St. Thomas Energy Inc.

2011 EDR

EB-2010-0141

Technical Conference

Responses to Written Questions

May 31, 2011

EXHIBIT 12_Tab 01_S01
Ref: Response to Board staff IR No. 7

a) Were STESI's purchases of goods and services subject to applicable provincial sales tax prior to July 1, 2010? If so, were these costs included in the MSA fee? If not, why not?

b) Are STESI's purchases of goods and services subject to HST?

c) Does STESI remit HST amount and/or claim Input Tax Credits?

i.) If so, for 2010 what portion (and indicate the dollar amount) of incremental Input Tax Credits (i.e. for purchases that were previously subject to PST) are for St. Thomas related activities?

ii.) If so, for 2011 what portion (and indicate the dollar amount) of the expected incremental Input Tax Credits (i.e. for purchases that were previously subject to PST) are for St. Thomas related activities?

RESPONSE to Question 1 – OEB Staff, Second Set:
a) STESI's purchases of goods and services were subject, where applicable, to provincial sales taxes prior to July 1, 2010. These sales taxes were included in STESI's internal cost tracking for the MSA fee but the internal cost tracking of MSA fee by STESI has no impact on the MSA fee charged to STEI. As discussed in original response to Board staff IR No 7, the MSA fee is a fixed fee per customer based on services provided. This fee per customer has an efficiency factor and reduces each year.

b) Yes, STESI's purchases of goods and services are subject to HST.

c) Yes.

i) We do not have that readily available. As discussed in a), STESI didn't specifically consider the PST component as it was felt that it was going to have a minimal impact on the service operations for STESI. Another key reason was that the fixed fee per customer charged to STEI is a fee that has not been increased since the agreement was established. Furthermore, this fixed fee per customer has been reduced annually.

ii) We have not calculated the incremental input tax credits. To do so would have been a labour intensive task with little or no benefit for STESI. Budgeting was based on total potential cost changes for budget and PST would be a nominal component of the overall estimate and not independently identified.

EXHIBIT 12_Tab 01_S02
Ref: Response to Board staff IR No. 9

a) Does St. Thomas have audited statements for 2010?

b) If so, what are the actual capital expenditures for 2010?

c) If so, please update table 2-1-1-1A (Rate Base Additions Summary) found in Exhibit 2-1-1 p3, by replacing Bridge 2010 with Actuals for 2010.

RESPONSE to Question 2 – OEB Staff, Second Set:
a) Please refer to Exhibit 11, Tab 2, Schedule 3, Attachment 1 for the 2010 audited financial statements for St. Thomas Energy Inc.

b) Per the Statement of Cash Flow, the Additions to property, plant and equipment was $1,132,886.

c) STEI undertakes to update this evidence as soon as possible.

EXHIBIT 12_Tab 01_S03

Ref: Response to Board staff IR No.12 **(Re : May 6, 2011 Response - E11T01S12.doc)**

a) Regarding spare part inventory, the IR response states that “Whenput into service it is charged at STESI’s cost plus overhead to account for handling costs.” Does STESI’s cost mean the cost that STESI paid for the item? What is included in the overhead cost? Do the overhead costs include any STESI’s financial carrying or cash flow costs for the inventory?

b) Please reconcile the statement in the IR response that “The cost is not included in the fixed fee as the fixed fee relates to operation, maintenance and administration costs (OM&A); it is treated as a capital cost.” with the statement in the pre-filed evidence found at Exhibit 2-2-1 p.6 lines 25-27 that “The cost of STESI carrying this inventory on behalf of STEI is incorporated in the fixed fee identified in the Service Agreement included under the Exhibit 1, Tab 2, Section 4, Attachment 1.”

RESPONSE to Question 03 – Board Staff, Second Set:

a) When transformers are placed into service for STEI they are charged at STESI’s cost of purchasing transformers from suppliers and related delivery fees. HST is not included in the purchased cost as it is recovered by STESI. Overhead, representing direct labour (warehouse staff) and the use of warehousing equipment to handle inventory, storage of inventory and the financial cost of carrying inventory for subsequent use. A return of 20% on invested capital is also included, in addition to the purchased cost and overhead.

b) The pre-filed evidence was incorrectly stated and should have indicated that the practice is for Major Spare Equipment (Meters and Transformers), when placed into distribution system service (Capital Expenditures), will include inventory carrying costs. The Fixed Fee pertains exclusively to Operational, Maintenance and Administration activities. Any inventory carrying charges related to the placement of Major Spare Equipment into service are charged to capital activities as indicated in a) above.

EXHIBIT 12_Tab 01_S04

4. Ref: Response to Board staff IR No.13
a) Please explain why the capital contribution of $86,000, per the table 2 of the response, for the Parkside School project exceeds the capital expenditures for the project by $24,000.
b) Please clarify whether there were capital contributions for the CASO project ($40,148) and the Sutherland Hydro One Load Transfer project ($45,076).

RESPONSE to Question 4 – OEB, Second Set:

a) The capital contribution related to the Parkside School project exceeds the capital expenditures by $62,147.36 not $24,000 as identified. This variance primarily resulted from the re-deployment of a padmounted transformer valued at nearly $60,000 from another project to this one. In short, a transformer was planned to be purchased for this project, but as another became available it was used at Parkside School rather than returning it into inventory. The remaining variance of approximately $2,000 was related to metering costs coming under forecast.
b) There were capital contributions for the CASO project and these funds ($38,432.45) were received in 2009. No capital contributions were received for the "Build New O/H Powerline – Sutherland Line" project ($45,076.40).

EXHIBIT 12_Tab 01_S05

Ref. Exhibit 3 /Tab 1 /Schedule 2 attachment 1 p.8 **(New Question - COS APP Reference E03T01S02)**

For the GS < 50kW rate class, the "2004-2009 average use per customer" is shown as 24,440 kWh and the "2004 Hydro One Retail NAC" is 25,217 kWh. The "2004-2009 average use per customer" is about 3% less than the "2004 Hydro One Retail NAC".

a) Please confirm that St. Thomas used the "2004-2009 average use per customer" to prepare the load forecast.

b) Please explain what accounts for the 3% difference.

RESPONSE to Question 5 – OEB Staff, Second Set:

a) Confirmed. St. Thomas used the "2004-2009 average use per customer" to prepare the GS<50 kW Class load forecast.

In completing this interrogatory response, it was discovered that Table 4 in the filed version of Exhibit 3, Tab 1, Schedule 2, Attachment 1 contains an error for the Residential Class 2004-2009 Average. This should read 8,461 rather than 8,483. This affects the normalized and forecast values of the Residential Class, as described at Exhibit 11, Tab 1, Schedule 15.

b) Below, we have reproduced Table 3 from Exhibit 3, Tab 1, Schedule 2, Attachment 1 and have added to it observed annual heating degree days (HDD) and cooling degree days (CDD) from London. From this table, it can be seen that HDD and CDD in 2008 exceed HDD and CDD in 2004. It can also be seen that in the Residential Class, average use per customer in 2008 exceeds that in 2004 (8,488 vs. 8,279 or by about 2.5%), as would be expected due to cooling and heating requirements. However, in the GS<50 kW class, average use per customer in 2008 is less than what was observed in 2004 (24,014 vs. 24,992 or about –3.9%) despite weather demands to the contrary. This is consistent with the difference between the "2004 Hydro One Retail NAC" and the reported "2004-2009 average use per customer". It is evident that changes in the customer makeup of the class have contributed to an overall decline in average use per customer. A similar, although more significant, decline also occurs in the GS>50 kW class. This is likely due to structural changes in the local economy and changes in industrial and commercial customer demands.

Table 3
Average Use Per Customer and Degree Days (Actual)

Rate Class	2004	2005	2006	2007	2008	2009
Residential	8,279	8,922	8,360	8,662	8,488	8,056
GS<50	24,992	26,139	24,839	24,420	24,014	22,234
GS>50-4999	1,043,164	1,004,082	980,213	961,490	812,538	673,174
GS>5000	37,281,347	38,375,623	36,937,199	33,251,155	28,374,428	6,504,824
Street Light	644	640	642	642	639	643
Sentinel Light					1,169	1,133
HDD London	3,923	3,950	3,481	3,835	3,961	3,908
CDD London	171	408	275	310	240	159

EXHIBIT 12_Tab 01_S06

Ref: Response to Board staff IR No. 17 **(Re : May 6, 2011 Response - E11T01S17.doc)**

The purpose of IR No. 17 was to gain a clear understanding, by tracking the ERA load forecast of the level of CDM target achievement reflected in St. Thomas's 2011 load forecast. The IR response refers to attachment 3 for the answer to part c of the IR. The information sought is not readily apparent in Attachment 3

a) Please complete the table as requested in part c of the IR and answer, if appropriate, d, e and f of the original question.

RESPONSE to Question 6 – OEB Staff, Second Set:

The requested data has been provided at E11/T1/S13/p2. The format of the presentation varies from that requested in the interrogatory. STEI has filed the representation of the formula relied on by its rate making model to support transparency.

Please refer to E11/T2/S13/p2. The column titled "2011 Normalized" provides the data relied on for rate making purposes for the 2011 Test Year. The "Metered Kilowatt Hour" and "Kilowatts" data for the metered customer classes (i.e., Residential, GS<50, GS>50) is presented as differences. The first term is provided in the Load Forecast (kWh data is found at E11/T1/S13/A3/p2; kW data is found at E3/T1/S2/A1,p9) the second term is provided in the supporting detail on STEI's filed CDM plan (E11/T1/S17/Att4, "Annual Milestones").

EXHIBIT 12_Tab 01_S07

Ref: Response to Board staff IR No. 18 **(Re : May 6, 2011 Response - E11T01S18.doc)**

The Revenue Offset for 2010 shown in the response totals $779,887. The total in Exhibit 3-3-1 attachment 1 is $728,234.

a) Please explain the discrepancy.

RESPONSE to Question 07 – Board Staff, Second Set:

a) The difference between $779,887 and $728,234 noted above is $51,653 (Net amount of "Account 4375-Revenuesfrom Non-Utility Operations" and "Account 4380 Expenses from Non-Utility Operations").

   Exhibit 3-3-1 attachment 1:

   In 2010 Account 4375 and Account 4380 were included in the Revenue Offsetof $728,234. In 2011 those accounts were excluded from Revenue Offset of $802,798 because they relate solely to OPA CDM activities. In 2011 Account 4375 completely offsets Account 4380.

   Response Attachment to Board Staff IR No. 18:

   To be considered consistent in comparing with the 2011 Revenue Offset, the 2010 values in Accounts 4375 and 4380 were removed resulting in the amount of $ 779,887 shown as the Revenue Offset.

EXHIBIT 12_Tab 01_S08

Ref: Response to Board staff IR No. 19 **(Re : May 6, 2011 Response - E11T01S19.doc)**

Part (d) of IR19, asked for an estimate of the additional or incremental costs that are incurred to manage and administer the fees, charges and payments associated with the STESI -St. Thomas arrangement regarding the provision of goods and services. The IR response states that "All costs associated with administering the Master Services Agreement are included in the charges from STESI to STEI for a) and b) above and are administrative burdens."

a) Please clarify whether or not St. Thomas is stating that there are no additional or incremental costs due to the fact that a Master Service Agreement has to be managed and administered as compared to the case where St. Thomas itself were providing these services.

RESPONSE to Question 08 – Board Staff, Second Set:

a) We confirm that there are no additional or incremental costs for managing and administrating the Master Services Agreement.

EXHIBIT 12_Tab 01_S09
Ref: Response to Board staff IR No. 20

a) What is the actual % margin factor charged [to St. Thomas] on fully allocated costs that is intended to generate a portion of earnings for the STESI fixed assets

RESPONSE to Question 9 – OEB Staff, Second Set:
a) The mark up on the capital is a flat rate applied at 20% rate (before taxes) over allocated costs. This was consistent for the period 2009 through to the test year. Prior to 2009, the rate was lower (effectively 18.7% in 2008, 7.1% in 2007 and 4.9% in 2006). This mark up on allocated costs is used to cover unallocated costs within the STESI (which would, if allocated, increase other costs basis in the STESI). The mark up is also is used to provide a return on fixed assets of STESI utilized in its activities (ie. rolling stock, furniture, computers, etc.).

EXHIBIT 12_Tab 01_S10

Ref: Response to Board staff IR No. 24 **(Re : May 6, 2011 Response - E11T01S24.doc)**

a) Please break out the Director of Regulatory Affairs cost of $247,000 into 2 components: (i) amount for Salary, Incentive and Benefits/Pension and (ii) amount for Administrative Burden.

b) To the question "Will the Director of Regulatory Affairs provide any advice and/or support to St.Thomas's affiliates?" the IR response is "The Director, Regulatory Affairs exists solely to serve the needs of STEI." Please answer the original question.

RESPONSE to Question 10 – Board Staff, Second Set:

a) (i) $ 185,000 Salary, Incentive and Benefits/Pension
(ii) $ 39,500 Administrative Burden and $ 22,500 Return on Invested Capital

b) No. The Director of Regulatory Affairs will not provide any advice and/or support to St. Thomas's affiliates.

EXHIBIT 12_Tab 01_S11

Ref: Response to Board staff IR No. 27 **(Re : May 6, 2011 Response - E11T01S27.doc)**

Does St. Thomas agree that the projects listed in the original IR (for Office Building/Service Centre planned activities to : i. replace end-of-life HVAC equipment to address heating, cooling and air quality issues; ii. replace defective access gates to address security concerns (inventory was stolen in 2010);iii. install attic firewall separation to meet fire regulations (inspection was done in 2010); and iv. paving of outside parking areas to comply with accessibility legislation) have a future benefit lasting more than one 1 year?

RESPONSE to Question 11 – Board Staff, Second Set:

St. Thomas does agree that all of the projects listed in Board Staff IR No. 27 provide a benefit that will last more than one year. This answer in itself does not imply that the projects should be capitalized.

Additional information needs to be considered when determining whether to capitalize the activities or not: 1) How long will the benefit last ?, 2) remaining depreciable life of the asset ?, 3) does the activity extend the life of the asset or enhance it's "service potential" ?, 4) original cost of the asset and accumulated depreciation includes a portion of the asset that is no longer physically present but continues to be depreciated annually and 5) materiality of the activity compared to the original cost of the asset (CICA Handbook).

It would appear that (i) could qualify as a capital expenditure based on 3) above. Experience at St. Thomas has shown that HVAC units have a useful life of between 12 to 15 years. The Building is being depreciated over a 50 year life. 2011 marks the 18th year of asset life (36% depreciated). There is good possibility that all of the HVAC units will need to be replaced at least once more during the life of the Building. Is $ 20,000 per unit a material amount compared to the $ 2.3 million spent for the Building back in 1994? Based on 1), 2), 4) and 5) above the amount has been considered by St. Thomas to be an expense.

EXHIBIT 12_Tab 01_S12

Ref: Response to Board staff IR No. 29 **(Re : May 6, 2011 Response - E11T01S29.doc)**

a) What value is ascribed to this property in rate base?

b) Has St. Thomas included the proceeds of the sale in its Offsetting Revenue for 2011? If so please specify the amount and the account number which records it.

c) If not, why should rate payers bear the costs associated with the sale of the property?

RESPONSE to Question 12 – Board Staff, Second Set:

a) There are two vacant properties involved rather than one as indicated in the Response to Board Staff IR No. 29. Both properties have been vacant since 1997. Both properties are fully amortized resulting in $ 0 value ascribed in the rate base.
b) No.
c) The rate payers should bear the costs associated with sale of the property offset by any net gain involved in the sale. The net gain would consist of the proceeds less any expenses for legal, realtor fees and other related miscellaneous incidental expenses, if applicable. Due to an oversight the net gain was not included in 2011 revenues in the Cost of Service Rate Application. Upon further review it has been estimated that the combined net gain is estimated as ($ 21,000 proceeds less $ 3,000 in selling costs) $ 18,000. The scrap value of the transformer being disposed of in 2011 is estimated to be (3000 kVa x $1 per kVa) $ 3,000. Therefore the net gain that should have been recorded in the Cost of Service Rate Application is $ 21,000. The account number for recording the gains should have been 4355.

EXHIBIT 12_Tab 01_S13
Ref: Response to Board staff IR No. 30

a) Please confirm whether the capital structure and rates for 2011 shown in attachment 1 represents St. Thomas's latest proposal for its 2011 cost of capital (including any revisions to reflect capital parameters issued by the Board on March 3, 2011).

b) If it does not, please update the table so that it does.

RESPONSE to Question 13 – OEB Staff, Second Set:

a) The capital structure and rates does not fully reflect STEI's latest proposal.

b) Below is the latest proposal for Cost of Capital

2011 Cost of Capital					
	Rate Base Amount	Weight	Rate	Weighted Rate	Cost
Long Term Debt	$ 13,402,591	56.0%	5.60%	3.14%	$ 750,545
Short Term Debt	957,328	4.0%	2.46%	0.10%	23,550
Total Debt	14,359,919				774,095
Equity	9,573,280	40.0%	9.58%	3.83%	917,120
Total	$ 23,933,199	100.0%		7.07%	$ 1,691,215

EXHIBIT 12_Tab 01_S14

Ref: Response to Board staff IR No. 31

The response states that the guarantee indentified in the 2009 financial statements is no longer in effect in that a new banking arrangement was completed in 2010 and refers to Note 8 of the 2010 Financial Statements.

a) Please clarify whether under the new arrangement St. Thomas's guarantee obligations are legally segmented such that it is not guaranteeing all or any of the loans/advances/indebtedness of its affiliates that draw from/are covered by the banking arrangement.

RESPONSE to Question 14 – OEB Staff, Second Set:

a) As stated in Note 8 referred to above:

> "The Corporation has provided to the Bank of Nova Scotia a limited guarantee, not to exceed 25% ofthe Corporation's equity, towards the above facilities, secured by a general security agreement overall present and future personal property with appropriate insurance coverage. As at December 31,2010 the maximum guarantee for the Company would be $3,036,752."

This limited guarantee is not segregated.

EXHIBIT 12_Tab 01_S15

Ref: Response to Board staff IR No. 41 **(Re : May 6, 2011 Response - E11T01S41.doc)**

a) Please elaborate as to what provisions in the Energy Consumer Protection Act would cause St. Thomas's bad debt expense to increase from an historical average of $ 81,000 during the 2000-2010 period to $ 202,000 by 2014.

b) Please confirm that $81,000 is the amount of bad debt expense included in the 2011 Test Year OM&A.

RESPONSE to Question 15 – Board Staff, Second Set:

a) The Energy Consumer Protection Act introduces new provisions relating to disconnection and security deposits by electricity distributors. Areas of concern that could impact on increases in bad debt expense levels are in the following areas:

   - Bill Issuance & Payment – increase in length of time to pay bills
   - Disconnections for Non-Payment – increase in length of time before a service can be disconnected for non – payment
   - Security Deposits – applying security deposits to current bills and then attempting to re-collect security deposits over an increased length of time to apply to future bills.
   - Arrears Management Programs - increase in length of time to pay bills

   The increase in time to pay creates greater risk in collecting outstanding amounts. The figures provided by STEI in answering Board Staff IR No. 41 Part (b) are estimates. They are based on a historic data average but the factor is estimated. The only basis to go on for the factor is the perceived risk by STEI as these requirements are new and there is no data available yet.

   Clarification re; Response to Board Staff IR No. 41 Part (a) - The $ 81,000 historical average comes from the 2005 to 2010 period.

b) $ 115,095 is included for bad debts expense in the 2011 Test Year.

EXHIBIT 12_Tab 01_S16

Ref: Response to Board staff IR No. 44 **(Re : May 6, 2011 Response - E11T01S44.doc)**

The Smart Meter Revenue Requirement calculation, sheet 4, attached to the IR response, shows $150,000 in 2010 and $300,000 for Operating Expenses.

a) Please describe the nature of these expenses.

RESPONSE to Question 16 – Board Staff, Second Set:

a)

In general these costs would cover repairs to customer meter bases, vendor operating costs related to the Smart Meter Infrastructure, automated meter change software, legal costs (escrow) and customer education.

	2010	2011
Operating Expense Data:	Forecasted	Forecasted
2.1 Advanced Metering Communication Device (AMCD)	0	50,000
2.2 Advanced Metering Regional Collector (AMRC) (includes LAN)	0	10,000
2.3 Advanced Metering Control Computer (AMCC)	25,000	50,000
2.4 Wide Area Network (WAN)	10,000	20,000
2.5 Other AMI OM&A Costs Related To Minimum Functionality	115,000	170,000
Total O M & A Costs	150,000	300,000

EXHIBIT 12_Tab 01_S17

Ref: Response to Board staff IR No. 44 **(Re: May 6, 2011 Response - E11T01S44.doc)**

St. Thomas indicates that 94.9% of applicable customers will have converted to smart meters in 2010 and this will rise to 100% in 2011.

a) Would St. Thomas consider including smart meters capital costs (deferral account balances) as of the end of 2010 in 2011 rate base? If not, why not.

b) If yes, would St. Thomas be able to quantify the net book value of the associated stranded assets which would be removed from rate base?

RESPONSE to Question 17 – Board Staff, Second Set:

a) No. St Thomas plans on making a full Smart Meter filing later in 2011 through means of having an external audit done in advance of the year end closing. The assumption was that the disposition of the deferral accounts would be added to the 2012 rate implementation. Including smart meter capital costs in the 2011 rate base would delay this process.

b) N/A

EXHIBIT 12_Tab 02_S01

Ref: Exhibit 11, Tab 2, Schedule 2 & Exhibit 1, Tab 2, Schedule 4

(Re : May 6, 2011 Response - E11T02S02.doc & COS APP Reference E01T02S04)

a) Please confirm that the figures provided in Attachment 1 include actual 2010 figures. If this is not the case, please update Attachment 1 to reflect actual 2010 data.

b) The response provided to part (b) indicates that the meter reading is provided under the fixed fee (base financial consideration) and that the movement to smart meters is considered an additional regulatory cost and as such will be provided outside of the fixed fee arrangement and that a review will need to take place of the current and future meter reading activities to determine if an adjustment is required.

i) Has STEI initiated such a review? If yes, please provide details.
ii) Has STEI estimated the current meter reading costs included in the 2011 base financial consideration? If not, please provide such an estimate.
iii) Would the additional regulatory cost associated with reading the smart meters be added to the Base Direct Cost or the LDC Direct Cost? If neither, please explain where this cost would be added.

c) There is a significant increase in the Base Direct Costs shown in Attachment 1. Please provide a table that shows the breakdown for each of 2006 through 2011 between the direct costs noted on page 11 in section 5.01 (b) of the Services Agreement in Attachment 1 of Exhibit 1, Tab 2, Schedule 4. Please also provide a breakdown of any other costs included in the Base Direct Costs not covered by the list provided in the Services Agreement.

RESPONSE to Question 01 – Energy Probe, Second Set:

a) Please see attachment 1

b) i), ii), iii) A review has not been initiated at this time. To correct our previous response, the cost associated with the meter reading will not be taken out of the MSA as it is part of the original services provided. The change in costs associate with the Smart Meter project for reading the meters versus the current costs for reading the meter will be included in the “non-MSA” (Base Direct Costs) charges (or savings) from STESI to STEI. This “non-MSA” (Base Direct Costs) charge (or savings) will be captured by STEI in the existing deferral account mechanism for Smart Meters.

c) Please see attachment 2

MASTER SERVICES AGREEMENT SECTION 5.01

	Base Financial Consideration Fixed Fee						Base Direct Cost	LDC Direct Cost	Total O M & A
	(A)	(B)	(C)	(D)	(E)	(F)			
Year	Prior Year Base	Performance Based Regulation Reduction	Customer Count Adjustment	Current Year Base	Customer Count Change	80 % of Customer Count Change			
			(A x F)	(A + B + C)		(E x 80%)			
2005				2,412,332					
2006	2,412,332	-45,000	53,898	2,421,230	2.793%	2.234%	947,521	26,114	3,394,865
2007	2,421,230	-45,000	41,554	2,417,784	2.145%	1.716%	1,186,475	-58,259	3,546,000
2008	2,417,784	-45,000	36,488	2,409,272	1.886%	1.509%	701,794	-14,217	3,096,849
2009	2,409,272	-45,000	3,058	2,367,330	0.159%	0.127%	869,960	9,732	3,247,022
2010	2,367,330	-45,000	11,786	2,334,116	0.622%	0.498%	932,741	3,599	3,270,456
2011	2,334,116	-45,000	14,522	2,303,638	0.778%	0.622%	1,433,131	16,811	3,753,580

Base Direct Cost

	2006	2007	2008	2009	2010	2011	
Income and corporate taxes or payments in lieu of taxes	0	0	0	0	0	0	Not Part of OM & A
Property Taxes	0	0	0	0	0	0	Not Part of OM & A
Directors Fees	21,338	20,900	25,202	27,452	28,769	79,741	
Insurance not jointly held or provided by the Parties	0	0	0	0	0	0	Not Used
Costs of insurance jointly held will be shared on a pro rata basis	34,182	38,880	42,708	39,549	45,680	42,807	
Regulatory Costs -External	201,217	136,781	121,069	70,888	110,439	87,811	
Regulatory Costs -Internal	369,478	511,418	158,586	254,890	338,445	774,548	
Wholesale Power Settlement - Utilismart	73,450	47,917	50,082	81,222	80,997	93,713	
Auditors Costs	11,708	11,041	14,569	14,191	19,730	16,000	
Legal Fees	7,635	6,956	1,071	5,040	41,286	20,100	
Consultants	6,248	25,416	2,428	2,200	18,536	10,100	
Electrical Safety Authority Fees	0	9,258	11,852	9,958	15,927	15,840	
Office Building/Service Centre Maintenance	214,291	187,890	260,577	364,570	232,932	266,471	
3rd Tranche CDM	7,974	190,018	13,650	0	0	0	
Customer Account Credit Insurance						26,000	
	947,521	1,186,475	701,794	869,960	932,741	1,433,131	

EXHIBIT 12_Tab 02_S04

Ref: Exhibit 11, Tab 2, Schedule 4

(Re : May 6, 2011 Response - E11T02S04.doc)

The response indicates that the cost of long term debt is at the proposed level of 5.60%, however the RRWF in Attachment 1 shows a rate of 5.48%. Please reconcile and update the RRWF to reflect the proposed long term debt rate.

RESPONSE to Question 2 – Energy Probe, Second Set:

The attached RRWF reflects the proposed long-term debt rate of 5.6%.

REVENUE REQUIREMENT WORK FORM

Name of LDC:	St. Thomas Energy Inc.	(1)
File Number:	EB-2010-0141	
Rate Year:	2011	Version: 2.11

Ontario

Table of Content

Notes:

(1) Pale green cells represent inputs

(2) Pale yellow cells represent drop=down lists

(3) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

(4) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Ontario

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

	Data Input							(1)
	Initial Application		Adjustments	Settlement Agreement	(7)	Adjustments	Per Board Decision	
1 Rate Base								
Gross Fixed Assets (average)	$40,302,138		$ -	$ 40,302,138			$40,302,138	
Accumulated Depreciation (average)	($21,114,007)	(5)	$ -	-$ 21,114,007			($21,114,007)	
Allowance for Working Capital:								
Controllable Expenses	$3,875,076		$ -	$ 3,875,076			$3,875,076	
Cost of Power	$27,758,708		$ -	$ 27,758,708			$27,758,708	
Working Capital Rate (%)	15.00%						15.00%	
2 Utility Income								
Operating Revenues:								
Distribution Revenue at Current Rates	$5,794,876							
Distribution Revenue at Proposed Rates	$6,561,431							
Other Revenue:								
Specific Service Charges	$538,827							
Late Payment Charges	$138,817							
Other Distribution Revenue	$71,483							
Other Income and Deductions	$53,672							
Operating Expenses:								
OM+A Expenses	$3,753,580		$ -	$ 3,753,580			$3,753,580	
Depreciation/Amortization	$1,359,074		$ -	$ 1,359,074			$1,359,074	
Property taxes	$121,496		$ -	$ 121,496			$121,496	
Capital taxes	$0							
Other expenses	$ -		$ -	0			$0	
3 Taxes/PILs								
Taxable Income:								
Adjustments required to arrive at taxable income	$211,928	(3)						
Utility Income Taxes and Rates:								
Income taxes (not grossed up)	$318,956							
Income taxes (grossed up)	$444,538							
Capital Taxes	$ -	(6)			(6)			(6)
Federal tax (%)	16.50%							
Provincial tax (%)	11.75%							
Income Tax Credits	$ -							
4 Capitalization/Cost of Capital								
Capital Structure:								
Long-term debt Capitalization Ratio (%)	56.0%							
Short-term debt Capitalization Ratio (%)	4.0%	(2)			(2)			(2)
Common Equity Capitalization Ratio (%)	40.0%							
Prefered Shares Capitalization Ratio (%)								
	100.0%							
Cost of Capital								
Long-term debt Cost Rate (%)	5.60%							
Short-term debt Cost Rate (%)	2.46%							
Common Equity Cost Rate (%)	9.58%							
Prefered Shares Cost Rate (%)								

Notes:

(Rate Base through Revenue Requirement), except for Notes that the utility may wish to use to support the data. Notes should be put on the applicable pages to explain numbers shown.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)
(2) 4.0% unless an Applicant has proposed or been approved for another amount.
(3) Net of addbacks and deductions to arrive at taxable income.
(4) Average of Gross Fixed Assets at beginning and end of the Test Year
(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.
(6) Not applicable as of July 1, 2010
(7) Select option from drop-down list by clicking on cell M10. This columnallows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outsome of any Settlement Process can be reflected.

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Ontario

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$40,302,138	$ -	$40,302,138	$ -	$40,302,138
2	Accumulated Depreciation (average)	(3)	($21,114,007)	$ -	($21,114,007)	$ -	($21,114,007)
3	Net Fixed Assets (average)	(3)	$19,188,131	$ -	$19,188,131	$ -	$19,188,131
4	Allowance for Working Capital	(1)	$4,745,068	($4,745,068)	$ -	$4,745,068	$4,745,068
5	**Total Rate Base**		$23,933,199	($4,745,068)	$19,188,131	$4,745,068	$23,933,199

	(1) Allowance for Working Capital - Derivation						
6	Controllable Expenses		$3,875,076	$ -	$3,875,076	$ -	$3,875,076
7	Cost of Power		$27,758,708	$ -	$27,758,708	$ -	$27,758,708
8	Working Capital Base		$31,633,784	$ -	$31,633,784	$ -	$31,633,784
9	Working Capital Rate %	(2)	15.00%	-15.00%	0.00%	15.00%	15.00%
10	Working Capital Allowance		$4,745,068	($4,745,068)	$ -	$4,745,068	$4,745,068

Notes

(2) Generally 15%. Some distributors may have a unique rate due as a result of a lead-lag study.
(3) Average of opening and closing balances for the year.

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Utility income

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$6,561,431	($6,561,431)	$ -	$ -	$ -
2	Other Revenue	(1)	$802,798	($802,798)	$ -	$ -	$ -
3	Total Operating Revenues		$7,364,229	($7,364,229)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$3,753,580	$ -	$3,753,580	$ -	$3,753,580
5	Depreciation/Amortization		$1,359,074	$ -	$1,359,074	$ -	$1,359,074
6	Property taxes		$121,496	$ -	$121,496	$ -	$121,496
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -	$ -	$ -	$ -
9	Subtotal (lines 4 to 8)		$5,234,150	$ -	$5,234,150	$ -	$5,234,150
10	Deemed Interest Expense		$774,095	($774,095)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)		$6,008,246	($774,095)	$5,234,150	$ -	$5,234,150
12	**Utility income before income taxes**		$1,355,983	($6,590,133)	($5,234,150)	$ -	($5,234,150)
13	Income taxes (grossed-up)		$444,538	$ -	$444,538	$ -	$444,538
14	**Utility net income**		$911,445	($6,590,133)	($5,678,688)	$ -	($5,678,688)

Notes

(1)

Other Revenues / Revenue Offsets	Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
Specific Service Charges	$538,827		$ -		$ -
Late Payment Charges	$138,817		$ -		$ -
Other Distribution Revenue	$71,483		$ -		$ -
Other Income and Deductions	$53,672		$ -		$ -
Total Revenue Offsets	$802,798	$ -	$ -	$ -	$ -

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Ontario

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Taxes/PILs

Line No.	Particulars	Application		Settlement Agreement		Per Board Decision	
	Determination of Taxable Income						
1	Utility net income before taxes	$917,120		$ -		$ -	
2	Adjustments required to arrive at taxable utility income	$211,928		$ -		$211,928	
3	Taxable income	$1,129,048		$ -		$211,928	
	Calculation of Utility income Taxes						
4	Income taxes	$318,956		$318,956		$318,956	
5	Capital taxes	$ -	(1)	$ -	(1)	$ -	(1)
6	Total taxes	$318,956		$318,956		$318,956	
7	Gross-up of Income Taxes	$125,582		$125,582		$125,582	
8	Grossed-up Income Taxes	$444,538		$444,538		$444,538	
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$444,538		$444,538		$444,538	
10	Other tax Credits	$ -		$ -		$ -	
	Tax Rates						
11	Federal tax (%)	16.50%		16.50%		16.50%	
12	Provincial tax (%)	11.75%		11.75%		11.75%	
13	Total tax rate (%)	28.25%		28.25%		28.25%	

Notes

(1) Capital Taxes not applicable after July 1, 2010 (i.e. for 2011 and later test years)

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	Initial Application				
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$13,402,591	5.60%	$750,545
2	Short-term Debt	4.00%	$957,328	2.46%	$23,550
3	**Total Debt**	60.00%	$14,359,919	5.39%	$774,095
	Equity				
4	Common Equity	40.00%	$9,573,280	9.58%	$917,120
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$9,573,280	9.58%	$917,120
7	**Total**	100.00%	$23,933,199	7.07%	$1,691,216

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	Settlement Agreement				
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$ -
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
4	Common Equity	0.00%	$ -	0.00%	$ -
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	$ -
7	**Total**	0.00%	$19,188,131	0.00%	$ -

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	Per Board Decision				
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	0.00%	$ -	5.60%	$ -
9	Short-term Debt	0.00%	$ -	2.46%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	9.58%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$23,933,199	0.00%	$ -

Notes

(1) 4.0% unless an Applicant has proposed or been approved for another amount.

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Ontario

Revenue Sufficiency/Deficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Settlement Agreement: At Current Approved Rates	Settlement Agreement: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$772,231		($477,283)		$5,234,150
2	Distribution Revenue	$5,794,876	$5,789,200	$5,794,876	$7,038,714	$ -	($5,234,150)
3	Other Operating Revenue Offsets - net	$802,798	$802,798	$ -	$ -	$ -	$ -
4	**Total Revenue**	$6,597,673	$7,364,229	$5,794,876	$6,561,431	$ -	$ -
5	Operating Expenses	$5,234,150	$5,234,150	$5,234,150	$5,234,150	$5,234,150	$5,234,150
6	Deemed Interest Expense	$774,095	$774,095	$ -	$ -	$ -	$ -
	Total Cost and Expenses	$6,008,246	$6,008,246	$5,234,150	$5,234,150	$5,234,150	$5,234,150
7	**Utility Income Before Income Taxes**	$589,428	$1,355,983	$560,725	$1,327,281	($5,234,150)	($5,234,150)
8	Tax Adjustments to Accounting Income per 2009 PILs	$211,928	$211,928	$211,928	$211,928	$ -	$ -
9	**Taxable Income**	$801,356	$1,567,911	$772,653	$1,539,209	($5,234,150)	($5,234,150)
10	Income Tax Rate	28.25%	28.25%	28.25%	28.25%	28.25%	28.25%
11	**Income Tax on Taxable Income**	$226,383	$442,935	$218,275	$434,826	($1,478,648)	($1,478,648)
12	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
13	**Utility Net Income**	$363,045	$911,445	$342,451	($5,678,688)	($3,755,503)	($5,678,688)
14	**Utility Rate Base**	$23,933,199	$23,933,199	$19,188,131	$19,188,131	$23,933,199	$23,933,199
	Deemed Equity Portion of Rate Base	$9,573,280	$9,573,280	$ -	$ -	$ -	$ -
15	Income/Equity Rate Base (%)	3.79%	9.52%	0.00%	0.00%	0.00%	0.00%
16	Target Return - Equity on Rate Base	9.58%	9.58%	0.00%	0.00%	0.00%	0.00%
17	Sufficiency/Deficiency in Return on Equity	-5.79%	-0.06%	0.00%	0.00%	0.00%	0.00%
18	Indicated Rate of Return	4.75%	7.04%	1.78%	0.00%	-15.69%	0.00%
19	Requested Rate of Return on Rate Base	7.07%	7.07%	0.00%	0.00%	0.00%	0.00%
20	Sufficiency/Deficiency in Rate of Return	-2.32%	-0.02%	1.78%	0.00%	-15.69%	0.00%
21	Target Return on Equity	$917,120	$917,120	$ -	$ -	$ -	$ -
22	Revenue Deficiency/(Sufficiency)	$554,076	($5,675)	($342,451)	$ -	$3,755,503	$ -
23	**Gross Revenue Deficiency/(Sufficiency)**	$772,231 **(1)**		($477,283) **(1)**		$5,234,150 **(1)**	

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

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Ontario

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Revenue Requirement

Line No.	Particulars	Application		Settlement Agreement		Per Board Decision	
1	OM&A Expenses	$3,753,580		$3,753,580		$3,753,580	
2	Amortization/Depreciation	$1,359,074		$1,359,074		$1,359,074	
3	Property Taxes	$121,496		$121,496		$121,496	
4	Capital Taxes	$ -		$ -		$ -	
5	Income Taxes (Grossed up)	$444,538		$444,538		$444,538	
6	Other Expenses	$ -		$ -		$ -	
7	Return						
	Deemed Interest Expense	$774,095		$ -		$ -	
	Return on Deemed Equity	$917,120		$ -		$ -	
8	Distribution Revenue Requirement before Revenues	$7,369,904		$5,678,688		$5,678,688	
9	Distribution revenue	$6,561,431		$ -		$ -	
10	Other revenue	$802,798		$ -		$ -	
11	**Total revenue**	$7,364,229		$ -		$ -	
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($5,675)	(1)	($5,678,688)	(1)	($5,678,688)	(1)

Notes
(1) Line 11 - Line 8

REVENUE REQUIREMENT WORK FORM Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Residential

Consumption 800 kWh

		Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
1	Monthly Service Charge			1	$ -		1	$ -	$ -	
2	Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
3	Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
4	Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
5	Distribution Volumetric Rate			800	$ -		800	$ -	$ -	
6	Low Voltage Rate Adder			800	$ -		800	$ -	$ -	
7	Volumetric Rate Adder(s)			800	$ -		800	$ -	$ -	
8	Volumetric Rate Rider(s)			800	$ -		800	$ -	$ -	
9	Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
10	LRAM & SSM Rate Rider			800	$ -		800	$ -	$ -	
11	Deferral/Variance Account Disposition Rate Rider			800	$ -		800	$ -	$ -	
12					$ -			$ -	$ -	
13					$ -			$ -	$ -	
14					$ -			$ -	$ -	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ -**			**$ -**	**$ -**	
17	RTSR - Network			800	$ -		800	$ -	$ -	
18	RTSR - Line and Transformation Connection			800	$ -		800	$ -	$ -	
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ -**			**$ -**	**$ -**	
20	Wholesale Market Service Charge (WMSC)			800	$ -		800	$ -	$ -	
21	Rural and Remote Rate Protection (RRRP)			800	$ -		800	$ -	$ -	
22	Special Purpose Charge			800	$ -		800	$ -	$ -	
23	Standard Supply Service Charge			1	$ -		1	$ -	$ -	
24	Debt Retirement Charge (DRC)			800	$ -		800	$ -	$ -	
25	Energy			800	$ -		800	$ -	$ -	
26					$ -			$ -	$ -	
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ -**			**$ -**	**$ -**	
29	HST		13%		$ -	13%		$ -	$ -	
30	**Total Bill (including Sub-total B)**				**$ -**			**$ -**	**$ -**	
31	**Loss Factor (%)**	**Note 1**								

Notes:
Note 1: Enter existing and proposed total loss factor (Secondary Metered Customer < 5,000 kW) as a percentage.

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

General Service < 50 kW

Consumption 2000 kWh

		Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
1	Monthly Service Charge			1	$ -		1	$ -	$ -	
2	Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
3	Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
4	Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
5	Distribution Volumetric Rate			2000	$ -		2000	$ -	$ -	
6	Low Voltage Rate Adder			2000	$ -		2000	$ -	$ -	
7	Volumetric Rate Adder(s)			2000	$ -		2000	$ -	$ -	
8	Volumetric Rate Rider(s)			2000	$ -		2000	$ -	$ -	
9	Smart Meter Disposition Rider			2000	$ -		2000	$ -	$ -	
10	LRAM & SSM Rider			2000	$ -		2000	$ -	$ -	
11	Deferral/Variance Account Disposition Rate Rider			2000	$ -		2000	$ -	$ -	
12					$ -			$ -	$ -	
13					$ -			$ -	$ -	
14					$ -			$ -	$ -	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ -**			**$ -**	**$ -**	
17	RTSR - Network			2000	$ -		2000	$ -	$ -	
18	RTSR - Line and Transformation Connection			2000	$ -		2000	$ -	$ -	
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ -**			**$ -**	**$ -**	
20	Wholesale Market Service Charge (WMSC)			2000	$ -		2000	$ -	$ -	
21	Rural and Remote Rate Protection (RRRP)			2000	$ -		2000	$ -	$ -	
22	Special Purpose Charge			2000	$ -		2000	$ -	$ -	
23	Standard Supply Service Charge			1	$ -		1	$ -	$ -	
24	Debt Retirement Charge (DRC)			2000	$ -		2000	$ -	$ -	
25	Energy			2000	$ -		2000	$ -	$ -	
26					$ -			$ -	$ -	
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ -**			**$ -**	**$ -**	
29	HST		13%		$ -	13%		$ -	$ -	
30	**Total Bill (including Sub-total B)**				**$ -**			**$ -**	**$ -**	
31	**Loss Factor**	**Note 1**	0.00%			0.00%				

Notes:
Note 1: See Note 1 from Sheet 1A. Bill Impacts - Residential

EXHIBIT 12_Tab 02_S10

Ref: Exhibit 11, Tab 4, Schedule 12

(Re : May 6, 2011 Response - E11T04S12.doc)

Please provide Attachment 1 referred to in the response to part (c).

RESPONSE to Question10 – Energy Probe, Second Set:

Please see Exhibit 11, Tab 4, Schedule 12, Attachment 1 revised May 20, 2011.

EXHIBIT 12_Tab 02_S04

Ref: Exhibit 11, Tab 2, Schedule 13

(Re : May 6, 2011 Response - E11T02S13.doc)

Please provide the impact on the volumes, revenues, working capital, revenue deficiency and revenue requirement if the CDM adjustment is reduced from 3,730 MWh to 1,492 MWh. Please show all calculations.

RESPONSE to Question 4 – Energy Probe, Second Set:

	Per Application	Per Questions	Difference
Volumes	292,857,710	295,095,710	2,238,000
Revenues	$5,794,876	$5,815,299	$20,424
Working Capital	$4,745,068	$4,775,347	$30,280
Revenue Deficiency	-$766,535	-$748,240	$18,295
Revenue Requirement	$6,561,411	$6,563,539	$2,129

EXHIBIT 12_Tab 02_S05

Ref: Exhibit 11, Tab 2, Schedule 2, Attachment 1 & Exhibit 3, Tab 1, Schedule 1, Attachment 1

(Re : May 6, 2011 Response - E11T02S02.doc)

Please explain the derivation of the 0.944% increase in 2011 in the customer count change shown in the interrogatory response with a 0.85% increase in the customer count based on 21,314 in 2011 and 21,134 in 2010 shown in Exhibit 3.

RESPONSE to Question 05 – Energy Probe, Second Set:

The 0.944% is based solely on the classes of Residential, GS < 50 and GS > 50. The actual customer count at Dec 31, 2010 was used. An estimate for Dec 31, 2011 was provided independently of the load forecast information.

EXHIBIT 12_Tab 02_S06
Ref: Exhibit 11, Tab 2, Schedule 17

The answer provided to part (b) does not answer the question posed. Please provide a response to the question posed in part (b).

RESPONSE to Question 06 – Energy Probe, Second Set:
As indicated in the response, STEI directed the reference to Exhibit 11, Tab 1, Schedule 26, in which the costs associated with the governance training portion allocated to STEI as roughly $13,700/year for two years.

Also, in our response, we indicated “In respect to the question “why”, is that better corporate governance will strengthen the Board’s ability to govern the organization. Stronger corporate governance reduces risk within the corporation.” STEI believes that reducing risk associated with the operation of STEI is a cost associated with the rate payer and not the shareholder. STEI believes that reducing risks for STEI is essentially reducing potential costs in the future (similar to purchasing insurance).

EXHIBIT 12_Tab 02_S07
Ref: Exhibit 11, Tab 2, Schedule 21

a) The response to part (a) is not complete. Please confirm that the claw back was eliminated on July 1, 2010 and the provincial tax rate on the first $500,000 of taxable income is 4.5%.

b) The response part (b) refers to a "Tax Rates and Assumptions" page. Should this be the "Tax Rates and Exemptions" page?

c) Please turn to the "PILs, Tax Provision 2011 Test Year Final" page of Attachment 1, Exhibit 4, Tab 8, Schedule 3 with a regulatory taxable income figure of $1,136,707. Please explain why there is small business deduction amount of $500,000 shown in Box E. Please recalculate the tax provision for test year rate recovery reflecting this $500,000 and the associated $36,250 reduction provincial taxes for the small business deduction.

RESPONSE to Question 07 – Energy Probe, Second Set:
a) As indicated in our response, we had completed a review *"Tax Rates and Exemptions" page,* with our external auditors, and based the calculations on the discussion. Upon further review of the "PILs,Tax Provision 2010 Bridge Year" page and review of the new corporate income tax returns for years after 2010, we recalculated our income tax provision and confirm that we have overstated Ontario Income Tax by $22,085 (see Exhibit 12, Tab 02, Schedule 7, Attachment 1) in the Bridge Year and by $36,250 in the Test Year.

b) Yes.

c) Based on the recalculation, the "PILs, Tax Provision 2011 Test Year Final" page of Attachment 1, Exhibit 4, Tab 8, Schedule 3 becomes $380,135 (see Exhibit 12, Tab 02, Schedule 7, Attachment 3) versus the filed amount of $447,554. As well, the "PILs, Tax Provision 2011 Test Year Existing" page of Attachment 1, Exhibit 4, Tab 8, Schedule 3 becomes $349,736 (see Exhibit 12, Tab 02, Schedule 7, Attachment 2) versus the filed amount of $416,944.

PILS OR INCOME TAXES
Name of LDC: St. Thomas E
File Number: EB-2010-0141
Rate Year: 2011

PILs,Tax Provision 2010 Bri

Regulatory Taxable Income

Ontario Income Taxes
Income tax payable

Small business credit

Surtax

Ontario Income tax

Combined Tax Rate and PILs

Total Income Taxes

Investment Tax Credits
Miscellaneous Tax Credits
Total Tax Credits

Corporate PILs/Income Tax Provision for Test Yea

Corporate PILs/Income Tax Provision Gross Up

Income Tax (grossed-up)
Ontario Capital Tax (not grossed-up)

Tax Provision for Test Year Rate Recovery

WORK FORM
Energy Inc.

idge Year

Ontario income tax	13.00%	**B**	$ 174,596	**C = A * B**
Ontario Small Business Threshold	$ 500,000	**D**		
Rate reduction	-8.00%	**E**	-$ 40,000	**F = D * E**
	$ 843,043	**G = A - D**		
Ontario surtax claw-back	2.13%	**H**	$ 17,915	**I = G * H**
Effective Ontario Tax Rate			11.36%	**K = J / A**
Federal tax rate			18.00%	**L**
Combined tax rate				

ar

70.64%	**S = 1 - M**

Wires Only	
$ 1,343,043	**A**
$ 152,510	**J = C + F + I**
29.36%	**M = L + L**
$ 394,258	**N = A * M**
	O
	P
$ -	**Q = O + P**
$ 394,258	**R = N - Q**
$ 163,830	**T = R / S - N**
$ 558,088	**U = R + T**
$ 6,493	**V**
$ 564,581	**W = U + V**

PILS OR INCOME TAXES WORK FORM
Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Ontario

PILs,Tax Provision 2011 Test Year Existing

						Wires Only	
Regulatory Taxable Income						$ 1,058,964	**A**
Ontario Income Taxes							
Income tax payable	**Ontario income tax**	11.75%	**B**	$ 124,428	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**				
	Rate reduction	-7.25%	**E**	-$ 36,250	**F = D * E**		
Ontario Income tax						$ 88,178	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			8.33%	**K = J / A**		
	Federal tax rate			16.50%	**L**		
	Combined tax rate					24.83%	**M = L + L**
Total Income Taxes						**$ 262,907**	**N = A * M**
Investment Tax Credits						$ -	**O**
Miscellaneous Tax Credits						$ -	**P**
Total Tax Credits						**$ -**	**Q = O + P**
Corporate PILs/Income Tax Provision for Test Year						**$ 262,907**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up				75.17%	**S = 1 - M**	**$ 86,828**	**T = R / S - N**
Income Tax (grossed-up)						**$ 349,736**	**U = R + T**
Ontario Capital Tax (not grossed-up)						**$ -**	**V**
Tax Provision for Test Year Rate Recovery						**$ 349,736**	**W = U + V**

Ontario

PILS OR INCOME TAXES WORK FORM
Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

PILs,Tax Provision 2011 Test Year Final

							Wires Only	
Regulatory Taxable Income							$ 1,136,707	A
Ontario Income Taxes								
Income tax payable	**Ontario income tax**	11.75%	B	$ 133,563	C = A * B			
Small business credit	Ontario Small Business Threshold	$ 500,000	D					
	Rate reduction	-7.25%	E	-$ 36,250	F = D * E			
Ontario Income tax							$ 97,313	J = C + F
Combined Tax Rate and PILs	Effective Ontario Tax Rate			8.56%	K = J / A			
	Federal tax rate			16.50%	L			
	Combined tax rate						25.06%	M = L + L
Total Income Taxes							$ 284,870	N = A * M
Investment Tax Credits							$ -	O
Miscellaneous Tax Credits							$ -	P
Total Tax Credits							$ -	Q = O + P
Corporate PILs/Income Tax Provision for Test Year							$ 284,870	R = N - Q
Corporate PILs/Income Tax Provision Gross Up				74.94%	S = 1 - M		$ 95,266	T = R / S - N
Income Tax (grossed-up)							$ 380,135	U = R + T
Ontario Capital Tax (not grossed-up)							$ -	V
Tax Provision for Test Year Rate Recovery							$ 380,135	W = U + V

EXHIBIT 12_Tab 02_S08
Ref: Exhibit 11, Tab 2, Schedule 4

a) Please show the calculation of the long term debt rate if a rate of 5.48% is used in place of the 5.87% proposed by STEI on the affiliate loan.

b) What is the impact on the revenue requirement of this change?

RESPONSE to Question 08 – Energy Probe, Second Set:
a) Please refer to Exhibit 11, Tab 1, Schedule 34. As noted in the response, the average long term debt rate calculated is 5.60% which we are requesting as part of our cost of service application. If 5.48% were substituted in the table for the 5.87% rate used on one component of the long term debt, then the end result would be 5.33%. This rate is not what is being requested by STEI (5.60%) nor the rate that was included in the pre-filed evidence.

b) Please refer Exhibit 5, Tab 1, Schedules 1 and 2, and Schedule 2 Attachment 2.
In the weighted cost of capital calculation shown in the pre-filed evidence, STEI used a deemed Long Term Debt rate of 5.48% [Board deemed debt rate for Jan 1, 2011 rates]. St. Thomas indicated that it would be filing a revised rate [5.6%] to reflect its actual debt instruments. As highlighted on Exhibit 5, Tab 1, Schedule 2, Page 3 of 4

> *"In order to avoid delays in filing the application, STEI has not updated its evidence to reflect the proposed 5.6% weighted average cost of debt. The difference in revenue requirement between the 5.48% and 5.6% weighted average cost of debt is not material (approximately $13,300). STEI will update its evidence during the proceeding to reflect the 5.6% weighted average cost of debt."*

Since the evidence indicates the difference in revenue requirement between using the 5.60% and the 5.48% would be approximately $13,300, then it is reasonable to assume the revenue requirement when moving between using the 5.48% and the 5.33% (as per the request) will be less than $13,300 and not material.

EXHIBIT 12_Tab 02_S09
Ref: Exhibit 11, Tab 2, Schedule 22

a) Please explain why STEI did not obtain Infrastructure Ontario loans to finance the smart meter additions?

b) What were the Infrastructure Ontario rates available when STEI entered into the smart meter debt through the Bank of Nova Scotia?

c) Please confirm that the dollar amount drawn on this loan as the end of April 2011 was $567,500 at a rate of 4.95%. If this cannot be confirmed, please provide the actual figures..

RESPONSE to Question 09 – Energy Probe, Second Set:
a) STEI did not obtain financing from Infrastructure Ontario to finance the smart meter because STEI believed that the additional costs associated with changes to banking, record keeping, and complexity would, in the end, results in no potential costs savings for STEI. STEI believed that the infrastructure loan would only be available to finance the physical asset costs of the project. Then STEI would need to finance the non-physical asset costs of the project. Below are some examples of these costs:

- Stranded costs associated with the removal and scrap of old meters,
- Training,
- Communications costs associated with data collection, and
- Consulting fees.

To finance the remaining amounts would have been challenging. In addition, if the physical assets were financed by Infrastructure Ontario, there would be extra costs for STEI associated with the bank security changes, bank fees, additional financial reporting, etc. Overall, STEI believes that the rates obtained for the loans taken to date are reasonable as they are lower than OEB prescribed rates. Please refer to Exhibit 11, Tab 1, Schedule 34 for discussion on the overall financing for STEI and the impact on weighted cost of capital.

b) Similar to our response found in Exhibit 11, Tab 2, Schedule 22, STEI was not able to obtain the rate when STEI executed initial loan draw with Bank of Nova Scotia.

c) STEI confirms that there has been no change to our response in Exhibit 11, Tab 2, Schedule 22 (filed May 6, 2011) as at April 2011.

EXHIBIT 12_Tab 02_S10

Ref: Exhibit 11, Tab 4, Schedule 12

(Re : May 6, 2011 Response - E11T04S12.doc)

Please provide Attachment 1 referred to in the response to part (c).

RESPONSE to Question10 – Energy Probe, Second Set:

Please see Exhibit 11, Tab 4, Schedule 12, Attachment 1 revised May 20, 2011, attached.

C1 Line Loss Factors

Enter historical kWh's and Supply Facility Loss Factors

	Unbilled Revenue - Basis of Calculation	Jan & Feb Actual	Jan & Feb Actual	Feb Estimate	Feb Estimate	Jan & Feb Actual	Jan & Feb Actual
		2005 Actual	**2006 Actual**	**2007 Actual**	**2008 Actual**	**2009 Actual**	**2010 Actual**
A1	"Wholesale" kWh delivered to distributor (higher value)	388,862,413	379,676,158	378,201,558	353,330,605	302,033,075	307,614,776
A2	"Wholesale" kWh delivered to distributor (lower value)	387,120,371	378,351,926	376,882,469	352,098,261	300,979,646	306,541,879
B	Portion of "Wholesale" kWh delivered to distributor for Large User Customer(s)	38,759,379	37,306,571	33,583,667	28,658,172	6,569,872	0
C	**Net "Wholesale" kWh delivered to distributor (A2)-(B)**	**348,360,992**	**341,045,355**	**343,298,802**	**323,440,089**	**294,409,774**	**306,541,879**
D	"Retail" kWh delivered by distributor	377,078,667	367,218,614	366,885,093	343,399,651	290,431,811	297,089,354
E	Portion of "Retail' kWh delivered by distributor for Large Use Customer(s)	38,375,623	36,937,199	33,251,155	28,374,428	6,504,824	0
F	**Net "Retail" kWh delivered by distributor (D)-(E)**	**338,703,044**	**330,281,415**	**333,633,938**	**315,025,223**	**283,926,987**	**297,089,354**
G	Loss Factor in distributor's system [C/F]	1.0285	1.0326	1.0290	1.0267	1.0369	1.0318
H	Supply Facility Loss Factor	1.0045	1.0035	1.0035	1.0035	1.0035	1.0035
I	**Total Loss Factor [(G)x(H)]**	**1.0331**	**1.0362**	**1.0326**	**1.0303**	**1.0405**	**1.0354**

Average Total Loss Factor:	**1.0354**
Primary Metering Adjustment:	0.99
Primary Total Loss Factor:	**1.0251**

Ref: Exhibit 11, Tab 1, Schedule 11
(Re : May 6, 2011 Response - E11T01S11.doc)
Please explain why STESI sets the capital expenditure plans (lines 11 - 12) of page 2, rather than the regulated utility STEI.

RESPONSE to Question 11 – Energy Probe:

STEI has no employees. Therefore, the capital budget is prepared by STESI for the approval of STEI through its board of directors.

EXHIBIT 12_Tab 02_S12

Ref: Exhibit 11, Tab 1, Schedule 29

(Re : May 6, 2011 Response - E11T01S29.doc)

Please provide further details related to the vacant substation property and the obsolete transformer that are being disposed of including the following:

i) net book value included in the 2011 rate base at the beginning of 2011 of the property;
ii) net book value included in the 2011 rate base at the end of 2011 of the property;
iii) forecasted disposal date of the property;
iv) forecasted sale value excluding disposal costs for the property;
v) net book value of the transformer included in the 2011 rate base at the beginning of 2011;
vi) net book value of the transformer included in the 2011 rate base at the end of 2011;
vii) forecasted disposal date of the transformer; and
viii) forecasted scrap value of the transformer.

RESPONSE to Question 12 – Energy Probe, Second Set:

i)	$ 0
ii)	$ 0
iii)	2011
iv)	$ 18,000 Net Gain
v)	$0
vi)	$0
vii)	2011
viii)	$ 3,000 Net Gain

Please also refer to the response to Board Staff Technical Conference Question # 12.

EXHIBIT 12_Tab 02_S13
Ref: Exhibit 11, Tab 3, Schedule 8

Does STESI include any type of mark up on the cost related to the capital projects undertaken on behalf of STEI? If yes, please provide details on how this mark up is determined.

RESPONSE to Question 13 – Energy Probe, Second Set:
Please refer to STEI response to Board IR question 9 (May 25).

EXHIBIT 12_Tab 02_S14

Ref: All Interrogatory Responses ***(New Question - No Specific Reference)***

a) Please update the Revenue Requirement Work Form to reflect any changes proposed by STEI as a result of the interrogatory responses provided, including any changes resulting from corrections to the original filing, updates, or adoption of changes resulting from the interrogatory responses.

b) Please provide a tracking sheet that shows the impact of each change proposed by STEI.

RESPONSE to Question 14 – Energy Probe, Second Set:

Please refer to the attached Revenue Requirement Work Form (please note that the column titled “Settlement Agreement” presents the corrected values).

REVENUE REQUIREMENT WORK FORM

Name of LDC:	St. Thomas Energy Inc.	(1)
File Number:	EB-2010-0141	
Rate Year:	2011	Version: 2.11

Table of Content

Notes:

(1) Pale green cells represent inputs

(2) Pale yellow cells represent drop=down lists

(3) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

(4) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Ontario

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Data Input (1)

		Initial Application		Adjustments		Settlement Agreement	(7)	Adjustments		Per Board Decision	
1	**Rate Base**										
	Gross Fixed Assets (average)	$40,302,138		$31,640		$ 40,333,778				$40,333,778	
	Accumulated Depreciation (average)	($21,114,007)	(5)	($1,266)		-$ 21,115,273				($21,115,273)	
	Allowance for Working Capital:										
	Controllable Expenses	$3,875,076		$ -		$ 3,875,076				$3,875,076	
	Cost of Power	$27,758,708		$1,053,785		$ 28,812,493				$28,812,493	
	Working Capital Rate (%)	15.00%				15.00%				15.00%	
2	**Utility Income**										
	Operating Revenues:										
	Distribution Revenue at Current Rates	$5,794,876		$0		$5,794,876					
	Distribution Revenue at Proposed Rates	$6,561,820		$0		$6,561,820					
	Other Revenue:										
	Specific Service Charges	$538,827		$0		$538,827					
	Late Payment Charges	$138,817		$0		$138,817					
	Other Distribution Revenue	$71,483		$0		$71,483					
	Other Income and Deductions	$53,672		$21,000		$74,672					
	Operating Expenses:										
	OM+A Expenses	$3,753,580		$ -		$ 3,753,580				$3,753,580	
	Depreciation/Amortization	$1,359,074		$1,266		$ 1,360,340				$1,360,340	
	Property taxes	$121,496		$ -		$ 121,496				$121,496	
	Capital taxes	$0				$0					
	Other expenses	$ -		$ -		0				$0	
3	**Taxes/PILs**										
	Taxable Income:										
	Adjustments required to arrive at taxable income	$211,928	(3)			$211,928					
	Utility Income Taxes and Rates:										
	Income taxes (not grossed up)	$321,135				$284,870					
	Income taxes (grossed up)	$447,574				$380,131					
	Capital Taxes	$ -	(6)			$ -	(6)				(6)
	Federal tax (%)	16.50%				16.50%					
	Provincial tax (%)	11.75%				8.56%					
	Income Tax Credits	$ -				$ -					
4	**Capitalization/Cost of Capital**										
	Capital Structure:										
	Long-term debt Capitalization Ratio (%)	56.0%				56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	(2)			4.0%	(2)				(2)
	Common Equity Capitalization Ratio (%)	40.0%				40.0%					
	Prefered Shares Capitalization Ratio (%)					0.0%					
		100.0%				100.0%					
	Cost of Capital										
	Long-term debt Cost Rate (%)	5.48%				5.60%					
	Short-term debt Cost Rate (%)	2.43%				2.46%					
	Common Equity Cost Rate (%)	9.66%				9.58%					
	Prefered Shares Cost Rate (%)										

Notes:

(Rate Base through Revenue Requirement), except for Notes that the utility may wish to use to support the data. Notes should be put on the applicable pages to explain numbers shown.

- **(1)** All inputs are in dollars ($) except where inputs are individually identified as percentages (%)
- **(2)** 4.0% unless an Applicant has proposed or been approved for another amount.
- **(3)** Net of addbacks and deductions to arrive at taxable income.
- **(4)** Average of Gross Fixed Assets at beginning and end of the Test Year
- **(5)** Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.
- **(6)** Not applicable as of July 1, 2010
- **(7)** Select option from drop-down list by clicking on cell M10. This columnallows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outsome of any Settlement Process can be reflected.

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$40,302,138	$31,640	$40,333,778	$ -	$40,333,778
2	Accumulated Depreciation (average)	(3)	($21,114,007)	($1,266)	($21,115,273)	$ -	($21,115,273)
3	Net Fixed Assets (average)	(3)	$19,188,131	$30,375	$19,218,506	$ -	$19,218,506
4	Allowance for Working Capital	(1)	$4,745,068	$158,068	$4,903,135	$ -	$4,903,135
5	**Total Rate Base**		$23,933,199	$188,442	$24,121,641	$ -	$24,121,641

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$3,875,076	$ -	$3,875,076	$ -	$3,875,076
7	Cost of Power		$27,758,708	$1,053,785	$28,812,493	$ -	$28,812,493
8	Working Capital Base		$31,633,784	$1,053,785	$32,687,569	$ -	$32,687,569
9	Working Capital Rate %	(2)	15.00%	0.00%	15.00%	0.00%	15.00%
10	Working Capital Allowance		$4,745,068	$158,068	$4,903,135	$ -	$4,903,135

Notes

(2) Generally 15%. Some distributors may have a unique rate due as a result of a lead-lag study.

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

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Utility income

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$6,561,820	$ -	$6,561,820	$ -	$6,561,820
2	Other Revenue	(1)	$802,798	($1,626,595)	$823,798	$ -	$823,798
3	Total Operating Revenues		$7,364,618	($1,626,595)	$7,385,618	$ -	$7,385,618
	Operating Expenses:						
4	OM+A Expenses		$3,753,580	$ -	$3,753,580	$ -	$3,753,580
5	Depreciation/Amortization		$1,359,074	$1,266	$1,360,340	$ -	$1,360,340
6	Property taxes		$121,496	$ -	$121,496	$ -	$121,496
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -	$ -	$ -	$ -
9	Subtotal (lines 4 to 8)		$5,234,150	$1,266	$5,235,416	$ -	$5,235,416
10	Deemed Interest Expense		$757,725	$22,465	$780,190	($16,499)	$763,691
11	Total Expenses (lines 9 to 10)		$5,991,876	$23,731	$6,015,606	($16,499)	$5,999,107
12	**Utility income before income taxes**		$1,372,742	($1,650,326)	$1,370,011	$16,499	$1,386,511
13	Income taxes (grossed-up)		$447,574	($67,444)	$380,131	$ -	$380,131
14	**Utility net income**		$925,168	($1,582,883)	$989,881	$16,499	$1,006,380

Notes

		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
(1)	**Other Revenues / Revenue Offsets**					
	Specific Service Charges	$538,827	$ -	$538,827		$538,827
	Late Payment Charges	$138,817	$ -	$138,817		$138,817
	Other Distribution Revenue	$71,483	$ -	$71,483		$71,483
	Other Income and Deductions	$53,672	$21,000	$74,672		$74,672
	Total Revenue Offsets	$802,798	$21,000	$823,798	$ -	$823,798

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Ontario

Taxes/PILs

Line No.	Particulars	Application		Settlement Agreement		Per Board Decision	
	Determination of Taxable Income						
1	Utility net income before taxes	$924,779		$924,341		$932,060	
2	Adjustments required to arrive at taxable utility income	$211,928		$211,928		$211,928	
3	Taxable income	$1,136,707		$1,136,270		$1,143,988	
	Calculation of Utility income Taxes						
4	Income taxes	$321,135		$284,870		$284,870	
5	Capital taxes	$ -	(1)	$ -	(1)	$ -	(1)
6	Total taxes	$321,135		$284,870		$284,870	
7	Gross-up of Income Taxes	$126,440		$95,261		$95,261	
8	Grossed-up Income Taxes	$447,574		$380,131		$380,131	
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$447,574		$380,131		$380,131	
10	Other tax Credits	$ -		$ -		$ -	
	Tax Rates						
11	Federal tax (%)	16.50%		16.50%		16.50%	
12	Provincial tax (%)	11.75%		8.56%		8.56%	
13	Total tax rate (%)	28.25%		25.06%		25.06%	

Notes

(1) Capital Taxes not applicable after July 1, 2010 (i.e. for 2011 and later test years)

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Ontario

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	Initial Application				
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$13,402,591	5.48%	$734,462
2	Short-term Debt	4.00%	$957,328	2.43%	$23,263
3	**Total Debt**	60.00%	$14,359,919	5.28%	$757,725
	Equity				
4	Common Equity	40.00%	$9,573,280	9.66%	$924,779
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$9,573,280	9.66%	$924,779
7	**Total**	100.00%	$23,933,199	7.03%	$1,682,504

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	Settlement Agreement				
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$13,508,119	5.60%	$756,455
2	Short-term Debt	4.00%	$964,866	2.46%	$23,736
3	**Total Debt**	60.00%	$14,472,985	5.39%	$780,190
	Equity				
4	Common Equity	40.00%	$9,648,656	9.58%	$924,341
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$9,648,656	9.58%	$924,341
7	**Total**	100.00%	$24,121,641	7.07%	$1,704,532

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	Per Board Decision				
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$13,508,119	5.48%	$740,245
9	Short-term Debt	4.00%	$964,866	2.43%	$23,446
10	**Total Debt**	60.00%	$14,472,985	5.28%	$763,691
	Equity				
11	Common Equity	40.00%	$9,648,656	9.66%	$932,060
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$9,648,656	9.66%	$932,060
14	**Total**	100.00%	$24,121,641	7.03%	$1,695,751

Notes

(1) 4.0% unless an Applicant has proposed or been approved for another amount.

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Revenue Sufficiency/Deficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Settlement Agreement: At Current Approved Rates	Settlement Agreement: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$766,535		$701,244		$695,045
2	Distribution Revenue	$5,794,876	$5,795,285	$5,794,876	$5,860,576	$5,794,876	$5,866,775
3	Other Operating Revenue Offsets - net	$802,798	$802,798	$823,798	$823,798	$823,798	$823,798
4	**Total Revenue**	$6,597,673	$7,364,618	$6,618,673	$7,385,618	$6,618,673	$7,385,618
5	Operating Expenses	$5,234,150	$5,234,150	$5,235,416	$5,235,416	$5,235,416	$5,235,416
6	Deemed Interest Expense	$757,725	$757,725	$780,190	$780,190	$763,691	$763,691
	Total Cost and Expenses	$5,991,876	$5,991,876	$6,015,606	$6,015,606	$5,999,107	$5,999,107
7	**Utility Income Before Income Taxes**	$605,798	$1,372,742	$603,067	$1,370,011	$619,566	$1,386,511
8	Tax Adjustments to Accounting Income per 2009 PILs	$211,928	$211,928	$211,928	$211,928	$211,928	$211,928
9	**Taxable Income**	$817,726	$1,584,670	$814,995	$1,581,940	$831,494	$1,598,439
10	Income Tax Rate	28.25%	28.25%	25.06%	25.06%	25.06%	25.06%
11	**Income Tax on Taxable Income**	$231,008	$447,669	$204,238	$396,434	$208,372	$400,569
12	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
13	**Utility Net Income**	$374,790	$925,168	$398,829	$989,881	$411,194	$1,006,380
14	**Utility Rate Base**	$23,933,199	$23,933,199	$24,121,641	$24,121,641	$24,121,641	$24,121,641
	Deemed Equity Portion of Rate Base	$9,573,280	$9,573,280	$9,648,656	$9,648,656	$9,648,656	$9,648,656
15	Income/Equity Rate Base (%)	3.91%	9.66%	4.13%	10.26%	4.26%	10.43%
16	Target Return - Equity on Rate Base	9.66%	9.66%	9.58%	9.58%	9.66%	9.66%
17	Sufficiency/Deficiency in Return on Equity	-5.75%	0.00%	-5.45%	0.68%	-5.40%	0.77%
18	Indicated Rate of Return	4.73%	7.03%	4.89%	7.34%	4.87%	7.34%
19	Requested Rate of Return on Rate Base	7.03%	7.03%	7.07%	7.07%	7.03%	7.03%
20	Sufficiency/Deficiency in Rate of Return	-2.30%	0.00%	-2.18%	0.27%	-2.16%	0.31%
21	Target Return on Equity	$924,779	$924,779	$924,341	$924,341	$932,060	$932,060
22	Revenue Deficiency/(Sufficiency)	$549,989	$389	$525,512	$65,539	$520,867	$74,320
23	**Gross Revenue Deficiency/(Sufficiency)**	$766,535 **(1)**		$701,244 **(1)**		$695,045 **(1)**	

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

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Ontario

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Revenue Requirement

Line No.	Particulars	Application		Settlement Agreement		Per Board Decision	
1	OM&A Expenses	$3,753,580		$3,753,580		$3,753,580	
2	Amortization/Depreciation	$1,359,074		$1,360,340		$1,360,340	
3	Property Taxes	$121,496		$121,496		$121,496	
4	Capital Taxes	$ -		$ -		$ -	
5	Income Taxes (Grossed up)	$447,574		$380,131		$380,131	
6	Other Expenses	$ -		$ -		$ -	
7	Return						
	Deemed Interest Expense	$757,725		$780,190		$763,691	
	Return on Deemed Equity	$924,779		$924,341		$932,060	
8	Distribution Revenue Requirement before Revenues	$7,364,229		$7,320,078		$7,311,298	
9	Distribution revenue	$6,561,820		$6,561,820		$6,561,820	
10	Other revenue	$802,798		$823,798		$823,798	
11	**Total revenue**	$7,364,618		$7,385,618		$7,385,618	
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$389	(1)	$65,539	(1)	$74,320	(1)

Notes
(1) Line 11 - Line 8

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Residential

Consumption 800 **kWh**

			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
1	Monthly Service Charge		$ 10.9300	1	$ 10.93	$ 11.7500	1	$ 11.75	$ 0.82	7.50%
2	Smart Meter Rate Adder		$ 0.5200	1	$ 0.52	$ 3.2900	1	$ 3.29	$ 2.77	532.69%
3	Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
4	Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
5	Distribution Volumetric Rate		$ 0.0156	800	$ 12.48	$ 0.0169	800	$ 13.52	$ 1.04	8.33%
6	Low Voltage Rate Adder			800	$ -		800	$ -	$ -	
7	Volumetric Rate Adder(s)			800	$ -		800	$ -	$ -	
8	Volumetric Rate Rider(s)		-$ 0.0005	800	-$ 0.40	$ 0.0025	800	$ 1.98	$ 2.38	-594.57%
9	Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
10	LRAM & SSM Rate Rider			800	$ -	$ 0.0004	800	$ 0.32	$ 0.32	
11	Deferral/Variance Account Disposition Rate Rider			800	$ -		800	$ -	$ -	
12					$ -			$ -	$ -	
13					$ -			$ -	$ -	
14					$ -			$ -	$ -	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 23.53**			**$ 30.86**	**$ 7.33**	**31.14%**
17	RTSR - Network		$ 0.0060	828.804	$ 4.97	$ 0.0060	826.981	$ 4.96	-$ 0.01	-0.22%
18	RTSR - Line and Transformation Connection		$ 0.0052	828.804	$ 4.31	$ 0.0052	826.981	$ 4.30	-$ 0.01	-0.22%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 32.81**			**$ 40.12**	**$ 7.31**	**22.27%**
20	Wholesale Market Service Charge (WMSC)		$ 0.0052	828.804	$ 4.31	$ 0.0052	826.981	$ 4.30	-$ 0.01	-0.22%
21	Rural and Remote Rate Protection (RRRP)		$ 0.0013	828.804	$ 1.08	$ 0.0013	826.981	$ 1.08	-$ 0.00	-0.22%
22	Special Purpose Charge			828.804	$ -		826.981	$ -	$ -	
23	Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)		$ 0.0070	828.804	$ 5.80	$ 0.0070	826.981	$ 5.79	-$ 0.01	-0.22%
25	Energy		$ 0.0684	828.804	$ 56.67	$ 0.0684	826.981	$ 56.55	-$ 0.12	-0.22%
26					$ -			$ -	$ -	
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 100.93**			**$ 108.08**	**$ 7.16**	**7.09%**
29	HST		13%		$ 13.12	13%		$ 14.05	$ 0.93	7.09%
30	**Total Bill (including Sub-total B)**				**$ 114.05**			**$ 122.13**	**$ 8.08**	**7.08%**
31	**Loss Factor (%)**	**Note 1**	3.60%			3.37%				

Notes:
Note 1: Enter existing and proposed total loss factor (Secondary Metered Customer < 5,000 kW) as a percentage.

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

General Service < 50 kW

Consumption 2000 kWh

		Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
1	Monthly Service Charge		$ 15.5000	1	$ 15.50	$ 19.6000	1	$ 19.60	$ 4.10	26.45%
2	Smart Meter Rate Adder		$ 0.5200	1	$ 0.52	$ 3.2900	1	$ 3.29	$ 2.77	532.69%
3	Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
4	Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
5	Distribution Volumetric Rate		$ 0.0142	2000	$ 28.40	$ 0.0149	2000	$ 29.80	$ 1.40	4.93%
6	Low Voltage Rate Adder			2000	$ -		2000	$ -	$ -	
7	Volumetric Rate Adder(s)			2000	$ -		2000	$ -	$ -	
8	Volumetric Rate Rider(s)			2000	$ -		2000	$ -	$ -	
9	Smart Meter Disposition Rider			2000	$ -		2000	$ -	$ -	
10	LRAM & SSM Rider			2000	$ -		2000	$ -	$ -	
11	Deferral/Variance Account Disposition Rate Rider		-$ 0.0005	2000	-$ 1.00	$ 0.0024	2000	$ 4.83	$ 5.83	-583.34%
12					$ -			$ -	$ -	
13					$ -			$ -	$ -	
14					$ -			$ -	$ -	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 43.42**			**$ 57.52**	**$ 14.10**	**32.48%**
17	RTSR - Network		$ 0.0059	2072.01	$ 12.22	$ 0.0059	2067.45	$ 12.20	-$ 0.03	-0.22%
18	RTSR - Line and Transformation Connection		$ 0.0049	2072.01	$ 10.15	$ 0.0049	2067.45	$ 10.13	-$ 0.02	-0.22%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 65.80**			**$ 79.85**	**$ 14.05**	**21.36%**
20	Wholesale Market Service Charge (WMSC)		$ 0.0052	2072.01	$ 10.77	$ 0.0052	2067.45	$ 10.75	-$ 0.02	-0.22%
21	Rural and Remote Rate Protection (RRRP)		$ 0.0013	2072.01	$ 2.69	$ 0.0013	2067.45	$ 2.69	-$ 0.01	-0.22%
22	Special Purpose Charge			2072.01	$ -		2067.45	$ -	$ -	
23	Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)		$ 0.0070	2072.01	$ 14.50	$ 0.0070	2067.45	$ 14.47	-$ 0.03	-0.22%
25	Energy		$ 0.0684	2072.01	$ 141.68	$ 0.0684	2067.45	$ 141.37	-$ 0.31	-0.22%
26					$ -			$ -	$ -	
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 235.70**			**$ 249.38**	**$ 13.68**	**5.80%**
29	HST		13%		$ 30.64	13%		$ 32.42	$ 1.78	5.80%
30	**Total Bill (including Sub-total B)**				**$ 266.35**			**$ 281.80**	**$ 15.45**	**5.80%**
31	**Loss Factor**	**Note 1**	3.60%			3.37%				

Notes:
Note 1: See Note 1 from Sheet 1A. Bill Impacts - Residential

EXHIBIT 12_Tab 03_S01

[SEC #3] (Re : May 6, 2011 Response - E11T03S03doc)
While STESI and STEI Board of Director costs are not included in this application, the information is important with respect to examining the relationship between these entities and STEI. Please provide the list of the Board of Directors and their brief biographies for STESI and STEI.

RESPONSE to Question 01 – SEC, Second Set:
The STEI board members have previously been provided. Please see Exhibit 11, Tab 3, Schedule 3, Attachment 1 for a listing of STEI board members and a brief bio for each.

For the board members of STESI, they are:

1. Peter Ostojic (member of STEI board)
2. Maureen Bedeck (Employee of London Catholic District School Board)
3. Heather Jackson-Chapman (Mayor of the City of St. Thomas)
4. Tom Johnston (Alderman for the City of St. Thomas)
5. John Laverty (member of STEI board)
6. Joseph Starcevic (member of STEI board)

For the board members of STHI, they are:

1. James Akey (Tara Hall Nursing Home)
2. Brian Dempsey (TD Canada Trust Banking)
3. Heather Jackson-Chapman
4. Tom Johnston
5. John Laverty
6. Joseph Starcevic

We undertake to provide brief bio's for:

1. Maureen Bedeck
2. Heather Jackson-Chapman
3. Tom Johnston
4. Brian Dempsey
5. James Akey

EXHIBIT 12_Tab 03_S02
[SEC #9]   (Re : May 6, 2011 Response - E11T03S09.doc)

Please provide any financial statements for STESI and its affiliates for 2010.

RESPONSE to Question 02 – SEC, Second Set:
The 2010 audited financial statements for St. Thomas Energy Services Inc. are included under Exhibit 12, Tab 3, Schedule 2, Attachment 1. STEI declines to provide financial statements for its other affiliates.

EXHIBIT 12_Tab 03_S03

[SEC #19b] **(Re : May 6, 2011 Response - E11T03S19.doc)**

With respect to the position of Director, Regulatory Affairs:

a) Please provide a breakdown of the compensation

b) How was the salary determined? Please provide all supporting documentation.

RESPONSE to Question 03 – SEC, Second Set:

a) Please refer to the response to Board Staff Technical Conference Question # 10 Part (a).

b) The position created in 2010, Director, Regulatory Affairs, was compared to the then current MEARIE (Municipal Electric Association Reciprocal Insurance Exchange) Industry Specific Salary Survey for compensation level. A further discussion, concerning the compensation level for this position, was held with the external consultant who was involved in setting up a formal compensation structure for management employees in 2007. There is no supporting internal documentation available.

EXHIBIT 12_Tab 03_S04
[SEC #20]   (Re : May 6, 2011 Response - E11T03S20.doc)

Please update the evidence to account for the 5.6% weighted average cost of debt that STEI has requested.

RESPONSE to Question 04 – SEC, Second Set:
Please refer STEI's response to Energy Probe's Technical Conference Question #8 b) included below.

> Please refer Exhibit 5, Tab 1, Schedules 1 and 2, and Schedule 2 Attachment 2. In the weighted cost of capital calculation shown in the pre-filed evidence, STEI used a deemed Long Term Debt rate of 5.48% [Board deemed debt rate for Jan 1, 2011 rates]. St. Thomas indicated that it would be filing a revised rate [5.6%] to reflect its actual debt instruments. As highlighted on Exhibit 5, Tab 1, Schedule 2, Page 3 of 4
>
>> *"In order to avoid delays in filing the application, STEI has not updated its evidence to reflect the proposed 5.6% weighted average cost of debt. The difference in revenue requirement between the 5.48% and 5.6% weighted average cost of debt is not material (approximately $13,300). STEI will update its evidence during the proceeding to reflect the 5.6% weighted average cost of debt."*
>
> Since the evidence indicates the difference in revenue requirement between using the 5.60% and the 5.48% would be approximately $13,300, then it is reasonable to assume the revenue requirement when moving between using the 5.48% and the 5.33% (as per the request) will be less than $13,300 and not material.

EXHIBIT 12_Tab03_S05

5. [SEC #22, Board Staff #38]
Please explain why STEI should not conform with the Ontario Energy Board's Cost Allocation Model.

RESPONSE to Question 5 – SEC, Second Set:

STEI has decided to remain close to the existing Fixed / Variable split despite the fixed charge being greater than the upper bound in order to spread the impact of the proposed rate changes more uniformly over the class.

EXHIBIT 12_Tab 03_S06

[SEC #23] **(Re : May 6, 2011 Response - E11T03S23.doc)**

Has STEI consulted with the City of St. Thomas about the proposal to eliminate the Large User customer class? If so, please provide details.

.

RESPONSE to Question 06 – SEC, Second Set:

STEI consulted with its Shareholder, St. Thomas Holding Inc. at a November 2010 Board Meeting. Two members of the St. Thomas Holding Inc. Board are appointed by its Shareholder, the City of St. Thomas.

STEI did not consult directly with the City of St. Thomas to the best of our knowledge.

EXHIBIT 12_Tab 03_S07
[VECC #23] *(Re : May 6, 2011 Response - E11T04S23.doc)*

Please provide details with respect to the senior lenders consulted about financing alternatives for the promissory note from the City of St. Thomas.

RESPONSE to Question 07 – SEC, Second Set:
In addition to STEI's senior lender, The Bank of Nova Scotia, the other senior lenders STEI had spoken with were Canadian Imperial Bank of Commerce, TD Canada Trust, and the Royal Bank of Canada. STEI discussed various financing topics surrounding direction of interest rates, industry experience, and products.

EXHIBIT 12_Tab 03_S08

[EP #19] **(Re : May 6, 2011 Response - E11T02S19.doc)**

Should this matter not proceed to an oral hearing, what would the impact be on the various regulatory costs outlined in the interrogatory answer.

RESPONSE to Question 08– SEC, Second Set:

The regulatory costs would not change, as they contemplate either the preparation of a settlement agreement or attendance at an oral hearing. If there were both a partial settlement and an oral hearing, the regulatory budget would likely be deficient.

EXHIBIT 12_Tab 03_S09
[EP #22] *(Re : May 6, 2011 Response - E11T02S22.doc)*

Please provide any documentation from the meeting with the regional representative from Infrastructure Ontario and the reasons supporting the decision to not make use of the debt program.

RESPONSE to Question 09 – SEC, Second Set:
We met in person with the regional representative from Infrastructure Ontario.

STEI did not obtain financing from Infrastructure Ontario to finance the smart meter because STEI believed that the additional costs associated with changes to banking, record keeping, and complexity would, in the end, results in no potential costs savings for STEI. STEI believed that the infrastructure loan would only be available to finance the physical asset costs of the project. Then STEI would need to finance the non-physical asset costs of the project. Below are some examples of these costs:

- Stranded costs associated with the removal and scrap of old meters,
- Training,
- Communications costs associated with data collection, and
- Consulting fees.

To finance the remaining amounts would have been challenging. In addition, if the physical assets were financed by Infrastructure Ontario, there would be extra costs for STEI associated with the bank security changes, bank fees, additional financial reporting, etc. Overall, STEI believes that the rates obtained for the loans taken to date are reasonable as they are lower than OEB prescribed rates. Please refer to Exhibit 11, Tab 1, Schedule 34 for discussion on the overall financing for STEI and the impact on weighted cost of capital.

EXHIBIT 12_Tab 03_S10

[Board Staff #10] **(Re : May 6, 2011 Response - E11T01S10.doc)**

Please provide the update to the cost of power input for the Allowance for Working Capital (WCA) calculation.

RESPONSE to Question 10 – SEC, Second Set:

The April 19th, 2011 Regulated Price Plan - Price Report forecasts the RPP cost of power for the period May 1, 2011 – April 30, 2012 to be $72.98 Per MWh. This results in Power Supply Expenses of $28,884,988 which is $1,126,280 greater than STEI's proposed Cost of Power.

STEI will undertake to update the cost of power input of its WCA calculation using the most current cost of power information available prior to the close of the evidentiary record in this proceeding.

EXHIBIT 12_Tab 03_S11
[[Board Staff #20]   (Re : May 6, 2011 Response - E11T01S20.doc)

Please provide any studies or analysis to confirm the ‘belief’ that the fees paid are below market.

RESPONSE to Question 11 – SEC, Second Set:
To be answered orally at the technical conference.

EXHIBIT 12_Tab 03_S12
[Board Staff #21]   (Re : May 6, 2011 Response - E11T01S21.doc)

Please provide the requested calculation of the OM&A portion of the Expenses and confirm whether, or to what extent, the resulting variance will reverse by the end of the year expected to be 'minimal', and indicate by what percentage.

RESPONSE to Question 12 – SEC, Second Set:
STEI has not populated its rate model with the December 2009 budgeted date. To do so would be a significant undertaking that would require a great deal of time and resources. We question whether there is alternative information that could be provided in regard to the inquiry that would be more manageable for STEI.

EXHIBIT 12_Tab 04_S01

Reference: **(Re : May 6, 2011 Response - E11T01S14.doc & E11T01S15.doc & E11T02S09.doc & COS APP Reference E03T01S02)**

i) Board Staff #14 and #15
ii) Energy Probe #9
iii) Exhibit 3/Tab 1/Schedule 2, Attachment 1

a) Please update Table #4 in Reference (iii) to include the years 2004-2010.
b) Please provide a revised version of Table #5 in Reference (iii) to reflect the updated NAC values from part (a).

RESPONSE to Question 1 – VECC, Second Set:

a)

Updated Table 4 - St. Thomas Hydro
Class Average Use

Rate Class	*2004-2010 Avg*	2004 H1 Retail NAC
Residential	*8,445*	8,409
GS<50	*24,072*	25,217
GS>50-4999	*883,980*	1,051,888
GS>5000	*30,120,763*	37,281,347
Street Light	*642*	644
Sentinel Light	*1,175*	n/a

b)

Updated Table 5
Weather Normal kWh Forecast

Rate Class	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011F**
Residential	109,605,776	111,925,460	114,678,677	116,414,921	119,698,091	120,748,142	121,908,688	122,981,577
GS<50	38,029,909	38,066,017	38,370,930	39,821,274	40,310,740	40,296,698	40,326,788	40,344,842
GS>50-4999	172,035,175	176,216,393	174,069,461	170,744,600	151,470,639	127,173,724	136,459,223	136,934,691
GS>5000	37,281,347	38,375,623	36,937,199	33,251,155	28,374,428	6,504,824	0	0
Street Light	2,874,586	2,903,745	2,938,634	2,977,270	2,998,494	3,047,943	3,065,784	3,108,437
Sentinel Light	0	0	0	0	53,774	56,665	61,164	61,164
Total	359,826,792	367,487,237	366,994,902	363,209,221	342,906,166	297,827,996	301,821,647	303,430,712

EXHIBIT 12_Tab 04_S02

Reference: **(Re : May 6, 2011 Response - E11T01S17.doc & COS APP References E03T01S01 & E03T01S02)**

i) Board Staff #17
ii) Exhibit 3/Tab 1/Schedule 1, Attachment 1
iii) Exhibit 3/Tab 1/Schedule 2, Attachment 1

a) Please confirm whether Attachment 1 to Reference (i) is based on the 2011 forecast per the original Application or per the revised forecast provided in response to Board Staff #15. Note: The total 2011 kWh shown in Reference (i) (i.e., 292,857,710 kWh – per Reference (ii)) matches that in the original Application. However, the 2011 Residential sales – prior to the CDM adjustment (i.e., 123,211,245 kWh) – appear to match that of the revised forecast.
b) Please provide two versions of Reference (i), Attachment 3: One which reconciles to the original forecast (per the Application) and a second which reconciles to the revised forecast per Board Staff #15.
c) With respect to Reference (i), Attachment 3, please explain why it is appropriate to adjust the annual billing kW for GS>50 by the GS.50 contribution to the CDM MW target (i.e., 286 MW).

RESPONSE to Question 2 – VECC, Second Set:

a) Exhibit 11, Tab 1, Schedule 17, Attachment 1 provides STEI's October 29, 2010 CDM plan that was filed with the OEB and the April 28, 2011 Addendum that was also filed with the OEB. The CDM plan was prepared independent of the 2011 Load Forecast. Please review E11/T1/S15 and its attachments.
b) Please note that Exhibit 3, Tab 1, Schedule 1, Attachment 1, p2 relies on the correct Load Forecast; this is demonstrated at Exhibit 11, Tab 1, Schedule 17, Attachment 3. STEI declines to provide a version that incorporates a transcription error.
c) As described at Exhibit 3, Tab 1, Schedule 1, page 1, lines 9-11, STEI reduced Elenchus' 2011 Test Year Load Forecast by the expected 2011 results of its CDM programs. The data relied on for the CDM adjustment is provided at Exhibit 11, Tab 1, Schedule 17, Attachment 4, p1 "Annual Milestones". The General Service >50 kW 2011 forecast metered kW were reduced by the projected kW savings due to CDM for that customer class so that a reasonable estimate of 2011 Distribution revenues could be computed. Similarly, the Residential and General Service < 50 kW 2011 forecast energy deliveries were reduced by the projected kWh savings due to CDM for those customer classes.

EXHIBIT 12_Tab 04_S03

Reference: **(Re : May 6, 2011 Response - E11T04S02.doc)**

i) VECC #2 c)

a) Please indicate which of the two interpretations provided in the original question matches STEI's interpretation as provided in the response.

RESPONSE to Question 3 – VECC, Second Set:

a) The following interpretation matches STEI's interpretation "The sum of the savings reported in each of the four years from programs in that year, plus savings persisting from previous years' programs implemented in during the period".

EXHIBIT 12_Tab 04_S04

Reference: **(Re : May 6, 2011 Response - E11T04S06.doc & COS APP Reference E03T03S01)**

i) VECC #6 a)
ii) Exhibit 3/Tab 3/Schedule 1, Attachment 1, page 3

a) Please explain the basis for the negative value (i.e., -$5,115) under USOA #4080 – Other.

RESPONSE to Question 04 – VECC, Second Set:

This estimated value relates to net Load Transfers between Hydro One and STEI. It represent distribution charges:

Source of Supply	Residential	GS < 50 kW	Total
Purchased from Hydro One	$ 5,614	$ 154	$ 5,768
Sold to Hydro One	$(653)		$(653)

Net Load Transfer			$ 5,115
			======

Exhibit 12_Tab04_S05

QUESTION TC #5
Reference: i) Board Staff #36 and #37
ii) Energy Probe #23
iii) OEB Decision EB-2010-0125 (Brant County Power Inc.). p. 5
a) In light of the Board's recent Decision regarding Brant County Power's 2011 Rates, does STEI wish to change its proposed 2011 revenue to cost ratios for the GS<50 and GS>50 classes? If yes, what it the revised proposal? If not, why not?

RESPONSE to Question 05 – VECC, Second set:

STEI proposes to leave its proposed 2011 revenue to cost ratios as filed and clarified in the first round of Interrogatories. STEI believes the proposed revenue to cost ratios are the most fair to all customer classes, and will leave this issue to be resolved by the Board.

EXHIBIT 12_Tab 04_S06

Reference: **(Re : May 6, 2011 Response - E11T01S41.doc)**

i) Board Staff #41

a) Please justify the factors (i.e., 1.5, 2.0 and 2.5) used to estimate the bad debt expense for 2011-2014.

b) Why would it not be appropriate to address any material increase in bad debt costs as a Z-factor adjustment?

RESPONSE to Question 06 – VECC, Second Set:

a) Please refer to the response to Board Staff Technical Conference Question # 15.

b) As an alternative to creating a specific deferral account, regarding Energy Consumer Protection Act costs, the Z factor adjustment could be used (based on the bad debt expense estimates given in the response to Board Staff IR # 41 for the years 2012 to 2014).In the event that the materiality threshold is not reached in any particular year there would be no means by which to record the variance for disposition consideration if a specific deferral account is not used.

EXHIBIT 12_Tab 04_S07

Reference: **(Re : May 6, 2011 Response - E11T01S43.doc & E11T04S17.doc)**

i) Board Staff #43, Attachment D
ii) VECC #17, page 2

a) Confirm that the amended LRAM/SSM claim and rate riders are as set out in these responses

RESPONSE to Question 07 – VECC, Second Set:

a) Confirming that the amended LRAM/SSM claim and rate riders are as set out in these responses <u>with one exception</u> :

   The GS > 50 Class rate rider should be $0.1766 (rounding issue – was stated in the response as $ 0.1765).

EXHIBIT 12_Tab 04_S8

Reference:
I) Board Staff #4
ii) VECC #36 and #37

a) Provide a Copy of the Compliance Plan referenced in the Letter of July 2006 in Attachment 4 to VECC #37
b) Provide an update of the status of STEI's ARC compliance
c) Provide the Service schedules and costs for the historic and test years as requested in part b) of VECC #36.

RESPONSE to Question 8 – VECC, Second Set:
a) The referenced Compliance Plan is at Exhibit 1, Tab 2, Schedule 4, Attachment 2. Although the title of that document is not "Compliance Plan", that document is in fact the compliance plan that was filed by STEI as referenced in the July 2006 letter.

b) There has been no other correspondence beyond what has been provided.

c) There is no additional information beyond what has been documented in Exhibit 11, Tab 4, Schedule 36.

EXHIBIT 12_Tab 04_S9
Reference:
I) Board Staff #7 a)

a) Does this response indicate that (i) STESI does not charge PST or get any input tax credits with respect to services and capital it provides to affiliates, and
(ii) all of the fees charged by STESI are invariant with respect to any applicable ad valorem taxes?

RESPONSE to Question 9 – VECC, Second Set:
a) Please refer to response to Board staff#1, Second set of questions. The question and response are included below:

Board Staff Question #1
Ref: Response to Board staff IR No. 7

a) Were STESI's purchases of goods and services subject to applicable provincial sales tax prior to July 1, 2010? If so, were these costs included in the MSA fee? If not, why not?

b) Are STESI's purchases of goods and services subject to HST?

c) Does STESI remit HST amount and/or claim Input Tax Credits?

> *i.) If so, for 2010 what portion (and indicate the dollar amount) of incremental Input Tax Credits (i.e. for purchases that were previously subject to PST) are for St. Thomas related activities?*
> *ii.) If so, for 2011 what portion (and indicate the dollar amount) of the expected incremental Input Tax Credits (i.e. for purchases that were previously subject to PST) are for St. Thomas related activities?*

RESPONSE to Question 1 – OEB Staff, Second Set:
a) STESI's purchases of goods and services were subject, where applicable, to provincial sales taxes prior to July 1, 2010. These sales taxes were included in STESI's internal cost tracking for the MSA fee but the internal cost tracking of MSA fee by STESI has no impact on the MSA fee charged to STEI. As discussed in original response to Board staff IR No 7, the MSA fee is a fixed fee per customer based on services provided. This fee per customer has an efficiency factor and reduces each year.

b) Yes, STESI's purchases of goods and services are subject to HST.

c) Yes.

> i) We do not have that readily available. As discussed in a), STESI didn't specifically consider the PST component as it was felt that it was going to have a minimal impact on the service operations for STESI. Another key reason was that the fixed fee per customer charged to STEI is a fee that has not been increased since the agreement was established. Furthermore, this fixed fee per customer has been reduced annually.

ii) We have not calculated the incremental input tax credits. To do so would have been a labour intensive task with little or no benefit for STESI. Budgeting was based on total potential cost changes for budget and PST would be a nominal component of the overall estimate and not independently identified.

EXHIBIT 12_Tab 04_S10
Reference
I) VECC #18 a)

a) Does STEI agree that savings attributed to fees that do not increase with inflation would be overstated if the fixed fee agreed upon initially was overly generous?

RESPONSE to Question 10 – VECC, Second Set:

a) The fees were based on actual costs prior to the MSA.

EXHIBIT 12_Tab 04_S10
Reference:
I) VECC #20 c)

a) The reference provided in response to the original interrogatory, i.e., Exhibit 11, Tab 4, Schedule 4, appears to be in error. Please provide a corrected reference (if applicable) along with a table or list showing all unaffiliated third parties to whom STESI provides services.

RESPONSE to Question 10 – VECC, Second Set:
a) The reference should have been to Exhibit 1, Tab 1, Schedule 4.

As provided in the reference to SEC's interrogatory #4 (Exhibit 11, Tab 3, Schedule 4):

> Please refer to the Note 13 and the Statement of Operations as disclosed in the 2009 audited financial statements of STESI. As per the information provided:
> - $5,2619,715 or 77% of Service Sales is to STEI
> - $430,553 or 6% of Service Sales is to the Corporation of the City of St. Thomas
> - $801,936 or 12% of Service Sales is to other related entities
> - $333,493 or 5% of Service Sales is to non-related parties
>
> We are not able to provide additional detail on our Service Sales to non-related parties

We don't believe that it is reasonable to provide a customer list.