ 2,298.2	$ 2,353.2
Interest Expense	$ 71.4	$ 75.3
Return on Equity	$ 88.1	$ 90.2
Return on Rate Base	$ 159.4	$ 165.5
OM&A	$ 231.2	$ 229.9
Property & Municipal Taxes	$ 6.8	$ 5.9
Other	$ -	$ -
Total OM&A	$ 238.0	$ 235.8
Amortisation of Assets	$ 138.8	$ 146.4
Distribution Expenses	$ 376.8	$ 382.2
PILs	$ 11.8	$ 9.0
Service Revenue Requirement	$ 548.1	$ 556.7
Revenue Offsets	$ (26.0)	$ (24.3)
Base Revenue Requirement	$ 522.0	$ 532.5
ROE	9.58%	9.94%

Y

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.4

INTERROGATORY 115:

Reference(s): Tab 2, page 13, Table 1

a) Please provide references as to specifically where in the Application the various values presented in Table 1 are calculated and can be found. If there are no supporting calculations, please provide.

RESPONSE:

a) The values shown for the Standard Methodology Revenue Requirements can be found at Tab 4, Schedule E1.1, E2.1, and E3.1, page 12. The values shown for the Standard Methodology Rate Adders can be found at Tab 4, Schedules E1.3, E2.3, and E3.3, page 1.

The values shown for the Alternative Methodology Revenue Requirement and Rate Adders use exactly the same ICM models, but remove the deadband from the Threshold calculation, and apply the half year rule to the ICM amounts.

THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will affect the models requested in this interrogatory, such that providing a response now would not materially assist the OEB or intervenors. THESL will provide the ICM models for the Alternative Methodology, as well as new versions of the Standard Methodology, with its forthcoming evidentiary update.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 3.1

INTERROGATORY 81:

Reference(s): T5 PILs Recovery Worksheets

Please explain how THESL determined the PILs amounts associated with unbilled revenue accrual as at April 30, 2006 and how this was included in the various Excel worksheets.

RESPONSE:

THESL calculated the amount of PILs included in unbilled revenue as of April 30, 2006 by calculating the PILs portion of distribution rates between March 2002 and April 2006, and applying this to sales by class over the period to determine total PILs revenue collected. The calculations are shown in Tab 5, Schedule M. The proportion of PILs revenue collected to total distribution revenue collected was then applied to the unbilled balance as of April 30, 2006. The resulting PILs in unbilled revenue is included in the total amount of PILs Revenue Collected in Rates (Tab 5, Schedule M, page 1) and is included in the Continuity schedule for account 1562 as PILs collected from customers – Proxy (Tab 5, Schedule A, Row 19).

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INTERROGATORY 82:

Reference(s): T5 PILs Recovery Worksheets

With respect to taxable capital gains and gains on disposals of fixed assets, THESL included its fixed assets in the calculation of rate base for the 2000-2001 application. The Board approved the rate base for use in the determination of distribution rates. THESL continued to receive the return on these assets from ratepayers even though it may have disposed of assets during the period 2001 through 2005.

In the 2005 SIMPIL model, the variances caused by taxable capital gains and gains on disposal of fixed assets that THESL input on sheet TAXREC2 are greater than the materiality threshold and true up to ratepayers on sheet TAXCALC rows 107 and 118.

Please explain why in THESL's view these variances should true up to ratepayers, or if THESL is not of this view, please move the fixed asset transactions to the SIMPIL model sheet TAXREC3 and update the PILs continuity schedule and final balance for disposition.

RESPONSE:

THESL has reviewed its treatment of the variances from capital gains and disposals of fixed assets and agrees that those transactions should not true up to ratepayers. THESL has moved the transactions to the SIMPIL model sheet TAXREC3 and has updated its PILs continuity schedules for the change. Please see revised SIMPIL models and updated PILs continuity schedule as provided in OEB Staff 84j (Tab 6I, Schedule I-84, part j).

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INTERROGATORY 83:

Reference(s): T5

THESL has shown additions and deductions for scientific research expenses. When taken as a deduction in one year some amount has been added back to taxable income in the following year.

a) Please explain the treatment for income taxes and why the items should true up to the shareholder.

RESPONSE:

a) The scientific research and development credit ("SRED") is calculated with the provision of an investment tax credit ("ITC") and an adjustment to net income for tax purposes. The SRED trues up to ratepayers rather than to the shareholder. Given that the SIMPIL model provides the ITC as a benefit to the ratepayers, the adjustment to net income for tax purposes must also true up to ratepayers. Otherwise, the benefit to ratepayers would be missing an integral part of the SRED calculation. In 2005, the adjustment to net income is greater than the materiality threshold and should true up to ratepayers.

b) Please state whether or not ratepayers benefit from these investments and if so what the benefit was.

RESPONSE:

b) Ratepayers benefit from investments in SRED in two ways. Investment in SRED delivers benefits in performance and efficiencies, as well as reduces maintenance and

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 3.1

labour costs, and increases safety. In addition to these, eligible costs qualify for the investment tax credit which reduces THESL's overall tax liability and therefore reduces rates to ratepayers.

c) The 2005 adjustments for scientific research expenses were greater than the materiality threshold and trued up to ratepayers in sheet TAXCALC rows 107 and 118 in the 2005 SIMPIL model. Please explain why these adjustments should true up to ratepayers.

RESPONSE:

c) Please see responses in a) and b) above.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 3.1

INTERROGATORY 84:

Reference(s): T5

With respect to actual and deemed interest expense for tax years 2001 to 2005 for true-up calculations, when the actual interest expense, as reflected in the financial statements and tax returns, exceeds the maximum deemed interest amount approved by the Board, the excess amount is subject to a claw-back penalty and is shown in the TAXCALC worksheet as an extra deduction in the true-up calculations.

a) Please provide a table for the years 2001 to 2005 that shows all of the components of interest expense and the amount associated with each type of interest. For each year, please balance the numbers in the table to the financial statements, to the tax returns and to the amounts used in SIMPIL sheet TAXCALC for the interest true-up calculations.

RESPONSE:

a) Please see attached Appendix A showing the components of interest expense.

b) Please state whether or not THESL had interest expense related to other than debt that is disclosed as interest expense in its financial statements.

RESPONSE:

b) THESL has provided all of the components of interest expense in Appendix A as provided in part a).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 3.1

c) Please state whether or not THESL netted interest income against interest expense in deriving the amount it shows as actual interest expense in the SIMPIL models. If yes, please provide details to what the interest income relates and explain why interest income and expense should be netted to reduce the interest expense used in the true-up calculations.

RESPONSE:

c) THESL did not net interest income against interest expense except in the year 2002. The interest income in 2002 was excluded in the true-up calculation (please see Appendix A).

d) The Board has decided in a number of recent decisions that interest expense used to calculate the interest claw-back variance should not include interest on customer deposits (Hydro One Brampton, EB-2011-0174, December 22, 2011. Kingston Hydro, EB-2011-0178, April 19, 2012. Innisfil Hydro, EB-2011-0176, April 19, 2012.) Please redo the interest true-up calculations excluding interest expense on customer security deposits. If THESL chooses not to redo the calculations, please explain why.

RESPONSE:

d) THESL excluded the interest expense on customer deposits in the true-up calculation (please see Appendix A).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 3.1

e) Please state whether or not THESL included interest income on customer security deposits in the disclosed amount of interest expense in its financial statements and tax returns.

RESPONSE:

e) THESL did not include interest income on customer security deposits in the disclosed amount of interest expense and therefore it is not included in the true-up calculation.

f) The Board has decided in a number of recent decisions (Burlington Hydro, EB-2011-015, March 20, 2012. Kitchener-Wilmot Hydro, EB-2011-0179, April 4, 2012. Thunder Bay Hydro Electricity Distribution Inc., EB-2011-0197, April 4, 2012) that that prudential costs are interest expense and should be included in the interest claw-back variance calculations. Please state whether or not THESL incurred interest expense or standby fees or charges on IESO or other prudentials. Please provide a table that lists all of the prudential costs by year for 2001-2005 with the amounts by type of charge for letters or lines of credit whether shown as interest expense or as OM&A.

RESPONSE:

f) THESL incurred interest expense, standby fees and other IESO prudential costs. Please see attached Appendix B outlining the components of these costs for 2001 to 2005. The costs were reflected as interest expense rather than OM&A.

g) Please state whether or not THESL included interest carrying charges on regulatory assets or liabilities in interest expense.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 3.1

RESPONSE:

g) THESL did not include interest carrying charges (expense) on regulatory assets or liabilities in interest expense. The capitalized interest income in 2002 was excluded in the true-up calculation (please see Appendix A).

h) Please state whether or not THESL included the amortization of debt issue costs, debt discounts or debt premiums in interest expense.

RESPONSE:

h) THESL included the amortization of debt issue costs, debt discounts or debt premiums in interest expense. These costs are reflected in the true-up calculation.

i) Please state whether or not THESL deducted capitalized interest in deriving the interest expense disclosed in its financial statements. If yes, did THESL add back the capitalized interest to the actual interest expense amount for purposes of the interest true-up calculations? Please explain.

RESPONSE:

i) THESL did not deduct capitalized interest in deriving the interest expense disclosed in its financial statements except in the year 2002. THESL added back the capitalized interest to the actual interest expense amount for purposes of the interest true-up calculation (please see Appendix A).

j) If any revisions are made, please file the revised SIMPIL models and update the PILs continuity schedule and final balance for disposition in active Excel format.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 3.1

RESPONSE:

j) Please see revised SIMPIL models and updated PILs continuity schedule provided.

Interrogatory - OEB Staff 84 a)
Account 1562- PILs true up variance- Excess interest

Appendix A

	2001	2002	2003	2004	2005
Calculation on SIMPIL Filing					
Interest deducted on MoF filing (per SIMPIL sheet TAXCALC Cell E201) - see Table A	**40,787,000**	**71,176,000**	**76,618,505**	**78,673,000**	**78,529,552**
OEB deemed interest (per SIMPIL sheetTAXCALC Cell E202)	**80,006,981**	**80,006,981**	**80,006,981**	**80,006,981**	**80,006,981**
Excess interest, if + ve	**0**	**0**	**0**	**0**	**0**
Table A: Interest deducted on MoF filing					
Long term notes	40,787,000	66,656,000	67,091,000	78,673,000	78,533,000
Short term interest	0	5,160,265	2,267,749	0	0
Short term interest-interco.	0	0	7,260,361	0	0
AFUDC on transition costs	0	(640,265)	0	0	0
Rounding	0	0	(605)	0	(3,448)
Total interest deducted on MoF filing	40,787,000	71,176,000	76,618,505	78,673,000	78,529,552
Revised calculation filed October 5, 2012					
Interest deducted on MoF filing (per SIMPIL sheet TAXCALC Cell E201) - see Table B	**40,787,000**	**72,952,718**	**78,385,351**	**80,175,879**	**79,681,859**
OEB deemed interest (per TAXCALC Cell E202)	**80,006,981**	**80,006,981**	**80,006,981**	**80,006,981**	**80,006,981**
Excess interest, if + ve	**0**	**0**	**0**	**168,898**	**0**
Table B: Interest deducted on MoF filing					
Long term notes	40,787,000	66,656,000	67,091,000	78,673,000	78,533,000
Short term interest	0	5,160,265	2,267,749	0	0
Short term interest-interco.	0	0	7,260,361	0	0
Financing costs	0	1,136,687	1,766,846	1,502,173	1,152,305
Rounding	0	(234)	(605)	706	(3,446)
Total interest deducted on MoF filing	40,787,000	72,952,718	78,385,351	80,175,879	79,681,859
Interest expense per financial statements					
Long term notes	**40,787,000**	**66,656,000**	**67,091,000**	**78,673,000**	**78,533,000**
Other interest - Table C		**4,520,000**	**13,049,000**	**2,935,000**	**2,087,000**
Interest expense per financial statements	**40,787,000**	**71,176,000**	**80,140,000**	**81,608,000**	**80,620,000**
Table C: Components of other interest:					
Short term interest	0	5,160,265	2,267,749	0	0
Short term interest-interco.	0	0	7,260,361	0	0
Interest on customer deposits	0	198,921	1,168,571	909,828	613,631
Interest on tax payments	0	0	0	35,662	0
Vehicle lease payments	0	423,333	586,078	486,631	324,510
AFUDC on transition costs	0	(2,398,972)	0	0	0
Financing costs	0	1,136,687	1,766,846	1,502,173	1,152,305
Rounding	0	(234)	(605)	706	(3,446)
	0	4,520,000	13,049,000	2,935,000	2,087,000

	A	B	D	F	H	J
1	**Interrogatory - OEB Staff 84 a)**					
2	**Account 1562- PILs true up variance- Excess interest**					
3						
4	**Appendix A**					
5						
6		**2001**	**2002**	**2003**	**2004**	**2005**
7						
55	**Reconciliation to SIMPIL Filing - revised October 5, 2012**					
56	Interest expense per financial statements	40,787,000	71,176,000	80,140,000	81,608,000	80,620,000
57						
58	Less: Interest on customer deposits	-	(198,921)	(1,168,571)	(909,828)	(613,631)
59	Less: Interest on tax payments	-	-	-	(35,662)	-
60	Less: Vehicle lease payments	-	(423,333)	(586,078)	(486,631)	(324,510)
61	Add: AFUDC on transition costs	-	2,398,972	-	-	-
62						
63	Interest expense per SIMPIL Filing - revised October 5, 2012	40,787,000	72,952,718	78,385,351	80,175,879	79,681,859
64						
65						
66	**Interest expense claimed on tax return**					
67						
68	Interest expense per financial statements	40,787,000	71,176,000	80,140,000	81,608,000	80,620,000
69						
70	Tax adjustments per tax return: (Addback) Deduction					
71	Financing fees deducted in books	-	(534,688)	(1,536,876)	(731,936)	(484,528)
72	Financing fees S.20(1)(e) deduction	-	134,250	1,027,325	1,270,925	1,121,325
73	Non-deductible Interest on tax payments			-	(35,183)	(800)
74	AFUDC on transition costs	-	2,398,972	-	-	-
75	Interest expense deducted in books re: vehicle lease payments	-	-	-	-	(2,830)
76	Rounding	-	234	605	(706)	3,446
77	Net Tax adjustment per tax return: (Addback) Deduction	-	1,998,768	(508,946)	503,100	636,613
78						
79	**Total interest expense claimed on tax return**	**40,787,000**	**73,174,768**	**79,631,054**	**82,111,100**	**81,256,613**
80						
81	**Reconciliation to SIMPIL Filing - revised October 5, 2012**					
82	Total interest expense claimed on tax return	40,787,000	73,174,768	79,631,054	82,111,100	81,256,613
83						
84	Less: Interest on customer deposits	-	(198,921)	(1,168,571)	(909,828)	(613,631)
85	Less: Interest on tax payments	-	-	-	(35,662)	-
86	Less: Vehicle lease payments	-	(423,333)	(586,078)	(486,631)	(324,510)
87	Less: Financing fees deducted in books	-	534,688	1,536,876	731,936	484,528
88	Add: Financing fees S.20(1)(e) deduction	-	(134,250)	(1,027,325)	(1,270,925)	(1,121,325)
89	Add: Non-deductible interest on tax payments	-	-	-	35,183	800
90	Add: Interest expense deducted in books re: vehicle lease payments	-	-	-	-	2,830
91	Rounding	-	(234)	(605)	706	(3,446)
92						
93	Interest expense per SIMPIL Filing - revised October 5, 2012	40,787,000	72,952,718	78,385,351	80,175,879	79,681,859

	A	B	C	D	E	F
1	**Interrogatory - OEB Staff 84 f)**					
2	**Account 1562- PILs true up variance- Summary of Financing costs**					
3						
4	**Appendix B**					
5						
6		**2001**	**2002**	**2003**	**2004**	**2005**
7						
8	Letter of Credit Fees - Interest on Prudentials	-	187,292	503,159	443,616	384,658
9						
10	Credit Line - Standby Fees	-	227,604	647,327	594,786	563,203
11						
12	Credit Line- Arangement fees	-	721,791	616,360	463,771	204,444
13						
14	**Total Financing costs**	**-**	**1,136,687**	**1,766,846**	**1,502,173**	**1,152,305**

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA
1	**PILs TAXES**																										
2	**Analysis of Account 1562:**	**Deferred Payments in lieu of Taxes**																									
3	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**																										
4	**Reporting Period:2001-2012**				**Sign Convention: + for increase; - for decrease**																						
5																											
6																											
7																											
8	**Year start:**		01/10/2001		01/01/2002		01/01/2003		01/01/2004		01/01/2005		01/01/2006		01/01/2007		01/01/2008		01/01/2009		01/01/2010		01/01/2011		01/01/2012		
9	**Year end:**		31/12/2001		31/12/2002		31/12/2003		31/12/2004		31/12/2005		31/12/2006		31/12/2007		31/12/2008		31/12/2009		31/12/2010		31/12/2011		30/04/2012		Total
10																											
11	**Opening balance:**	=	0		5,028,333		8,127,575		8,284,720		-619,716		-3,773,161		-4,931,121		-5,214,708		-5,453,455		-5,521,690		-5,569,529		-5,657,709		0
12	**Board-approved PILs tax proxy from Decisions (1)**	+/-	5,000,000	A	55,000,000	A	60,000,000	B	58,571,734	D	60,109,102	E	20,204,045	F													258,884,881
13	**True-up Variance Adjustment Q4, 2001 (2)**	+/-			-290,810																						-290,810
14	**True-up Variance Adjustment (3)**	+/-					2,156,868		-6,024,420		-1,684,166		-350,320														-5,902,038
15	**Deferral Account Variance Adjustment Q4, 2001 (4)**																										0
16	**Deferral Account Variance Adjustment (5)**	+/-					-2,412,196	C	-3,807,479	C																	-6,219,675
17	**Adjustments to reported prior years' variances-(6)**	+/-											-1,069,868	G													-1,069,868
18	**Carrying charges (7)**	+/-	28,333		720,305		562,257		269,130		-225,213		-287,268		-283,587		-238,747		-68,235		-47,839		-88,180		-29,393		311,563
19	**PILs collected from customers - Proxy (8)**	-	0		-52,330,253		-60,149,784		-57,913,401		-61,353,168		-19,654,549														-251,401,155
20																											
21	**Ending balance: # 1562**		5,028,333		8,127,575		8,284,720		-619,716		-3,773,161		-4,931,121		-5,214,708		-5,453,455		-5,521,690		-5,569,529		-5,657,709		-5,687,102		-5,687,102

22
23
24 **NOTE:** The purpose of this worksheet is to show the movement in Account 1562 which establishes the receivable from or liability to ratepayers.
25 For explanation of Account 1562 please refer to Accounting Procedures Handbook for Electric Distribution Utilities and FAQ April 2003.
26
27 **Method 3 was used to account for the PILs proxy and recovery.**
28 **Footnotes:**
29 A Amount agrees to Rate Decision RP-2002-0002/EB-2002-0011, which differs from RUD model
30 B PILs based on 2001 and 2002 approved amounts
31 C Deferral account variances are in respect of applicable year
32 D PILs for 2004 based on 2002 RUD model
33 E PILs based on 2002 RUD model apply for Jan 1 to Mar 31 2005 period and 2005 PILs proxy applies for balance of year.
34 F Prorated 2005 PILs proxy used for Jan 1 to Apr 30 2006 period
35 G Adjustment for elimination of LCT

PILs Deferral Variance Analysis
Account 1562
April 30, 2012

Interest Rates	
2001 to Q1 2006	6.80%
Q2 2006	4.14%
Q3 2006 to Q3 2007	4.59%
Q4 2007 to Q1 2008	5.14%
Q2 2008	4.08%
Q3 2008 to Q4 2008	3.35%
Q1 2009	2.45%
Q2 2009	1.00%
Q3 2009 to Q2 2010	0.55%
Q3 2010	0.89%
Q4 2010	1.20%
Q1 2011 to April 30 2012	1.47%

2001

	PY CFWD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Annual Subtotal	Cumulative Total
Approved PILs	-	-	-	-	-	-	-	-	-	-	1,666,667	1,666,666	1,666,667	5,000,000	5,000,000
PILs Billed to Customers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SIMPL Variance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal	-	-	-	-	-	-	-	-	-	-	1,666,667	1,666,666	1,666,667	5,000,000	5,000,000
Interest	-	-	-	-	-	-	-	-	-	-	-	9,444	18,889	28,333	28,333
Total	-	-	-	-	-	-	-	-	-	-	1,666,667	1,676,110	1,685,556	5,028,333	5,028,333
Cumulative Principal	-	-	-	-	-	-	-	-	-	-	1,666,667	3,333,333	5,000,000		
Cumulative Interest	-	-	-	-	-	-	-	-	-	-	-	9,444	28,333		
Cumulative Total	-	-	-	-	-	-	-	-	-	-	1,666,667	3,342,777	5,028,333		

2002

	PY CFWD	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Annual Subtotal	Cumulative Total
Approved PILs	5,000,000	4,583,333	4,583,333	4,583,333	4,583,333	4,583,333	4,583,333	4,583,333	4,583,333	4,583,333	4,583,333	4,583,333	4,583,337	55,000,000	60,000,000
PILs Billed to Customers	-	-	-	(5,128,917)	(4,844,074)	(4,963,624)	(5,167,317)	(5,881,045)	(5,666,001)	(5,259,679)	(5,034,408)	(5,063,288)	(5,321,900)	(52,330,253)	(52,330,253)
SIMPL Variance	-	-	-	-	-	-	**(290,810)**	-	-	-	-	-	-	(290,810)	(290,810)
Subtotal	5,000,000	4,583,333	4,583,333	(545,584)	(260,741)	(380,291)	(874,794)	(1,297,712)	(1,082,668)	(676,346)	(451,075)	(479,955)	(738,563)	2,378,937	7,378,937
Interest	28,333	28,333	54,306	80,278	77,186	75,709	73,554	68,596	61,243	55,108	51,275	48,719	45,999	720,305	748,638
Total	5,028,333	4,611,666	4,637,639	(465,306)	(183,555)	(304,582)	(801,240)	(1,229,116)	(1,021,425)	(621,238)	(399,800)	(431,236)	(692,564)	3,099,242	8,127,575
Cumulative Principal	5,000,000	9,583,333	14,166,666	13,621,082	13,360,341	12,980,050	12,105,256	10,807,544	9,724,876	9,048,530	8,597,455	8,117,500	7,378,937		
Cumulative Interest	28,333	56,667	110,972	191,250	268,436	344,145	417,698	486,295	547,538	602,645	653,920	702,639	748,638		
Cumulative Total	5,028,333	9,640,000	14,277,638	13,812,332	13,628,777	13,324,195	12,522,954	11,293,839	10,272,414	9,651,175	9,251,375	8,820,139	8,127,575		

2003

Row	A	PY CFWD	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Annual Subtotal	Cumulative Total
64	Approved PILs	60,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	60,000,000	120,000,000
65	PILs Billed to Customers	(52,330,253)	(5,317,066)	(4,922,031)	(5,072,630)	(4,853,275)	(4,765,135)	(4,996,389)	(5,294,225)	(5,267,442)	(4,881,929)	(4,871,659)	(4,814,453)	(5,093,550)	(60,149,784)	(112,480,037)
66	SIMPL Variance	(290,810)	-	-	-	-	-	**2,156,868**	-	-	-	-	-	**(2,412,196)**	(255,328)	(546,138)
68	Subtotal	7,378,937	(317,066)	77,969	(72,630)	146,725	234,865	2,160,479	(294,225)	(267,442)	118,071	128,341	185,547	(2,505,746)	(405,112)	6,973,825
70	Interest	748,638	41,814	40,017	40,459	40,048	40,879	42,210	54,453	52,785	51,270	51,939	52,666	53,718	562,257	1,310,895
72	Total	8,127,575	(275,252)	117,986	(32,171)	186,773	275,744	2,202,689	(239,772)	(214,657)	169,341	180,280	238,213	(2,452,028)	157,145	8,284,720
75	Cumulative Principal	7,378,937	7,061,871	7,139,840	7,067,210	7,213,935	7,448,800	9,609,279	9,315,054	9,047,612	9,165,683	9,294,024	9,479,571	6,973,825		
76	Cumulative Interest	748,638	790,452	830,469	870,929	910,976	951,855	994,065	1,048,518	1,101,303	1,152,573	1,204,512	1,257,178	1,310,895		
77	Cumulative Total	8,127,575	7,852,323	7,970,309	7,938,139	8,124,911	8,400,655	10,603,344	10,363,572	10,148,915	10,318,256	10,498,536	10,736,749	8,284,720		

2004

Row	A	PY CFWD	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Annual Subtotal	Cumulative Total
86	Approved PILs	120,000,000	5,000,000	5,000,000	5,000,000	4,841,304	4,841,304	4,841,304	4,841,304	4,841,304	4,841,304	4,841,304	4,841,304	4,841,302	58,571,734	178,571,734
87	PILs Billed to Customers	(112,480,037)	(5,375,228)	(4,935,067)	(4,994,877)	(4,729,326)	(4,749,755)	(4,781,694)	(4,818,314)	(4,802,895)	(4,739,821)	(4,536,844)	(4,531,281)	(4,918,299)	(57,913,401)	(170,393,438)
88	SIMPL Variance	(546,138)	-	-	-	-	-	(6,024,420)	-	-	-	-	-	(3,807,479)	(9,831,899)	(10,378,037)
90	Subtotal	6,973,825	(375,228)	64,933	5,123	111,978	91,549	(5,964,810)	22,990	38,409	101,483	304,460	310,023	(3,884,476)	(9,173,566)	(2,199,741)
92	Interest	1,310,895	39,518	37,392	37,760	37,789	38,424	38,942	5,142	5,272	5,490	6,065	7,790	9,547	269,130	1,580,026
94	Total	8,284,720	(335,710)	102,325	42,883	149,767	129,973	(5,925,868)	28,132	43,681	106,973	310,525	317,813	(3,874,929)	(8,904,436)	(619,715)
97	Cumulative Principal	6,973,825	6,598,597	6,663,530	6,668,653	6,780,631	6,872,180	907,370	930,360	968,769	1,070,252	1,374,712	1,684,735	(2,199,741)		
98	Cumulative Interest	1,310,895	1,350,414	1,387,806	1,425,566	1,463,355	1,501,778	1,540,721	1,545,862	1,551,134	1,556,624	1,562,689	1,570,479	1,580,026		
99	Cumulative Total	8,284,720	7,949,011	8,051,336	8,094,219	8,243,986	8,373,958	2,448,091	2,476,222	2,519,903	2,626,876	2,937,401	3,255,214	(619,715)		

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
102																			
103																			
104									**2005**										
105																**Annual**	**Cumulative**		
106			**PY CFWD**	**Jan-05**	**Feb-05**	**Mar-05**	**Apr-05**	**May-05**	**Jun-05**	**Jul-05**	**Aug-05**	**Sep-05**	**Oct-05**	**Nov-05**	**Dec-05**	**Subtotal**	**Total**		
107																			
108	Approved PILs		178,571,734	4,883,333	4,883,333	4,883,333	5,051,011	5,051,011	5,051,011	5,051,011	5,051,011	5,051,011	5,051,011	5,051,011	5,051,015	60,109,102	238,680,836		
109	PILs Billed to Customers		(170,393,438)	(5,257,509)	(4,774,976)	(5,024,642)	(4,583,422)	(4,650,094)	(5,510,478)	(5,958,010)	(5,769,967)	(5,001,100)	(4,604,789)	(4,778,520)	(5,439,661)	(61,353,168)	(231,746,606)		
110	SIMPL Variance		(10,378,037)	-	-	-	-	-	-	-	(1,684,166)	-	-	-	-	(1,684,166)	(12,062,203)		
111																			
112	Subtotal		(2,199,741)	(374,176)	108,357	(141,309)	467,589	400,917	(459,467)	(906,999)	(2,403,122)	49,911	446,222	272,491	(388,646)	(2,928,232)	(5,127,973)		
113																			
114	Interest		1,580,026	(12,465)	(14,586)	(13,972)	(14,772)	(12,123)	(9,851)	(12,454)	(17,594)	(31,212)	(30,929)	(28,400)	(26,856)	(225,213)	1,354,812		
115																			
116	Total		(619,715)	(386,641)	93,771	(155,281)	452,817	388,794	(469,318)	(919,453)	(2,420,716)	18,699	415,293	244,091	(415,502)	(3,153,445)	(3,773,161)		
117																			
118																			
119	Cumulative Principal		(2,199,741)	(2,573,917)	(2,465,560)	(2,606,869)	(2,139,280)	(1,738,363)	(2,197,830)	(3,104,829)	(5,507,951)	(5,458,040)	(5,011,818)	(4,739,327)	(5,127,973)				
120	Cumulative Interest		1,580,026	1,567,560	1,552,975	1,539,003	1,524,231	1,512,109	1,502,258	1,489,804	1,472,209	1,440,998	1,410,069	1,381,669	1,354,812				
121	Cumulative Total		(619,715)	(1,006,357)	(912,585)	(1,067,866)	(615,049)	(226,254)	(695,572)	(1,615,025)	(4,035,742)	(4,017,042)	(3,601,749)	(3,357,658)	(3,773,161)				
122																			
123																			
124																			
125																			
126									**2006**										
127																**Annual**	**Cumulative**		
128			**PY CFWD**	**Jan-06**	**Feb-06**	**Mar-06**	**Apr-06**	**May-06**	**Jun-06**	**Jul-06**	**Aug-06**	**Sep-06**	**Oct-06**	**Nov-06**	**Dec-06**	**Subtotal**	**Total**		
129																			
130	Approved PILs		238,680,836	5,051,011	5,051,011	5,051,011	5,051,012	-	-	-	-	-	-	-	-	20,204,045	258,884,881		
131	PILs Billed to Customers		(231,746,606)	(5,208,059)	(4,911,712)	(5,071,451)	(4,463,328)	-	-	-		-	-	-	-	(19,654,550)	(251,401,156)		
132	SIMPL Variance		(12,062,203)	-	-	-	-	-	-	-	(350,320)	-	-	-	-	(350,320)	(12,412,523)		
133	Removal of LCT		-	(267,467)	(267,467)	(267,467)	(267,467)									(1,069,868)	(1,069,868)		
134																			
135	Subtotal		(5,127,973)	(424,515)	(128,168)	(287,907)	320,217	-	-	-	(350,320)	-	-	-	-	(870,693)	(5,998,666)		
136																			
137	Interest		1,354,812	(29,059)	(31,464)	(32,190)	(20,592)	(19,487)	(19,487)	(21,605)	(21,605)	(22,945)	(22,945)	(22,945)	(22,945)	(287,268)	1,067,545		
138																			
139	Total		(3,773,161)	(453,574)	(159,632)	(320,097)	299,625	(19,487)	(19,487)	(21,605)	(371,925)	(22,945)	(22,945)	(22,945)	(22,945)	(1,157,961)	(4,931,121)		
140																			
141																			
142	Cumulative Principal		(5,127,973)	(5,552,488)	(5,680,656)	(5,968,563)	(5,648,346)	(5,648,346)	(5,648,346)	(5,648,346)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)				
143	Cumulative Interest		1,354,812	1,325,754	1,294,290	1,262,099	1,241,508	1,222,021	1,202,534	1,180,929	1,159,324	1,136,380	1,113,435	1,090,490	1,067,545				
144	Cumulative Total		(3,773,161)	(4,226,734)	(4,386,366)	(4,706,464)	(4,406,838)	(4,426,325)	(4,445,812)	(4,467,417)	(4,839,342)	(4,862,286)	(4,885,231)	(4,908,176)	(4,931,121)				
145																			
146																			

2007

	PY CFWD	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Annual Subtotal	Cumulative Total
Approved PILs	258,884,881	-	-	-	-	-	-	-	-	-	-	-	-	-	258,884,881
PILs Billed to Customers	(251,401,156)	-	-	-	-	-	-	-	-	-	-	-	-	-	(251,401,156)
SIMPL Variance	(12,412,523)	-	-	-	-	-	-	-	-	-	-	-	-	-	(12,412,523)
Removal of LCT	(1,069,868)													-	(1,069,868)
Subtotal	(5,998,666)	-	-	-	-	-	-	-	-	-	-	-	-	-	(5,998,666)
Interest	1,067,545	(22,945)	(22,945)	(22,945)	(22,945)	(22,945)	(22,945)	(22,945)	(22,945)	(22,945)	(25,694)	(25,694)	(25,694)	(283,587)	783,958
Total	(4,931,121)	(22,945)	(22,945)	(22,945)	(22,945)	(22,945)	(22,945)	(22,945)	(22,945)	(22,945)	(25,694)	(25,694)	(25,694)	(283,587)	(5,214,708)
Cumulative Principal	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)		
Cumulative Interest	1,067,545	1,044,600	1,021,655	998,710	975,765	952,820	929,875	906,931	883,986	861,041	835,346	809,652	783,958		
Cumulative Total	(4,931,121)	(4,954,066)	(4,977,011)	(4,999,956)	(5,022,901)	(5,045,846)	(5,068,791)	(5,091,735)	(5,114,680)	(5,137,625)	(5,163,320)	(5,189,014)	(5,214,708)		

2008

	PY CFWD	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Annual Subtotal	Cumulative Total
Approved PILs	258,884,881	-	-	-	-	-	-	-	-	-	-	-	-	-	258,884,881
PILs Billed to Customers	(251,401,156)	-	-	-	-	-	-	-	-	-	-	-	-	-	(251,401,156)
SIMPL Variance	(12,412,523)	-	-	-	-	-	-	-	-	-	-	-	-	-	(12,412,523)
Removal of LCT	(1,069,868)													-	(1,069,868)
Subtotal	(5,998,666)	-	-	-	-	-	-	-	-	-	-	-	-	-	(5,998,666)
Interest	783,958	(25,694)	(25,694)	(25,694)	(20,395)	(20,395)	(20,395)	(16,746)	(16,746)	(16,746)	(16,746)	(16,746)	(16,746)	(238,747)	545,212
Total	(5,214,708)	(25,694)	(25,694)	(25,694)	(20,395)	(20,395)	(20,395)	(16,746)	(16,746)	(16,746)	(16,746)	(16,746)	(16,746)	(238,747)	(5,453,454)
Cumulative Principal	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)		
Cumulative Interest	783,958	758,264	732,569	706,875	686,480	666,084	645,689	628,942	612,196	595,450	578,704	561,957	545,211		
Cumulative Total	(5,214,708)	(5,240,402)	(5,266,097)	(5,291,791)	(5,312,186)	(5,332,582)	(5,352,977)	(5,369,724)	(5,386,470)	(5,403,216)	(5,419,962)	(5,436,709)	(5,453,455)		

2009

	PY CFWD	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Annual Subtotal	Cumulative Total
Approved PILs	258,884,881	-	-	-	-	-	-	-	-	-	-	-	-	-	258,884,881
PILs Billed to Customers	(251,401,156)	-	-	-	-	-	-	-	-	-	-	-	-	-	(251,401,156)
SIMPL Variance	(12,412,523)	-	-	-	-	-	-	-	-	-	-	-	-	-	(12,412,523)
Removal of LCT	(1,069,868)													-	(1,069,868)
Subtotal	(5,998,666)	-	-	-	-	-	-	-	-	-	-	-	-	-	(5,998,666)
Interest	545,212	(12,247)	(12,247)	(12,247)	(4,999)	(4,999)	(4,999)	(2,749)	(2,749)	(2,749)	(2,749)	(2,749)	(2,749)	(68,235)	476,977
Total	(5,453,454)	(12,247)	(12,247)	(12,247)	(4,999)	(4,999)	(4,999)	(2,749)	(2,749)	(2,749)	(2,749)	(2,749)	(2,749)	(68,235)	(5,521,689)
Cumulative Principal	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)		
Cumulative Interest	545,212	532,965	520,717	508,470	503,471	498,472	493,473	490,724	487,975	485,225	482,476	479,727	476,977		
Cumulative Total	(5,453,454)	(5,465,701)	(5,477,949)	(5,490,196)	(5,495,195)	(5,500,194)	(5,505,193)	(5,507,942)	(5,510,691)	(5,513,441)	(5,516,190)	(5,518,939)	(5,521,689)		

2010

	PY CFWD	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Annual Subtotal	Cumulative Total
Approved PILs	258,884,881	-	-	-	-	-	-	-	-	-	-	-	-	-	258,884,881
PILs Billed to Customers	(251,401,156)	-	-	-	-	-	-	-	-	-	-	-	-	-	(251,401,156)
SIMPL Variance	(12,412,523)	-	-	-	-	-	-	-	-	-	-	-	-	-	(12,412,523)
Removal of LCT	(1,069,868)													-	(1,069,868)
Subtotal	(5,998,666)	-	-	-	-	-	-	-	-	-	-	-	-	-	(5,998,666)
Interest	476,977	(2,749)	(2,749)	(2,749)	(2,749)	(2,749)	(2,749)	(4,449)	(4,449)	(4,449)	(5,999)	(5,999)	(5,999)	(47,839)	429,139
Total	(5,521,689)	(2,749)	(2,749)	(2,749)	(2,749)	(2,749)	(2,749)	(4,449)	(4,449)	(4,449)	(5,999)	(5,999)	(5,999)	(47,839)	(5,569,527)
Cumulative Principal	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)		
Cumulative Interest	476,977	474,228	471,478	468,729	465,980	463,230	460,481	456,032	451,583	447,134	441,135	435,136	429,138		
Cumulative Total	(5,521,689)	(5,524,438)	(5,527,188)	(5,529,937)	(5,532,686)	(5,535,436)	(5,538,185)	(5,542,634)	(5,547,083)	(5,551,532)	(5,557,531)	(5,563,530)	(5,569,528)		

2011

Row	A	PY CFWD	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Annual Subtotal	Cumulative Total
244	Approved PILs	258,884,881	-	-	-	-	-	-	-	-	-	-	-	-	-	258,884,881
245	PILs Billed to Customers	(251,401,156)	-	-	-	-	-	-	-	-	-	-	-	-	-	(251,401,156)
246	SIMPL Variance	(12,412,523)	-	-	-	-	-	-	-	-	-	-	-	-	-	(12,412,523)
247	Removal of LCT	(1,069,868)													-	(1,069,868)
249	Subtotal	(5,998,666)	-	-	-	-	-	-	-	-	-	-	-	-	-	(5,998,666)
251	Interest	429,139	(7,348)	(7,348)	(7,348)	(7,348)	(7,348)	(7,348)	(7,348)	(7,348)	(7,348)	(7,348)	(7,348)	(7,348)	(88,180)	340,957
253	Total	(5,569,527)	(7,348)	(7,348)	(7,348)	(7,348)	(7,348)	(7,348)	(7,348)	(7,348)	(7,348)	(7,348)	(7,348)	(7,348)	(88,180)	(5,657,709)
256	Cumulative Principal	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)		
257	Cumulative Interest	429,139	421,790	414,442	407,094	399,745	392,397	385,049	377,700	370,352	363,003	355,655	348,307	340,958		
258	Cumulative Total	(5,569,527)	(5,576,876)	(5,584,224)	(5,591,572)	(5,598,921)	(5,606,269)	(5,613,617)	(5,620,966)	(5,628,314)	(5,635,663)	(5,643,011)	(5,650,359)	(5,657,708)		

2012

Row	A	PY CFWD	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Annual Subtotal	Cumulative Total
265	PILs Billed to Customers	258,884,881	-	-	-	-	-	-	-	-	-	-	-	-	-	258,884,881
266	SIMPL Variance	(251,401,156)	-	-	-	-	-	-	-	-	-	-	-	-	-	(251,401,156)
267	Removal of LCT	(12,412,523)													-	(12,412,523)
268		(1,069,868)													-	(1,069,868)
270	Subtotal	(5,998,666)	-	-	-	-	-	-	-	-	-	-	-	-	-	(5,998,666)
272	Interest	340,957	(7,348)	(7,348)	(7,348)	(7,348)									(29,393)	311,565
274	Total	(5,657,709)	(7,348)	(7,348)	(7,348)	(7,348)	-	-	-	-	-	-	-	-	(29,393)	(5,687,101)
277	Cumulative Principal	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)	(5,998,666)		
278	Cumulative Interest	340,957	333,609	326,261	318,912	311,564	311,564	311,564	311,564	311,564	311,564	311,564	311,564	311,564		
279	Cumulative Total	(5,657,709)	(5,665,057)	(5,672,405)	(5,679,754)	(5,687,102)	(5,687,102)	(5,687,102)	(5,687,102)	(5,687,102)	(5,687,102)	(5,687,102)	(5,687,102)	(5,687,102)		

	A	B	C	D	E
1	**PILs TAXES - EB-2012-0064**				**Version 2009.1**
2	**REGULATORY INFORMATION (REGINFO)**				
3	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**			Colour Code	
4	**Reporting period: 2002**			**Input Cell**	
5				**Formula in Cell**	
6	**Days in reporting period:**	365	days		
7	**Total days in the calendar year:**	365	days		
8					
9	**BACKGROUND**				
10	Has the utility reviewed section 149(1) ITA to				
11	confirm that it is not subject to regular corporate				
12	tax (and therefore subject to PILs)?		Y/N	Y	
13					
14	Was the utility recently acquired by Hydro One				
15	and now subject to s.89 & 90 PILs?		Y/N	N	
16					
17	Is the utility a non-profit corporation?		Y/N	N	
18	(If it is a non-profit corporation, please contact the Rates Manager at the OEB)				
19	Are the Ontario Capital Tax & Large Corporations Tax Exemptions	OCT	Y/N	Y	
20	shared among the corporate group?	LCT	Y/N	N	
21	Please identify the % used to allocate the OCT and LCT exemptions in	OCT		100%	
22	Cells C65 & C74 in the TAXCALC spreadsheet.	LCT		100%	
23					
24	Accounting Year End		Date	12-31-2002	
25					
26	**MARR NO TAX CALCULATIONS**				**Regulatory**
27	**SHEET #7 FINAL RUD MODEL DATA**				**Income**
28	**(FROM 1999 FINANCIAL STATEMENTS)**				
29	**USE BOARD-APPROVED AMOUNTS**				
30					
31	Rate Base (wires-only)			1,810,112,688	
32					
33	Common Equity Ratio (CER)			35.00%	
34					
35	1-CER			65.00%	
36					
37	Target Return On Equity			9.88%	
38					
39	Debt rate			6.80%	
40					
41	Market Adjusted Revenue Requirement			142,600,678	
42					
43	1999 return from RUD Sheet #7			23,304,000	23,304,000
44					
45	Total Incremental revenue			119,296,678	
46	**Input: Board-approved dollar amounts phased-in**				
47	Amount allowed in 2001			39,765,559	39,765,559
48	Amount allowed in 2002			39,765,559	39,765,559
49	Amount allowed in 2003 and 2004 (will be zero due to Bill 210				0
50	unless authorized by the Minister and the Board)				0
51	Amount allowed in 2005 - Third tranche of MARR re: CDM			39,765,559	39,765,559
52	Other Board-approved changes to MARR or incremental revenue				0
53					0
54	**Total Regulatory Income**				142,600,677
55					
56	Equity			633,539,441	
57					
58	Return at target ROE			62,593,697	
59					
60	Debt			1,176,573,247	
61					
62	Deemed interest amount in 100% of MARR			80,006,981	
63					
64	Phase-in of interest - Year 1 (2001)			35,385,561	
65	((D43+D47)/D41)*D61				
66	Phase-in of interest - Year 2 (2002)			57,696,271	
67	((D43+D47+D48)/D41)*D61				
68	Phase-in of interest - Year 3 (2003) and forward			57,696,271	
69	((D43+D47+D48)/D41)*D61 (due to Bill 210)				
70	Phase-in of interest - 2005			80,006,981	
71					

	A	B	C	D	E	F	G	H
1	**PILs TAXES - EB-2012-0064**	**ITEM**	**Initial**		M of F	M of F	**Tax**	
2	**PILs DEFERRAL AND VARIANCE ACCOUNTS**		**Estimate**		Filing	Filing	**Returns**	
3	**TAX CALCULATIONS (TAXCALC)**				Variance	Variance		
4	("Wires-only" business - see Tab TAXREC)				K-C	Explanation		
5	**0**						**Version 2009.1**	
6	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**							
7	**Reporting period: 2002**							
8							**Column**	
9	**Days in reporting period:**	365	days				**Brought**	
10	**Total days in the calendar year:**	365	days				**From**	
11							**TAXREC**	
12			$		$		$	
13								
14	**I) CORPORATE INCOME TAXES**							
15								
16	Regulatory Net Income REGINFO E53	1	102,835,118		37,237,600		140,072,718	
17								
18	BOOK TO TAX ADJUSTMENTS							
19	***Additions:***							
20	Depreciation & Amortization	2	106,229,000		15,765,000		121,994,000	
21	Employee Benefit Plans - Accrued, Not Paid	3	33,129,140		-33,129,140		0	
22	Tax reserves - beginning of year	4			0		0	
23	Reserves from financial statements - end of year	4			119,132,936		119,132,936	
24	Regulatory Adjustments - increase in income	5			0		0	
25	Other Additions (See Tab entitled "TAXREC")							
26	"Material" Items from "TAXREC" worksheet	6			0		0	
27	Other Additions (not "Material") "TAXREC"	6			0		0	
28	"Material Items from "TAXREC 2" worksheet	6			1,529,753		1,529,753	
29	Other Additions (not "Material") "TAXREC 2"	6			3,104,309		3,104,309	
30	**Items on which true-up does not apply "TAXREC 3"**				16,464,375		16,464,375	
31								
32	***Deductions:*** ***Input positive numbers***							
33	Capital Cost Allowance and CEC	7	76,692,530		114,800,551		191,493,081	
34	Employee Benefit Plans - Paid Amounts	8	30,011,140		-30,011,140		0	
35	Items Capitalized for Regulatory Purposes	9	0		0		0	
36	Regulatory Adjustments - deduction for tax purposes in Item 5	10			0		0	
37	Interest Expense Deemed/ Incurred	11	57,696,271		15,256,447		72,952,718	
38	Tax reserves - end of year	4			0		0	
39	Reserves from financial statements - beginning of year	4			114,054,159		114,054,159	
40	Contributions to deferred income plans	3			0		0	
41	Contributions to pension plans	3			0		0	
42	Interest capitalized for accounting but deducted for tax	11			0		0	
43	Other Deductions (See Tab entitled "TAXREC")							
44	"Material" Items from "TAXREC" worksheet	12			0		0	
45	Other Deductions (not "Material") "TAXREC"	12			24,769		24,769	
46	Material Items from "TAXREC 2" worksheet	12			0		0	
47	Other Deductions (not "Material") "TAXREC 2"	12			1,334,612		1,334,612	
48	**Items on which true-up does not apply "TAXREC 3"**				9,954,324		9,954,324	
49								
50	TAXABLE INCOME/ (LOSS)		77,793,317		-65,308,889	Before loss C/F	12,484,428	
51								
52	BLENDED INCOME TAX RATE							
53	Tab Tax Rates - Regulatory from Table 1; Actual from Table 3	13	38.62%		0.0000%		38.62%	
54								
55	REGULATORY INCOME TAX		30,043,779		-30,043,779	Actual	0	
56								
57								
58	Miscellaneous Tax Credits	14			0	Actual	0	
59								
60	**Total Regulatory Income Tax**		30,043,779		-30,043,779	Actual	0	
61								
62								
63	**II) CAPITAL TAXES**							
64								
65	***Ontario***							
66	Base	15	1,810,112,688		125,416,854		1,935,529,542	
67	Less: Exemption -Tax Rates - Regulatory, Table 1; Actual, Table 3	16	5,000,000		-413,782		4,586,218	
68	Taxable Capital		1,805,112,688		125,003,072		1,930,943,324	
69								
70	Rate - Tax Rates - Regulatory, Table 1; Actual, Table 3	17	0.3000%		0.0000%		0.3000%	
71								
72	Ontario Capital Tax		5,415,338		377,492		5,792,830	
73								
74	***Federal Large Corporations Tax***							
75	Base	18	1,810,112,688		135,778,341		1,945,891,029	
76	Less: Exemption -Tax Rates - Regulatory, Table 1; Actual, Table 3	19	10,000,000		0		10,000,000	
77	Taxable Capital		1,800,112,688		135,778,341		1,935,891,029	
78								
79	Rate - Tax Rates - Regulatory, Table 1; Actual, Table 3	20	0.2250%		0.0000%		0.2250%	
80								
81	Gross Amount of LCT before surtax offset (Taxable Capital x Rate)		4,050,254		305,501		4,355,755	
82	Less: Federal Surtax 1.12% x Taxable Income	21	871,285		-871,285		0	
83								
84	Net LCT		3,178,968		1,176,786		4,355,755	
85								

	A	B	C	D	E	F	G	H
1	**PILs TAXES - EB-2012-0064**	**ITEM**	**Initial**		M of F	M of F	**Tax**	
2	**PILs DEFERRAL AND VARIANCE ACCOUNTS**		**Estimate**		Filing	Filing	**Returns**	
3	**TAX CALCULATIONS (TAXCALC)**				Variance	Variance		
4	("Wires-only" business - see Tab TAXREC)				K-C	Explanation		
5	**0**						**Version 2009.1**	
6	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**							
7	**Reporting period: 2002**							
8							**Column**	
9	**Days in reporting period:**	365	days				**Brought**	
10	**Total days in the calendar year:**	365	days				**From**	
11							**TAXREC**	
12			$		$		$	
13								
86	**III) INCLUSION IN RATES**							
87								
88	Income Tax Rate used for gross- up (exclude surtax)		37.50%					
89								
90	Income Tax (proxy tax is grossed-up)	22	48,070,047			**Actual 2002**	0	
91	LCT (proxy tax is grossed-up)	23	5,086,349			**Actual 2002**	4,355,755	
92	Ontario Capital Tax (no gross-up since it is deductible)	24	5,415,338			**Actual 2002**	5,792,830	
93								
94								
95	***Total PILs for Rate Adjustment -- MUST AGREE WITH 2002***	25	58,571,734			**Actual 2002**	10,148,585	
96	**RAM DECISION**							
97	**Total PILs, as approved**		**55,000,000**					
98								
99	***IV) FUTURE TRUE-UPS***							
100	**IV a) Calculation of the True-up Variance**				**DR/(CR)**			
101	***In Additions:***							
102	Employee Benefit Plans - Accrued, Not Paid	3			-33,129,140			
103	Tax reserves deducted in prior year	4			0			
104	Reserves from financial statements-end of year	4			119,132,936			
105	Regulatory Adjustments	5			0			
106	Other additions "Material" Items TAXREC	6			0			
107	Other additions "Material" Items TAXREC 2	6			1,529,753			
108	***In Deductions - positive numbers***							
109	Employee Benefit Plans - Paid Amounts	8			-30,011,140			
110	Items Capitalized for Regulatory Purposes	9			0			
111	Regulatory Adjustments	10			0			
112	Interest Adjustment for tax purposes **(See Below - cell I204)**	11			0			
113	Tax reserves claimed in current year	4			0			
114	Reserves from F/S beginning of year	4			114,054,159			
115	Contributions to deferred income plans	3			0			
116	Contributions to pension plans	3			0			
117	Other deductions "Material" Items TAXREC	12			0			
118	Other deductions "Material" Item TAXREC 2	12			0			
119								
120	Total TRUE-UPS before tax effect	26		=	3,490,530			
121								
122	Income Tax Rate (excluding surtax) from **2002** Utility's tax return			x	38.62%			
123								
124	Income Tax Effect on True-up adjustments			=	1,348,043			
125								
126	Less: Miscellaneous Tax Credits	14			0			
127								
128	Total Income Tax on True-ups				1,348,043			
129								
130	Income Tax Rate used for gross-up (exclude surtax)				37.50%			
131								
132	**TRUE-UP VARIANCE ADJUSTMENT**				2,156,868			
133								
134	**IV b) Calculation of the Deferral Account Variance caused by changes in legislation**							
135								
136	REGULATORY TAXABLE INCOME /(LOSSES) (as reported in the initial estimate column)			=	77,793,317			
137								
138	REVISED CORPORATE INCOME TAX RATE			x	38.62%			
139								
140	REVISED REGULATORY INCOME TAX			=	30,043,779			
141								
142	Less: Revised Miscellaneous Tax Credits			-	0			
143								
144	Total Revised Regulatory Income Tax			=	30,043,779			
145								
146	Less: Regulatory Income Tax reported in the Initial Estimate Column (Cell C58)			-	30,043,779			
147								
148	Regulatory Income Tax Variance			=	0			
149								

	A	B	C	D	E	F	G	H
1	**PILs TAXES - EB-2012-0064**	**ITEM**	**Initial**		M of F	M of F	**Tax**	
2	**PILs DEFERRAL AND VARIANCE ACCOUNTS**		**Estimate**		Filing	Filing	**Returns**	
3	**TAX CALCULATIONS (TAXCALC)**				Variance	Variance		
4	("Wires-only" business - see Tab TAXREC)				K-C	Explanation		
5	**0**						**Version 2009.1**	
6	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**							
7	**Reporting period: 2002**							
8							**Column**	
9	**Days in reporting period:**	365	days				**Brought**	
10	**Total days in the calendar year:**	365	days				**From**	
11							**TAXREC**	
12			$		$		$	
13								
150	**Ontario Capital Tax**							
151	Base			=	1,810,112,688			
152	Less: Exemption from tab Tax Rates, Table 2, cell C39			-	5,000,000			
153	Revised deemed taxable capital			=	1,805,112,688			
154								
155	Rate - Tab Tax Rates cell C54			x	0.3000%			
156								
157	Revised Ontario Capital Tax			=	5,415,338			
158	Less: Ontario Capital Tax reported in the initial estimate column (Cell C70)			-	5,415,338			
159	Regulatory Ontario Capital Tax Variance			=	0			
160								
161	**Federal LCT**							
162	Base				1,810,112,688			
163	Less: Exemption from tab Tax Rates, Table 2, cell C40			-	10,000,000			
164	Revised Federal LCT			=	1,800,112,688			
165								
166	Rate (as a result of legislative changes) tab 'Tax Rates' cell C51				0.2250%			
167								
168	Gross Amount				4,050,254			
169	Less: Federal surtax			-	871,285			
170	Revised Net LCT			=	3,178,968			
171								
172	Less: Federal LCT reported in the initial estimate column (Cell C82)			-	3,178,968			
173	Regulatory Federal LCT Variance			=	0			
174								
175	Actual Income Tax Rate used for gross-up (exclude surtax)				37.50%			
176								
177	**Income Tax (grossed-up)**			+	0			
178	**LCT (grossed-up)**			+	0			
179	**Ontario Capital Tax**			+	0			
180								
181	**DEFERRAL ACCOUNT VARIANCE ADJUSTMENT**			=	0			
182								
183	**TRUE-UP VARIANCE (from cell I130)**			+	2,156,868			
184								
185	**Total Deferral Account Entry (Positive Entry = Debit)**			=	2,156,868			
186	*(Deferral Account Variance + True-up Variance)*							
187								
188								
189								
190	**V) INTEREST PORTION OF TRUE-UP**							
191	**Variance Caused By Phase-in of Deemed Debt**							
192								
193	Total deemed interest (REGINFO)				80,006,981			
194	Interest phased-in (Cell C36)				57,696,271			
195								
196	Variance due to phase-in of debt component of MARR in rates				22,310,710			
197	according to the Board's decision							
198								
199	**Other Interest Variances (i.e. Borrowing Levels**							
200	**Above Deemed Debt per Rate Handbook)**							
201	Interest deducted on MoF filing (Cell K36+K41)				72,952,718			
202	Total deemed interest (REGINFO CELL D61)				80,006,981			
203								
204	Variance caused by excess debt				0			
205								
206	**Interest Adjustment for Tax Purposes (carry forward to Cell I110)**				0			
207								
208	**Total Interest Variance**				22,310,710			
209								

	A	B	C	D	E
1	**PILs TAXES - EB-2012-0064**	**LINE**	**M of F**	Non-wires	**Wires-only**
2	**TAX RETURN RECONCILIATION (TAXREC)**		**Corporate**	Eliminations	**Tax**
3	(for "wires-only" business - see s. 72 OEB Act)		**Tax**		**Return**
4	**0**		**Return**		
5					**Version 2009.1**
6	**Section A: Identification:**				
7	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**				
8	**Reporting period: 2002**				
9	**Taxation Year's start date:**		01/01/2002		
10	**Taxation Year's end date:**		31/12/2002		
11	**Number of days in taxation year:**		365	days	
12					
13	**Please enter the Materiality Level :**		1,523,493	< - enter materiality level	
14	**(0.25% x Rate Base x CER)**	Y/N	N		
15	**(0.25% x Net Assets)**	Y/N	Y		
16	**Or other measure (please provide the basis of the amount)**	Y/N			
17	**Does the utility carry on non-wires related operation?**	Y/N	N		
18	**(Please complete the questionnaire in the Background questionnaire worksheet.)**				
19					
20	Note: Carry forward Wires-only Data to Tab "TAXCALC" Column K				
21					
22	**Section B: Financial statements data:**				
23	*Input unconsolidated financial statement data submitted with Tax returns.*				
24	*The actual categories of the income statements should be used.*				
25	*If required please change the descriptions except for amortization, interest expense and provision for income tax*				
26					
27	*Please enter the non-wire operation's amount as a positive number, the program automatically treats all amounts*				
28	*in the "non-wires elimination column" as negative values in TAXREC and TAXREC2.*				
29					
30	**Income:**				
31	Energy Sales	+			0
32	Distribution Revenue	+	2,389,886,000		2,389,886,000
33	Other Income	+	10,343,000		10,343,000
34	Miscellaneous income	+	1,280,000		1,280,000
35		+			0
36	Revenue should be entered above this line				
37					
38	**Costs and Expenses:**				
39	Cost of energy purchased	-	1,974,923,000		1,974,923,000
40	Administration	-			0
41	Customer billing and collecting	-			0
42	Operations and maintenance	-	166,296,000		166,296,000
43	Amortization	-	121,994,000		121,994,000
44	Ontario Capital Tax	-			0
45	Reg Assets	-			0
46	OEB Staff 84 a) revision	-	-1,776,718		-1,776,718
47		-			0
48		-			0
49					
50	**Net Income Before Interest & Income Taxes EBIT**	=	140,072,718	0	140,072,718
51	Less: Interest expense for accounting purposes	-	72,952,718		72,952,718
52	Provision for payments in lieu of income taxes	-	4,270,000		4,270,000
53	**Net Income (loss)**	=	62,850,000	0	62,850,000
54	(The Net Income (loss) on the MoF column should equal to the net income (loss) per financial statements on Schedule 1 of the tax return.)				
55					

	A	B	C	D	E
1	**PILs TAXES - EB-2012-0064**	**LINE**	**M of F**	Non-wires	**Wires-only**
2	**TAX RETURN RECONCILIATION (TAXREC)**		**Corporate**	Eliminations	**Tax**
3	(for "wires-only" business - see s. 72 OEB Act)		**Tax**		**Return**
4	**0**		**Return**		
5					**Version 2009.1**
56	**Section C: Reconciliation of accounting income to taxable income**				
57	***From T2 Schedule 1***				
58	**BOOK TO TAX ADDITIONS:**				
59	Provision for income tax	+	4,270,000	0	4,270,000
60	Federal large corporation tax	+			0
61	Depreciation & Amortization	+	121,994,000	0	121,994,000
62	Employee benefit plans-accrued, not paid	+		0	0
63	Tax reserves - beginning of year	+	0	0	0
64	Reserves from financial statements- end of year	+	119,132,936	0	119,132,936
65	Regulatory adjustments on which true-up may apply (see A66)	+			0
66	***Items on which true-up does not apply "TAXREC 3"***		16,464,375	0	16,464,375
67	Material addition items from TAXREC 2	+	1,529,753	0	1,529,753
68	Other addition items (not Material) from TAXREC 2	+	3,104,309	0	3,104,309
69					
70	*Subtotal*		266,495,373	0	266,495,373
71					
72	*Other Additions: (Please explain the nature of the additions)*				
73	Recapture of CCA	+			0
74	Non-deductible meals and entertainment expense	+			0
75	Capital items expensed	+			0
76	DEPRECIATION DIFFERENCE	+			0
77		+			0
78		+			0
79		+			0
80	*Total Other Additions*	=	0	0	0
81					
82	Total Additions	=	266,495,373	0	266,495,373
83					
84	Recap Material Additions:				
85			0	0	0
86			0	0	0
87			0	0	0
88			0	0	0
89			0	0	0
90			0	0	0
91			0	0	0
92	*Total Other additions >materiality level*		0	0	0
93	Other additions (less than materiality level)		0	0	0
94	Total Other Additions		0	0	0
95					

	A	B	C	D	E
1	**PILs TAXES - EB-2012-0064**	**LINE**	**M of F**	Non-wires	**Wires-only**
2	**TAX RETURN RECONCILIATION (TAXREC)**		**Corporate**	Eliminations	**Tax**
3	(for "wires-only" business - see s. 72 OEB Act)		**Tax**		**Return**
4	**0**		**Return**		
5					**Version 2009.1**
96	BOOK TO TAX DEDUCTIONS:				
97	Capital cost allowance	-	190,104,129		190,104,129
98	Cumulative eligible capital deduction	-	1,388,952		1,388,952
99	Employee benefit plans-paid amounts	-			0
100	Items capitalized for regulatory purposes	-			0
101	*Regulatory adjustments :*	-			0
102	*CCA*	-			0
103	*other deductions*	-			0
104	*Tax reserves - end of year*	-	0	0	0
105	*Reserves from financial statements- beginning of year*	-	114,054,159	0	114,054,159
106	*Contributions to deferred income plans*	-			0
107	*Contributions to pension plans*	-			0
108	***Items on which true-up does not apply "TAXREC 3"***		9,954,324	0	9,954,324
109	Interest capitalized for accounting deducted for tax	-			0
110	Material deduction items from TAXREC 2	-	0	0	0
111	Other deduction items (not Material) from TAXREC 2	-	1,334,612	0	1,334,612
112					
113	Subtotal	=	316,836,176	0	316,836,176
114	*Other deductions (Please explain the nature of the deductions)*				
115	**Charitable donations - tax basis**	-	24,769		24,769
116	*Gain on disposal of assets*	-			0
117		-			0
118					0
119		-			0
120	*Total Other Deductions*	=	24,769	0	24,769
121					
122	Total Deductions	=	316,860,945	0	316,860,945
123					
124	Recap Material Deductions:				
125			0	0	0
126			0	0	0
127			0	0	0
128			0	0	0
129			0	0	0
130	*Total Other Deductions exceed materiality level*		0	0	0
131	Other Deductions less than materiality level		24,769	0	24,769
132	Total Other Deductions		24,769	0	24,769
133					
134	TAXABLE INCOME	=	12,484,428	0	12,484,428
135	DEDUCT:				
136	Non-capital loss applied positive number	-	12,484,428		12,484,428
137	Net capital loss applied positive number	-			0
138					0
139	NET TAXABLE INCOME	=	0	0	0
140					
141	**FROM ACTUAL TAX RETURNS**				
142	Net Federal Income Tax (Must agree with tax return)	+			0
143	Net Ontario Income Tax (Must agree with tax return)	+			0
144	Subtotal	=	0	0	0
145	Less: Miscellaneous tax credits (Must agree with tax returns)	-	0		0
146	**Total Income Tax**	=	0	0	0
147					

	A	B	C	D	E
1	**PILs TAXES - EB-2012-0064**	**LINE**	**M of F**	Non-wires	**Wires-only**
2	**TAX RETURN RECONCILIATION (TAXREC)**		**Corporate**	Eliminations	**Tax**
3	(for "wires-only" business - see s. 72 OEB Act)		**Tax**		**Return**
4	**0**		**Return**		
5					**Version 2009.1**
148	**FROM ACTUAL TAX RETURNS**				
149	Net Federal Income Tax Rate (Must agree with tax return)		26.12%		26.12%
150	Net Ontario Income Tax Rate (Must agree with tax return)		12.50%		12.50%
151	Blended Income Tax Rate		38.62%	***************	38.62%
152					
153	**Section F: Income and Capital Taxes**				
154					
155	**RECAP**				
156	Total Income Taxes	+	0	0	0
157	Ontario Capital Tax	+	5,792,830		5,792,830
158	Federal Large Corporations Tax	+	4,355,755		4,355,755
159					
160	**Total income and capital taxes**	=	10,148,585	0	10,148,585

	A	B	C	D	E
1	**PILs TAXES - EB-2012-0064**	LINE	M of F	Non-wires	**Wires-only**
2	**Tax and Accounting Reserves**		Corporate	Eliminations	**Tax**
3	For MoF Column of TAXCALC		Tax		**Return**
4	(for "wires-only" business - see s. 72 OEB Act)		Return		
5	**0**				**Version 2009.1**
6					
7	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**				
8	**Reporting period: 2002**				
9					
10	**TAX RESERVES**				
11					
12	**Beginning of Year:**				
13					0
14	Reserve for doubtful accounts ss. 20(1)(l)				0
15	Reserve for goods & services ss.20(1)(m)				0
16	Reserve for unpaid amounts ss.20(1)(n)				0
17	Debt and share issue expenses ss.20(1)(e)				0
18	Other - Please describe				0
19	Other - Please describe				0
20					0
21					0
22	**Total (**carry forward to the TAXREC worksheet)		0	0	0
23					
24	**End of Year:**				
25					0
26	Reserve for doubtful accounts ss. 20(1)(l)				0
27	Reserve for goods & services ss.20(1)(m)				0
28	Reserve for unpaid amounts ss.20(1)(n)				0
29	Debt and share issue expenses ss.20(1)(e)				0
30	Other - Please describe				0
31	Other - Please describe				0
32					0
33					0
34	Insert line above this line				
35	**Total (**carry forward to the TAXREC worksheet)		0	0	0
36					
37					
38	**FINANCIAL STATEMENT RESERVES**				
39					
40	**Beginning of Year:**				
41					0
42					0
43	Environmental		1,800,596		1,800,596
44	Allowance for doubtful accounts				0
45	Inventory obsolescence		7,525,248		7,525,248
46	Property taxes				0
47	Other - Post employment benefits		103,550,000		103,550,000
48	Other - Holdback payable		1,178,315		1,178,315
49					0
50	**Total (**carry forward to the TAXREC worksheet)		114,054,159	0	114,054,159
51					
52	**End of Year:**				
53					0
54					0
55	Environmental		3,333,000		3,333,000
56	Allowance for doubtful accounts		9,000,000		9,000,000
57	Inventory obsolescence		2,935,988		2,935,988
58	Property taxes				0
59	Other - Post employment benefits		103,795,000		103,795,000
60	Other - Holdback payable		68,948		68,948
61					0
62	Insert line above this line				
63	**Total (**carry forward to the TAXREC worksheet)		119,132,936	0	119,132,936
64					

	A	B	C	D	E	F
1						
2	**PILs TAXES - EB-2012-0064**	LINE	M of F	Non-wires	**Wires-only**	
3	**TAX RETURN RECONCILIATION (TAXREC 2)**		Corporate	Eliminations	**Tax**	
4	(for "wires-only" business - see s. 72 OEB Act)		Tax		**Return**	
5	**RATEPAYERS ONLY**		Return			
6	**Shareholder-only Items should be shown on TAXREC 3**				**Version 2009.1**	
7						
8	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**					
9	**Reporting period: 2002**					
10	**Number of days in taxation year:**		365			
11	**Materiality Level:**		1,523,493			
12						
13						
14						
15	**Section C: Reconciliation of accounting income to taxable income**					
16	**Add:**					
17		+			0	
18	Gain on sale of eligible capital property	+			0	
19	Loss on disposal of assets	+	229,284		229,284	
20	Charitable donations (Only if it benefits ratepayers)	+	11,594		11,594	
21	Taxable capital gains	+			0	
22		+			0	
23	Scientific research expenditures deducted	+			0	
24	per financial statements	+	1,200,362		1,200,362	
25	Capitalized interest	+			0	
26	Soft costs on construction and renovation of buildings	+			0	
27	Capital items expensed	+			0	
28	Debt issue expense	+			0	
29	Financing fees deducted in books	+	534,688		534,688	
30	Gain on settlement of debt	+			0	
31	Interest paid on income debentures	+			0	
32	Recapture of SR&ED expenditures	+			0	
33	Share issue expense	+			0	
34	Write down of capital property	+			0	
35	Amounts received in respect of qualifying environment trust	+			0	
36	Provision for bad debts	+	1,038,000		1,038,000	
37		+			0	
38	*Other Additions: (please explain in detail the nature of the item)*	+			0	
39	Stationery/Advertising expense	+	90,381		90,381	
40		+			0	
41		+			0	
42		+			0	
43		+			0	
44	Nondeductible inventory obsolescence	+	1,529,753		1,529,753	
45		+			0	
46	Total Additions	=	4,634,062	0	4,634,062	
47						
48	Recap of Material Additions:					
49			0	0	0	
50			0	0	0	
51			0	0	0	
52			0	0	0	
53			0	0	0	
54			0	0	0	
55			0	0	0	
56			0	0	0	
57			0	0	0	
58			0	0	0	
59			0	0	0	
60			0	0	0	
61			0	0	0	
62			0	0	0	

	A	B	C	D	E	F
1						
2	**PILs TAXES - EB-2012-0064**	LINE	M of F	Non-wires	**Wires-only**	
3	**TAX RETURN RECONCILIATION (TAXREC 2)**		Corporate	Eliminations	**Tax**	
4	(for "wires-only" business - see s. 72 OEB Act)		Tax		**Return**	
5	**RATEPAYERS ONLY**		Return			
6	**Shareholder-only Items should be shown on TAXREC 3**				**Version 2009.1**	
7						
8	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**					
9	**Reporting period: 2002**					
10	**Number of days in taxation year:**		365			
11	**Materiality Level:**		1,523,493			
12						
13						
63			0	0	0	
64			0	0	0	
65			0	0	0	
66			0	0	0	
67			0	0	0	
68			0	0	0	
69			0	0	0	
70			0	0	0	
71			0	0	0	
72			0	0	0	
73			0	0	0	
74			0	0	0	
75	Nondeductible inventory obsolescence		1,529,753	0	1,529,753	
76			0	0	0	
77	Total Material additions		1,529,753	0	1,529,753	
78	Other additions less than materiality level		3,104,309	0	3,104,309	
79	Total Additions		4,634,062	0	4,634,062	

	A	B	C	D	E	F
1						
2	**PILs TAXES - EB-2012-0064**	LINE	M of F	Non-wires	**Wires-only**	
3	**TAX RETURN RECONCILIATION (TAXREC 2)**		Corporate	Eliminations	**Tax**	
4	(for "wires-only" business - see s. 72 OEB Act)		Tax		**Return**	
5	**RATEPAYERS ONLY**		Return			
6	**Shareholder-only Items should be shown on TAXREC 3**				**Version 2009.1**	
7						
8	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**					
9	**Reporting period: 2002**					
10	**Number of days in taxation year:**		365			
11	**Materiality Level:**		1,523,493			
12						
13						
80						
81	Deduct:					
82	Gain on disposal of assets per f/s	-			0	
83	Dividends not taxable under section 83	-			0	
84	Terminal loss from Schedule 8	-			0	
85	Depreciation in inventory, end of prior year	-			0	
86	Scientific research expenses claimed in year from Form T661	-	1,200,362		1,200,362	
87	Bad debts	-			0	
88	Book income of joint venture or partnership	-			0	
89	Equity in income from subsidiary or affiliates	-			0	
90	Contributions to a qualifying environment trust	-			0	
91	Other income from financial statements	-			0	
92	Financing fees deducted for tax	-	134,250		134,250	
93		-			0	
94		-			0	
95	*Other deductions: (Please explain in detail the nature of the item)*	-			0	
96		-			0	
97		-			0	
98		-			0	
99	Total Deductions	=	1,334,612	0	1,334,612	
100						
101	Recap of Material Deductions:					
102			0	0	0	
103			0	0	0	
104			0	0	0	
105			0	0	0	
106			0	0	0	
107			0	0	0	
108			0	0	0	
109			0	0	0	
110			0	0	0	
111			0	0	0	
112			0	0	0	
113			0	0	0	
114			0	0	0	
115			0	0	0	
116			0	0	0	
117			0	0	0	
118			0	0	0	
119	Total Deductions exceed materiality level		0	0	0	
120	Other deductions less than materiality level		1,334,612	0	1,334,612	
121	Total Deductions		1,334,612	0	1,334,612	
122						

	A	B	C	D	E	F
1						
2	**PILs TAXES - EB-2012-0064**					
3	**TAX RETURN RECONCILIATION (TAXREC 3)**					
4	**Shareholder-only Items should be shown on TAXREC 3**	LINE	M of F	Non-wires	**Wires-only**	
5	**ITEMS ON WHICH TRUE-UP DOES NOT APPLY**		Corporate	Eliminations	**Tax**	
6	(for "wires-only" business - see s. 72 OEB Act)		Tax		**Return**	
7	**0**		Return			
8	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**				**Version 2009.1**	
9						
10						
11	**Reporting period: 2002**					
12	**Number of days in taxation year:**		365			
13						
14						
15						
16	**Section C: Reconciliation of accounting income to taxable income**					
17	**Add:**					
18						
19	Recapture of capital cost allowance	+			0	
20	CCA adjustments	+			0	
21	CEC adjustments	+			0	
22	Gain on sale of non-utility eligible capital property	+			0	
23	Gain on sale of utility eligible capital property	+			0	
24	Loss from joint ventures or partnerships	+			0	
25	Deemed dividend income	+			0	
26	Loss in equity of subsidiaries and affiliates	+			0	
27	Loss on disposal of utility assets	+			0	
28	Loss on disposal of non-utility assets	+			0	
29	Depreciation in inventory -end of year	+			0	
30	Depreciation and amortization adjustments	+			0	
31	Dividends credited to investment account	+			0	
32	Non-deductible meals	+	52,480		52,480	
33	Non-deductible club dues	+	24,847		24,847	
34	Non-deductible automobile costs	+	371		371	
35	**Donations - amount per books**				0	
36	Interest and penalties on unpaid taxes				0	
37	Management bonuses unpaid after 180 days of year end				0	
38	Imputed interest expense on Regulatory Assets				0	
39	**Ontario capital tax adjustments**	+			0	
40	**Changes in Regulatory Asset balances**	+			0	
41	*Other Additions: (please explain in detail the nature of the item)*	+			0	
42	pre October 2001 bad debt expense	+	1,842,375		1,842,375	
43	net fibre rental expense for prior year	+	1,527,898		1,527,898	
44		+			0	
45		+			0	
46	Meter error re Ellesmere-net income adjustment	+	13,016,404		13,016,404	
47	**Total Additions on which true-up does not apply**	=	16,464,375	0	16,464,375	
48						
49	**Deduct:**					
50						
51	CCA adjustments	-			0	
52	CEC adjustments	-			0	
53	Depreciation and amortization adjustments	-			0	
54	Gain on disposal of assets per financial statements	-			0	
55	Financing fee amortization - considered to be interest expense for PILs	-			0	
56	Imputed interest income on Regulatory Assets	-	2,511,963		2,511,963	
57	**Donations - amount deductible for tax purposes**	-			0	
58	Income from joint ventures or partnerships	-			0	
59		-			0	
60		-			0	
61		-			0	
62		-			0	
63		-			0	
64	**Ontario capital tax adjustments to current or prior year**	-			0	
65		-			0	
66	**Changes in Regulatory Asset balances**	-	5,015,433		5,015,433	
67		-			0	
68	*Other deductions: (Please explain in detail the nature of the item)*	-			0	
69		-			0	
70		-			0	
71	Decrease in income due to meter error	-	2,426,928		2,426,928	
72		-			0	
73	**Total Deductions on which true-up does not apply**	=	9,954,324	0	9,954,324	
74						

	A	B	C	D	E	F	G
1	**PILs TAXES - EB-2012-0064**						
2	**Corporate Tax Rates**					**Version 2009.1**	
3	**Exemptions, Deductions, or Thresholds**						
4	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**						
5	**Reporting period: 2002**						
6							
7						**Table 1**	
8	**Rates Used in 2002 RAM PILs Applications for 2002**						
9	**Income Range**		**0**		**200,001**		
10	**RAM 2002**		**to**		**to**	**>700,000**	
11		**Year**	**200,000**		**700,000**		
12	**Income Tax Rate**						
13	***Proxy Tax Year***	***2002***					
14	***Federal (Includes surtax)***					26.12%	
15	***and Ontario blended***					12.50%	
16	***Blended rate***					38.62%	
17							
18	**Capital Tax Rate**		0.300%				
19	**LCT rate**		0.225%				
20	**Surtax**		1.12%				
21	**Ontario Capital Tax Exemption ****	**MAX $5MM**	5,000,000				
22	**Federal Large Corporations Tax Exemption ****	**MAX $10MM**	10,000,000				
23	****Exemption amounts must agree with the Board-approved 2002 RAM PILs filing**						
24							
25						**Table 2**	
26	**Expected Income Tax Rates for 2002 and Capital Tax Exemptions for 2002**						
27	**Income Range**		**0**		**200,001**		
28	**Expected Rates**		**to**		**to**	**>700,000**	
29		**Year**	**200,000**		**700,000**		
30	**Income Tax Rate**						
31	***Current year***	***2002***					
32	***Federal (Includes surtax)***					26.12%	
33	***Ontario***					12.50%	
34	***Blended rate***					38.62%	
35							
36	**Capital Tax Rate**		0.300%				
37	**LCT rate**		0.225%				
38	**Surtax**		1.12%				
39	**Ontario Capital Tax Exemption *** 2002**	**MAX $5MM**	5,000,000				
40	**Federal Large Corporations Tax Exemption *** 2002**	**MAX $10MM**	10,000,000				
41	*****Allocation of exemptions must comply with the Board's instructions**						
42	**regarding regulated activities.**						
43						**Table 3**	
44	**Input Information from Utility's Actual 2002 Tax Returns**						
45	**Income Range**		**0**		**200,001**		
46			**to**		**to**	**>700,000**	
47		**Year**	**200,000**		**700,000**		
48	**Income Tax Rate**						
49	***Current year***	***2002***					
50	***Federal (Includes surtax)***					26.12%	
51	***Ontario***					12.50%	
52	***Blended rate***					38.62%	
53							
54	**Capital Tax Rate**		0.300%				
55	**LCT rate**		0.225%				
56	**Surtax**		1.12%				
57	**Ontario Capital Tax Exemption ***	**MAX $5MM**	4,586,218				
58	**Federal Large Corporations Tax Exemption ***	**MAX $10MM**	10,000,000				
59	*** Include copies of the actual tax return allocation calculations in your**						
60	**submission: Ontario CT23 page 11; federal T2 Schedule 36**						
61							

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**PILs TAXES - EB-2012-0064**														
2	**Analysis of PILs Tax Account 1562:**														
3	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**														**Version 2009.1**
4	**Reporting period: 2002**				**Sign Convention: + for increase; - for decrease**										**0**
5															
6															
7															
8	**Year start:**		01/10/2001		01/01/2002		01/01/2003		01/01/2004		01/01/2005		01/01/2006		
9	**Year end:**		31/12/2001		31/12/2002		31/12/2003		31/12/2004		31/12/2005		30/04/2006		Total
10															
11	**Opening balance:**	=	0		5,028,333				0		0		0		0
12	**Board-approved PILs tax proxy from Decisions (1)**	+/-	5,000,000		55,000,000								0		60,000,000
13	**PILs proxy from April 1, 2005 - input 9/12 of amount**														0
14	**True-up Variance Adjustment Q4, 2001 (2)**	+/-			-290,810										-290,810
15	**True-up Variance Adjustment (3)**	+/-					2,156,868						0		2,156,868
16	**Deferral Account Variance Adjustment Q4, 2001 (4)**														0
17	**Deferral Account Variance Adjustment (5)**	+/-											0		0
18	**Adjustments to reported prior years' variances (6)**	+/-													0
19	**Carrying charges (7)**	+/-	28,333		720,305										748,638
20	**PILs billed to (collected from) customers (8)**	-	0		-52,330,253										-52,330,253
21															
22	**Ending balance: # 1562**		5,028,333		8,127,575				0		0		0		10,284,443

23
24
25
26 **Uncollected PILs**
27
28 **NOTE:** The purpose of this worksheet is to show the movement in Account 1562 which establishes the receivable from or liability to ratepayers.
29 For explanation of Account 1562 please refer to Accounting Procedures Handbook for Electric Distribution Utilities and FAQ April 2003.
30
31 **Please identify if Method 1, 2 or 3 was used to account for the PILs proxy and recovery. ANSWER: METHOD 3**
32
33 (1) (i) From the Board's Decision - see Inclusion in Rates, Part III of the TAXCALC spreadsheet for Q4 2001 and 2002.
34 Please insert the Q4, 2001 proxy in column C even though it was approved effective March 1, 2002.
35 If the Board gave more than one decision in the year, calculate a weighted average proxy.
36 (ii) If the Board approved different amounts, input the Board-approved amounts in cells C13 and E13.
37 (iii) Column G - In 2003, the initial estimate should include the Q4 2001 PILs tax proxy and the 2002 PILs tax proxy.
38 (iv) Column I - The Q4 2001 PILs tax proxy was removed from rates on April 1, 2004 and the 2002 PILs tax proxy remained.
39 (v) Column K - The 2002 PILs tax proxy applies to January 1 to March 31, 2005, and the new 2005 PILs tax proxy from April 1 to December 31, 2005.
40 (vi) Column M - The 2005 PILs tax proxy will used for the period from January 1 to April 30, 2006.
41
42 (2) From the Ministry of Finance Variance Column, under Future True-ups, Part IV a, cell I132, of the TAXCALC spreadsheet. The Q4, 2001 proxy has to be
43 trued up in 2002, 2003 and for the period January 1- March 31, 2004. Input the variance in the whole year reconcilation.
44
45 (3) From the Ministry of Finance Variance Column, under Future True-ups, Part IV a, cell I132, of the TAXCALC spreadsheet.
46 The true-up will compare to the 2002 proxy for 2002, 2003, 2004 and January 1 to March 31, 2005.
47
48 (4) From the Ministry of Finance Variance Column, under Future True-ups, Part IV b, cell I181, of the TAXCALC spreadsheet. The Q4, 2001 proxy has to be
49 trued up in 2002, 2003 and for the period January 1- March 31, 2004. Input the deferral variance in the whole year reconciliation.
50
51 (5) From the Ministry of Finance Variance Column, under Future True-ups, Part IV a, cell I181, of the TAXCALC spreadsheet.
52 The true-up will compare to the 2002 proxy for 2002, 2003, 2004 and January 1 to March 31, 2005.
53
54 (6) The correcting entry should be shown in the year the entry was made. The true-up of the carrying charges will have to be reviewed.
55
56 (7) Carrying charges are calculated on a simple interest basis.
57
58 (8) (i) PILs collected from customers from March 1, 2002 to March 31, 2004 were based on a fixed charge and a volumetric charge recovery by class. The PILs rate
59 components for Q4, 2001and 2002 were calculated in the 2002 approved RAM on sheet 6 and sheet 8. In April 2004, the PILs recovery was based on the
60 2002 PILs tax proxy recovered by the volumetric rate by class as calculated on sheet 7 of the 2004 RAM.
61 The 2005 PILs tax proxy is being recovered on a volumetric basis by class.
62
63 (ii) Collections should equal: (a) the actual volumes/ load (kWhs, kWs, Kva) for the period (including net unbilled at period end), multiplied
64 by the PILs volumetric proxy rates by class (from the Q4, 2001and 2002 RAM worksheets) for 2002, 2003 and January 1 to March 31, 2004;
65 plus, (b) customer counts by class in the same period multiplied by the PILs fixed charge rate components.
67 In 2004, use the Board-approved 2002 PILs proxy, recovered on a volumetric basis by class as calculated by the 2004 RAM, sheet 7,
68 for the period April 1 to December 31, 2004, and add this total to the results from the sentence above for January 1 to March 31, 2004.
70 In 2005, use the Board-approved 2005 PILs proxy, recovered on a volumetric basis by class as calculated by the 2005 RAM, sheet 4,
71 for the period April 1 to December 31, 2005. To this total, the 2004 volumetric PILs proxy rate by class should be used
72 to calculate the recovery for the period January 1 to March 31, 2005.
73
74 (9) Any interim PILs recovery from Board Decisions will be recorded in APH Account # 1590. Final reconciliation of PILs proxy taxes
75 will have to include amounts from 1562 and from 1590.

	A	B	C	D	E
1	**PILs TAXES - EB-2012-0064**				**Version 2009.1**
2	**REGULATORY INFORMATION (REGINFO)**				
3	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**			Colour Code	
4	**Reporting period: 2003**			**Input Cell**	
5				**Formula in Cell**	
6	**Days in reporting period:**	365	days		
7	**Total days in the calendar year:**	365	days		
8					
9	**BACKGROUND**				
10	Has the utility reviewed section 149(1) ITA to				
11	confirm that it is not subject to regular corporate				
12	tax (and therefore subject to PILs)?		Y/N	Y	
13					
14	Was the utility recently acquired by Hydro One				
15	and now subject to s.89 & 90 PILs?		Y/N	N	
16					
17	Is the utility a non-profit corporation?		Y/N	N	
18	(If it is a non-profit corporation, please contact the Rates Manager at the OEB)				
19	Are the Ontario Capital Tax & Large Corporations Tax Exemptions	OCT	Y/N	Y	
20	shared among the corporate group?	LCT	Y/N	N	
21	Please identify the % used to allocate the OCT and LCT exemptions in	OCT		100%	
22	Cells C65 & C74 in the TAXCALC spreadsheet.	LCT		100%	
23					
24	Accounting Year End		Date	12-31-2003	
25					
26	**MARR NO TAX CALCULATIONS**				**Regulatory**
27	**SHEET #7 FINAL RUD MODEL DATA**				**Income**
28	**(FROM 1999 FINANCIAL STATEMENTS)**				
29	**USE BOARD-APPROVED AMOUNTS**				
30					
31	Rate Base (wires-only)			1,810,112,688	
32					
33	Common Equity Ratio (CER)			35.00%	
34					
35	1-CER			65.00%	
36					
37	Target Return On Equity			9.88%	
38					
39	Debt rate			6.80%	
40					
41	Market Adjusted Revenue Requirement			142,600,678	
42					
43	1999 return from RUD Sheet #7			23,304,000	23,304,000
44					
45	Total Incremental revenue			119,296,678	
46	**Input: Board-approved dollar amounts phased-in**				
47	Amount allowed in 2001			39,765,559	39,765,559
48	Amount allowed in 2002			39,765,559	39,765,559
49	Amount allowed in 2003 and 2004 (will be zero due to Bill 210				0
50	unless authorized by the Minister and the Board)				0
51	Amount allowed in 2005 - Third tranche of MARR re: CDM			39765559	39,765,559
52	Other Board-approved changes to MARR or incremental revenue				0
53					0
54	**Total Regulatory Income**				142,600,677
55					
56	Equity			633,539,441	
57					
58	Return at target ROE			62,593,697	
59					
60	Debt			1,176,573,247	
61					
62	Deemed interest amount in 100% of MARR			80,006,981	
63					
64	Phase-in of interest - Year 1 (2001)			35,385,561	
65	((D43+D47)/D41)*D61				
66	Phase-in of interest - Year 2 (2002)			57,696,271	
67	((D43+D47+D48)/D41)*D61				
68	Phase-in of interest - Year 3 (2003) and forward			57,696,271	
69	((D43+D47+D48)/D41)*D61 (due to Bill 210)				
70	Phase-in of interest - 2005			80,006,981	
71					

	A	B	C	D	E	F	G	H
1	**PILs TAXES - EB-2012-0064**	**ITEM**	**Initial**		M of F	M of F	**Tax**	
2	**PILs DEFERRAL AND VARIANCE ACCOUNTS**		**Estimate**		Filing	Filing	**Returns**	
3	**TAX CALCULATIONS (TAXCALC)**				Variance	Variance		
4	("Wires-only" business - see Tab TAXREC)				K-C	Explanation		
5	**0**						**Version 2009.1**	
6	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**							
7	**Reporting period: 2003**							
8							**Column**	
9	**Days in reporting period:**	365	days				**Brought**	
10	**Total days in the calendar year:**	365	days				**From**	
11							**TAXREC**	
12			$		$		$	
13								
14	**I) CORPORATE INCOME TAXES**							
15								
16	Regulatory Net Income REGINFO E53	1	102,835,118		82,999,233		185,834,351	
17								
18	BOOK TO TAX ADJUSTMENTS							
19	***Additions:***							
20	Depreciation & Amortization	2	106,229,000		11,453,140		117,682,140	
21	Employee Benefit Plans - Accrued, Not Paid	3	33,129,140		-33,129,140		0	
22	Tax reserves - beginning of year	4			0		0	
23	Reserves from financial statements - end of year	4			108,977,216		108,977,216	
24	Regulatory Adjustments - increase in income	5			0		0	
25	Other Additions (See Tab entitled "TAXREC")							
26	"Material" Items from "TAXREC" worksheet	6			0		0	
27	Other Additions (not "Material") "TAXREC"	6			0		0	
28	"Material Items from "TAXREC 2" worksheet	6			4,132,505		4,132,505	
29	Other Additions (not "Material") "TAXREC 2"	6			2,385,415		2,385,415	
30	**Items on which true-up does not apply "TAXREC 3"**				12,122,319		12,122,319	
31								
32	***Deductions: Input positive numbers***							
33	Capital Cost Allowance and CEC	7	76,692,530		80,170,009		156,862,539	
34	Employee Benefit Plans - Paid Amounts	8	30,011,140		-30,011,140		0	
35	Items Capitalized for Regulatory Purposes	9	0		0		0	
36	Regulatory Adjustments - deduction for tax purposes in Item 5	10			0		0	
37	Interest Expense Deemed/ Incurred	11	57,696,271		20,689,080		78,385,351	
38	Tax reserves - end of year	4			0		0	
39	Reserves from financial statements - beginning of year	4			119,132,936		119,132,936	
40	Contributions to deferred income plans	3			0		0	
41	Contributions to pension plans	3			0		0	
42	Interest capitalized for accounting but deducted for tax	11			0		0	
43	Other Deductions (See Tab entitled "TAXREC")							
44	"Material" Items from "TAXREC" worksheet	12			0		0	
45	Other Deductions (not "Material") "TAXREC"	12			0		0	
46	Material Items from "TAXREC 2" worksheet	12			0		0	
47	Other Deductions (not "Material") "TAXREC 2"	12			3,628,453		3,628,453	
48	**Items on which true-up does not apply "TAXREC 3"**				2,233,343		2,233,343	
49								
50	TAXABLE INCOME/ (LOSS)		77,793,317		-6,901,993	Before loss C/F	70,891,324	
51								
52	BLENDED INCOME TAX RATE							
53	Tab Tax Rates - Regulatory from Table 1; Actual from Table 3	13	38.62%		-2.0000%		36.62%	
54								
55	REGULATORY INCOME TAX		30,043,779		-19,346,149	Actual	10,697,630	
56								
57								
58	Miscellaneous Tax Credits	14			538,238	Actual	538,238	
59								
60	**Total Regulatory Income Tax**		30,043,779		-19,884,387	Actual	10,159,392	
61								
62								
63	**II) CAPITAL TAXES**							
64								
65	***Ontario***							
66	Base	15	1,810,112,688		258,496,941		2,068,609,629	
67	Less: Exemption -Tax Rates - Regulatory, Table 1; Actual, Table 3	16	5,000,000		-271,438		4,728,562	
68	Taxable Capital		1,805,112,688		258,225,503		2,063,881,067	
69								
70	Rate - Tax Rates - Regulatory, Table 1; Actual, Table 3	17	0.3000%		0.0000%		0.3000%	
71								
72	Ontario Capital Tax		5,415,338		776,305		6,191,643	
73								
74	***Federal Large Corporations Tax***							
75	Base	18	1,810,112,688		272,448,650		2,082,561,338	
76	Less: Exemption -Tax Rates - Regulatory, Table 1; Actual, Table 3	19	10,000,000		0		10,000,000	
77	Taxable Capital		1,800,112,688		272,448,650		2,072,561,338	
78								
79	Rate - Tax Rates - Regulatory, Table 1; Actual, Table 3	20	0.2250%		0.0000%		0.2250%	
80								
81	Gross Amount of LCT before surtax offset (Taxable Capital x Rate)		4,050,254		613,009		4,663,263	
82	Less: Federal Surtax 1.12% x Taxable Income	21	871,285		-544,105		327,180	
83								
84	Net LCT		3,178,968		1,157,115		4,336,083	
85								

	A	B	C	D	E	F	G	H
1	**PILs TAXES - EB-2012-0064**	**ITEM**	**Initial**		M of F	M of F	**Tax**	
2	**PILs DEFERRAL AND VARIANCE ACCOUNTS**		**Estimate**		Filing	Filing	**Returns**	
3	**TAX CALCULATIONS (TAXCALC)**				Variance	Variance		
4	("Wires-only" business - see Tab TAXREC)				K-C	Explanation		
5	**0**						**Version 2009.1**	
6	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**							
7	**Reporting period: 2003**							
8							**Column**	
9	**Days in reporting period:**	365	days				**Brought**	
10	**Total days in the calendar year:**	365	days				**From**	
11							**TAXREC**	
12			$		$		$	
13								
86	**III) INCLUSION IN RATES**							
87								
88	Income Tax Rate used for gross- up (exclude surtax)		37.50%					
89								
90	Income Tax (proxy tax is grossed-up)	22	48,070,047			**Actual 2003**	10,159,392	
91	LCT (proxy tax is grossed-up)	23	5,086,349			**Actual 2003**	4,336,083	
92	Ontario Capital Tax (no gross-up since it is deductible)	24	5,415,338			**Actual 2003**	6,191,643	
93								
94								
95	***Total PILs for Rate Adjustment -- MUST AGREE WITH 2002***	25	58,571,734			**Actual 2003**	20,687,118	
96	**RAM DECISION**							
97								
98								
99	***IV) FUTURE TRUE-UPS***							
100	**IV a) Calculation of the True-up Variance**				**DR/(CR)**			
101	***In Additions:***							
102	Employee Benefit Plans - Accrued, Not Paid	3			-33,129,140			
103	Tax reserves deducted in prior year	4			0			
104	Reserves from financial statements-end of year	4			108,977,216			
105	Regulatory Adjustments	5			0			
106	Other additions "Material" Items TAXREC	6			0			
107	Other additions "Material" Items TAXREC 2	6			4,132,505			
108	***In Deductions - positive numbers***							
109	Employee Benefit Plans - Paid Amounts	8			-30,011,140			
110	Items Capitalized for Regulatory Purposes	9			0			
111	Regulatory Adjustments	10			0			
112	Interest Adjustment for tax purposes **(See Below - cell I204)**	11			0			
113	Tax reserves claimed in current year	4			0			
114	Reserves from F/S beginning of year	4			119,132,936			
115	Contributions to deferred income plans	3			0			
116	Contributions to pension plans	3			0			
117	Other deductions "Material" Items TAXREC	12			0			
118	Other deductions "Material" Item TAXREC 2	12			0			
119								
120	Total TRUE-UPS before tax effect	26		=	-9,141,215			
121								
122	Income Tax Rate (excluding surtax) from **2003** Utility's tax return			x	36.62%			
123								
124	Income Tax Effect on True-up adjustments			=	-3,347,513			
125								
126	Less: Miscellaneous Tax Credits	14			538,238			
127								
128	Total Income Tax on True-ups				-3,885,751			
129								
130	Income Tax Rate used for gross-up (exclude surtax)				35.50%			
131								
132	**TRUE-UP VARIANCE ADJUSTMENT**				-6,024,420			
133								
134	**IV b) Calculation of the Deferral Account Variance caused by changes in legislation**							
135								
136	REGULATORY TAXABLE INCOME /(LOSSES) (as reported in the initial estimate column)			=	77,793,317			
137								
138	REVISED CORPORATE INCOME TAX RATE			x	36.62%			
139								
140	REVISED REGULATORY INCOME TAX			=	28,487,913			
141								
142	Less: Revised Miscellaneous Tax Credits			-				
143								
144	Total Revised Regulatory Income Tax			=	28,487,913			
145								
146	Less: Regulatory Income Tax reported in the Initial Estimate Column (Cell C58)			-	30,043,779			
147								
148	Regulatory Income Tax Variance			=	-1,555,866			
149								

	A	B	C	D	E	F	G	H
1	**PILs TAXES - EB-2012-0064**	**ITEM**	**Initial**		M of F	M of F	**Tax**	
2	**PILs DEFERRAL AND VARIANCE ACCOUNTS**		**Estimate**		Filing	Filing	**Returns**	
3	**TAX CALCULATIONS (TAXCALC)**				Variance	Variance		
4	("Wires-only" business - see Tab TAXREC)				K-C	Explanation		
5	**0**						**Version 2009.1**	
6	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**							
7	**Reporting period: 2003**							
8							**Column**	
9	**Days in reporting period:**	365	days				**Brought**	
10	**Total days in the calendar year:**	365	days				**From**	
11							**TAXREC**	
12			$		$		$	
13								
150	**Ontario Capital Tax**							
151	Base			=	1,810,112,688			
152	Less: Exemption from tab Tax Rates, Table 2, cell C39			-	5,000,000			
153	Revised deemed taxable capital			=	1,805,112,688			
154								
155	Rate - Tab Tax Rates cell C54			x	0.3000%			
156								
157	Revised Ontario Capital Tax			=	5,415,338			
158	Less: Ontario Capital Tax reported in the initial estimate column (Cell C70)			-	5,415,338			
159	Regulatory Ontario Capital Tax Variance			=	0			
160								
161	**Federal LCT**							
162	Base				1,810,112,688			
163	Less: Exemption from tab Tax Rates, Table 2, cell C40			-	10,000,000			
164	Revised Federal LCT			=	1,800,112,688			
165								
166	Rate (as a result of legislative changes) tab 'Tax Rates' cell C51				0.2250%			
167								
168	Gross Amount				4,050,254			
169	Less: Federal surtax			-	871,285			
170	Revised Net LCT			=	3,178,968			
171								
172	Less: Federal LCT reported in the initial estimate column (Cell C82)			-	3,178,968			
173	Regulatory Federal LCT Variance			=	0			
174								
175	Actual Income Tax Rate used for gross-up (exclude surtax)				35.50%			
176								
177	**Income Tax (grossed-up)**			+	(2,412,196)			
178	**LCT (grossed-up)**			+	0			
179	**Ontario Capital Tax**			+	0			
180								
181	**DEFERRAL ACCOUNT VARIANCE ADJUSTMENT**			=	(2,412,196)			
182								
183	**TRUE-UP VARIANCE (from cell I130)**			+	(6,024,420)			
184								
185	**Total Deferral Account Entry (Positive Entry = Debit)**			=	(8,436,616)			
186	*(Deferral Account Variance + True-up Variance)*							
187								
188								
189								
190	**V) INTEREST PORTION OF TRUE-UP**							
191	**Variance Caused By Phase-in of Deemed Debt**							
192								
193	Total deemed interest (REGINFO)				80,006,981			
194	Interest phased-in (Cell C36)				57,696,271			
195								
196	Variance due to phase-in of debt component of MARR in rates				22,310,710			
197	according to the Board's decision							
198								
199	**Other Interest Variances (i.e. Borrowing Levels**							
200	**Above Deemed Debt per Rate Handbook)**							
201	Interest deducted on MoF filing (Cell K36+K41)				78,385,351			
202	Total deemed interest (REGINFO CELL D61)				80,006,981			
203								
204	Variance caused by excess debt				0			
205								
206	**Interest Adjustment for Tax Purposes (carry forward to Cell I110)**				0			
207								
208	**Total Interest Variance**				22,310,710			
209								
210								
211								

	A	B	C	D	E
1	**PILs TAXES - EB-2012-0064**	**LINE**	**M of F**	Non-wires	**Wires-only**
2	**TAX RETURN RECONCILIATION (TAXREC)**		**Corporate**	Eliminations	**Tax**
3	(for "wires-only" business - see s. 72 OEB Act)		**Tax**		**Return**
4	**0**		**Return**		
5					**Version 2009.1**
6	**Section A: Identification:**				
7	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**				
8	**Reporting period: 2003**				
9	**Taxation Year's start date:**		01/01/2003		
10	**Taxation Year's end date:**		31/12/2003		
11	**Number of days in taxation year:**		365	days	
12					
13	**Please enter the Materiality Level :**		1,736,868	< - enter materiality level	
14	**(0.25% x Rate Base x CER)**	Y/N	N		
15	**(0.25% x Net Assets)**	Y/N	Y		
16	**Or other measure (please provide the basis of the amount)**	Y/N	N		
17	**Does the utility carry on non-wires related operation?**	Y/N	N		
18	**(Please complete the questionnaire in the Background questionnaire worksheet.)**				
19					
20	Note: Carry forward Wires-only Data to Tab "TAXCALC" Column K				
21					
22	**Section B: Financial statements data:**				
23	*Input unconsolidated financial statement data submitted with Tax returns.*				
24	*The actual categories of the income statements should be used.*				
25	*If required please change the descriptions except for amortization, interest expense and provision for income tax*				
26					
27	*Please enter the non-wire operation's amount as a positive number, the program automatically treats all amounts*				
28	*in the "non-wires elimination column" as negative values in TAXREC and TAXREC2.*				
29					
30	**Income:**				
31	Energy Sales	+			0
32	Distribution Revenue	+	2,389,949,000		2,389,949,000
33	Other Income	+	22,034,000		22,034,000
34	Miscellaneous income	+	11,364,000		11,364,000
35		+			0
36	Revenue should be entered above this line				
37					
38	**Costs and Expenses:**				
39	Cost of energy purchased	-	1,957,184,000		1,957,184,000
40	Administration	-			0
41	Customer billing and collecting	-			0
42	Operations and maintenance	-	160,995,000		160,995,000
43	Amortization	-	117,579,000		117,579,000
44	Ontario Capital Tax	-			0
45	Reg Assets	-			0
46	Financing expenses	-	3,521,495		3,521,495
47	OEB Staff 84 a) revision	-	-1,766,846		-1,766,846
48		-			0
49					
50	**Net Income Before Interest & Income Taxes EBIT**	=	185,834,351	0	185,834,351
51	Less: Interest expense for accounting purposes	-	78,385,351		78,385,351
52	Provision for payments in lieu of income taxes	-	34,490,000		34,490,000
53	**Net Income (loss)**	=	72,959,000	0	72,959,000
54	(The Net Income (loss) on the MoF column should equal to the net income (loss) per financial statements on Schedule 1 of the tax return.)				
55					

	A	B	C	D	E
1	**PILs TAXES - EB-2012-0064**	**LINE**	**M of F**	Non-wires	**Wires-only**
2	**TAX RETURN RECONCILIATION (TAXREC)**		**Corporate**	Eliminations	**Tax**
3	(for "wires-only" business - see s. 72 OEB Act)		**Tax**		**Return**
4	**0**		**Return**		
5					**Version 2009.1**
56	**Section C: Reconciliation of accounting income to taxable income**				
57	***From T2 Schedule 1***				
58	**BOOK TO TAX ADDITIONS:**				
59	Provision for income tax	+	34,490,000	0	34,490,000
60	Federal large corporation tax	+			0
61	Depreciation & Amortization	+	117,682,140	0	117,682,140
62	Employee benefit plans-accrued, not paid	+		0	0
63	Tax reserves - beginning of year	+	0	0	0
64	Reserves from financial statements- end of year	+	108,977,216	0	108,977,216
65	Regulatory adjustments on which true-up may apply (see A66)	+			0
66	***Items on which true-up does not apply "TAXREC 3"***		12,122,319	0	12,122,319
67	Material addition items from TAXREC 2	+	4,132,505	0	4,132,505
68	Other addition items (not Material) from TAXREC 2	+	2,385,415	0	2,385,415
69					
70	*Subtotal*		279,789,595	0	279,789,595
71					
72	*Other Additions: (Please explain the nature of the additions)*				
73	Recapture of CCA	+			0
74	Non-deductible meals and entertainment expense	+			0
75	Capital items expensed	+			0
76	DEPRECIATION DIFFERENCE	+			0
77		+			0
78		+			0
79		+			0
80	*Total Other Additions*	=	0	0	0
81					
82	Total Additions	=	279,789,595	0	279,789,595
83					
84	Recap Material Additions:				
85			0	0	0
86			0	0	0
87			0	0	0
88			0	0	0
89			0	0	0
90			0	0	0
91			0	0	0
92	*Total Other additions >materiality level*		0	0	0
93	Other additions (less than materiality level)		0	0	0
94	Total Other Additions		0	0	0
95					

	A	B	C	D	E
1	**PILs TAXES - EB-2012-0064**	**LINE**	**M of F**	Non-wires	**Wires-only**
2	**TAX RETURN RECONCILIATION (TAXREC)**		**Corporate**	Eliminations	**Tax**
3	(for "wires-only" business - see s. 72 OEB Act)		**Tax**		**Return**
4	**0**		**Return**		
5					**Version 2009.1**
96	BOOK TO TAX DEDUCTIONS:				
97	Capital cost allowance	-	155,566,254		155,566,254
98	Cumulative eligible capital deduction	-	1,296,285		1,296,285
99	Employee benefit plans-paid amounts	-			0
100	Items capitalized for regulatory purposes	-			0
101	*Regulatory adjustments :*	-			0
102	*CCA*	-			0
103	*other deductions*	-			0
104	*Tax reserves - end of year*	-	0	0	0
105	*Reserves from financial statements- beginning of year*	-	119,132,936	0	119,132,936
106	*Contributions to deferred income plans*	-			0
107	*Contributions to pension plans*	-			0
108	***Items on which true-up does not apply "TAXREC 3"***		2,233,343	0	2,233,343
109	Interest capitalized for accounting deducted for tax	-			0
110	Material deduction items from TAXREC 2	-	0	0	0
111	Other deduction items (not Material) from TAXREC 2	-	3,628,453	0	3,628,453
112					
113	Subtotal	=	281,857,271	0	281,857,271
114	*Other deductions (Please explain the nature of the deductions)*				
115	**Charitable donations - tax basis**	-			0
116	*Gain on disposal of assets*	-			0
117		-			0
118					0
119		-			0
120	*Total Other Deductions*	=	0	0	0
121					
122	Total Deductions	=	281,857,271	0	281,857,271
123					
124	Recap Material Deductions:				
125			0	0	0
126			0	0	0
127			0	0	0
128			0	0	0
129			0	0	0
130	*Total Other Deductions exceed materiality level*		0	0	0
131	Other Deductions less than materiality level		0	0	0
132	Total Other Deductions		0	0	0
133					
134	TAXABLE INCOME	=	70,891,324	0	70,891,324
135	DEDUCT:				
136	Non-capital loss applied positive number	-	41,678,475		41,678,475
137	Net capital loss applied positive number	-			0
138					0
139	NET TAXABLE INCOME	=	29,212,849	0	29,212,849
140					
141	**FROM ACTUAL TAX RETURNS**				
142	Net Federal Income Tax (Must agree with tax return)	+	7,046,063		7,046,063
143	Net Ontario Income Tax (Must agree with tax return)	+	3,651,567		3,651,567
144	Subtotal	=	10,697,630	0	10,697,630
145	Less: Miscellaneous tax credits (Must agree with tax returns)	-	538,238		538,238
146	**Total Income Tax**	=	10,159,392	0	10,159,392
147					

	A	B	C	D	E
1	**PILs TAXES - EB-2012-0064**	**LINE**	**M of F**	Non-wires	**Wires-only**
2	**TAX RETURN RECONCILIATION (TAXREC)**		**Corporate**	Eliminations	**Tax**
3	(for "wires-only" business - see s. 72 OEB Act)		**Tax**		**Return**
4	**0**		**Return**		
5					**Version 2009.1**
148	**FROM ACTUAL TAX RETURNS**				
149	Net Federal Income Tax Rate (Must agree with tax return)		24.12%		24.12%
150	Net Ontario Income Tax Rate (Must agree with tax return)		12.50%		12.50%
151	Blended Income Tax Rate		36.62%	***************	36.62%
152					
153	**Section F: Income and Capital Taxes**				
154					
155	**RECAP**				
156	Total Income Taxes	+	10,159,392	0	10,159,392
157	Ontario Capital Tax	+	6,191,643		6,191,643
158	Federal Large Corporations Tax	+	4,336,083		4,336,083
159					
160	**Total income and capital taxes**	=	20,687,118	0	20,687,118

	A	B	C	D	E	F
1	**PILs TAXES - EB-2012-0064**	LINE	M of F	Non-wires	**Wires-only**	
2	**Tax and Accounting Reserves**		Corporate	Eliminations	**Tax**	
3	For MoF Column of TAXCALC		Tax		**Return**	
4	(for "wires-only" business - see s. 72 OEB Act)		Return			
5	**0**				**Version 2009.1**	
6						
7	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**					
8	**Reporting period: 2003**					
9						
10	**TAX RESERVES**					
11						
12	**Beginning of Year:**					
13					0	
14	Reserve for doubtful accounts ss. 20(1)(l)				0	
15	Reserve for goods & services ss.20(1)(m)				0	
16	Reserve for unpaid amounts ss.20(1)(n)				0	
17	Debt and share issue expenses ss.20(1)(e)				0	
18	Other - Please describe				0	
19	Other - Please describe				0	
20					0	
21					0	
22	**Total (**carry forward to the TAXREC worksheet)		0	0	0	
23						
24	**End of Year:**					
25					0	
26	Reserve for doubtful accounts ss. 20(1)(l)				0	
27	Reserve for goods & services ss.20(1)(m)				0	
28	Reserve for unpaid amounts ss.20(1)(n)				0	
29	Debt and share issue expenses ss.20(1)(e)				0	
30	Other - Please describe				0	
31	Other - Please describe				0	
32					0	
33					0	
34	Insert line above this line					
35	**Total (**carry forward to the TAXREC worksheet)		0	0	0	
36						
37						
38	**FINANCIAL STATEMENT RESERVES**					
39						
40	**Beginning of Year:**					
41					0	
42					0	
43	Environmental		3,333,000		3,333,000	
44	Allowance for doubtful accounts		9,000,000		9,000,000	
45	Inventory obsolescence		2,935,988		2,935,988	
46	Property taxes				0	
47	Other - Post employment benefits		103,795,000		103,795,000	
48	Other - Holdback payable		68,948		68,948	
49					0	
50	**Total (**carry forward to the TAXREC worksheet)		119,132,936	0	119,132,936	
51						

	A	B	C	D	E	F
52	**End of Year:**					
53					0	
54					0	
55	Environmental				0	
56	Allowance for doubtful accounts		585,360		585,360	
57	Inventory obsolescence		2,668,190		2,668,190	
58	Property taxes		2,000,000		2,000,000	
59	Other - Post employment benefits		103,677,000		103,677,000	
60	Other - Holdback payable		0		0	
61	Other		46,666		46,666	
62	Insert line above this line					
63	**Total (**carry forward to the TAXREC worksheet)		108,977,216	0	108,977,216	
64						

	A	B	C	D	E	F
1						
2	**PILs TAXES - EB-2012-0064**	LINE	M of F	Non-wires	**Wires-only**	
3	**TAX RETURN RECONCILIATION (TAXREC 2)**		Corporate	Eliminations	**Tax**	
4	(for "wires-only" business - see s. 72 OEB Act)		Tax		**Return**	
5	**RATEPAYERS ONLY**		Return			
6	**Shareholder-only Items should be shown on TAXREC 3**				**Version 2009.1**	
7						
8	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**					
9	**Reporting period: 2003**					
10	**Number of days in taxation year:**		365			
11	**Materiality Level:**		1,736,868			
12						
13						
14						
15	**Section C: Reconciliation of accounting income to taxable income**					
16	**Add:**					
17		+			0	
18	Gain on sale of eligible capital property	+			0	
19	Loss on disposal of assets	+			0	
20	Charitable donations (Only if it benefits ratepayers)	+	316		316	
21	Taxable capital gains	+			0	
22		+			0	
23	Scientific research expenditures deducted	+			0	
24	per financial statements	+	655,621		655,621	
25	Capitalized interest	+			0	
26	Soft costs on construction and renovation of buildings	+			0	
27	Capital items expensed	+			0	
28	Debt issue expense	+			0	
29	Financing fees deducted in books	+	1,536,876		1,536,876	
30	Gain on settlement of debt	+			0	
31	Interest paid on income debentures	+			0	
32	Recapture of SR&ED expenditures	+			0	
33	Share issue expense	+			0	
34	Write down of capital property	+			0	
35	Amounts received in respect of qualifying environment trust	+			0	
36	Provision for bad debts	+			0	
37		+			0	
38		+			0	
39		+			0	
40	*Other Additions: (please explain in detail the nature of the item)*	+			0	
41		+			0	
42	Asset retirement obligation- accretion expense	+	192,602		192,602	
43	Reversal of environmental provision- reserve adjustment	+	4,132,505		4,132,505	
44		+			0	
45		+			0	
46	Total Additions	=	6,517,920	0	6,517,920	
47						
48	Recap of Material Additions:					
49			0	0	0	
50			0	0	0	
51			0	0	0	
52			0	0	0	
53			0	0	0	
54			0	0	0	
55			0	0	0	
56			0	0	0	
57			0	0	0	
58			0	0	0	
59			0	0	0	
60			0	0	0	
61			0	0	0	
62			0	0	0	

	A	B	C	D	E	F
1						
2	**PILs TAXES - EB-2012-0064**	LINE	M of F	Non-wires	**Wires-only**	
3	**TAX RETURN RECONCILIATION (TAXREC 2)**		Corporate	Eliminations	**Tax**	
4	(for "wires-only" business - see s. 72 OEB Act)		Tax		**Return**	
5	**RATEPAYERS ONLY**		Return			
6	**Shareholder-only Items should be shown on TAXREC 3**				**Version 2009.1**	
7						
8	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**					
9	**Reporting period: 2003**					
10	**Number of days in taxation year:**		365			
11	**Materiality Level:**		1,736,868			
12						
13						
63			0	0	0	
64			0	0	0	
65			0	0	0	
66			0	0	0	
67			0	0	0	
68			0	0	0	
69			0	0	0	
70			0	0	0	
71			0	0	0	
72			0	0	0	
73			0	0	0	
74	Reversal of environmental provision- reserve adjustment		4,132,505	0	4,132,505	
75			0	0	0	
76			0	0	0	
77	Total Material additions		4,132,505	0	4,132,505	
78	Other additions less than materiality level		2,385,415	0	2,385,415	
79	Total Additions		6,517,920	0	6,517,920	

	A	B	C	D	E	F
1						
2	**PILs TAXES - EB-2012-0064**	LINE	M of F	Non-wires	**Wires-only**	
3	**TAX RETURN RECONCILIATION (TAXREC 2)**		Corporate	Eliminations	**Tax**	
4	(for "wires-only" business - see s. 72 OEB Act)		Tax		**Return**	
5	**RATEPAYERS ONLY**		Return			
6	**Shareholder-only Items should be shown on TAXREC 3**				**Version 2009.1**	
7						
8	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**					
9	**Reporting period: 2003**					
10	**Number of days in taxation year:**		365			
11	**Materiality Level:**		1,736,868			
12						
13						
80						
81	Deduct:					
82	Gain on disposal of assets per f/s	-	396,506		396,506	
83	Dividends not taxable under section 83	-			0	
84	Terminal loss from Schedule 8	-			0	
85	Depreciation in inventory, end of prior year	-			0	
86	Scientific research expenses claimed in year from Form T661	-	655,621		655,621	
87	Bad debts	-	1,038,000		1,038,000	
88	Book income of joint venture or partnership	-			0	
89	Equity in income from subsidiary or affiliates	-			0	
90	Contributions to a qualifying environment trust	-			0	
91	Other income from financial statements	-			0	
92		-				
93		-			0	
94		-			0	
95	*Other deductions: (Please explain in detail the nature of the item)*	-			0	
96	Asset retirement obligation- cash payment deducted for tax	-	511,000		511,000	
97	Debt financing fees- deducted for tax	-	1,027,326		1,027,326	
98		-			0	
99	Total Deductions	=	3,628,453	0	3,628,453	
100						
101	Recap of Material Deductions:					
102			0	0	0	
103			0	0	0	
104			0	0	0	
105			0	0	0	
106			0	0	0	
107			0	0	0	
108			0	0	0	
109			0	0	0	
110			0	0	0	
111			0	0	0	
112			0	0	0	
113			0	0	0	
114			0	0	0	
115			0	0	0	
116			0	0	0	
117			0	0	0	
118			0	0	0	
119	Total Deductions exceed materiality level		0	0	0	
120	Other deductions less than materiality level		3,628,453	0	3,628,453	
121	Total Deductions		3,628,453	0	3,628,453	
122						

	A	B	C	D	E	F
1						
2	**PILs TAXES - EB-2012-0064**					
3	**TAX RETURN RECONCILIATION (TAXREC 3)**					
4	**Shareholder-only Items should be shown on TAXREC 3**	LINE	M of F	Non-wires	**Wires-only**	
5	**ITEMS ON WHICH TRUE-UP DOES NOT APPLY**		Corporate	Eliminations	**Tax**	
6	(for "wires-only" business - see s. 72 OEB Act)		Tax		**Return**	
7	**0**		Return			
8	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**				**Version 2009.1**	
9						
10						
11	**Reporting period: 2003**					
12	**Number of days in taxation year:**		365			
13						
14						
15						
16	**Section C: Reconciliation of accounting income to taxable income**					
17	**Add:**					
18						
19	Recapture of capital cost allowance	+			0	
20	CCA adjustments	+			0	
21	CEC adjustments	+			0	
22	Gain on sale of non-utility eligible capital property	+			0	
23	Gain on sale of utility eligible capital property	+			0	
24	Loss from joint ventures or partnerships	+			0	
25	Deemed dividend income	+			0	
26	Loss in equity of subsidiaries and affiliates	+			0	
27	Loss on disposal of utility assets	+			0	
28	Loss on disposal of non-utility assets	+			0	
29	Depreciation in inventory -end of year	+			0	
30	Depreciation and amortization adjustments	+			0	
31	Dividends credited to investment account	+			0	
32	Non-deductible meals	+	58,651		58,651	
33	Non-deductible club dues	+	49,334		49,334	
34	Non-deductible automobile costs	+			0	
35	**Donations - amount per books**				316	
36	Interest and penalties on unpaid taxes				0	
37	Management bonuses unpaid after 180 days of year end				0	
38	Imputed interest expense on Regulatory Assets				0	
39	**Ontario capital tax adjustments**	+			0	
40	**Changes in Regulatory Asset balances**	+			0	
41	*Other Additions: (please explain in detail the nature of the item)*	+			0	
42	Increase in net income due to restatement	+	10,061,000		10,061,000	
43	Nondeductible penalties	+	1,953,334		1,953,334	
44		+			0	
45		+			0	
46		+				
47	**Total Additions on which true-up does not apply**	=	12,122,319	0	12,122,635	
48						
49	**Deduct:**					
50						
51	CCA adjustments	-			0	
52	CEC adjustments	-			0	
53	Depreciation and amortization adjustments	-			0	
54	Gain on disposal of assets per financial statements	-			0	
55	Financing fee amorization - considered to be interest expense for PILs	-			0	
56	Imputed interest income on Regulatory Assets	-	2,233,343		2,233,343	
57	**Donations - amount deductible for tax purposes**	-			0	
58	Income from joint ventures or partnerships	-			0	
59		-			0	
60		-			0	
61		-			0	

	A	B	C	D	E	F
4	**Shareholder-only Items should be shown on TAXREC 3**	LINE	M of F	Non-wires	**Wires-only**	
5	**ITEMS ON WHICH TRUE-UP DOES NOT APPLY**		Corporate	Eliminations	**Tax**	
6	(for "wires-only" business - see s. 72 OEB Act)		Tax		**Return**	
7	**0**		Return			
8	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**				**Version 2009.1**	
62		-			0	
63		-			0	
64	**Ontario capital tax adjustments to current or prior year**	-			0	
65		-			0	
66	**Changes in Regulatory Asset balances**	-			0	
67		-			0	
68	*Other deductions: (Please explain in detail the nature of the item)*	-			0	
69		-			0	
70		-			0	
71		-			0	
72		-			0	
73	**Total Deductions on which true-up does not apply**	=	2,233,343	0	2,233,343	
74						

	A	B	C	D	E	F	G
1	**PILs TAXES - EB-2012-0064**						
2	**Corporate Tax Rates**					**Version 2009.1**	
3	**Exemptions, Deductions, or Thresholds**						
4	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**						
5	**Reporting period: 2003**						
6							
7						**Table 1**	
8	**Rates Used in 2002 RAM PILs Applications for 2002**						
9	**Income Range**		**0**		**200,001**		
10	**RAM 2002**		**to**		**to**	**>700,000**	
11		**Year**	**200,000**		**700,000**		
12	**Income Tax Rate**						
13	***Proxy Tax Year***	***2002***					
14	***Federal (Includes surtax)***					26.12%	
15	***and Ontario blended***					12.50%	
16	***Blended rate***					38.62%	
17							
18	**Capital Tax Rate**		0.300%				
19	**LCT rate**		0.225%				
20	**Surtax**		1.12%				
21	**Ontario Capital Tax Exemption ****	**MAX $5MM**	5,000,000				
22	**Federal Large Corporations Tax Exemption ****	**MAX $10MM**	10,000,000				
23	****Exemption amounts must agree with the Board-approved 2002 RAM PILs filing**						
24							
25						**Table 2**	
26	**Expected Income Tax Rates for 2003 and Capital Tax Exemptions for 2003**						
27	**Income Range**		**0**		**200,001**		
28	**Expected Rates**		**to**		**to**	**>700,000**	
29		**Year**	**200,000**		**700,000**		
30	**Income Tax Rate**						
31	***Current year***	***2003***					
32	***Federal (Includes surtax)***					24.12%	
33	***Ontario***					12.50%	
34	***Blended rate***					36.62%	
35							
36	**Capital Tax Rate**		0.300%				
37	**LCT rate**		0.225%				
38	**Surtax**		1.12%				
39	**Ontario Capital Tax Exemption *** 2002**	**MAX $5MM**	5,000,000				
40	**Federal Large Corporations Tax Exemption *** 2002**	**MAX $10MM**	10,000,000				
41	*****Allocation of exemptions must comply with the Board's instructions**						
42	**regarding regulated activities.**						

	A	B	C	D	E	F	G
43						**Table 3**	
44	**Input Information from Utility's Actual 2003 Tax Returns**						
45	**Income Range**		**0**		**200,001**		
46			**to**		**to**	**>700,000**	
47		**Year**	**200,000**		**700,000**		
48	**Income Tax Rate**						
49	***Current year***	***2003***					
50	***Federal (Includes surtax)***					24.12%	
51	***Ontario***					12.50%	
52	***Blended rate***					36.62%	
53							
54	**Capital Tax Rate**		0.300%				
55	**LCT rate**		0.225%				
56	**Surtax**		1.12%				
57	**Ontario Capital Tax Exemption** *	**MAX $5MM**	4,728,562				
58	**Federal Large Corporations Tax Exemption** *	**MAX $10MM**	10,000,000				
59	*** Include copies of the actual tax return allocation calculations in your**						
60	**submission: Ontario CT23 page 11; federal T2 Schedule 36**						
61							

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**PILs TAXES - EB-2012-0064**														
2	**Analysis of PILs Tax Account 1562:**														
3	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**														**Version 2009.1**
4	**Reporting period: 2003**				**Sign Convention: + for increase; - for decrease**										**0**
5															
6															
7															
8	**Year start:**		01/10/2001		01/01/2002		01/01/2003		01/01/2004		01/01/2005		01/01/2006		
9	**Year end:**		31/12/2001		31/12/2002		31/12/2003		31/12/2004		31/12/2005		30/04/2006		Total
10															
11	**Opening balance:**	=	0		5,028,333		8,127,575		8,284,720		2,260,300		2,260,300		0
12	**Board-approved PILs tax proxy from Decisions (1)**	+/-	5,000,000		55,000,000		60,000,000						0		120,000,000
13	**PILs proxy from April 1, 2005 - input 9/12 of amount**														0
14	**True-up Variance Adjustment Q4, 2001 (2)**	+/-			-290,810										-290,810
15	**True-up Variance Adjustment (3)**	+/-					2,156,868		-6,024,420						-3,867,552
16	**Deferral Account Variance Adjustment Q4, 2001 (4)**														0
17	**Deferral Account Variance Adjustment (5)**	+/-					-2,412,196								-2,412,196
18	**Adjustments to reported prior years' variances (6)**	+/-													0
19	**Carrying charges (7)**	+/-	28,333		720,305		562,257								1,310,895
20	**PILs billed to (collected from) customers (8)**	-	0		-52,330,253		-60,149,784								-112,480,037
21															
22	**Ending balance: # 1562**		5,028,333		8,127,575		8,284,720		2,260,300		2,260,300		2,260,300		2,260,300

Uncollected PILs

NOTE: The purpose of this worksheet is to show the movement in Account 1562 which establishes the receivable from or liability to ratepayers.
For explanation of Account 1562 please refer to Accounting Procedures Handbook for Electric Distribution Utilities and FAQ April 2003.

Please identify if Method 1, 2 or 3 was used to account for the PILs proxy and recovery. ANSWER: METHOD 3

(1) (i) From the Board's Decision - see Inclusion in Rates, Part III of the TAXCALC spreadsheet for Q4 2001 and 2002.
Please insert the Q4, 2001 proxy in column C even though it was approved effective March 1, 2002.
If the Board gave more than one decision in the year, calculate a weighted average proxy.
(ii) If the Board approved different amounts, input the Board-approved amounts in cells C13 and E13.
(iii) Column G - In 2003, the initial estimate should include the Q4 2001 PILs tax proxy and the 2002 PILs tax proxy.
(iv) Column I - The Q4 2001 PILs tax proxy was removed from rates on April 1, 2004 and the 2002 PILs tax proxy remained.
(v) Column K - The 2002 PILs tax proxy applies to January 1 to March 31, 2005, and the new 2005 PILs tax proxy from April 1 to December 31, 2005.
(vi) Column M - The 2005 PILs tax proxy will used for the period from January 1 to April 30, 2006.

(2) From the Ministry of Finance Variance Column, under Future True-ups, Part IV a, cell I132, of the TAXCALC spreadsheet. The Q4, 2001 proxy has to be trued up in 2002, 2003 and for the period January 1- March 31, 2004. Input the variance in the whole year reconcilation.

(3) From the Ministry of Finance Variance Column, under Future True-ups, Part IV a, cell I132, of the TAXCALC spreadsheet.
The true-up will compare to the 2002 proxy for 2002, 2003, 2004 and January 1 to March 31, 2005.

(4) From the Ministry of Finance Variance Column, under Future True-ups, Part IV b, cell I181, of the TAXCALC spreadsheet. The Q4, 2001 proxy has to be trued up in 2002, 2003 and for the period January 1- March 31, 2004. Input the deferral variance in the whole year reconciliation.

(5) From the Ministry of Finance Variance Column, under Future True-ups, Part IV a, cell I181, of the TAXCALC spreadsheet.
The true-up will compare to the 2002 proxy for 2002, 2003, 2004 and January 1 to March 31, 2005.

(6) The correcting entry should be shown in the year the entry was made. The true-up of the carrying charges will have to be reviewed.

(7) Carrying charges are calculated on a simple interest basis.

(8) (i) PILs collected from customers from March 1, 2002 to March 31, 2004 were based on a fixed charge and a volumetric charge recovery by class. The PILs rate components for Q4, 2001and 2002 were calculated in the 2002 approved RAM on sheet 6 and sheet 8. In April 2004, the PILs recovery was based on the 2002 PILs tax proxy recovered by the volumetric rate by class as calculated on sheet 7 of the 2004 RAM.
The 2005 PILs tax proxy is being recovered on a volumetric basis by class.

(ii) Collections should equal: (a) the actual volumes/ load (kWhs, kWs, Kva) for the period (including net unbilled at period end), multiplied by the PILs volumetric proxy rates by class (from the Q4, 2001and 2002 RAM worksheets) for 2002, 2003 and January 1 to March 31, 2004; plus, (b) customer counts by class in the same period multiplied by the PILs fixed charge rate components.

In 2004, use the Board-approved 2002 PILs proxy, recovered on a volumetric basis by class as calculated by the 2004 RAM, sheet 7, for the period April 1 to December 31, 2004, and add this total to the results from the sentence above for January 1 to March 31, 2004.

In 2005, use the Board-approved 2005 PILs proxy, recovered on a volumetric basis by class as calculated by the 2005 RAM, sheet 4, for the period April 1 to December 31, 2005. To this total, the 2004 volumetric PILs proxy rate by class should be used to calculate the recovery for the period January 1 to March 31, 2005.

(9) Any interim PILs recovery from Board Decisions will be recorded in APH Account # 1590. Final reconciliation of PILs proxy taxes will have to include amounts from 1562 and from 1590.

	A	B	C	D	E
1	**PILs TAXES - EB-2012-0064**				**Version 2009.1**
2	**REGULATORY INFORMATION (REGINFO)**				
3	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**			Colour Code	
4	**Reporting period: 2004**			**Input Cell**	
5				**Formula in Cell**	
6	**Days in reporting period:**	365	days		
7	**Total days in the calendar year:**	365	days		
8					
9	**BACKGROUND**				
10	Has the utility reviewed section 149(1) ITA to				
11	confirm that it is not subject to regular corporate				
12	tax (and therefore subject to PILs)?		Y/N	Y	
13					
14	Was the utility recently acquired by Hydro One				
15	and now subject to s.89 & 90 PILs?		Y/N	N	
16					
17	Is the utility a non-profit corporation?		Y/N	N	
18	(If it is a non-profit corporation, please contact the Rates Manager at the OEB)				
19	Are the Ontario Capital Tax & Large Corporations Tax Exemptions	OCT	Y/N	N	
20	shared among the corporate group?	LCT	Y/N	N	
21	Please identify the % used to allocate the OCT and LCT exemptions in	OCT		100%	
22	Cells C65 & C74 in the TAXCALC spreadsheet.	LCT		100%	
23					
24	Accounting Year End		Date	12-31-2004	
25					
26	**MARR NO TAX CALCULATIONS**				**Regulatory**
27	**SHEET #7 FINAL RUD MODEL DATA**				**Income**
28	**(FROM 1999 FINANCIAL STATEMENTS)**				
29	**USE BOARD-APPROVED AMOUNTS**				
30					
31	Rate Base (wires-only)			1,810,112,688	
32					
33	Common Equity Ratio (CER)			35.00%	
34					
35	1-CER			65.00%	
36					
37	Target Return On Equity			9.88%	
38					
39	Debt rate			6.80%	
40					
41	Market Adjusted Revenue Requirement			142,600,678	
42					
43	1999 return from RUD Sheet #7			23,304,000	23,304,000
44					
45	Total Incremental revenue			119,296,678	
46	**Input: Board-approved dollar amounts phased-in**				
47	Amount allowed in 2001			39,765,559	39,765,559
48	Amount allowed in 2002			39,765,559	39,765,559
49	Amount allowed in 2003 and 2004 (will be zero due to Bill 210				0
50	unless authorized by the Minister and the Board)				0
51	Amount allowed in 2005 - Third tranche of MARR re: CDM			39,765,559	39,765,559
52	Other Board-approved changes to MARR or incremental revenue				0
53					0
54	**Total Regulatory Income**				142,600,677
55					
56	Equity			633,539,441	
57					
58	Return at target ROE			62,593,697	
59					
60	Debt			1,176,573,247	
61					
62	Deemed interest amount in 100% of MARR			80,006,981	
63					
64	Phase-in of interest - Year 1 (2001)			35,385,561	
65	((D43+D47)/D41)*D61				
66	Phase-in of interest - Year 2 (2002)			57,696,271	
67	((D43+D47+D48)/D41)*D61				
68	Phase-in of interest - Year 3 (2003) and forward			57,696,271	
69	((D43+D47+D48)/D41)*D61 (due to Bill 210)				
70	Phase-in of interest - 2005			80,006,981	
71					

	A	B	C	D	E	F	G	H
1	**PILs TAXES - EB-2012-0064**	**ITEM**	**Initial**		M of F	M of F	**Tax**	
2	**PILs DEFERRAL AND VARIANCE ACCOUNTS**		**Estimate**		Filing	Filing	**Returns**	
3	**TAX CALCULATIONS (TAXCALC)**				Variance	Variance		
4	("Wires-only" business - see Tab TAXREC)				K-C	Explanation		
5	**0**						**Version 2009.1**	
6	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**							
7	**Reporting period: 2004**							
8							**Column**	
9	**Days in reporting period:**	365	days				**Brought**	
10	**Total days in the calendar year:**	365	days				**From**	
11							**TAXREC**	
12			$		$		$	
13								
14	**I) CORPORATE INCOME TAXES**							
15								
16	Regulatory Net Income REGINFO E53	1	102,835,118		81,300,761		184,135,879	
17								
18	BOOK TO TAX ADJUSTMENTS							
19	***Additions:***							
20	Depreciation & Amortization	2	106,229,000		16,297,000		122,526,000	
21	Employee Benefit Plans - Accrued, Not Paid	3	33,129,140		-33,129,140		0	
22	Tax reserves - beginning of year	4			0		0	
23	Reserves from financial statements - end of year	4			109,978,621		109,978,621	
24	Regulatory Adjustments - increase in income	5			0		0	
25	Other Additions (See Tab entitled "TAXREC")							
26	"Material" Items from "TAXREC" worksheet	6			0		0	
27	Other Additions (not "Material") "TAXREC"	6			0		0	
28	"Material Items from "TAXREC 2" worksheet	6			0		0	
29	Other Additions (not "Material") "TAXREC 2"	6			1,993,341		1,993,341	
30	**Items on which true-up does not apply "TAXREC 3"**				161,244		161,244	
31								
32	***Deductions:*** ***Input positive numbers***							
33	Capital Cost Allowance and CEC	7	76,692,530		42,485,312		119,177,842	
34	Employee Benefit Plans - Paid Amounts	8	30,011,140		-30,011,140		0	
35	Items Capitalized for Regulatory Purposes	9	0		0		0	
36	Regulatory Adjustments - deduction for tax purposes in Item 5	10			0		0	
37	Interest Expense Deemed/ Incurred	11	57,696,271		22,479,608		80,175,879	
38	Tax reserves - end of year	4			0		0	
39	Reserves from financial statements - beginning of year	4			108,977,216		108,977,216	
40	Contributions to deferred income plans	3			0		0	
41	Contributions to pension plans	3			0		0	
42	Interest capitalized for accounting but deducted for tax	11			0		0	
43	Other Deductions (See Tab entitled "TAXREC")							
44	"Material" Items from "TAXREC" worksheet	12			0		0	
45	Other Deductions (not "Material") "TAXREC"	12			0		0	
46	Material Items from "TAXREC 2" worksheet	12			0		0	
47	Other Deductions (not "Material") "TAXREC 2"	12			3,298,862		3,298,862	
48	**Items on which true-up does not apply "TAXREC 3"**				2,233,343		2,233,343	
49								
50	TAXABLE INCOME/ (LOSS)		77,793,317		27,138,626	Before loss C/F	104,931,943	
51								
52	BLENDED INCOME TAX RATE							
53	Tab Tax Rates - Regulatory from Table 1; Actual from Table 3	13	38.62%		-2.5000%		36.12%	
54								
55	REGULATORY INCOME TAX		30,043,779		6,564,681	Actual	36,608,460	
56								
57								
58	Miscellaneous Tax Credits	14			269,188	Actual	269,188	
59								
60	**Total Regulatory Income Tax**		30,043,779		6,295,493	Actual	36,339,272	
61								
62								
63	**II) CAPITAL TAXES**							
64								
65	***Ontario***							
66	Base	15	1,810,112,688		259,954,523		2,070,067,211	
67	Less: Exemption -Tax Rates - Regulatory, Table 1; Actual, Table 3	16	5,000,000		0		5,000,000	
68	Taxable Capital		1,805,112,688		259,954,523		2,065,067,211	
69								
70	Rate - Tax Rates - Regulatory, Table 1; Actual, Table 3	17	0.3000%		0.0000%		0.3000%	
71								
72	Ontario Capital Tax		5,415,338		779,864		6,195,202	
73								
74	***Federal Large Corporations Tax***							
75	Base	18	1,810,112,688		228,148,967		2,038,261,655	
76	Less: Exemption -Tax Rates - Regulatory, Table 1; Actual, Table 3	19	10,000,000		40,000,000		50,000,000	
77	Taxable Capital		1,800,112,688		268,148,967		1,988,261,655	
78								
79	Rate - Tax Rates - Regulatory, Table 1; Actual, Table 3	20	0.2250%		-0.0250%		0.2000%	
80								
81	Gross Amount of LCT before surtax offset (Taxable Capital x Rate)		4,050,254		-73,730		3,976,523	
82	Less: Federal Surtax 1.12% x Taxable Income	21	871,285		302,312		1,173,597	
83								
84	Net LCT		3,178,968		-376,042		2,802,926	
85								

	A	B	C	D	E	F	G	H
1	**PILs TAXES - EB-2012-0064**	**ITEM**	**Initial**		M of F	M of F	**Tax**	
2	**PILs DEFERRAL AND VARIANCE ACCOUNTS**		**Estimate**		Filing	Filing	**Returns**	
3	**TAX CALCULATIONS (TAXCALC)**				Variance	Variance		
4	("Wires-only" business - see Tab TAXREC)				K-C	Explanation		
5	**0**						**Version 2009.1**	
6	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**							
7	**Reporting period: 2004**							
8							**Column**	
9	**Days in reporting period:**	365	days				**Brought**	
10	**Total days in the calendar year:**	365	days				**From**	
11							**TAXREC**	
12			$		$		$	
13								
86	**III) INCLUSION IN RATES**							
87								
88	Income Tax Rate used for gross- up (exclude surtax)		37.50%					
89								
90	Income Tax (proxy tax is grossed-up)	22	48,070,047			**Actual 2004**	36,339,272	
91	LCT (proxy tax is grossed-up)	23	5,086,349			**Actual 2004**	2,802,927	
92	Ontario Capital Tax (no gross-up since it is deductible)	24	5,415,338			**Actual 2004**	6,195,202	
93								
94								
95	***Total PILs for Rate Adjustment -- MUST AGREE WITH 2002***	25	58,571,734			**Actual 2004**	45,337,401	
96	**RAM DECISION**							
97								
98								
99	***IV) FUTURE TRUE-UPS***							
100	**IV a) Calculation of the True-up Variance**				**DR/(CR)**			
101	***In Additions:***							
102	Employee Benefit Plans - Accrued, Not Paid	3			-33,129,140			
103	Tax reserves deducted in prior year	4			0			
104	Reserves from financial statements-end of year	4			109,978,621			
105	Regulatory Adjustments	5			0			
106	Other additions "Material" Items TAXREC	6			0			
107	Other additions "Material" Items TAXREC 2	6			0			
108	***In Deductions - positive numbers***							
109	Employee Benefit Plans - Paid Amounts	8			-30,011,140			
110	Items Capitalized for Regulatory Purposes	9			0			
111	Regulatory Adjustments	10			0			
112	Interest Adjustment for tax purposes **(See Below - cell I204)**	11			168,898			
113	Tax reserves claimed in current year	4			0			
114	Reserves from F/S beginning of year	4			108,977,216			
115	Contributions to deferred income plans	3			0			
116	Contributions to pension plans	3			0			
117	Other deductions "Material" Items TAXREC	12			0			
118	Other deductions "Material" Item TAXREC 2	12			0			
119								
120	Total TRUE-UPS before tax effect	26		=	-2,285,493			
121								
122	Income Tax Rate (excluding surtax) from 2004 Utility's tax return			x	36.12%			
123								
124	Income Tax Effect on True-up adjustments			=	-825,520			
125								
126	Less: Miscellaneous Tax Credits	14			269,188			
127								
128	Total Income Tax on True-ups				-1,094,708			
129								
130	Income Tax Rate used for gross-up (exclude surtax)				35.00%			
131								
132	**TRUE-UP VARIANCE ADJUSTMENT**				-1,684,166			
133								
134	**IV b) Calculation of the Deferral Account Variance caused by changes in legislation**							
135								
136	REGULATORY TAXABLE INCOME /(LOSSES) (as reported in the initial estimate column)			=	77,793,317			
137								
138	REVISED CORPORATE INCOME TAX RATE			x	36.12%			
139								
140	REVISED REGULATORY INCOME TAX			=	28,098,946			
141								
142	Less: Revised Miscellaneous Tax Credits			-				
143								
144	Total Revised Regulatory Income Tax			=	28,098,946			
145								
146	Less: Regulatory Income Tax reported in the Initial Estimate Column (Cell C58)			-	30,043,779			
147								
148	Regulatory Income Tax Variance			=	-1,944,833			
149								

	A	B	C	D	E	F	G	H
1	**PILs TAXES - EB-2012-0064**	**ITEM**	**Initial**		M of F	M of F	**Tax**	
2	**PILs DEFERRAL AND VARIANCE ACCOUNTS**		**Estimate**		Filing	Filing	**Returns**	
3	**TAX CALCULATIONS (TAXCALC)**				Variance	Variance		
4	("Wires-only" business - see Tab TAXREC)				K-C	Explanation		
5	**0**						**Version 2009.1**	
6	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**							
7	**Reporting period: 2004**							
8							**Column**	
9	**Days in reporting period:**	365	days				**Brought**	
10	**Total days in the calendar year:**	365	days				**From**	
11							**TAXREC**	
12			$		$		$	
13								
150	**Ontario Capital Tax**							
151	Base			=	1,810,112,688			
152	Less: Exemption from tab Tax Rates, Table 2, cell C39			-	5,000,000			
153	Revised deemed taxable capital			=	1,805,112,688			
154								
155	Rate - Tab Tax Rates cell C54			x	0.3000%			
156								
157	Revised Ontario Capital Tax			=	5,415,338			
158	Less: Ontario Capital Tax reported in the initial estimate column (Cell C70)			-	5,415,338			
159	Regulatory Ontario Capital Tax Variance			=	0			
160								
161	**Federal LCT**							
162	Base				1,810,112,688			
163	Less: Exemption from tab Tax Rates, Table 2, cell C40			-	50,000,000			
164	Revised Federal LCT			=	1,760,112,688			
165								
166	Rate (as a result of legislative changes) tab 'Tax Rates' cell C51				0.2000%			
167								
168	Gross Amount				3,520,225			
169	Less: Federal surtax			-	871,285			
170	Revised Net LCT			=	2,648,940			
171								
172	Less: Federal LCT reported in the initial estimate column (Cell C82)			-	3,178,968			
173	Regulatory Federal LCT Variance			=	-530,028			
174								
175	Actual Income Tax Rate used for gross-up (exclude surtax)				35.00%			
176								
177	**Income Tax (grossed-up)**			+	(2,992,051)			
178	**LCT (grossed-up)**			+	(815,428)			
179	**Ontario Capital Tax**			+	0			
180								
181	**DEFERRAL ACCOUNT VARIANCE ADJUSTMENT**			=	(3,807,479)			
182								
183	**TRUE-UP VARIANCE (from cell I130)**			+	(1,684,166)			
184								
185	**Total Deferral Account Entry (Positive Entry = Debit)**			=	(5,491,645)			
186	*(Deferral Account Variance + True-up Variance)*							
187								
188								
189								
190	**V) INTEREST PORTION OF TRUE-UP**							
191	**Variance Caused By Phase-in of Deemed Debt**							
192								
193	Total deemed interest (REGINFO)				80,006,981			
194	Interest phased-in (Cell C36)				57,696,271			
195								
196	Variance due to phase-in of debt component of MARR in rates				22,310,710			
197	according to the Board's decision							
198								
199	**Other Interest Variances (i.e. Borrowing Levels**							
200	**Above Deemed Debt per Rate Handbook)**							
201	Interest deducted on MoF filing (Cell K36+K41)				80,175,879			
202	Total deemed interest (REGINFO CELL D61)				80,006,981			
203								
204	Variance caused by excess debt				168,898			
205								
206	**Interest Adjustment for Tax Purposes (carry forward to Cell I110)**				168,898			
207								
208	**Total Interest Variance**				22,141,812			
209								

	A	B	C	D	E
1	**PILs TAXES - EB-2012-0064**	**LINE**	**M of F**	Non-wires	**Wires-only**
2	**TAX RETURN RECONCILIATION (TAXREC)**		**Corporate**	Eliminations	**Tax**
3	(for "wires-only" business - see s. 72 OEB Act)		**Tax**		**Return**
4	**0**		**Return**		
5					**Version 2009.1**
6	**Section A: Identification:**				
7	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**				
8	**Reporting period: 2004**				
9	**Taxation Year's start date:**		01/01/2004		
10	**Taxation Year's end date:**		31/12/2004		
11	**Number of days in taxation year:**		365	days	
12					
13	**Please enter the Materiality Level :**		1,764,205	< - enter materiality level	
14	**(0.25% x Rate Base x CER)**	Y/N	N		
15	**(0.25% x Net Assets)**	Y/N	Y		
16	**Or other measure (please provide the basis of the amount)**	Y/N	N		
17	**Does the utility carry on non-wires related operation?**	Y/N	N		
18	**(Please complete the questionnaire in the Background questionnaire worksheet.)**				
19					
20	Note: Carry forward Wires-only Data to Tab "TAXCALC" Column K				
21					
22	**Section B: Financial statements data:**				
23	*Input unconsolidated financial statement data submitted with Tax returns.*				
24	*The actual categories of the income statements should be used.*				
25	*If required please change the descriptions except for amortization, interest expense and provision for income tax*				
26					
27	*Please enter the non-wire operation's amount as a positive number, the program automatically treats all amounts*				
28	*in the "non-wires elimination column" as negative values in TAXREC and TAXREC2.*				
29					
30	**Income:**				
31	Energy Sales	+			0
32	Distribution Revenue	+	2,235,154,000		2,235,154,000
33	Other Income	+	27,240,000		27,240,000
34	Miscellaneous income	+	10,325,000		10,325,000
35		+			0
36	Revenue should be entered above this line				
37					
38	**Costs and Expenses:**				
39	Cost of energy purchased	-	1,798,008,000		1,798,008,000
40	Administration	-			0
41	Customer billing and collecting	-			0
42	Operations and maintenance	-	166,617,000		166,617,000
43	Amortization	-	122,526,000		122,526,000
44	Ontario Capital Tax	-			0
45	Reg Assets	-			0
46	Financing expenses	-	2,935,000		2,935,000
47	OEB Staff 84 a) revision	-	-1,502,879		-1,502,879
48		-			0
49					
50	**Net Income Before Interest & Income Taxes EBIT**	=	184,135,879	0	184,135,879
51	Less: Interest expense for accounting purposes	-	80,175,879		80,175,879
52	Provision for payments in lieu of income taxes	-	43,825,000		43,825,000
53	**Net Income (loss)**	=	60,135,000	0	60,135,000
54	(The Net Income (loss) on the MoF column should equal to the net income (loss) per financial statements on Schedule 1 of the tax return.)				
55					

	A	B	C	D	E
1	**PILs TAXES - EB-2012-0064**	**LINE**	**M of F**	Non-wires	**Wires-only**
2	**TAX RETURN RECONCILIATION (TAXREC)**		**Corporate**	Eliminations	**Tax**
3	(for "wires-only" business - see s. 72 OEB Act)		**Tax**		**Return**
4	**0**		**Return**		
5					**Version 2009.1**
56	**Section C: Reconciliation of accounting income to taxable income**				
57	***From T2 Schedule 1***				
58	**BOOK TO TAX ADDITIONS:**				
59	Provision for income tax	+	43,825,000	0	43,825,000
60	Federal large corporation tax	+			0
61	Depreciation & Amortization	+	122,526,000	0	122,526,000
62	Employee benefit plans-accrued, not paid	+		0	0
63	Tax reserves - beginning of year	+	0	0	0
64	Reserves from financial statements- end of year	+	109,978,621	0	109,978,621
65	Regulatory adjustments on which true-up may apply (see A66)	+			0
66	***Items on which true-up does not apply "TAXREC 3"***		161,244	0	161,244
67	Material addition items from TAXREC 2	+	0	0	0
68	Other addition items (not Material) from TAXREC 2	+	1,993,341	0	1,993,341
69					
70	*Subtotal*		278,484,206	0	278,484,206
71					
72	*Other Additions: (Please explain the nature of the additions)*				
73	Recapture of CCA	+			0
74	Non-deductible meals and entertainment expense	+			0
75	Capital items expensed	+			0
76	DEPRECIATION DIFFERENCE	+			0
77		+			0
78		+			0
79		+			0
80	*Total Other Additions*	=	0	0	0
81					
82	Total Additions	=	278,484,206	0	278,484,206
83					
84	Recap Material Additions:				
85			0	0	0
86			0	0	0
87			0	0	0
88			0	0	0
89			0	0	0
90			0	0	0
91			0	0	0
92	*Total Other additions >materiality level*		0	0	0
93	Other additions (less than materiality level)		0	0	0
94	Total Other Additions		0	0	0
95					

	A	B	C	D	E
1	**PILs TAXES - EB-2012-0064**	**LINE**	**M of F**	Non-wires	**Wires-only**
2	**TAX RETURN RECONCILIATION (TAXREC)**		**Corporate**	Eliminations	**Tax**
3	(for "wires-only" business - see s. 72 OEB Act)		**Tax**		**Return**
4	**0**		**Return**		
5					**Version 2009.1**
96	BOOK TO TAX DEDUCTIONS:				
97	Capital cost allowance	-	117,861,765		117,861,765
98	Cumulative eligible capital deduction	-	1,316,077		1,316,077
99	Employee benefit plans-paid amounts	-			0
100	Items capitalized for regulatory purposes	-			0
101	*Regulatory adjustments :*	-			0
102	*CCA*	-			0
103	*other deductions*	-			0
104	*Tax reserves - end of year*	-	0	0	0
105	*Reserves from financial statements- beginning of year*	-	108,977,216	0	108,977,216
106	*Contributions to deferred income plans*	-			0
107	*Contributions to pension plans*	-			0
108	***Items on which true-up does not apply "TAXREC 3"***		2,233,343	0	2,233,343
109	Interest capitalized for accounting deducted for tax	-			0
110	Material deduction items from TAXREC 2	-	0	0	0
111	Other deduction items (not Material) from TAXREC 2	-	3,298,862	0	3,298,862
112					
113	Subtotal	=	233,687,263	0	233,687,263
114	*Other deductions (Please explain the nature of the deductions)*				
115	**Charitable donations - tax basis**	-			0
116	*Gain on disposal of assets*	-			0
117		-			0
118					0
119		-			0
120	*Total Other Deductions*	=	0	0	0
121					
122	Total Deductions	=	233,687,263	0	233,687,263
123					
124	Recap Material Deductions:				
125			0	0	0
126			0	0	0
127			0	0	0
128			0	0	0
129			0	0	0
130	*Total Other Deductions exceed materiality level*		0	0	0
131	Other Deductions less than materiality level		0	0	0
132	Total Other Deductions		0	0	0
133					
134	TAXABLE INCOME	=	104,931,943	0	104,931,943
135	DEDUCT:				
136	Non-capital loss applied positive number	-			0
137	Net capital loss applied positive number	-			0
138					0
139	NET TAXABLE INCOME	=	104,931,943	0	104,931,943
140					
141	**FROM ACTUAL TAX RETURNS**				
142	Net Federal Income Tax (Must agree with tax return)	+	23,178,535		23,178,535
143	Net Ontario Income Tax (Must agree with tax return)	+	13,429,925		13,429,925
144	Subtotal	=	36,608,460	0	36,608,460
145	Less: Miscellaneous tax credits (Must agree with tax returns)	-	269,188		269,188
146	**Total Income Tax**	=	36,339,272	0	36,339,272
147					

	A	B	C	D	E
1	**PILs TAXES - EB-2012-0064**	**LINE**	**M of F**	Non-wires	**Wires-only**
2	**TAX RETURN RECONCILIATION (TAXREC)**		**Corporate**	Eliminations	**Tax**
3	(for "wires-only" business - see s. 72 OEB Act)		**Tax**		**Return**
4	**0**		**Return**		
5					**Version 2009.1**
148	**FROM ACTUAL TAX RETURNS**				
149	Net Federal Income Tax Rate (Must agree with tax return)		22.12%		22.12%
150	Net Ontario Income Tax Rate (Must agree with tax return)		14.00%		14.00%
151	Blended Income Tax Rate		36.12%	***************	36.12%
152					
153	**Section F: Income and Capital Taxes**				
154					
155	**RECAP**				
156	Total Income Taxes	+	36,339,272	0	36,339,272
157	Ontario Capital Tax	+	6,195,202		6,195,202
158	Federal Large Corporations Tax	+	2,802,926		2,802,926
159					
160	**Total income and capital taxes**	=	45,337,400	0	45,337,400

	A	B	C	D	E	F
1	**PILs TAXES - EB-2012-0064**	LINE	M of F	Non-wires	**Wires-only**	
2	**Tax and Accounting Reserves**		Corporate	Eliminations	**Tax**	
3	For MoF Column of TAXCALC		Tax		**Return**	
4	(for "wires-only" business - see s. 72 OEB Act)		Return			
5	**0**				**Version 2009.1**	
6						
7	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**					
8	**Reporting period: 2004**					
9						
10	**TAX RESERVES**					
11						
12	**Beginning of Year:**					
13					0	
14	Reserve for doubtful accounts ss. 20(1)(l)				0	
15	Reserve for goods & services ss.20(1)(m)				0	
16	Reserve for unpaid amounts ss.20(1)(n)				0	
17	Debt and share issue expenses ss.20(1)(e)				0	
18	Other - Please describe				0	
19	Other - Please describe				0	
20					0	
21					0	
22	**Total (**carry forward to the TAXREC worksheet)		0	0	0	
23						
24	**End of Year:**					
25					0	
26	Reserve for doubtful accounts ss. 20(1)(l)				0	
27	Reserve for goods & services ss.20(1)(m)				0	
28	Reserve for unpaid amounts ss.20(1)(n)				0	
29	Debt and share issue expenses ss.20(1)(e)				0	
30	Other - Please describe				0	
31	Other - Please describe				0	
32					0	
33					0	
34	Insert line above this line					
35	**Total (**carry forward to the TAXREC worksheet)		0	0	0	
36						
37						
38	**FINANCIAL STATEMENT RESERVES**					
39						
40	**Beginning of Year:**					
41					0	
42					0	
43	Environmental				0	
44	Allowance for doubtful accounts		585,360		585,360	
45	Inventory obsolescence		2,668,190		2,668,190	
46	Property taxes		2,000,000		2,000,000	
47	Other - Post employment benefits		103,677,000		103,677,000	
48	Other		46,666		46,666	
49					0	
50	**Total (**carry forward to the TAXREC worksheet)		108,977,216	0	108,977,216	
51						
52	**End of Year:**					

	A	B	C	D	E	F
53					0	
54					0	
55	Environmental				0	
56	Allowance for doubtful accounts		6,570		6,570	
57	Inventory obsolescence		1,575,051		1,575,051	
58	Property taxes				0	
59	Other - Post employment benefits		108,397,000		108,397,000	
60	Other - Holdback payable		0		0	
61	Other				0	
62	Insert line above this line					
63	**Total (**carry forward to the TAXREC worksheet)		109,978,621	0	109,978,621	
64						

	A	B	C	D	E	F
1						
2	**PILs TAXES - EB-2012-0064**	LINE	M of F	Non-wires	**Wires-only**	
3	**TAX RETURN RECONCILIATION (TAXREC 2)**		Corporate	Eliminations	**Tax**	
4	(for "wires-only" business - see s. 72 OEB Act)		Tax		**Return**	
5	**RATEPAYERS ONLY**		Return			
6	**Shareholder-only Items should be shown on TAXREC 3**				**Version 2009.1**	
7						
8	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**					
9	**Reporting period: 2004**					
10	**Number of days in taxation year:**		365			
11	**Materiality Level:**		1,764,205			
12						
13						
14						
15	**Section C: Reconciliation of accounting income to taxable income**					
16	**Add:**					
17		+			0	
18	Gain on sale of eligible capital property	+			0	
19	Loss on disposal of assets	+			0	
20	Charitable donations (Only if it benefits ratepayers)	+			0	
21	Taxable capital gains	+	146,332		146,332	
22		+			0	
23	Scientific research expenditures deducted	+			0	
24	per financial statements	+	844,629		844,629	
25	Capitalized interest	+			0	
26	Soft costs on construction and renovation of buildings	+			0	
27	Capital items expensed	+			0	
28	Debt issue expense	+			0	
29	Financing fees deducted in books	+	731,936		731,936	
30	Gain on settlement of debt	+			0	
31	Interest paid on income debentures	+			0	
32	Recapture of SR&ED expenditures	+			0	
33	Share issue expense	+			0	
34	Write down of capital property	+			0	
35	Amounts received in respect of qualifying environment trust	+			0	
36	Provision for bad debts	+			0	
37		+			0	
38		+			0	
39		+			0	
40	*Other Additions: (please explain in detail the nature of the item)*	+			0	
41	Asset retirement obligation- accretion expense	+	235,261		235,261	
42		+			0	
43	Interest and penalties on unpaid taxes	+	35,183		35,183	
44		+			0	
45		+			0	
46	Total Additions	=	1,993,341	0	1,993,341	
47						
48	Recap of Material Additions:					
49			0	0	0	
50			0	0	0	
51			0	0	0	
52			0	0	0	
53			0	0	0	
54			0	0	0	
55			0	0	0	
56			0	0	0	
57			0	0	0	
58			0	0	0	
59			0	0	0	
60			0	0	0	
61			0	0	0	
62			0	0	0	
63			0	0	0	

	A	B	C	D	E	F
1						
2	**PILs TAXES - EB-2012-0064**	LINE	M of F	Non-wires	**Wires-only**	
3	**TAX RETURN RECONCILIATION (TAXREC 2)**		Corporate	Eliminations	**Tax**	
4	(for "wires-only" business - see s. 72 OEB Act)		Tax		**Return**	
5	**RATEPAYERS ONLY**		Return			
6	**Shareholder-only Items should be shown on TAXREC 3**				**Version 2009.1**	
7						
8	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**					
9	**Reporting period: 2004**					
10	**Number of days in taxation year:**		365			
11	**Materiality Level:**		1,764,205			
12						
13						
64			0	0	0	
65			0	0	0	
66			0	0	0	
67			0	0	0	
68			0	0	0	
69			0	0	0	
70			0	0	0	
71			0	0	0	
72			0	0	0	
73			0	0	0	
74			0	0	0	
75			0	0	0	
76			0	0	0	
77	Total Material additions		0	0	0	
78	Other additions less than materiality level		1,993,341	0	1,993,341	
79	Total Additions		1,993,341	0	1,993,341	

	A	B	C	D	E	F
1						
2	**PILs TAXES - EB-2012-0064**	LINE	M of F	Non-wires	**Wires-only**	
3	**TAX RETURN RECONCILIATION (TAXREC 2)**		Corporate	Eliminations	**Tax**	
4	(for "wires-only" business - see s. 72 OEB Act)		Tax		**Return**	
5	**RATEPAYERS ONLY**		Return			
6	**Shareholder-only Items should be shown on TAXREC 3**				**Version 2009.1**	
7						
8	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**					
9	**Reporting period: 2004**					
10	**Number of days in taxation year:**		365			
11	**Materiality Level:**		1,764,205			
12						
13						
80						
81	Deduct:					
82	Gain on disposal of assets per f/s	-	1,043,000		1,043,000	
83	Dividends not taxable under section 83	-			0	
84	Terminal loss from Schedule 8	-			0	
85	Depreciation in inventory, end of prior year	-			0	
86	Scientific research expenses claimed in year from Form T661	-	306,391		306,391	
87	Bad debts	-			0	
88	Book income of joint venture or partnership	-			0	
89	Equity in income from subsidiary or affiliates	-			0	
90	Contributions to a qualifying environment trust	-			0	
91	Other income from financial statements	-			0	
92		-				
93		-			0	
94	*Other deductions: (Please explain in detail the nature of the item)*	-			0	
95		-			0	
96	Asset retirement obligation- cash payment deducted for tax	-	140,308		140,308	
97	Debt financing fees- deducted for tax S 20(1)(e)	-	1,270,925		1,270,925	
98	ITC booked to accounting income	-	538,238		538,238	
99	Total Deductions	=	3,298,862	0	3,298,862	
100						
101	Recap of Material Deductions:					
102			0	0	0	
103			0	0	0	
104			0	0	0	
105			0	0	0	
106			0	0	0	
107			0	0	0	
108			0	0	0	
109			0	0	0	
110			0	0	0	
111			0	0	0	
112			0	0	0	
113			0	0	0	
114			0	0	0	
115			0	0	0	
116			0	0	0	
117			0	0	0	
118			0	0	0	
119	Total Deductions exceed materiality level		0	0	0	
120	Other deductions less than materiality level		3,298,862	0	3,298,862	
121	Total Deductions		3,298,862	0	3,298,862	
122						

	A	B	C	D	E	F
1						
2	**PILs TAXES - EB-2012-0064**					
3	**TAX RETURN RECONCILIATION (TAXREC 3)**					
4	**Shareholder-only Items should be shown on TAXREC 3**	LINE	M of F	Non-wires	**Wires-only**	
5	**ITEMS ON WHICH TRUE-UP DOES NOT APPLY**		Corporate	Eliminations	**Tax**	
6	(for "wires-only" business - see s. 72 OEB Act)		Tax		**Return**	
7	**0**		Return			
8	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**				**Version 2009.1**	
9						
10						
11	**Reporting period: 2004**					
12	**Number of days in taxation year:**		365			
13						
14						
15						
16	**Section C: Reconciliation of accounting income to taxable income**					
17	**Add:**					
18						
19	Recapture of capital cost allowance	+			0	
20	CCA adjustments	+			0	
21	CEC adjustments	+			0	
22	Gain on sale of non-utility eligible capital property	+			0	
23	Gain on sale of utility eligible capital property	+			0	
24	Loss from joint ventures or partnerships	+			0	
25	Deemed dividend income	+			0	
26	Loss in equity of subsidiaries and affiliates	+			0	
27	Loss on disposal of utility assets	+			0	
28	Loss on disposal of non-utility assets	+			0	
29	Depreciation in inventory -end of year	+			0	
30	Depreciation and amortization adjustments	+			0	
31	Dividends credited to investment account	+			0	
32	Non-deductible meals	+	101,426		101,426	
33	Non-deductible club dues	+	59,818		59,818	
34	Non-deductible automobile costs	+			0	
35	**Donations - amount per books**				0	
36	Interest and penalties on unpaid taxes				0	
37	Management bonuses unpaid after 180 days of year end				0	
38	Imputed interest expense on Regulatory Assets				0	
39	**Ontario capital tax adjustments**	+			0	
40	**Changes in Regulatory Asset balances**	+			0	
41	*Other Additions: (please explain in detail the nature of the item)*	+			0	
42		+			0	
43		+			0	
44		+			0	
45		+			0	
46		+				
47	**Total Additions on which true-up does not apply**	=	161,244	0	161,244	
48						

	A	B	C	D	E	F
4	**Shareholder-only Items should be shown on TAXREC 3**	LINE	M of F	Non-wires	**Wires-only**	
5	**ITEMS ON WHICH TRUE-UP DOES NOT APPLY**		Corporate	Eliminations	**Tax**	
6	(for "wires-only" business - see s. 72 OEB Act)		Tax		**Return**	
7	**0**		Return			
8	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**				**Version 2009.1**	
49	**Deduct:**					
50						
51	CCA adjustments	-			0	
52	CEC adjustments	-			0	
53	Depreciation and amortization adjustments	-			0	
54	Gain on disposal of assets per financial statements	-			0	
55	Financing fee amorization - considered to be interest expense for PILs	-			0	
56	Imputed interest income on Regulatory Assets	-	2,233,343		2,233,343	
57	**Donations - amount deductible for tax purposes**	-			0	
58	Income from joint ventures or partnerships	-			0	
59		-			0	
60		-			0	
61		-			0	
62		-			0	
63		-			0	
64	**Ontario capital tax adjustments to current or prior year**	-			0	
65		-			0	
66	**Changes in Regulatory Asset balances**	-			0	
67		-			0	
68	*Other deductions: (Please explain in detail the nature of the item)*	-			0	
69		-			0	
70		-			0	
71		-			0	
72		-			0	
73	**Total Deductions on which true-up does not apply**	=	2,233,343	0	2,233,343	
74						

	A	B	C	D	E	F	G
1	**PILs TAXES - EB-2012-0064**						
2	**Corporate Tax Rates**					**Version 2009.1**	
3	**Exemptions, Deductions, or Thresholds**						
4	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**						
5	**Reporting period: 2004**						
6							
7						**Table 1**	
8	**Rates Used in 2002 RAM PILs Applications for 2002**						
9	**Income Range**		**0**		**200,001**		
10	**RAM 2002**		**to**		**to**	**>700,000**	
11		**Year**	**200,000**		**700,000**		
12	**Income Tax Rate**						
13	***Proxy Tax Year***	***2002***					
14	***Federal (Includes surtax)***					26.12%	
15	***and Ontario blended***					12.50%	
16	***Blended rate***					38.62%	
17							
18	**Capital Tax Rate**		0.300%				
19	**LCT rate**		0.225%				
20	**Surtax**		1.12%				
21	**Ontario Capital Tax Exemption ****	**MAX $5MM**	5,000,000				
22	**Federal Large Corporations Tax Exemption ****	**MAX $10MM**	10,000,000				
23	****Exemption amounts must agree with the Board-approved 2002 RAM PILs filing**						
24							
25						**Table 2**	
26	**Expected Income Tax Rates for 2004 and Capital Tax Exemptions for 2004**						
27	**Income Range**		**0**		**200,001**		
28	**Expected Rates**		**to**		**to**	**>700,000**	
29		**Year**	**200,000**		**700,000**		
30	**Income Tax Rate**						
31	***Current year***	***2004***					
32	***Federal (Includes surtax)***					22.12%	
33	***Ontario***					14.00%	
34	***Blended rate***					36.12%	
35							
36	**Capital Tax Rate**		0.300%				
37	**LCT rate**		0.200%				
38	**Surtax**		1.12%				
39	**Ontario Capital Tax Exemption *** 2004**	**MAX $5MM**	5,000,000				
40	**Federal Large Corporations Tax Exemption *** 2004**	**MAX $50MM**	50,000,000				
41	*****Allocation of exemptions must comply with the Board's instructions regarding regulated activities.**						
42							

	A	B	C	D	E	F	G
43						**Table 3**	
44	**Input Information from Utility's Actual 2004 Tax Returns**						
45	**Income Range**		**0**		**200,001**		
46			**to**		**to**	**>700,000**	
47		**Year**	**200,000**		**700,000**		
48	**Income Tax Rate**						
49	***Current year***	***2004***					
50	***Federal (Includes surtax)***		0.00%		0.00%	22.12%	
51	***Ontario***		0.00%		0.00%	14.00%	
52	***Blended rate***		0.00%		0.00%	36.12%	
53							
54	**Capital Tax Rate**		0.300%				
55	**LCT rate**		0.200%				
56	**Surtax**		1.12%				
57	**Ontario Capital Tax Exemption ***	**MAX $5MM**	5,000,000				
58	**Federal Large Corporations Tax Exemption ***	**MAX $50MM**	50,000,000				
59	*** Include copies of the actual tax return allocation calculations in your**						
60	**submission: Ontario CT23 page 11; federal T2 Schedule 36**						

A	B	C	E	G	I	K	M	O
PILs TAXES - EB-2012-0064								
Analysis of PILs Tax Account 1562:								
Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED								**Version 2009.1**
Reporting period: 2004			**Sign Convention: + for increase; - for decrease**					**0**
Year start:		01/10/2001	01/01/2002	01/01/2003	01/01/2004	01/01/2005	01/01/2006	
Year end:		31/12/2001	31/12/2002	31/12/2003	31/12/2004	31/12/2005	30/04/2006	Total
Opening balance:	=	0	5,028,333	8,127,575	8,284,720	-619,716	-2,303,882	0
Board-approved PILs tax proxy from Decisions (1)	+/-	5,000,000	55,000,000	60,000,000	58,571,734		0	178,571,734
PILs proxy from April 1, 2005 - input 9/12 of amount								0
True-up Variance Adjustment Q4, 2001 (2)	+/-		-290,810					-290,810
True-up Variance Adjustment (3)	+/-			2,156,868	-6,024,420	-1,684,166		-5,551,718
Deferral Account Variance Adjustment Q4, 2001 (4)								0
Deferral Account Variance Adjustment (5)	+/-			-2,412,196	-3,807,479			-6,219,675
Adjustments to reported prior years' variances (6)	+/-							0
Carrying charges (7)	+/-	28,333	720,305	562,257	269,130			1,580,025
PILs billed to (collected from) customers (8)	-	0	-52,330,253	-60,149,784	-57,913,401			-170,393,438
Ending balance: # 1562		5,028,333	8,127,575	8,284,720	-619,716	-2,303,882	-2,303,882	-2,303,882

Uncollected PILs

NOTE: The purpose of this worksheet is to show the movement in Account 1562 which establishes the receivable from or liability to ratepayers.
For explanation of Account 1562 please refer to Accounting Procedures Handbook for Electric Distribution Utilities and FAQ April 2003.

Please identify if Method 1, 2 or 3 was used to account for the PILs proxy and recovery. ANSWER: METHOD 3

(1) (i) From the Board's Decision - see Inclusion in Rates, Part III of the TAXCALC spreadsheet for Q4 2001 and 2002.
Please insert the Q4, 2001 proxy in column C even though it was approved effective March 1, 2002.
If the Board gave more than one decision in the year, calculate a weighted average proxy.
(ii) If the Board approved different amounts, input the Board-approved amounts in cells C13 and E13.
(iii) Column G - In 2003, the initial estimate should include the Q4 2001 PILs tax proxy and the 2002 PILs tax proxy.
(iv) Column I - The Q4 2001 PILs tax proxy was removed from rates on April 1, 2004 and the 2002 PILs tax proxy remained.
(v) Column K - The 2002 PILs tax proxy applies to January 1 to March 31, 2005, and the new 2005 PILs tax proxy from April 1 to December 31, 2005.
(vi) Column M - The 2005 PILs tax proxy will used for the period from January 1 to April 30, 2006.

(2) From the Ministry of Finance Variance Column, under Future True-ups, Part IV a, cell I132, of the TAXCALC spreadsheet. The Q4, 2001 proxy has to be trued up in 2002, 2003 and for the period January 1- March 31, 2004. Input the variance in the whole year reconcilation.

(3) From the Ministry of Finance Variance Column, under Future True-ups, Part IV a, cell I132, of the TAXCALC spreadsheet.
The true-up will compare to the 2002 proxy for 2002, 2003, 2004 and January 1 to March 31, 2005.

(4) From the Ministry of Finance Variance Column, under Future True-ups, Part IV b, cell I181, of the TAXCALC spreadsheet. The Q4, 2001 proxy has to be trued up in 2002, 2003 and for the period January 1- March 31, 2004. Input the deferral variance in the whole year reconciliation.

(5) From the Ministry of Finance Variance Column, under Future True-ups, Part IV a, cell I181, of the TAXCALC spreadsheet.
The true-up will compare to the 2002 proxy for 2002, 2003, 2004 and January 1 to March 31, 2005.

(6) The correcting entry should be shown in the year the entry was made. The true-up of the carrying charges will have to be reviewed.

(7) Carrying charges are calculated on a simple interest basis.

(8) (i) PILs collected from customers from March 1, 2002 to March 31, 2004 were based on a fixed charge and a volumetric charge recovery by class. The PILs rate components for Q4, 2001and 2002 were calculated in the 2002 approved RAM on sheet 6 and sheet 8. In April 2004, the PILs recovery was based on the 2002 PILs tax proxy recovered by the volumetric rate by class as calculated on sheet 7 of the 2004 RAM.
The 2005 PILs tax proxy is being recovered on a volumetric basis by class.

(ii) Collections should equal: (a) the actual volumes/ load (kWhs, kWs, Kva) for the period (including net unbilled at period end), multiplied by the PILs volumetric proxy rates by class (from the Q4, 2001and 2002 RAM worksheets) for 2002, 2003 and January 1 to March 31, 2004; plus, (b) customer counts by class in the same period multiplied by the PILs fixed charge rate components.

In 2004, use the Board-approved 2002 PILs proxy, recovered on a volumetric basis by class as calculated by the 2004 RAM, sheet 7, for the period April 1 to December 31, 2004, and add this total to the results from the sentence above for January 1 to March 31, 2004.

In 2005, use the Board-approved 2005 PILs proxy, recovered on a volumetric basis by class as calculated by the 2005 RAM, sheet 4, for the period April 1 to December 31, 2005. To this total, the 2004 volumetric PILs proxy rate by class should be used to calculate the recovery for the period January 1 to March 31, 2005.

(9) Any interim PILs recovery from Board Decisions will be recorded in APH Account # 1590. Final reconciliation of PILs proxy taxes will have to include amounts from 1562 and from 1590.

	A	B	C	D	E
1	**PILs TAXES - EB-2012-0064**				**Version 2009.1**
2	**REGULATORY INFORMATION (REGINFO)**				
3	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**			Colour Code	
4	**Reporting period: 2005**			**Input Cell**	
5				**Formula in Cell**	
6	**Days in reporting period:**	365	days		
7	**Total days in the calendar year:**	365	days		
8					
9	**BACKGROUND**				
10	Has the utility reviewed section 149(1) ITA to				
11	confirm that it is not subject to regular corporate				
12	tax (and therefore subject to PILs)?		Y/N	Y	
13					
14	Was the utility recently acquired by Hydro One				
15	and now subject to s.89 & 90 PILs?		Y/N	N	
16					
17	Is the utility a non-profit corporation?		Y/N	N	
18	(If it is a non-profit corporation, please contact the Rates Manager at the OEB)				
19	Are the Ontario Capital Tax & Large Corporations Tax Exemptions	OCT	Y/N	N	
20	shared among the corporate group?	LCT	Y/N	N	
21	Please identify the % used to allocate the OCT and LCT exemptions in	OCT		100%	
22	Cells C65 & C74 in the TAXCALC spreadsheet.	LCT		100%	
23					
24	Accounting Year End		Date	12-31-2005	
25					
26	**MARR NO TAX CALCULATIONS**				**Regulatory**
27	**SHEET #7 FINAL RUD MODEL DATA**				**Income**
28	**(FROM 1999 FINANCIAL STATEMENTS)**				
29	**USE BOARD-APPROVED AMOUNTS**				
30					
31	Rate Base (wires-only)			1,810,112,688	
32					
33	Common Equity Ratio (CER)			35.00%	
34					
35	1-CER			65.00%	
36					
37	Target Return On Equity			9.88%	
38					
39	Debt rate			6.80%	
40					
41	Market Adjusted Revenue Requirement			142,600,678	
42					
43	1999 return from RUD Sheet #7			23,304,000	23,304,000
44					
45	Total Incremental revenue			119,296,678	
46	**Input: Board-approved dollar amounts phased-in**				
47	Amount allowed in 2001			39,765,559	39,765,559
48	Amount allowed in 2002			39,765,559	39,765,559
49	Amount allowed in 2003 and 2004 (will be zero due to Bill 210				0
50	unless authorized by the Minister and the Board)				0
51	Amount allowed in 2005 - Third tranche of MARR re: CDM			39,765,559	39,765,559
52	Other Board-approved changes to MARR or incremental revenue				0
53					0
54	**Total Regulatory Income**				142,600,677
55					
56	Equity			633,539,441	
57					
58	Return at target ROE			62,593,697	
59					
60	Debt			1,176,573,247	
61					
62	Deemed interest amount in 100% of MARR			80,006,981	
63					
64	Phase-in of interest - Year 1 (2001)			35,385,561	
65	((D43+D47)/D41)*D61				
66	Phase-in of interest - Year 2 (2002)			57,696,271	
67	((D43+D47+D48)/D41)*D61				
68	Phase-in of interest - Year 3 (2003) and forward			57,696,271	
69	((D43+D47+D48)/D41)*D61 (due to Bill 210)				
70	Phase-in of interest - 2005			80,006,981	
71					

	A	B	C	D	E	F	G	H
1	**PILs TAXES - EB-2012-0064**	**ITEM**	**Initial**		M of F	M of F	**Tax**	
2	**PILs DEFERRAL AND VARIANCE ACCOUNTS**		**Estimate**		Filing	Filing	**Returns**	
3	**TAX CALCULATIONS (TAXCALC)**				Variance	Variance		
4	("Wires-only" business - see Tab TAXREC)				K-C	Explanation		
5	**0**						**Version 2009.1**	
6	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**							
7	**Reporting period: 2005**							
8							**Column**	
9	**Days in reporting period:**	365	days				**Brought**	
10	**Total days in the calendar year:**	365	days				**From**	
11							**TAXREC**	
12			$		$		$	
13								
14	**I) CORPORATE INCOME TAXES**							
15								
16	Regulatory Net Income REGINFO E53	1	142,600,677		63,568,550		206,169,227	
17								
18	BOOK TO TAX ADJUSTMENTS							
19	***Additions:***							
20	Depreciation & Amortization	2	106,229,000		18,758,458		124,987,458	
21	Employee Benefit Plans - Accrued, Not Paid	3	9,886,000		-9,886,000		0	
22	Tax reserves - beginning of year	4			0		0	
23	Reserves from financial statements - end of year	4			116,997,819		116,997,819	
24	Regulatory Adjustments - increase in income	5			0		0	
25	Other Additions (See Tab entitled "TAXREC")							
26	"Material" Items from "TAXREC" worksheet	6			0		0	
27	Other Additions (not "Material") "TAXREC"	6			0		0	
28	"Material Items from "TAXREC 2" worksheet	6			24,733,897		24,733,897	
29	Other Additions (not "Material") "TAXREC 2"	6			2,150,830		2,150,830	
30	**Items on which true-up does not apply "TAXREC 3"**				10,988,385		10,988,385	
31								
32	***Deductions:*** ***Input positive numbers***							
33	Capital Cost Allowance and CEC	7	76,692,530		36,663,215		113,355,745	
34	Employee Benefit Plans - Paid Amounts	8	5,166,000		-5,166,000		0	
35	Items Capitalized for Regulatory Purposes	9	0		0		0	
36	Regulatory Adjustments - deduction for tax purposes in Item 5	10			0		0	
37	Interest Expense Deemed/ Incurred	11	80,006,981		-325,122		79,681,859	
38	Tax reserves - end of year	4			0		0	
39	Reserves from financial statements - beginning of year	4			109,978,620		109,978,620	
40	Contributions to deferred income plans	3			0		0	
41	Contributions to pension plans	3			0		0	
42	Interest capitalized for accounting but deducted for tax	11			0		0	
43	Other Deductions (See Tab entitled "TAXREC")							
44	"Material" Items from "TAXREC" worksheet	12			0		0	
45	Other Deductions (not "Material") "TAXREC"	12			0		0	
46	Material Items from "TAXREC 2" worksheet	12			26,333,927		26,333,927	
47	Other Deductions (not "Material") "TAXREC 2"	12			4,445,767		4,445,767	
48	**Items on which true-up does not apply "TAXREC 3"**				3,522,672		3,522,672	
49	**CDM 2005 incremental OM&A expenses per 2005 PILs model**		4,895,000		-4,895,000			
50	TAXABLE INCOME/ (LOSS)		91,955,166		56,753,860	Before loss C/F	148,709,026	
51								
52	BLENDED INCOME TAX RATE							
53	Tab Tax Rates - Regulatory from Table 1; Actual from Table 3	13	36.12%		0.0000%		36.12%	
54								
55	REGULATORY INCOME TAX		33,214,206		20,686,831	Actual	53,901,037	
56								
57								
58	Miscellaneous Tax Credits	14			480,248	Actual	480,248	
59								
60	**Total Regulatory Income Tax**		33,214,206		20,206,583	Actual	53,420,789	
61								
62								
63	**II) CAPITAL TAXES**							
64								
65	***Ontario***							
66	Base	15	1,810,112,688		309,209,207		2,119,321,895	
67	Less: Exemption -Tax Rates - Regulatory, Table 1; Actual, Table 3	16	7,500,000		0		7,500,000	
68	Taxable Capital		1,802,612,688		309,209,207		2,111,821,895	
69								
70	Rate - Tax Rates - Regulatory, Table 1; Actual, Table 3	17	0.3000%		0.0000%		0.3000%	
71								
72	Ontario Capital Tax		5,407,838		927,628		6,335,466	
73								
74	***Federal Large Corporations Tax***							
75	Base	18	1,810,112,688		218,649,135		2,028,761,823	
76	Less: Exemption -Tax Rates - Regulatory, Table 1; Actual, Table 3	19	50,000,000		0		50,000,000	
77	Taxable Capital		1,760,112,688		218,649,135		1,978,761,823	
78								
79	Rate - Tax Rates - Regulatory, Table 1; Actual, Table 3	20	0.1750%		0.0000%		0.1750%	
80								
81	Gross Amount of LCT before surtax offset (Taxable Capital x Rate)		3,080,197		382,636		3,462,833	
82	Less: Federal Surtax 1.12% x Taxable Income	21	1,029,898		649,696		1,679,594	
83								
84	Net LCT		2,050,299		-267,060		1,783,239	
85								

	A	B	C	D	E	F	G	H
1	**PILs TAXES - EB-2012-0064**	**ITEM**	**Initial**		M of F	M of F	**Tax**	
2	**PILs DEFERRAL AND VARIANCE ACCOUNTS**		**Estimate**		Filing	Filing	**Returns**	
3	**TAX CALCULATIONS (TAXCALC)**				Variance	Variance		
4	("Wires-only" business - see Tab TAXREC)				K-C	Explanation		
5	**0**						**Version 2009.1**	
6	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**							
7	**Reporting period: 2005**							
8							**Column**	
9	**Days in reporting period:**	365	days				**Brought**	
10	**Total days in the calendar year:**	365	days				**From**	
11							**TAXREC**	
12			$		$		$	
13								
86	**III) INCLUSION IN RATES**							
87								
88	Income Tax Rate used for gross- up		36.12%					
89								
90	Income Tax (proxy tax is grossed-up)	22	51,994,687			**Actual 2005**	53,420,789	
91	LCT (proxy tax is grossed-up)	23	3,209,611			**Actual 2005**	1,783,239	
92	Ontario Capital Tax (no gross-up since it is deductible)	24	5,407,838			**Actual 2005**	6,335,466	
93								
94								
95	***Total PILs for Rate Adjustment -- AGREES WITH 2005 RAM***	25	60,612,136			**Actual 2005**	61,539,494	
96	**DECISION**							
97								
98								
99	***IV) FUTURE TRUE-UPS***							
100	**IV a) Calculation of the True-up Variance**				**DR/(CR)**			
101	***In Additions:***							
102	Employee Benefit Plans - Accrued, Not Paid	3			-9,886,000			
103	Tax reserves deducted in prior year	4			0			
104	Reserves from financial statements-end of year	4			116,997,819			
105	Regulatory Adjustments	5			0			
106	Other additions "Material" Items TAXREC	6			0			
107	Other additions "Material" Items TAXREC 2	6			24,733,897			
108	***In Deductions - positive numbers***							
109	Employee Benefit Plans - Paid Amounts	8			-5,166,000			
110	Items Capitalized for Regulatory Purposes	9			0			
111	Regulatory Adjustments	10			0			
112	Interest Adjustment for tax purposes **(See Below - cell I204)**	11			0			
113	Tax reserves claimed in current year	4			0			
114	Reserves from F/S beginning of year	4			109,978,620			
115	Contributions to deferred income plans	3			0			
116	Contributions to pension plans	3			0			
117	Other deductions "Material" Items TAXREC	12			0			
118	Other deductions "Material" Item TAXREC 2	12			26,333,927			
119								
120	Total TRUE-UPS before tax effect	26		=	699,169			
121								
122	Income Tax Rate from **2005** Utility's tax return			x	36.12%			
123								
124	Income Tax Effect on True-up adjustments			=	252,540			
125								
126	Less: Miscellaneous Tax Credits	14			480,248			
127								
128	Total Income Tax on True-ups				(227,708)			
129								
130	Income Tax Rate used for gross-up (exclude surtax)				35.00%			
131								
132	**TRUE-UP VARIANCE ADJUSTMENT**				(350,320)			
133								
134	**IV b) Calculation of the Deferral Account Variance caused by changes in legislation**							
135								
136	REGULATORY TAXABLE INCOME /(LOSSES) (as reported in the initial estimate column)			=	91,955,166			
137								
138	REVISED CORPORATE INCOME TAX RATE			x	36.12%			
139								
140	REVISED REGULATORY INCOME TAX			=	33,214,206			
141								
142	Less: Revised Miscellaneous Tax Credits			-				
143								
144	Total Revised Regulatory Income Tax			=	33,214,206			
145								
146	Less: Regulatory Income Tax reported in the Initial Estimate Column (Cell C58)			-	33,214,206			
147								
148	Regulatory Income Tax Variance			=	0			
149								

	A	B	C	D	E	F	G
1	**PILs TAXES - EB-2012-0064**	**ITEM**	**Initial**		M of F	M of F	**Tax**
2	**PILs DEFERRAL AND VARIANCE ACCOUNTS**		**Estimate**		Filing	Filing	**Returns**
3	**TAX CALCULATIONS (TAXCALC)**				Variance	Variance	
4	("Wires-only" business - see Tab TAXREC)				K-C	Explanation	
5	**0**						**Version 2009.1**
6	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**						
7	**Reporting period: 2005**						
8							**Column**
9	**Days in reporting period:**	365	days				**Brought**
10	**Total days in the calendar year:**	365	days				**From**
11							**TAXREC**
12			$		$		$
13							
150	**Ontario Capital Tax**						
151	Base			=	1,810,112,688		
152	Less: Exemption from tab Tax Rates, Table 2, cell C39			-	7,500,000		
153	Revised deemed taxable capital			=	1,802,612,688		
154							
155	Rate - Tab Tax Rates cell C54			x	0.3000%		
156							
157	Revised Ontario Capital Tax			=	5,407,838		
158	Less: Ontario Capital Tax reported in the initial estimate column (Cell C70)			-	5,407,838		
159	Regulatory Ontario Capital Tax Variance			=	0		
160							
161	**Federal LCT**						
162	Base				1,810,112,688		
163	Less: Exemption from tab Tax Rates, Table 2, cell C40			-	50,000,000		
164	Revised Federal LCT			=	1,760,112,688		
165							
166	Rate (as a result of legislative changes) tab 'Tax Rates' cell C51				0.1750%		
167							
168	Gross Amount				3,080,197		
169	Less: Federal surtax			-	1,029,898		
170	Revised Net LCT			=	2,050,299		
171							
172	Less: Federal LCT reported in the initial estimate column (Cell C82)			-	2,050,299		
173	Regulatory Federal LCT Variance			=	0		
174							
175	Actual Income Tax Rate used for gross-up (exclude surtax)				35.00%		
176							
177	**Income Tax (grossed-up)**			+	0		
178	**LCT (grossed-up)**			+	0		
179	**Ontario Capital Tax**			+	0		
180							
181	**DEFERRAL ACCOUNT VARIANCE ADJUSTMENT**			=	0		
182							
183	**TRUE-UP VARIANCE (from cell I130)**			+	(350,320)		
184							
185	**Total Deferral Account Entry (Positive Entry = Debit)**			=	(350,320)		
186	*(Deferral Account Variance + True-up Variance)*						
187							
188							
189							
190	**V) INTEREST PORTION OF TRUE-UP**						
191	**Variance Caused By Phase-in of Deemed Debt**						
192							
193	Total deemed interest (REGINFO)				80,006,981		
194	Interest phased-in (Cell C36)				80,006,981		
195							
196	Variance due to phase-in of debt component of MARR in rates				0		
197	according to the Board's decision						
198							
199	**Other Interest Variances (i.e. Borrowing Levels**						
200	**Above Deemed Debt per Rate Handbook)**						
201	Interest deducted on MoF filing (Cell K36+K41)				79,681,859		
202	Total deemed interest (REGINFO CELL D61)				80,006,981		
203							
204	Variance caused by excess debt				0		
205							
206	**Interest Adjustment for Tax Purposes (carry forward to Cell I110)**				0		
207							
208	**Total Interest Variance**				0		
209							

	A	B	C	D	E
1	**PILs TAXES - EB-2012-0064**	**LINE**	**M of F**	Non-wires	**Wires-only**
2	**TAX RETURN RECONCILIATION (TAXREC)**		**Corporate**	Eliminations	**Tax**
3	(for "wires-only" business - see s. 72 OEB Act)		**Tax**		**Return**
4	**0**		**Return**		
5					**Version 2009.1**
6	**Section A: Identification:**				
7	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**				
8	**Reporting period: 2005**				
9	**Taxation Year's start date:**		01/01/2005		
10	**Taxation Year's end date:**		31/12/2005		
11	**Number of days in taxation year:**		365	days	
12					
13	**Please enter the Materiality Level :**		1,641,325	< - enter materiality level	
14	**(0.25% x Rate Base x CER)**	Y/N	N		
15	**(0.25% x Net Assets)**	Y/N	Y		
16	**Or other measure (please provide the basis of the amount)**	Y/N	N		
17	**Does the utility carry on non-wires related operation?**	Y/N	N		
18	**(Please complete the questionnaire in the Background questionnaire worksheet.)**				
19					
20	Note: Carry forward Wires-only Data to Tab "TAXCALC" Column K				
21					
22	**Section B: Financial statements data:**				
23	*Input unconsolidated financial statement data submitted with Tax returns.*				
24	*The actual categories of the income statements should be used.*				
25	*If required please change the descriptions except for amortization, interest expense and provision for income tax*				
26					
27	*Please enter the non-wire operation's amount as a positive number, the program automatically treats all amounts*				
28	*in the "non-wires elimination column" as negative values in TAXREC and TAXREC2.*				
29					
30	**Income:**				
31	Energy Sales	+			0
32	Distribution Revenue	+	2,686,750,529		2,686,750,529
33	Other Income	+	26,031,955		26,031,955
34	Miscellaneous income	+	10,485,354		10,485,354
35		+			0
36	Revenue should be entered above this line				
37					
38	**Costs and Expenses:**				
39	Cost of energy purchased	-	2,224,034,095		2,224,034,095
40	Administration	-			0
41	Customer billing and collecting	-			0
42	Operations and maintenance	-	161,413,363		161,413,363
43	Amortization	-	124,987,458		124,987,458
44	Ontario Capital Tax	-	5,725,556		5,725,556
45	Reg Assets	-			0
46	Financing expenses	-	2,090,446		2,090,446
47	OEB Staff 84 a) revision	-	-1,152,307		-1,152,307
48		-			0
49					
50	**Net Income Before Interest & Income Taxes EBIT**	=	206,169,227	0	206,169,227
51	Less: Interest expense for accounting purposes	-	79,681,859		79,681,859
52	Provision for payments in lieu of income taxes	-	61,113,786		61,113,786
53	**Net Income (loss)**	=	65,373,582	0	65,373,582
54	(The Net Income (loss) on the MoF column should equal to the net income (loss) per financial statements on Schedule 1 of the tax return.)				
55					

	A	B	C	D	E
1	**PILs TAXES - EB-2012-0064**	**LINE**	**M of F**	Non-wires	**Wires-only**
2	**TAX RETURN RECONCILIATION (TAXREC)**		**Corporate**	Eliminations	**Tax**
3	(for "wires-only" business - see s. 72 OEB Act)		**Tax**		**Return**
4	**0**		**Return**		
5					**Version 2009.1**
56	**Section C: Reconciliation of accounting income to taxable income**				
57	***From T2 Schedule 1***				
58	**BOOK TO TAX ADDITIONS:**				
59	Provision for income tax	+	61,113,786	0	61,113,786
60	Federal large corporation tax	+			0
61	Depreciation & Amortization	+	124,987,458	0	124,987,458
62	Employee benefit plans-accrued, not paid	+		0	0
63	Tax reserves - beginning of year	+	0	0	0
64	Reserves from financial statements- end of year	+	116,997,819	0	116,997,819
65	Regulatory adjustments on which true-up may apply (see A66)	+			0
66	***Items on which true-up does not apply "TAXREC 3"***		10,988,385	0	10,988,385
67	Material addition items from TAXREC 2	+	24,733,897	0	24,733,897
68	Other addition items (not Material) from TAXREC 2	+	2,150,830	0	2,150,830
69					
70	*Subtotal*		340,972,175	0	340,972,175
71					
72	*Other Additions: (Please explain the nature of the additions)*				
73	Recapture of CCA	+			0
74	Non-deductible meals and entertainment expense	+			0
75	Capital items expensed	+			0
76	DEPRECIATION DIFFERENCE	+			0
77		+			0
78		+			0
79		+			0
80	*Total Other Additions*	=	0	0	0
81					
82	Total Additions	=	340,972,175	0	340,972,175
83					
84	Recap Material Additions:				
85			0	0	0
86			0	0	0
87			0	0	0
88			0	0	0
89			0	0	0
90			0	0	0
91			0	0	0
92	*Total Other additions >materiality level*		0	0	0
93	Other additions (less than materiality level)		0	0	0
94	Total Other Additions		0	0	0
95					

	A	B	C	D	E
1	**PILs TAXES - EB-2012-0064**	**LINE**	**M of F**	Non-wires	**Wires-only**
2	**TAX RETURN RECONCILIATION (TAXREC)**		**Corporate**	Eliminations	**Tax**
3	(for "wires-only" business - see s. 72 OEB Act)		**Tax**		**Return**
4	**0**		**Return**		
5					**Version 2009.1**
96	BOOK TO TAX DEDUCTIONS:				
97	Capital cost allowance	-	112,131,793		112,131,793
98	Cumulative eligible capital deduction	-	1,223,952		1,223,952
99	Employee benefit plans-paid amounts	-			0
100	Items capitalized for regulatory purposes	-			0
101	*Regulatory adjustments :*	-			0
102	*CCA*	-			0
103	*other deductions*	-			0
104	*Tax reserves - end of year*	-	0	0	0
105	*Reserves from financial statements- beginning of year*	-	109,978,620	0	109,978,620
106	*Contributions to deferred income plans*	-			0
107	*Contributions to pension plans*	-			0
108	***Items on which true-up does not apply "TAXREC 3"***		3,522,672	0	3,522,672
109	Interest capitalized for accounting deducted for tax	-			0
110	Material deduction items from TAXREC 2	-	26,333,927	0	26,333,927
111	Other deduction items (not Material) from TAXREC 2	-	4,445,767	0	4,445,767
112					
113	Subtotal	=	257,636,731	0	257,636,731
114	*Other deductions (Please explain the nature of the deductions)*				
115	**Charitable donations - tax basis**	-			0
116	*Gain on disposal of assets*	-			0
117		-			0
118					0
119		-			0
120	*Total Other Deductions*	=	0	0	0
121					
122	Total Deductions	=	257,636,731	0	257,636,731
123					
124	Recap Material Deductions:				
125			0	0	0
126			0	0	0
127			0	0	0
128			0	0	0
129			0	0	0
130	*Total Other Deductions exceed materiality level*		0	0	0
131	Other Deductions less than materiality level		0	0	0
132	Total Other Deductions		0	0	0
133					
134	TAXABLE INCOME	=	148,709,026	0	148,709,026
135	DEDUCT:				
136	Non-capital loss applied positive number	-			0
137	Net capital loss applied positive number	-	399,695		399,695
138					0
139	NET TAXABLE INCOME	=	148,309,331	0	148,309,331
140					
141	**FROM ACTUAL TAX RETURNS**				
142	Net Federal Income Tax (Must agree with tax return)	+	33,053,639		33,053,639
143	Net Ontario Income Tax (Must agree with tax return)	+	20,847,398		20,847,398
144	Subtotal	=	53,901,037	0	53,901,037
145	Less: Miscellaneous tax credits (Must agree with tax returns)	-	480,248		480,248
146	**Total Income Tax**	=	53,420,789	0	53,420,789
147					

	A	B	C	D	E
1	**PILs TAXES - EB-2012-0064**	**LINE**	**M of F**	Non-wires	**Wires-only**
2	**TAX RETURN RECONCILIATION (TAXREC)**		**Corporate**	Eliminations	**Tax**
3	(for "wires-only" business - see s. 72 OEB Act)		**Tax**		**Return**
4	**0**		**Return**		
5					**Version 2009.1**
148	**FROM ACTUAL TAX RETURNS**				
149	Net Federal Income Tax Rate (Must agree with tax return)		22.12%		22.12%
150	Net Ontario Income Tax Rate (Must agree with tax return)		14.00%		14.00%
151	Blended Income Tax Rate		36.12%	***************	36.12%
152					
153	**Section F: Income and Capital Taxes**				
154					
155	**RECAP**				
156	Total Income Taxes	+	53,420,789	0	53,420,789
157	Ontario Capital Tax	+	6,335,466		6,335,466
158	Federal Large Corporations Tax	+	1,783,239		1,783,239
159					
160	**Total income and capital taxes**	=	61,539,494	0	61,539,494

	A	B	C	D	E	F
1	**PILs TAXES - EB-2012-0064**	LINE	M of F	Non-wires	**Wires-only**	
2	**Tax and Accounting Reserves**		Corporate	Eliminations	**Tax**	
3	For MoF Column of TAXCALC		Tax		**Return**	
4	(for "wires-only" business - see s. 72 OEB Act)		Return			
5	**0**				**Version 2009.1**	
6						
7	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**					
8	**Reporting period: 2005**					
9						
10	**TAX RESERVES**					
11						
12	**Beginning of Year:**					
13					0	
14	Reserve for doubtful accounts ss. 20(1)(l)				0	
15	Reserve for goods & services ss.20(1)(m)				0	
16	Reserve for unpaid amounts ss.20(1)(n)				0	
17	Debt and share issue expenses ss.20(1)(e)				0	
18	Other - Please describe				0	
19	Other - Please describe				0	
20					0	
21					0	
22	**Total (**carry forward to the TAXREC worksheet)		0	0	0	
23						
24	**End of Year:**					
25					0	
26	Reserve for doubtful accounts ss. 20(1)(l)				0	
27	Reserve for goods & services ss.20(1)(m)				0	
28	Reserve for unpaid amounts ss.20(1)(n)				0	
29	Debt and share issue expenses ss.20(1)(e)				0	
30	Other - Please describe				0	
31	Other - Please describe				0	
32					0	
33					0	
34	Insert line above this line					
35	**Total (**carry forward to the TAXREC worksheet)		0	0	0	
36						
37						
38	**FINANCIAL STATEMENT RESERVES**					
39						
40	**Beginning of Year:**					
41					0	
42					0	
43	Environmental				0	
44	Allowance for doubtful accounts		6,570		6,570	
45	Inventory obsolescence		1,575,050		1,575,050	
46	Property taxes				0	
47	Other - Post employment benefits		108,397,000		108,397,000	
48	Other-Holdback payable				0	
49					0	
50	**Total (**carry forward to the TAXREC worksheet)		109,978,620	0	109,978,620	
51						

	A	B	C	D	E	F
52	**End of Year:**					
53					0	
54					0	
55	Environmental				0	
56	Allowance for doubtful accounts		255,159		255,159	
57	Inventory obsolescence		2,064,675		2,064,675	
58	Property taxes				0	
59	Other - Post employment benefits		114,575,985		114,575,985	
60	Other - Holdback payable				0	
61	Other-termination accrual		102,000		102,000	
62	Insert line above this line					
63	**Total (**carry forward to the TAXREC worksheet)		116,997,819	0	116,997,819	
64						

	A	B	C	D	E	F
1						
2	**PILs TAXES - EB-2012-0064**	LINE	M of F	Non-wires	**Wires-only**	
3	**TAX RETURN RECONCILIATION (TAXREC 2)**		Corporate	Eliminations	**Tax**	
4	(for "wires-only" business - see s. 72 OEB Act)		Tax		**Return**	
5	**RATEPAYERS ONLY**		Return			
6	**Shareholder-only Items should be shown on TAXREC 3**				**Version 2009.1**	
7						
8	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**					
9	**Reporting period: 2005**					
10	**Number of days in taxation year:**		365			
11	**Materiality Level:**		1,641,325			
12						
13						
14						
15	**Section C: Reconciliation of accounting income to taxable income**					
16	**Add:**					
17		+			0	
18	Gain on sale of eligible capital property	+			0	
19	Loss on disposal of assets	+			0	
20	Charitable donations (Only if it benefits ratepayers)	+			0	
21	Taxable capital gains	+	1,309,959		1,309,959	
22		+			0	
23	Scientific research expenditures deducted	+			0	
24	per financial statements	+	1,714,361		1,714,361	
25	Capitalized interest	+			0	
26	Soft costs on construction and renovation of buildings	+			0	
27	Capital items expensed	+			0	
28	Debt issue expense	+			0	
29	Financing fees deducted in books	+	484,528		484,528	
30	Gain on settlement of debt	+			0	
31	Interest paid on income debentures	+			0	
32	Recapture of SR&ED expenditures	+			0	
33	Share issue expense	+			0	
34	Write down of capital property	+			0	
35	Amounts received in respect of qualifying environment trust	+			0	
36	Provision for bad debts	+			0	
37		+			0	
38	*Other Additions: (please explain in detail the nature of the item)*	+			0	
39	Ontario specified tax credit subject to tax	+	109,836		109,836	
40	Interest expense re capital lease obligations	+	2,830		2,830	
41	Asset retirement obligation- accretion expense	+	243,677		243,677	
42		+			0	
43		+			0	
44	Reversal of bad debt deduction for tax purposes on GST recovered	+	1,802,791		1,802,791	
45	Deferred revenue- 12(1)(a) inclusion	+	21,216,745		21,216,745	
46	Total Additions	=	26,884,727	0	26,884,727	
47						
48	Recap of Material Additions:					
49			0	0	0	
50			0	0	0	
51			0	0	0	
52			0	0	0	
53	Taxable capital gain-net against accounting gain		0	0	0	
54			0	0	0	
55			0	0	0	
56	Scientific research expenditures deducted		1,714,361	0	1,714,361	
57			0	0	0	
58			0	0	0	
59			0	0	0	
60			0	0	0	
61			0	0	0	

	A	B	C	D	E	F
1						
2	**PILs TAXES - EB-2012-0064**	LINE	M of F	Non-wires	**Wires-only**	
3	**TAX RETURN RECONCILIATION (TAXREC 2)**		Corporate	Eliminations	**Tax**	
4	(for "wires-only" business - see s. 72 OEB Act)		Tax		**Return**	
5	**RATEPAYERS ONLY**		Return			
6	**Shareholder-only Items should be shown on TAXREC 3**				**Version 2009.1**	
7						
8	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**					
9	**Reporting period: 2005**					
10	**Number of days in taxation year:**		365			
11	**Materiality Level:**		1,641,325			
12						
13						
62			0	0	0	
63			0	0	0	
64			0	0	0	
65			0	0	0	
66			0	0	0	
67			0	0	0	
68			0	0	0	
69			0	0	0	
70			0	0	0	
71			0	0	0	
72			0	0	0	
73			0	0	0	
74			0	0	0	
75	Reversal of bad debt deduction for tax purposes on GST recovered		1,802,791	0	1,802,791	
76	Deferred revenue- 12(1)(a) inclusion		21,216,745	0	21,216,745	
77	Total Material additions		24,733,897	0	24,733,897	
78	Other additions less than materiality level		2,150,830	0	2,150,830	
79	Total Additions		26,884,727	0	26,884,727	

	A	B	C	D	E	F
1						
2	**PILs TAXES - EB-2012-0064**	LINE	M of F	Non-wires	**Wires-only**	
3	**TAX RETURN RECONCILIATION (TAXREC 2)**		Corporate	Eliminations	**Tax**	
4	(for "wires-only" business - see s. 72 OEB Act)		Tax		**Return**	
5	**RATEPAYERS ONLY**		Return			
6	**Shareholder-only Items should be shown on TAXREC 3**				**Version 2009.1**	
7						
8	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**					
9	**Reporting period: 2005**					
10	**Number of days in taxation year:**		365			
11	**Materiality Level:**		1,641,325			
12						
13						
80						
81	Deduct:					
82	Gain on disposal of assets per f/s, net of taxable capital gain	-	2,964,336		2,964,336	
83	Dividends not taxable under section 83	-			0	
84	Terminal loss from Schedule 8	-			0	
85	Depreciation in inventory, end of prior year	-			0	
86	Scientific research expenses claimed in year from Form T661	-	1,445,173		1,445,173	
87	Bad debts	-			0	
88	Book income of joint venture or partnership	-			0	
89	Equity in income from subsidiary or affiliates	-			0	
90	Contributions to a qualifying environment trust	-			0	
91	Other income from financial statements	-			0	
92	Post employment benefits capitalized to fixed assets for acc'itng purposes	-	3,672,000		3,672,000	
93	Deferred revenue -20(1)(m) deduction	-	21,216,754		21,216,754	
94	*Other deductions: (Please explain in detail the nature of the item)*	-			0	
95		-			0	
96	Asset retirement obligation- cash payment deducted for tax	-	351,057		351,057	
97	Debt financing fees- deducted for tax S 20(1)(e)	-	1,121,325		1,121,325	
98	Lease payments	-	9,049		9,049	
99	Total Deductions	=	30,779,694	0	30,779,694	
100						
101	Recap of Material Deductions:					
102	Gain on disposal of assets per f/s, net of taxable capital gain		0	0	0	
103			0	0	0	
104			0	0	0	
105			0	0	0	
106	Scientific research expenses claimed for tax -net against add back		1,445,173	0	1,445,173	
107			0	0	0	
108			0	0	0	
109			0	0	0	
110			0	0	0	
111			0	0	0	
112	Post employment benefits capitalized to fixed assets for acc'itng purposes		3,672,000	0	3,672,000	
113	Deferred revenue -20(1)(m) deduction		21,216,754	0	21,216,754	
114			0	0	0	
115			0	0	0	
116			0	0	0	
117			0	0	0	
118			0	0	0	
119	Total Deductions exceed materiality level		26,333,927	0	26,333,927	
120	Other deductions less than materiality level		4,445,767	0	4,445,767	
121	Total Deductions		30,779,694	0	30,779,694	
122						

	A	B	C	D	E	F
1						
2	**PILs TAXES - EB-2012-0064**					
3	**TAX RETURN RECONCILIATION (TAXREC 3)**					
4	**Shareholder-only Items should be shown on TAXREC 3**	LINE	M of F	Non-wires	**Wires-only**	
5	**ITEMS ON WHICH TRUE-UP DOES NOT APPLY**		Corporate	Eliminations	**Tax**	
6	(for "wires-only" business - see s. 72 OEB Act)		Tax		**Return**	
7	**0**		Return			
8	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**				**Version 2009.1**	
9						
10						
11	**Reporting period: 2005**					
12	**Number of days in taxation year:**		365			
13						
14						
15						
16	**Section C: Reconciliation of accounting income to taxable income**					
17	**Add:**					
18						
19	Recapture of capital cost allowance	+			0	
20	CCA adjustments	+			0	
21	CEC adjustments	+			0	
22	Gain on sale of non-utility eligible capital property	+			0	
23	Gain on sale of utility eligible capital property	+			0	
24	Loss from joint ventures or partnerships	+			0	
25	Deemed dividend income	+			0	
26	Loss in equity of subsidiaries and affiliates	+			0	
27	Loss on disposal of utility assets	+			0	
28	Loss on disposal of non-utility assets	+			0	
29	Depreciation in inventory -end of year	+			0	
30	Depreciation and amortization adjustments	+			0	
31	Dividends credited to investment account	+			0	
32	Non-deductible meals	+	144,667		144,667	
33	Non-deductible club dues	+	65,882		65,882	
34	Non-deductible automobile costs	+			0	
35	**Donations - amount per books**				0	
36	Interest and penalties on unpaid taxes		800		800	
37	Management bonuses unpaid after 180 days of year end				0	
38	Imputed interest expense on Regulatory Assets				0	
39	**Ontario capital tax adjustments**	+			0	
40	**Changes in Regulatory Asset balances**	+	9,467,077		9,467,077	
41	*Other Additions: (please explain in detail the nature of the item)*	+			0	
42	Taxable capital gains	+	1,309,959		1,309,959	
43		+			0	
44		+			0	
45		+			0	
46		+				
47	**Total Additions on which true-up does not apply**	=	10,988,385	0	10,988,385	
48						
49	**Deduct:**					
50						
51	CCA adjustments	-			0	
52	CEC adjustments	-			0	
53	Depreciation and amortization adjustments	-			0	
54	Gain on disposal of assets per financial statements	-			0	
55	Financing fee amorization - considered to be interest expense for PILs	-			0	
56	Imputed interest income on Regulatory Assets	-	558,336		558,336	
57	**Donations - amount deductible for tax purposes**	-			0	
58	Income from joint ventures or partnerships	-			0	
59	Gain on disposal of assets per f/s, net of taxable capital gain	-	2,964,336		2,964,336	
60		-			0	

	A	B	C	D	E	F
4	**Shareholder-only Items should be shown on TAXREC 3**	LINE	M of F	Non-wires	**Wires-only**	
5	**ITEMS ON WHICH TRUE-UP DOES NOT APPLY**		Corporate	Eliminations	**Tax**	
6	(for "wires-only" business - see s. 72 OEB Act)		Tax		**Return**	
7	**0**		Return			
8	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**				**Version 2009.1**	
61		-			0	
62		-			0	
63		-			0	
64	**Ontario capital tax adjustments to current or prior year**	-			0	
65		-			0	
66	**Changes in Regulatory Asset balances**	-			0	
67		-			0	
68	*Other deductions: (Please explain in detail the nature of the item)*	-			0	
69		-			0	
70		-			0	
71		-			0	
72		-			0	
73	**Total Deductions on which true-up does not apply**	=	3,522,672	0	3,522,672	
74						

PILs TAXES - EB-2012-0064
Corporate Tax Rates **Version 2009.1**
Exemptions, Deductions, or Thresholds
Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED
Reporting period: 2005

Table 1

Rates Used in 2005 RAM PILs Applications for 2005

Income Range RAM 2002	Year	0 to 200,000		200,001 to 700,000	>700,000
Income Tax Rate					
Proxy Tax Year	*2005*				
Federal (Includes surtax)					22.12%
and Ontario blended					14.00%
Blended rate					36.12%
Capital Tax Rate		0.300%			
LCT rate		0.175%			
Surtax		1.12%			
Ontario Capital Tax Exemption **	MAX $7.5MM	7,500,000			
Federal Large Corporations Tax Exemption **	MAX $50MM	50,000,000			

****Exemption amounts must agree with the Board-approved 2005 RAM PILs filing**

Table 2

Expected Income Tax Rates for 2005 and Capital Tax Exemptions for 2005

Income Range Expected Rates	Year	0 to 200,000		200,001 to 700,000	>700,000
Income Tax Rate					
Current year	*2005*				
Federal (Includes surtax)					22.12%
Ontario					14.00%
Blended rate					36.12%
Capital Tax Rate		0.300%			
LCT rate		0.175%			
Surtax		1.12%			
Ontario Capital Tax Exemption ***	MAX $7.5MM	7,500,000			
Federal Large Corporations Tax Exemption ***	MAX $50MM	50,000,000			

*****Allocation of exemptions must comply with the Board's instructions regarding regulated activities.**

	A	B	C	D	E	F	G
43						**Table 3**	
44	**Input Information from Utility's Actual 2005 Tax Returns**						
45	**Income Range**		**0**		**200,001**		
46			**to**		**to**	**>700,000**	
47		**Year**	**200,000**		**700,000**		
48	**Income Tax Rate**						
49	***Current year***	***2005***					
50	***Federal (Includes surtax)***					22.12%	
51	***Ontario***					14.00%	
52	***Blended rate***					36.12%	
53							
54	**Capital Tax Rate**		0.300%				
55	**LCT rate**		0.175%				
56	**Surtax**		1.12%				
57	**Ontario Capital Tax Exemption** *	**MAX $7.5MM**	7,500,000				
58	**Federal Large Corporations Tax Exemption** *	**MAX $50MM**	50,000,000				
59	*** Include copies of the actual tax return allocation calculations in your**						
60	**submission: Ontario CT23 page 11; federal T2 Schedule 36**						
61							

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**PILs TAXES - EB-2012-0064**														
2	**Analysis of PILs Tax Account 1562:**														
3	**Utility Name: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED**														**Version 2009.1**
4	**Reporting period: 2005**				**Sign Convention: + for increase; - for decrease**										**0**
5															
6															
7															
8	**Year start:**		01/10/2001		01/01/2002		01/01/2003		01/01/2004		01/01/2005		01/01/2006		
9	**Year end:**		31/12/2001		31/12/2002		31/12/2003		31/12/2004		31/12/2005		30/04/2006		Total
10															
11	**Opening balance:**	=	0		5,028,333		8,127,575		8,284,720		-619,716		-3,773,161		0
12	**Board-approved PILs tax proxy from Decisions (1)**	+/-	5,000,000		55,000,000		60,000,000		58,571,734		60,109,102		0		238,680,836
13	**PILs proxy from April 1, 2005 - input 9/12 of amount**														0
14	**True-up Variance Adjustment Q4, 2001 (2)**	+/-			-290,810										-290,810
15	**True-up Variance Adjustment (3)**	+/-					2,156,868		-6,024,420		-1,684,166		-350,320		-5,902,038
16	**Deferral Account Variance Adjustment Q4, 2001 (4)**														0
17	**Deferral Account Variance Adjustment (5)**	+/-					-2,412,196		-3,807,479		0				-6,219,675
18	**Adjustments to reported prior years' variances (6)**	+/-													0
19	**Carrying charges (7)**	+/-	28,333		720,305		562,257		269,130		-225,213				1,354,812
20	**PILs billed to (collected from) customers (8)**	-	0		-52,330,253		-60,149,784		-57,913,401		-61,353,168				-231,746,606
21															
22	**Ending balance: # 1562**		5,028,333		8,127,575		8,284,720		-619,716		-3,773,161		-4,123,481		-4,123,481

Uncollected PILs

NOTE: The purpose of this worksheet is to show the movement in Account 1562 which establishes the receivable from or liability to ratepayers.
For explanation of Account 1562 please refer to Accounting Procedures Handbook for Electric Distribution Utilities and FAQ April 2003.

Please identify if Method 1, 2 or 3 was used to account for the PILs proxy and recovery. ANSWER: METHOD 3

(1) (i) From the Board's Decision - see Inclusion in Rates, Part III of the TAXCALC spreadsheet for Q4 2001 and 2002.
Please insert the Q4, 2001 proxy in column C even though it was approved effective March 1, 2002.
If the Board gave more than one decision in the year, calculate a weighted average proxy.
(ii) If the Board approved different amounts, input the Board-approved amounts in cells C13 and E13.
(iii) Column G - In 2003, the initial estimate should include the Q4 2001 PILs tax proxy and the 2002 PILs tax proxy.
(iv) Column I - The Q4 2001 PILs tax proxy was removed from rates on April 1, 2004 and the 2002 PILs tax proxy remained.
(v) Column K - The 2002 PILs tax proxy applies to January 1 to March 31, 2005, and the new 2005 PILs tax proxy from April 1 to December 31, 2005.
(vi) Column M - The 2005 PILs tax proxy will used for the period from January 1 to April 30, 2006.

(2) From the Ministry of Finance Variance Column, under Future True-ups, Part IV a, cell I132, of the TAXCALC spreadsheet. The Q4, 2001 proxy has to be trued up in 2002, 2003 and for the period January 1- March 31, 2004. Input the variance in the whole year reconcilation.

(3) From the Ministry of Finance Variance Column, under Future True-ups, Part IV a, cell I132, of the TAXCALC spreadsheet.
The true-up will compare to the 2002 proxy for 2002, 2003, 2004 and January 1 to March 31, 2005.

(4) From the Ministry of Finance Variance Column, under Future True-ups, Part IV b, cell I181, of the TAXCALC spreadsheet. The Q4, 2001 proxy has to be trued up in 2002, 2003 and for the period January 1- March 31, 2004. Input the deferral variance in the whole year reconciliation.

(5) From the Ministry of Finance Variance Column, under Future True-ups, Part IV a, cell I181, of the TAXCALC spreadsheet.
The true-up will compare to the 2002 proxy for 2002, 2003, 2004 and January 1 to March 31, 2005.

(6) The correcting entry should be shown in the year the entry was made. The true-up of the carrying charges will have to be reviewed.

(7) Carrying charges are calculated on a simple interest basis.

(8) (i) PILs collected from customers from March 1, 2002 to March 31, 2004 were based on a fixed charge and a volumetric charge recovery by class. The PILs rate components for Q4, 2001and 2002 were calculated in the 2002 approved RAM on sheet 6 and sheet 8. In April 2004, the PILs recovery was based on the 2002 PILs tax proxy recovered by the volumetric rate by class as calculated on sheet 7 of the 2004 RAM.
The 2005 PILs tax proxy is being recovered on a volumetric basis by class.

(ii) Collections should equal: (a) the actual volumes/ load (kWhs, kWs, Kva) for the period (including net unbilled at period end), multiplied by the PILs volumetric proxy rates by class (from the Q4, 2001and 2002 RAM worksheets) for 2002, 2003 and January 1 to March 31, 2004; plus, (b) customer counts by class in the same period multiplied by the PILs fixed charge rate components.

In 2004, use the Board-approved 2002 PILs proxy, recovered on a volumetric basis by class as calculated by the 2004 RAM, sheet 7, for the period April 1 to December 31, 2004, and add this total to the results from the sentence above for January 1 to March 31, 2004.

In 2005, use the Board-approved 2005 PILs proxy, recovered on a volumetric basis by class as calculated by the 2005 RAM, sheet 4, for the period April 1 to December 31, 2005. To this total, the 2004 volumetric PILs proxy rate by class should be used to calculate the recovery for the period January 1 to March 31, 2005.

(9) Any interim PILs recovery from Board Decisions will be recorded in APH Account # 1590. Final reconciliation of PILs proxy taxes will have to include amounts from 1562 and from 1590.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 3.1

INTERROGATORY 85:

Reference(s): T5

The federal large corporation tax (LCT) was repealed retroactively in 2006 with effect from January 1, 2006. However, both the 2005 and 2006 rates contained LCT since the repeal was issued after the Board's decisions were issued. Distributors have to account for the refund to ratepayers and were instructed to use both PILs account 1562 and account 1592 for this purpose.

a) Did THESL include the repeal of the large corporations tax (LCT) in account 1562 for the period January 1, 2006 to April 30, 2006 in accordance with FAQ July 2007?

RESPONSE:

a) THESL included the repeal of the LCT in account 1562 for the period January 1, 2006 to April 30, 2006 in accordance with FAQ July 2007.

b) If the answer is no, did THESL record the LCT amount related to this period in account 1592?

RESPONSE:

b) Not applicable, see answer in a) above.

c) Please state whether or not THESL has requested disposition of account 1592 since May 1, 2006, and whether or not the balance included the LCT amount related to the period January 1, 2006 to April 30, 2006.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 3.1

RESPONSE:

c) THESL has requested and received approval for disposition of account 1592 since May 1, 2006, and the balance did not include the LCT amount related to the period January 1, 2006 to April 30, 2006. Account 1592 captured the LCT amount for the period May 1, 2006 to April 30, 2007.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 3.1

INTERROGATORY 86:

Reference(s): T5

Please confirm that all tax years from 2001 to 2005 are now statute-barred.

RESPONSE:

Confirmed.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 4.1

INTERROGATORY 23:

Reference(s): Tab 2

What is the expected revenue in 2012 for the new Competitive Sector Multi-Unit Residential rate class? What would the revenue have been in 2012 from these customers if the rate change had not been made?

RESPONSE:

The following table shows the forecast revenues based on forecasted billing units for the new class (as presented in EB-2010-0142), the proposed distribution rates for the new class (excluding proposed rate adders and riders), and existing (2011) rates for the residential class.

Competitive Sector Multi-Unit Residential Class							
		Distribution Rates			Annual Distribution Revenue based on:		
	2012 Forecast Billing Units (Note 1)	2012 Proposed Rates	2011 Residential Rates		2012 Proposed Rates	2011 Residential Rates	
Customer Charge	24,898	17.12	18.25		5,186,087	5,528,393	
Volumetric Charge	99,791,184	0.02582	0.0152		2,576,608	1,516,826	
					7,762,696	7,045,219	
Notes							
1. Forecast billing units as filed in EB-2010-0142							

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 4.1

INTERROGATORY 116:

Reference(s): **Tab 2, page 26, lines 12-15**
Tab 3, Schedule B1, page 2

a) The types of metering used by "competitive sector sub-metering providers" are likely to change over time. How will THESL determine, on an ongoing basis, what metering technologies are "substantially similar" such that the associated customer should be classified as a Competitive Sector Multi-Unit Residential customer?

RESPONSE:

a) THESL is continuously aware of the various sub-metering technologies available in the market due to its participation in the competitive sub-metering sector. THESL will determine what is "substantially similar" based on the meter application (Multi-unit residential) and meter type (compact non-socket meters), and accordingly classify such customers under the Competitive Sector Multi-Unit Residential class.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES ON ISSUE 4.2

INTERROGATORY 36:

Reference(s): Tab 4, Schedule A, Page 1

Preamble:

The evidence indicates that THESL seeks the Board's approval for incremental revenue requirements of $26.8 M, $36.0 M and $13.5 M for the years 2012, 2013 and 2014, respectively, to be recovered from customers through fixed and variable class specific rate adders over the applicable calendar years commencing June 1, 2012 and May 1, 2013 and 2014, respectively, related to non-discretionary, incremental capital investments.

a) Please provide the rational [sic] for recovering ICM funds using fixed and variable rate adders?

RESPONSE:

a) The OEB's ICM model calculates ICM rate adders both on a Fixed and Variable basis (Option A in the model), and on a Variable only basis (Option B in the model). THESL sees no reason to treat the recovery of ICM capital amounts any differently than capital would be recovered under conventional Rebasing rate setting, which would recover these costs through both rate components.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 4.2

INTERROGATORY 24:

Reference(s): none provided

Assuming THESL's application, as filed, is accepted by the Board, please set out the distribution rate increase for a typical residential customer for each year 2012-2014. In addition, please provide the total bill impact for a typical residential customer for each year.

RESPONSE:

The information requested can be found in Tab 3, C1.2 (page 1), C2.2 (page 1) and C3.2 (page 1). For convenience, the information is summarized below.

Monthly Bill					Change		
2011 Approved Rates	2012 Proposed	2013 Proposed	2014 Proposed		2012 over 2011	2013 over 2012	2014 over 2013
29.50	33.31	35.71	36.67		3.81	2.40	0.96
9.74	11.23	11.23	11.23		1.49	0.00	0.00
73.29	76.32	76.32	76.32		3.03	0.00	0.00
112.53	120.86	123.27	124.22		8.33	2.41	0.95
Tab 3, C1.2, p. 1	Tab 3, C1.2, p. 1	Tab 3, C2.2, p. 1	Tab 3, C3.2, p. 1				

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 4.2

INTERROGATORY 25:

Reference(s): none provided

Please provide a schedule setting out an average annual THESL residential bill for each year 2006-2011. Please provide a forecast for 2012, 2013 and 2014, assuming THESL's proposals are approved.

RESPONSE:

a) The table below presents the estimated annual residential bill amounts for 2006 to 2011.

Estimated Annual Residential Bills						
Calendar Year	Distribution	Total Bill				
2006	$ 337.36	$ 1,130.20				
2007	$ 333.66	$ 1,109.24				
2008	$ 344.93	$ 1,097.68				
2009	$ 338.45	$ 1,153.53				
2010	$ 356.74	$ 1,244.94				
2011	$ 360.17	$ 1,300.66				
Notes:						
1. Average residential RPP customer using 800 kWh/month (830 kWh TLF adjusted)						
2. Distribution includes Rate Riders						
3. Energy prices are tiered RPP. The prices and the threshold amount (600 and 1000 kWh) change twice per year.						

THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response to this interrogatory for the forecast years, such that providing a

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 4.2

response now would not materially assist the OEB or intervenors. THESL accordingly defers providing the 2012 to 2014 values in the table above until after its forthcoming evidentiary update.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 4.2

INTERROGATORY 26:

Reference(s): Tab 2/p. 21

From a legal perspective how can the Board now declare rates interim effective June 1, 2012? Why would this not constitute retroactive rate-making?

RESPONSE:

Please also see the response to OEB Staff interrogatory 11 (Tab 6B, Schedule 1-11).

On May 30, 2012, the OEB issued an Order making rates interim effective June 1, 2012.

THESL emphasizes however, that it does not propose to re-bill customers for consumption over the period June 1, 2012 to the date of rate implementation. THESL's position on this matter is set out in the above-referenced response.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 4.2

INTERROGATORY 27:

Reference(s): **Tab 2/p. 21**

Assuming the Board approves THESL's proposals and effective date for 2012, how does THESL intend to communicate the rate changes to its customers? Has any communication been undertaken to date with respect to this issue? The Council's concern is that customers would not know, likely until Q1 2013, that the rates they have been paying will be subject to a retroactive adjustment back to June 1, 2012. This would be particularly problematic given the extremely hot summer in 2012. Please comment on how THESL proposes to address this concern.

RESPONSE:

Please see the response to OEB Staff interrogatory 11 (Tab 6B, Schedule 1-11). To notify its customers of rate changes, THESL uses bill inserts and its website.

THESL does not propose to re-bill customers for consumption that took place prior to the date of rate implementation. However, THESL proposes that fixed term 'foregone revenue' rate riders be implemented <u>prospectively</u> to enable THESL to recover the revenue it would have recovered had rates been implemented effective June 1. This is parallel to THESL's OEB-approved approach in the past in circumstances of delayed rate implementation. On this basis rates would change only prospectively, and the rate applicable to historical consumption would not change.

Should the OEB consider it advisable THESL would work with OEB Staff and interested parties on the content and method of customer communications about the implications of the Decision.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 4.2

INTERROGATORY 28:

Reference(s): **Tab 2/p. 21**

Please explain why THESL should get full recovery of its revenue requirement for 2012 given its application was not filed until May 10, 2012.

RESPONSE:

THESL does not control regulatory timelines and outcomes. In good faith THESL filed a comprehensive application for rates covering the 2012-2014 period on August 26, 2011. THESL followed the regulatory timeline and process for the determination of that application as set by the OEB. Ultimately that application was dismissed by the OEB. THESL then assessed the content and implications of that decision and promptly acted to re-formulate an application for the same period in light of the guidance provided by the OEB in its decision. THESL was not 'late' in initiating an application for 2012 and was diligent and timely in its participation in the regulatory process.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 4.2

INTERROGATORY 29:

Reference(s): **Tab 2**

Please provide a schedule setting out THESL's approved and actual ROE for each year 2006-2011. Please provide the most current estimate of its expected ROE for 2012.

RESPONSE:

Please see the table below.

Actual ROE vs Approved ROE				
Period	Rate Mechanism	Approved ROE	Actual ROE[1]	Projected
2006	COS	9.00%	11.32%	n/a
2007	IRM	9.00%	9.29%	n/a
2008	COS	8.57%	10.12%	n/a
2009	COS	8.01%	6.35%	n/a
2010	COS	9.85%	7.44%	n/a
2011	COS	9.58%	9.94%	n/a

[1] As per THESL published financial statements

THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response to this interrogatory, such that providing a response now would not materially assist the OEB or intervenors. THESL accordingly defers providing the ROE for 2012 until after its forthcoming evidentiary update.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 4.2

INTERROGATORY 56:

Reference(s): Managers Summary Tab 2, Page 27

Please provide a Summary Schedule that shows by rate class the following Components of rates for 2011 base rates through to 2014 (prefer Excel Spreadsheet):

1. 2012 price cap adjustment
2. adjusted Retail Transmission Service Rates
3. rate rider to refund shared tax savings
4. rate rider for disposition of account balances in accounts 1521 Special Purpose Charge and account 1562 PILs Deferral Account
5. rate adder for incremental capital projects

RESPONSE:

a) THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response to this interrogatory, such that providing a response now would not materially assist the OEB or intervenors. THESL accordingly defers its response to this interrogatory until after its forthcoming evidentiary update.

Residential

Rate component	2011	2012	2013	2014
2012 price cap adjustment				
Service Charge (fixed)	$ 18.25	$ 18.37	$ 18.50	$ 18.62
Distribution Volumetric Rate	$ 0.01520	$ 0.01518	$ 0.01528	$ 0.01538
Rate rider to refund shared tax savings	n/a	n/a	n/a	n/a
Deferral Account rate rider	-$ 0.00232	-$ 0.00050	n/a	n/a
Rate adder for incremental capital projects				
2012 ICM Rate Rider (fixed)	n/a	$ 0.92	$ 0.92	$ 0.92
2013 ICM Rate Rider (fixed)	n/a	n/a	$ 1.23	$ 1.23
2014 ICM Rate Rider (fixed)	n/a	n/a	n/a	$ 0.46
2012 ICM Rate Rider (variable)	n/a	$ 0.00077	$ 0.00077	$ 0.00077
2013 ICM Rate Rider (variable)	n/a	n/a	$ 0.00103	$ 0.00103
2014 ICM Rate Rider (variable)	n/a	n/a	n/a	$ 0.00039
Adjusted Retail Transmission Service Rates				
Network Service Rate	$ 0.00703	$ 0.00752	$ 0.00752	$ 0.00752
Line and Transformation Connection Service Rate	$ 0.00513	$ 0.00601	$ 0.00601	$ 0.00601

Competitive Sector Multi-unit Residential

Rate component	2011	2012	2013	2014
2012 price cap adjustment				
Service Charge (fixed)	n/a	$ 17.12	$ 17.23	$ 17.35
Distribution Volumetric Rate	n/a	$ 0.02582	$ 0.02600	$ 0.02618
Rate rider to refund shared tax savings	n/a	-$ 0.0001	n/a	n/a
Deferral Account rate rider	n/a	-$ 0.00056	n/a	n/a
Rate adder for incremental capital projects				
2012 ICM Rate Rider (fixed)	n/a	$ 0.34	$ 0.34	$ 0.34
2013 ICM Rate Rider (fixed)	n/a	n/a	$ 0.46	$ 0.46
2014 ICM Rate Rider (fixed)	n/a	n/a	n/a	$ 0.17
2012 ICM Rate Rider (variable)	n/a	$ 0.00131	$ 0.00131	$ 0.00131
2013 ICM Rate Rider (variable)	n/a	n/a	$ 0.00176	$ 0.00176
2014 ICM Rate Rider (variable)	n/a	n/a	n/a	$ 0.00066
Adjusted Retail Transmission Service Rates				
Network Service Rate	n/a	$ 0.00752	$ 0.00752	$ 0.00752
Line and Transformation Connection Service Rate	n/a	$ 0.00601	$ 0.00601	$ 0.00601

GS<50 kW

Rate component	2011	2012	2013	2014
2012 price cap adjustment				
Service Charge (fixed)	$ 24.3	$ 24.47	$ 24.63	$ 24.80
Distribution Volumetric Rate	$ 0.02247	$ 0.02262	$ 0.02278	$ 0.02293
Rate rider to refund shared tax savings	n/a	n/a	n/a	n/a
Deferral Account rate rider	-$ 0.00223	-$ 0.00037	n/a	n/a
Rate adder for incremental capital projects				
2012 ICM Rate Rider (fixed)	n/a	$ 1.22	$ 1.22	$ 1.22
2013 ICM Rate Rider (fixed)	n/a	n/a	$ 1.64	$ 1.64
2014 ICM Rate Rider (fixed)	n/a	n/a	n/a	$ 0.61
2012 ICM Rate Rider (variable)	n/a	$ 0.00115	$ 0.00115	$ 0.00115
2013 ICM Rate Rider (variable)	n/a	n/a	$ 0.00154	$ 0.00154
2014 ICM Rate Rider (variable)	n/a	n/a	n/a	$ 0.00058
Adjusted Retail Transmission Service Rates				
Network Service Rate	$ 0.00680	$ 0.00728	$ 0.00728	$ 0.00728
Line and Transformation Connection Service Rate	$ 0.00463	$ 0.00542	$ 0.00542	$ 0.00542

GS 50-999 kW

Rate component	2011	2012	2013	2014
2012 price cap adjustment				
Service Charge (fixed)	$ 35.6	$ 35.80	$ 36.05	$ 36.29
Distribution Volumetric Rate	$ 5.59560	$ 5.6337	$ 5.6720	$ 5.7105
Rate rider to refund shared tax savings	n/a	-$ 0.00670	n/a	n/a
Deferral Account rate rider	-$ 0.79260	-$ 0.06420	n/a	n/a
Rate adder for incremental capital projects				
2012 ICM Rate Rider (fixed)	n/a	$ 1.79	$ 1.79	$ 1.79
2013 ICM Rate Rider (fixed)	n/a	n/a	$ 2.40	$ 2.40
2014 ICM Rate Rider (fixed)	n/a	n/a	n/a	$ 0.90
2012 ICM Rate Rider (variable)	n/a	$ 0.28130	$ 0.28130	$ 0.28130
2013 ICM Rate Rider (variable)	n/a	n/a	$ 0.37770	$ 0.37770
2014 ICM Rate Rider (variable)	n/a	n/a	n/a	$ 0.14120
Adjusted Retail Transmission Service Rates				
Network Service Rate	$ 2.43510	$ 2.60570	$ 2.60570	$ 2.60570
Line and Transformation Connection Service Rate	$ 1.76300	$ 2.06480	$ 2.06480	$ 2.06480

GS 1,000-4,999 kW

Rate component	2011	2012	2013	2014
2012 price cap adjustment				
Service Charge (fixed)	$ 686.5	$ 691.13	$ 695.83	$ 700.56
Distribution Volumetric Rate	$ 4.44970	$ 4.4800	$ 4.5104	$ 4.5411
Rate rider to refund shared tax savings	n/a	-$ 0.00560	n/a	n/a
Deferral Account rate rider	-$ 0.90550	-$ 0.05080	n/a	n/a
Rate adder for incremental capital projects				
2012 ICM Rate Rider (fixed)	n/a	$ 34.51	$ 34.51	$ 34.51
2013 ICM Rate Rider (fixed)	n/a	n/a	$ 46.34	$ 46.34
2014 ICM Rate Rider (fixed)	n/a	n/a	n/a	$ 17.32
2012 ICM Rate Rider (variable)	n/a	$ 0.22370	$ 0.22370	$ 0.22370
2013 ICM Rate Rider (variable)	n/a	n/a	$ 0.30030	$ 0.30030
2014 ICM Rate Rider (variable)	n/a	n/a	n/a	$ 0.11230
Adjusted Retail Transmission Service Rates				
Network Service Rate	$ 2.35270	$ 2.51750	$ 2.51750	$ 2.51750
Line and Transformation Connection Service Rate	$ 1.76130	$ 2.06280	$ 2.06280	$ 2.06280

Large Use

Rate component	2011	2012	2013	2014
2012 price cap adjustment				
Service Charge (fixed)	$ 3,009.1	$ 3,029.57	$ 3,050.17	$ 3,070.91
Distribution Volumetric Rate	$ 4.74060	$ 4.7728	$ 4.8053	$ 4.8380
Rate rider to refund shared tax savings	n/a	-$ 0.00590	n/a	n/a
Deferral Account rate rider	-$ 0.98110	-$ 0.05280	n/a	n/a
Rate adder for incremental capital projects				
2012 ICM Rate Rider (fixed)	n/a	$ 151.26	$ 151.26	$ 151.26
2013 ICM Rate Rider (fixed)	n/a	n/a	$ 203.11	$ 203.11
2014 ICM Rate Rider (fixed)	n/a	n/a	n/a	$ 75.94
2012 ICM Rate Rider (variable)	n/a	$ 0.23830	$ 0.23830	$ 0.23830
2013 ICM Rate Rider (variable)	n/a	n/a	$ 0.32000	$ 0.32000
2014 ICM Rate Rider (variable)	n/a	n/a	n/a	$ 0.11960
Adjusted Retail Transmission Service Rates				
Network Service Rate	$ 2.68200	$ 2.86990	$ 2.86990	$ 2.86990
Line and Transformation Connection Service Rate	$ 1.95670	$ 2.29170	$ 2.29170	$ 2.29170

Street Lighting

Rate component	2011	2012	2013	2014
2012 price cap adjustment				
Service Charge (fixed, per connection)	$ 1.3	$ 1.31	$ 1.32	$ 1.33
Distribution Volumetric Rate	$ 28.72480	$ 28.9201	$ 29.1168	$ 29.3148
Rate rider to refund shared tax savings	n/a	-$ 0.04250	n/a	n/a
Deferral Account rate rider	-$ 0.93670	-$ 0.45290	n/a	n/a
Rate adder for incremental capital projects				
2012 ICM Rate Rider (fixed)	n/a	$ 0.07	$ 0.07	$ 0.07
2013 ICM Rate Rider (fixed)	n/a	n/a	$ 0.09	$ 0.09
2014 ICM Rate Rider (fixed)	n/a	n/a	n/a	$ 0.03
2012 ICM Rate Rider (variable)	n/a	$ 1.44390	$ 1.44390	$ 1.44390
2013 ICM Rate Rider (variable)	n/a	n/a	$ 1.93890	$ 1.93890
2014 ICM Rate Rider (variable)	n/a	n/a	n/a	$ 0.72490
Adjusted Retail Transmission Service Rates				
Network Service Rate	$ 2.16580	$ 2.31750	$ 2.31750	$ 2.31750
Line and Transformation Connection Service Rate	$ 2.10220	$ 2.46210	$ 2.46210	$ 2.46210

Unmetered Scattered Load

Rate component	2011	2012	2013	2014
2012 price cap adjustment				
Service Charge (fixed, per connection)	$ 0.49	$ 0.49	$ 0.50	$ 0.50
Service Charge (fixed, per customer)	$ 4.84	$ 4.87	$ 4.91	$ 4.94
Distribution Volumetric Rate	$ 0.06070	$ 0.0611	$ 0.0615	$ 0.0620
Rate rider to refund shared tax savings	n/a	-$ 0.00010	n/a	n/a
Deferral Account rate rider	-$ 0.00238	-$ 0.00102	n/a	n/a
Rate adder for incremental capital projects				
2012 ICM Rate Rider (fixed, per connection)	n/a	$ 0.24	$ 0.24	$ 0.24
2012 ICM Rate Rider (fixed, per customer)	n/a	0.02	$ 0.02	$ 0.02
2013 ICM Rate Rider (fixed, per connection)	n/a	n/a	$ 0.33	$ 0.33
2013 ICM Rate Rider (fixed, per customer)	n/a	n/a	$ 0.03	$ 0.03
2014 ICM Rate Rider (fixed, per connection)	n/a	n/a	n/a	$ 0.12
2014 ICM Rate Rider (fixed, per customer)	n/a	n/a	n/a	$ 0.01
2012 ICM Rate Rider (variable)	n/a	$ 0.00309	$ 0.00309	$ 0.00309
2013 ICM Rate Rider (variable)	n/a	n/a	$ 0.00415	$ 0.00415
2014 ICM Rate Rider (variable)	n/a	n/a	n/a	$ 0.00155
Adjusted Retail Transmission Service Rates				
Network Service Rate	$ 0.00428	$ 0.00458	$ 0.00458	$ 0.00458
Line and Transformation Connection Service Rate	$ 0.00324	$ 0.00379	$ 0.00379	$ 0.00379

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 4.2

INTERROGATORY 57:

Reference(s): **EB-2010-0142 Settlement Agreement Appendix B, Table 1**

a) Please Provide a version of the Referenced Table that projects the data from 2011-2014. (prefer Excel Spreadsheet)

b) Please provide any necessary explanatory notes

RESPONSE:

a) and b)

THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response to this interrogatory, such that providing a response now would not materially assist the OEB or intervenors. THESL accordingly defers its response to the information request until after its forthcoming evidentiary update.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 4.2

INTERROGATORY 58:

Reference(s): Managers Summary Tab 2, Page 21

a) Why does THESL meet the Board's criteria for Interim Rates effective June 1, 2012 when it did not withdraw its legal challenge until the end of August 2012?

RESPONSE:

a) Please see THESL's responses to CCC interrogatories 26 to 28 (Tab 6L, Schedules 6-26 to 6-28).

b) Why does THESL meet the Board's criteria for a Rate Order with rates effective at an earlier date, for example September 1, 2012 when the delays in hearing the Application were as a result of THESL's legal actions?

RESPONSE:

b) Please see THESL's responses to CCC interrogatories 26 to 28 (Tab 6L, Schedules 6-26 to 6-28). THESL does not accept the premise of this question.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 4.2

INTERROGATORY 30:

Reference(s): none provided

Please revise all avoid estimated risk cost calculations to take into account any changes to the application and project schedule that arise due to the Applicant's evidence update referred to in its letter to the Board, dated September 14th, 2012.

RESPONSE:

THESL's risk cost calculations will not be impacted by the changes in the pending evidence update.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 4.2

INTERROGATORY 117:

Reference(s): Tab 2, pages 11 and 27

a) Please clarify THESL's proposal for calculation and approval of the ICM rates riders associated with the 2013 and 2014 capital spending. Specifically, is THESL:

- Asking the Board to approve the ICM rate riders as set out in Tab 3, Schedules B2 and B3 for implementation on May 1, 2013 and May 1, 2014 respectively, or
- Providing the ICM rate riders set out in these schedules as "illustrative" rates and THESL will be re-calculating its proposed ICM rate riders related to capital spending in those years using ICM threshold values that reflect the PCI values prescribed by the Board for those years and (if available) updated growth values based on more recent data but based on the capital spending for 2013 and 2014 as approved in this proceeding?

RESPONSE:

a) THESL will follow the OEB's direction in this matter. THESL intends to file applications for the PCI adjustments to rates for 2013 and 2014, and proposes filing updated ICM rate adders reflecting the new PCI parameters applied to the approved capital spending, at those times.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 4.2

INTERROGATORY 118:

Reference(s): **Tab 1, page 4, lines 17-20**

a) Given the timing of THESL's Application, why is a June 1, 2012 "effective date" appropriate?

RESPONSE:

a) Please refer to THESL's responses to OEB Staff interrogatory 11 (Tab 6B, Schedule 1-11), and CCC interrogatories 26, 27, and 28 (Tab 6L, Schedules 6-26, 6-27, and 6-28).

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 4.2

INTERROGATORY 119:

Reference(s): Tab 2, page 30, lines 9-13

a) Please indicate the “recent” Board rulings that are being referred to in this paragraph.

RESPONSE:

a) THESL is referring to recent Board Decisions concerning applications by various utilities for LRAM adjustments in which CDM savings achieved during COS years, originating from programs implemented during COS years, were deemed ineligible for LRAM relief. Recent examples, among several, would include Whitby Hydro Electric Corporations (EB-2011-0206) and Hearst Power Distribution Company Limited (EB-2011-0171). The OEB’s Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003), released shortly before the filing of this application, reiterated these findings.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 4.2

INTERROGATORY 120:

Reference(s): Tab 3, Schedule B1

a) Please confirm that Schedule B1 sets out the rates that would flow from the Application assuming it was approved as filed and the rates could have been implemented June 1, 2012. If not, please explain.

RESPONSE:

a) The rates calculated and shown in the rate schedules are based on a 12-month recovery period and are based on the OEB's standard ICM models. If THESL's proposed modifications to the ICM revenue requirements (Tab 2, pages 10-14) are approved by the OEB, the ICM rate adders would be different.

b) Assuming the Application were approved as filed, would the only changes to the schedule be: i) the Implementation Date, ii) the addition of a "foregone ICM rate adder revenue" rider reflecting an implementation date later than June 1 2012 and iii) the addition of a "foregone distribution revenue" rider also reflecting an implementation date later than June 1, 2012? If not, please explain.

RESPONSE:

b) In addition to the consideration described in part a) above, if the application were approved as filed, the implementation date would change, and rate riders related to forgone revenue for the distribution rates would be requested. In addition, rate riders for the 2011 Half Year Rule, Shared Tax Savings, and Deferral and Variance accounts would also be affected. Please also refer to THESL's response to OEB Staff interrogatory 11 (Tab 6B, Schedule 1-11) with respect to ICM rate adders.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 4.2

INTERROGATORY 121:

Reference(s): **Tab 3, Schedules B2 and B3**

a) If the Application were approved as filed, please explain how these schedules differ from what THESL would expect the Board to approve for 2013 and 2014 rates.

RESPONSE:

a) THESL has provided rates using the Board's IRM and ICM models using inputs known at the time THESL filed its application. While THESL is seeking approval of capital spending as summarized by Project in Tab 4, Schedule A, Appendix 1, THESL anticipates updating the IRM and ICM models for annual updates to the PCI index (price escalator, productivity factor and stretch factor) as well as the associated changes in the Threshold calculation for 2013 and 2014. These will ultimately affect the calculated distribution and ICM rate adders for 2013 and 2014. In addition, THESL expects to update the retail transmission rates based on approved Hydro One transmission charges.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 4.2

INTERROGATORY 122:

Reference(s): **Tab 3, Schedule C1.2, page 1**

a) Based on the approved 2011 load forecast, what is the average monthly usage for a customer in the Residential class?

RESPONSE:

a) The 2011 approved load for the Residential class (exclusive of the new Competitive Sector Multi-Unit Residential class) was 4,886,977,489 kWh, and the approved mid-year number of customers was 598,508. Based on these values, the average monthly load per customer is 680.4 kWh.

b) If the response to part (a) differs from 800 kWh/month, please re-do the schedule on page 1 using the response to part (a).

RESPONSE:

b) Please see the attached Appendix A. The calculations are based on an average monthly load per customer of 680.4 kWh.

Residential	Current			2012			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	18.25	18.25	1	18.37	18.37	0.12	0.7%
Distribution	680	0.01520	10.34	680	0.01518	10.33	(0.01)	-0.1%
Smart Meter Rider (per 30 days)	1	0.68	0.68	1	0.68	0.68	-	0.0%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	680	(0.00189)	(1.29)	-	-	-	1.29	-100.0%
Regulatory Assets - 2011 Rate Rider	680	(0.00043)	(0.29)	-	-	-	0.29	-100.0%
Contact Voltage	1	0.16	0.16	-	-	-	(0.16)	-100.0%
Late Payment Penalty	1	0.24	0.24	1	0.24	0.24	-	0.0%
Foregone Revenue Rate Rider - fixed rate	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate	680	(0.00017)	(0.12)	-	-	-	0.12	-100.0%
2011 Unfunded Capex Rate Rider - MFC	-	-	-	1	0.44	0.44	0.44	n/a
2011 Unfunded Capex Rate Rider - DVR	-	-	-	680	0.00037	0.25	0.25	n/a
Shared Tax Savings Rate Rider - DVR	-	-	-	-	-	-	-	n/a
ICM Rate Rider - MFC	-	-	-	1	0.92	0.92	0.92	n/a
ICM Rate Rider - DVR	-	-	-	680	0.00077	0.52	0.52	n/a
Deferral/Variance Account Rate Rider	-	-	-	680	(0.00050)	(0.34)	(0.34)	n/a
Sub Total A - Distribution			27.98			31.41	3.44	12.3%
RTST - Network	706	0.00703	4.96	706	0.00752	5.31	0.35	7.0%
RTSR - Connection	706	0.00513	3.62	706	0.00601	4.24	0.62	17.2%
Sub Total B (including Sub-Total A) - Distribution			36.56			40.97	4.40	12.0%
Wholesale Market Rate	706	0.00520	3.67	706	0.00520	3.67	-	0.0%
RRRP	706	0.00130	0.92	706	0.00110	0.78	(0.14)	-15.4%
DRC	680	0.00700	4.76	680	0.00700	4.76	-	0.0%
Standard Supply Service Charge	1	0.25	0.25	1	0.25	0.25	-	0.0%
SPC	706	-	-	706	-	-	-	n/a
Cost of Power Commodity - 1st Tier	600	0.071	42.60	600	0.075	45.00	2.40	5.6%
Cost of Power Commodity - 2nd Tier	106	0.083	8.80	106	0.088	9.33	0.53	6.0%
Total Bill (including Sub-Total B)			97.56			104.75	7.19	7.4%

	kWh
Consumption Details	**680.4**
Total Loss Factor	1.0376