

# St. Thomas energy inc.

*We're Your Local Power Distributor*

June 17, 2011

Ontario Energy Board  
2300 Yonge Street, Suite 2701  
Toronto, ON M4P 1E4  
Attn: K. Walli, Board Secretary

Dear Ms. Walli

Re: 2011 Cost of Service Application - Proposed Settlement Agreement - EB-2010-0141

Pursuant to Procedural Order # 2 we enclose two hard copies of the settlement agreement in the above referenced proceeding.

If you have any questions on this matter please do not hesitate to contact the writer at 519.631.4211 extension 223 or at [dwitt@sttenergy.com](mailto:dwitt@sttenergy.com).

Sincerely



Mr. Dana A. Witt, CGA  
Director, Regulatory Affairs  
Encl.

# **ST. THOMAS ENERGY INC.**

## **Proposed Settlement Agreement June 17, 2011**

This settlement agreement (the “Settlement Proposal” or “Settlement Agreement”) is for the consideration of the Ontario Energy Board (the “Board”) in its determination of the Electricity Distribution Rate Application by St. Thomas Energy Inc. (“STEI”), EB-2010-0141, for 2011 electricity distribution rates. STEI’s Application was received by the Board on February 10, 2011. From a revenue deficiency perspective the Settlement Proposal, which is a complete settlement of all the issues, provides for a reduction in the filed Application of a \$766,535 revenue deficiency, to a settled deficiency of \$350,000.00.

Pursuant to Procedural Order No. 2, dated May 16, 2011, a settlement conference was scheduled for June 6, 2011 (the “Settlement Conference”). The Settlement Conference was duly convened in accordance with Procedural Order No. 2 with Mr. Chris Haussmann as the facilitator. The Settlement Conference concluded on June 7, 2011. STEI and the following intervenors (the “Intervenors” and collectively including STEI, the “Parties”) participated in the Settlement Conference:

- Energy Probe Research Foundation (“EP”)
- School Energy Coalition (“SEC”)
- Vulnerable Energy Consumers Coalition (“VECC”)

The intervenor Rogers Cable Communications Inc. did not participate in the Settlement Conference. The role adopted by the Board Staff in the Settlement Conference is set out on page 5 of the Board’s Settlement Conference Guidelines (the “Guidelines”). Although the Board Staff is not a party to this Settlement Agreement, as noted in the Guidelines, the members of Board Staff who did participate in the Settlement Conference are bound by the same confidentiality standards that apply to the Parties to the proceeding.

These settlement proceedings are subject to the rules relating to confidentiality and privilege contained in the Guidelines. The parties understand this to mean that the documents and other information provided, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement – or not – of each issue during the Settlement Conference are strictly confidential and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception: the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal.

This Agreement represents a complete settlement of all issues. It is acknowledged and agreed that none of the Parties will withdraw from this Agreement under any circumstances, except as provided under Rule 32.05 of the Board’s Rules of Practice and Procedure. The Parties explicitly request that the Board consider and accept this Settlement Agreement as a package. None of the

matters in respect of which a settlement has been reached are severable. Numerous compromises were made by the Parties with respect to various matters to arrive at this comprehensive Settlement Agreement. The distinct issues addressed in this proposal are intricately interrelated, and reductions or increases to the agreed-upon amounts may have financial consequences in other areas of this proposal which may be unacceptable to one or more of the Parties. If the Board does not accept the Settlement Agreement in its entirety, then there is no settlement unless the Parties agree that those portions of the Settlement Agreement that the Board does accept may continue as a valid settlement.

It is also agreed that this Settlement Agreement is without prejudice to any of the Parties re-examining these issues in any subsequent proceeding and taking positions inconsistent with the resolution of these issues in this Settlement Agreement. However, none of the Parties will in any subsequent proceeding take the position that the resolution therein of any issue settled in this Settlement Agreement, if inconsistent with the terms of this Settlement Agreement, should be applicable for all or any part of the 2011 Test Year.

References to the evidence supporting this Agreement on each issue are set out in each section of the Agreement. Best efforts have been made to identify all of the evidence that relates to each settled issue. The identification and listing of the evidence that relates to each issue is provided to assist the Board. The identification and listing of the evidence that relates to each settled issue is not intended to limit any party who wishes to assert that other evidence is relevant to a particular settled issue.

The Appendices to the Settlement Agreement provide further evidentiary support. The Parties agree that this Settlement Agreement and the Appendices form part of the record in EB-2010-0141. The Appendices were prepared by the Applicant. The intervenors are relying on the accuracy and completeness of the Appendices in entering into this Agreement.

There is no approved issues list for this proceeding. However, for the purposes of organizing this Settlement Agreement, the Parties have followed the issues listed within this Settlement Agreement. The appendices attached to this Settlement Agreement are:

- “A” - STEI's Proposed 2011 Tariff of Rates and Charges, Effective July1, 2011
- “B” – Sheet O1, 2011 Cost Allocation Model arising from this Settlement Agreement
- “C” – The Rate Design Module arising from this Settlement Agreement
- “D” – Bill Impact Summaries arising from this Settlement Agreement
- “E” – STEI 2011 Revenue Deficiency arising from this Settlement Agreement
- “F” – STEI 2011 Revenue Requirement Work Form

The following table summarizes the settlement on the key ratemaking components:

### Summary Comparison – Application Vs. Settlement

#### Key Rate Making Components

	Original Application	Application As Amended 2011 *	Settlement (2011)
<b>Rate Base (Exhibit 2)</b>			
Average Net Plant	19,188,131	19,218,506	18,940,682
Allowance for Working Capital	4,745,068	4,903,135	4,936,990
Rate Base	23,933,199	24,121,641	23,877,673
<b>Operating Costs (Exhibit 4)</b>			
OM&A (including Property Taxes)	3,875,076	3,875,076	3,571,434
Amortization	1,359,074	1,360,340	1,356,340
Income Taxes	447,554	380,131	377,416
<b>Revenue (Exhibits 3 &amp; 6)</b>			
Service Revenue Requirement	7,364,208	7,320,078	6,992,482
Base Revenue Requirement	6,561,411	6,496,280	6,168,684
Revenue Offsets	802,798	823,798	823,798
Revenue Deficiency	766,535	701,244	350,000
<b>Cost of Capital (Exhibit 5)</b>			
Short Term Interest Rate	2.43%	2.46%	2.46%
Long Term Interest Rate	5.48%	5.60%	5.60%
Return on Equity	9.66%	9.58%	9.58%
Capital Structure	60% Debt / 40% Equity	60% Debt / 40% Equity	60% Debt / 40% Equity
Return on Rate Base	7.03%	7.07%	7.07%

\* as per the RRWF provided in response to Energy Probe technical conference question #14

The 2011 Cost Allocation in this Settlement Agreement is based on the 2010 Cost Allocation Study filed in the original application adjusted proportionally for the 2011 revenue requirement. The current distribution revenue from rates is premised on a 2011 Customer and Load Forecast, which for settlement purposes was accepted, subject to the adjustments set out in section #3 below. The 2011 Cost Allocation approach and results have been included in Appendix B.

The revenue requirement and rate adjustments arising from this Settlement Agreement will allow STEI to make the necessary investments to serve customers, maintain the integrity of the distribution system, to maintain and improve the quality of its service and to meet all compliance requirements during 2011. While STEI has filed budgets for the Test Year that are illustrative of how it would achieve these goals, as is always the case with forward test year cost of service cases, the actual decisions as to how to allocate resources, and in what areas to spend the agreed upon capital and OM&A, are ones that must be made by the utility during the course of the year, subject to the Board's normal review in subsequent proceedings.

## **Settlement Terms by Issue**

### **1. Administration (Exhibit 1)**

1a. Is the proposed effective date of May 1, 2011 appropriate?

**Complete Settlement:** For the purpose of obtaining a complete settlement of all issues, the Parties accept a July 1, 2011 effective date using rates for the distribution of electricity determined on the basis of the 2011 revenue requirement. The Parties agree that a foregone revenue rate rider would be appropriate should STEI be unable to implement the rates for July 1, 2011.

#### **Evidence:**

Application	Exhibit 1	Tab 1	Schedule 2 & 4
Board Staff	Exhibit 11	QT#	1

**Supporting parties:** STEI, SEC, EP and VECC

**Parties taking no position:** None

**Opposing parties:** None

## **2. Rate Base (Exhibit 2)**

2 a. Is the amount proposed for the 2010 average net plant appropriate?

**Complete Settlement:** For the purpose of obtaining a complete settlement of all issues, the Parties accept the proposed 2010 average net plant of \$18,927,195, which reflects actual capital additions in 2010.

### **Evidence:**

Application	Exhibit 2	Tab 1	Schedule 1
Board Staff	Exhibit 11	QT#	9
Energy Probe	Exhibit 11	QT#	5-6
VECC	Exhibit 11	QT#	24-29

**Supporting parties:** STEI, SEC, EP and VECC

**Parties taking no position:** None

**Opposing parties:** None

2 b. Is the amount proposed for the 2011 Rate Base appropriate?

**Complete Settlement:** For the purpose of obtaining a complete settlement of all issues, the Parties agree to a 2011 rate base of \$23,877,673, reflecting a \$243,968 reduction from the \$24,121,641 rate base in the application as amended. This reduction can primarily be attributed to a \$200,000 reduction in 2011 capital expenditures as agreed upon in section 2d below and movement to the full year rule of depreciation from 2005 to 2010 while maintaining the half year rule for 2011 as indicated in the resolution of issue 2 e below.

### **Evidence:**

Application	Exhibit 2	Tab 1	Schedule 1 & 2
Application	Exhibit 2	Tab 2	Schedule 1 & 4
Application	Exhibit 2	Tab 3	Schedule 1-3
Application	Exhibit 2	Tab 4	
Board Staff	Exhibit 11	QT#	10-13
SEC	Exhibit 11	QT#	8
Board Staff	Exhibit 12	QT#	3,4,12
Energy Probe	Exhibit 12	QT#	12

**Supporting parties:** STEI, SEC, EP and VECC

**Parties taking no position:** None

**Opposing parties:** None

2 c. Is the amount proposed for the 2010 capital expenditures appropriate?

**Complete Settlement:** For the purpose of obtaining a complete settlement of all issues, the Parties accept that the proposed 2010 capital expenditures of \$1,132,886 are appropriate. This amount represents actual capital expenditures in 2010, as updated in STEI's response to Energy Probe's technical conference question #14.

**Evidence:**

Application	Exhibit 2	Tab 1	Schedule 2
Application	Exhibit 2	Tab 2	Schedule 1 & 4
Application	Exhibit 2	Tab 3	Schedule 1
Application	Exhibit 2	Tab 4	
Board Staff	Exhibit 11	QT#	9,13
SEC	Exhibit 11	QT#	13
Board Staff	Exhibit 12	QT#	2

**Supporting parties:** STEI, SEC, EP and VECC

**Parties taking no position:** None

**Opposing parties:** None

2d. Is the amount proposed for the 2011 capital expenditures appropriate?

**Complete Settlement:** For the purpose of obtaining a complete settlement of all issues, the Parties agree that STEI's proposed capital expenditures of \$1,942,961 should be reduced by \$200,000 on an envelope basis, resulting in an agreed upon amount for 2011 capital expenditures of \$1,742,961.

**Evidence:**

Application	Exhibit 2	Tab 1	Schedule 1-2
Application	Exhibit 2	Tab 2	Schedule 1 & 4
Application	Exhibit 2	Tab 3	Schedule 1
Application	Exhibit 2	Tab 4	
Board Staff	Exhibit 11	QT#	11
SEC	Exhibit 11	QT#	5,14
VECC	Exhibit 11	QT#	22
Energy Probe	Exhibit 12	QT#	11,13



**Supporting parties:** STEI, SEC, EP and VECC

**Parties taking no position:** None

**Opposing parties:** None

2e. Is it appropriate to use the half-year rule for the 2010 Bridge Year as proposed by STEI in the Application?

**Complete Settlement:** For the purpose of obtaining a complete settlement of all issues, the Parties agree that it would be appropriate for STEI to use the full-year rule for depreciation for the years 2005 through 2010, and the half-year rule for the 2011 Test Year.

**Evidence:**

Energy Probe Exhibit 11 QT# 7

**Supporting parties:** STEI, SEC, EP and VECC

**Parties taking no position:** None

**Opposing parties:** None

2f. Should the cost of power estimate for the determination of working capital allowance be based on the 2010 RPP/Non-RPP split, or the 2009 RPP/Non-RPP split as originally proposed by STEI?

**Complete Settlement:** For the purpose of obtaining a complete settlement of all issues, the Parties agree that it would be appropriate for STEI to use a cost of power estimate for the determination of working capital allowance that is based on the 2010 RPP/Non-RPP split. The impact of this change to revenue requirement is a \$784 decrease.

**Evidence:**

Application Exhibit 2 Tab 5 Schedule 1  
Energy Probe Exhibit 11 QT# 15

**Supporting parties:** STEI, SEC, EP and VECC

**Parties taking no position:** None

**Opposing parties:** None

### 3. Operating Revenue (Exhibit 3)

3a. Is the Customer and Load Forecast appropriate?

**Complete Settlement:** For the purpose of obtaining complete settlement of all issues, the Parties agree with STEI's proposed customer and load forecast, subject to the following two adjustments:

i. For the purpose of determining a 2011 volume forecast for the GS>50 class, the average of the 2009 and 2010 consumption for this class (693,662 kWh) is to be used to determine the average consumption/customer in the class (based on the average number of customers in the class in 2009 and 2010), and then that number is to be multiplied by the 2011 customer forecast (192) for the class. The resulting 2011 volume forecast for the GS>50 class agreed upon by the parties is 132,743,408 kWh.

ii. The 2011 kWh consumption for the metered customer classes will be reduced by 10% of STEI's OEB/OPA directed CDM target of 14.92 GWhs in order to reflect the impact of CDM activity, rather than the proposed reduction of 25% of 14.92 GWhs.

#### **Evidence:**

Application	Exhibit 3	Tab 1	Schedule 1-2
Board Staff	Exhibit 11	QT#	14-17
Energy Probe	Exhibit 11	QT#	9-14
SEC	Exhibit 11	QT#	2
VECC	Exhibit 11	QT#	1-4
Board Staff	Exhibit 12	QT#	5-6
Energy Probe	Exhibit 12	QT#	3-5
VECC	Exhibit 12	QT#	1-4
Undertaking			JT1.2, JT1.4, JT1.5

**Supporting parties:** STEI, SEC, EP and VECC

**Parties taking no position:** None

**Opposing parties:** None

3b. Is the forecast of 2011 other revenues appropriate?

**Complete Settlement:** For the purpose of obtaining complete settlement of all issues, the Parties accept the forecast of 2011 other revenues in the amount of \$823,798, which reflects the amount provided by STEI in its undertaking JT1.7, and is an increase of \$21,000 relative the \$802,798 originally applied for.

**Evidence:**

Application	Exhibit 3	Tab 3	Schedule 3-6
Board Staff	Exhibit 11	QT#	5,18
Energy Probe	Exhibit 11	QT#	16
SEC	Exhibit 11	QT#	15
VECC	Exhibit 11	QT#	6
Board Staff	Exhibit 12	QT#	7,12
Undertaking		JT1.7	

**Supporting parties:** STEI, SEC, EP and VECC

**Parties taking no position:** None

**Opposing parties:** None

#### **4. Operating Costs (Exhibit 4)**

4a. Are the proposed 2011 Operations, Maintenance and Administration (“OM&A”) expenses appropriate?

**Complete Settlement:** For the purpose of obtaining complete settlement of all issues, on an envelope basis the Parties agree that the proposed 2011 OM&A expense as amended of \$3,875,076 should be reduced by \$303,642, resulting in an agreed upon 2011 OM&A expense of \$3,571,434.

#### **Evidence:**

Application	Exhibit 4	Tab 1
Application	Exhibit 4	Tab 2 Schedule 1-3,6,7
Application	Exhibit 4	Tab 3
Application	Exhibit 4	Tab 4
Application	Exhibit 4	Tab 5
Application	Exhibit 4	Tab 6
Board Staff	Exhibit 11	QT# 4,12,19-29
Energy Probe	Exhibit 11	QT# 1-2,17-20
SEC	Exhibit 11	QT# 5,7,16-19,24
VECC	Exhibit 11	QT# 18-19,20-22,29-36
Board Staff	Exhibit 12	QT# 8-11,15
Energy Probe	Exhibit 12	QT# 1,6
SEC	Exhibit 12	QT# 3,8,11-12
VECC	Exhibit 12	QT# 6,10-11
Undertaking		KXT1.1

**Supporting parties:** STEI, SEC, EP and VECC

**Parties taking no position:** None.

**Opposing parties:** None

## **5. Cost of Capital and Rate of Return (Exhibit 5)**

5 a. Is the proposed Capital Structure appropriate?

**Complete Settlement:** For the purpose of obtaining complete settlement of all issues, the Parties accept the proposed capital structure of 40% equity, 56% long term debt and 4% short term debt.

### **Evidence:**

Application	Exhibit 5	Tab 1	Schedule 1
Board Staff	Exhibit 12	QT#	13-14

**Supporting parties:** STEI, EP, SEC and VECC

**Parties taking no position:** None

**Opposing parties:** None

5 b. Is the proposed Cost of Capital appropriate?

**Complete Settlement:** For the purpose of obtaining complete settlement of all issues, the Parties accept the proposed cost of capital being 5.60% for the weighted long-term debt, 2.46% for short-term debt and 9.58% for return on equity. For greater certainty, the Parties accept STEI's proposed 5.87% debt rate for its \$7.7 million Promissory Note for the limited purpose of calculating the weighted long-term debt rate for the 2011 Test Year.

### **Evidence:**

Application	Exhibit 5	Tab 1	Schedule 2
Board Staff	Exhibit 11	QT#	30-34
Energy Probe	Exhibit 11	QT#	4,22
SEC	Exhibit 11	QT#	20
VECC	Exhibit 11	QT#	23
Energy Probe	Exhibit 12	QT#	2,8-9
SEC	Exhibit 12	QT#	4,7

**Supporting parties:** STEI, EP, SEC and VECC

**Parties taking no position:** None

**Opposing parties:** None

## **6. Revenue Deficiency or Surplus (Exhibit 6)**

6a. Is the Revenue Deficiency proposed by STEI appropriate?

**Complete Settlement:** For the purposes of obtaining complete settlement of all issues, the Parties agree with the Revenue Deficiency for 2011 outlined in Appendix "E".

### **Evidence:**

Application	Exhibit 1	Tab 4	Schedule 9
Application	Exhibit 6	Tab 2	
Energy Probe	Exhibit 11	QT#	4

**Supporting parties:** STEI, EP, SEC and VECC

**Parties taking no position:** None

**Opposing parties:** None

## 7. Cost Allocation (Exhibit 7)

7a. Is the Cost Allocation proposed by STEI appropriate?

**Complete Settlement:** For the purposes of obtaining complete settlement of all issues, the Parties agree that the proposed cost allocation methodology is appropriate and the results flowing from the Output Sheet O1 of the Cost Allocation Model provided in Appendix “B” and also shown in Appendix “C” Table F3 are appropriate as explained below:

The Cost Allocation Model was updated as per the agreed upon settlement items with some minor changes in revenue to cost ratios as a result of the shifts in the costs. The principals were then applied that revenue to cost ratios were to be preserved except for the Street Lighting and Sentinel Lighting rate classes where the ratio changed to 40% and 50% respectively in order to move approximately half way to the bottom of the range. The entire benefit was then applied to the Residential rate class as it was, and remains at the highest ratio.

### Table of Changes:

Total	Residential	GS <50	GS >50	Street Light	Sentinel Light
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#### Cost Allocation Model

Output	94.99%	103.19%	96.23%	88.73%	10.90%	31.33%
Revenue to Expense scaled to 100% recovery	100.00%	108.62%	101.31%	93.40%	11.47%	32.98%

#### F3 Revenue Requirement Allocation

Revenue to Cost Ratio - As per Settlement	1.00	1.07	1.01	0.93	0.40	0.50
Revenue to Cost Ratio - Cost Allocation	1.00	1.09	1.01	0.93	0.11	0.33
Variance	0.00	-0.02	-0.00	-0.00	0.29	0.17

Floor

0.85	0.80	0.80	0.70	0.70
1.15	1.20	1.80	1.20	1.20

Ceiling

As referred to above the computed revenue to cost ratio for the Street Lighting rate class is at 0.11 and is below the floor value of 0.70. The ratio has been set at 0.40, approximately half way to the bottom of the range. The computed revenue to cost ratio for the Sentinel Lighting rate class is at 0.33 and is below the floor value of 0.70. The ratio has been set at 0.50, approximately half way to the bottom of the range. STEI proposes to adjust its 2012 and 2013 rates using the IRM’s revenue to cost ratio adjustment process to achieve the minimum value of the OEB’s target range for the Street Lighting and Sentinel Lighting rate classes by 2013. As noted above regarding 2011 adjustments, any resulting benefit from these actions will be applied solely to the Residential rate class in 2012 and 2013.

**Evidence:**

Application	Exhibit 7		
Board Staff	Exhibit 11	QT#	35
Energy Probe	Exhibit 11	QT#	23
SEC	Exhibit 11	QT#	21
VECC	Exhibit 11	QT#	7-9
SEC	Exhibit 12	QT#	5
VECC	Exhibit 12	QT#	5

**Supporting parties:** STEI, SEC, EP and VECC

**Parties taking no position:** None

**Opposing parties:** None



## **8. Rate Design (Exhibit 8)**

8 a. Are the fixed/variable proportions proposed by STEI appropriate?

**Complete Settlement:** For the purposes of obtaining complete settlement of all issues, the Parties agree that the fixed/variable proportions proposed by STEI are appropriate, subject to lowering the fixed charge for the GS>50 class to the permitted ceiling, as set out in Appendix "C" attached hereto.

### **Evidence:**

Application	Exhibit 8	Tab 2	Schedule 1
Board Staff	Exhibit 11	QT#	36-38
Energy Probe	Exhibit 11	QT#	24
SEC	Exhibit 11	QT#	22-23
VECC	Exhibit 11	QT#	10
SEC	Exhibit 12	QT#	6

**Supporting parties:** STEI, SEC, EP and VECC

**Parties taking no position:** None.

**Opposing parties:** None

8b. Is the loss factor proposed by STEI appropriate?

**Complete Settlement:** For the purposes of obtaining complete settlement of all issues, the Parties agree that the loss factor will be recalculated as 3.5%, which is based on a five-year average using the years 2006-2010 (i.e. including 2010), rather than 3.6%, being the 2006-2009 three-year average proposed by STEI.

### **Evidence:**

Application	Exhibit 8	Tab 3	Schedule 2
Energy Probe	Exhibit 11	QT#	25
VECC	Exhibit 11	QT#	12
Energy Probe	Exhibit 12	QT#	10

**Supporting parties:** STEI, SEC, EP and VECC

**Parties taking no position:** None.

**Opposing parties:** None

8 c. Are the Retail Transmission Service Rates (RTSRs) proposed by STEI appropriate?

**Complete Settlement:** For the purposes of obtaining complete settlement of all issues, the Parties accept STEI's proposal to leave its current Board approved RTSRs unchanged, as set out in Appendix A.

**Evidence:**

Application	Exhibit 3	Tab 1	Schedule 3	Page 2
Application	Exhibit 8	Tab 1	Schedule 1	Page 1
Application	Exhibit 8	Tab 3	Schedule 1	

**Supporting parties:** STEI, SEC, EP and VECC

**Parties taking no position:** None.

**Opposing parties:** None

## 9. Deferral and Variance Accounts (Exhibit 9)

9 a. Should STEI be granted the two new deferral and variance accounts it proposed?

**Complete Settlement:** For the purposes of obtaining complete settlement of all issues, the Parties agree that STEI should not be granted deferral accounts as proposed in the Application for Smart Meter Entity Charges and for the implementation of the *Energy Consumer Protection Act, 2010*, as these deferral accounts pertain generically to electricity distributors and if they are to be addressed, it should be done by the Board on a generic basis.

### **Evidence:**

Application	Exhibit 9	Tab 1	Schedule 1
Board Staff	Exhibit 11	QT#	39-41

**Supporting parties:** STEI, SEC, EP, and VECC

**Parties taking no position:** None

9 b. Over what time period should STEI's deferral account balances be disbursed?

**Complete Settlement:** For the purposes of obtaining complete settlement of all issues, the Parties agree that STEI should disburse its deferral accounts as proposed, but adjusted to account for an implementation date that is later than May 1, 2011. For clarity, STEI originally proposed to disburse its deferral and variance accounts described in Exhibit 9 of its pre-filed evidence over a twelve month period. Assuming a July 1, 2011 implementation date (i.e. two months later than May 1, 2011), the Parties agree that those balances would be disbursed over a ten month period instead. STEI also originally proposed that amounts claimed as the LRAM/SSW be recovered through a rate rider implemented May 1, 2011, over a period of three years. The Parties agree that assuming a July 1, 2011 implementation date, the rate rider should be based on a 34 month period (i.e. three years less two months). If implementation of the rates is delayed beyond July 1, 2011, the parties agree to adjust the disbursement period accordingly. For example, if rates are implemented on August 1, 2011, the disbursement times described herein would be reduced by one month (i.e. 9 months for the deferral and variance accounts, and 33 months for the LRAM/SSW rate rider).

### **Evidence:**

Application	Exhibit 9	Tab 1	Schedule 1
Application	Exhibit 9	Tab 2	Schedule 2
Energy Probe	Exhibit 11	QT#	27

**Supporting parties:** STEI, SEC, EP, and VECC

**Parties taking no position:** None

9 c. Is the proposed \$3.29 smart meter funding adder appropriate?

**Complete Settlement:** For the purposes of obtaining complete settlement of all issues, the Parties agree that a \$2.50 Smart Meter funding adder is appropriate, rather than \$3.29 proposed by STEI.

**Evidence:**

Application	Exhibit 9	Tab 3	
Board Staff	Exhibit 11	QT#	44
VECC	Exhibit 11	QT#	13-14
Board Staff	Exhibit 12	QT#	16-17

**Supporting parties:** STEI, SEC, EP, and VECC

**Parties taking no position:** None

9 d. Is the Late Payment Penalty Rate Rider from EB–2010-0295 appropriate?

As ordered by the Ontario Energy Board on February 22, 2011, STEI filed information regarding the above mentioned hearing, on February 28, 2011 concerning details of rate rider calculations per affected customer classes with a rate rider to become effective on May 1, 2011 for a period of one year. The amount requested to be recovered from rate payers (Class Action Lawsuit Settlement Payment) amounts to \$52,622.33.

Assuming a July 1, 2011 implementation date (i.e. two months later than May 1, 2011), the Parties agree that those balances would be disbursed over a ten month period instead.

## 10. Lost Revenue Adjustment Mechanism (Exhibit 10)

10 a. Is the Lost Revenue Adjustment Mechanism Claim proposed appropriate?

**Complete Settlement:** For the purposes of obtaining complete settlement of all issues, the Parties agree to STEI's Lost Revenue Adjustment mechanism claim as amended. The original claim and amended claim are shown below for comparison purposes.

### LRAM & SSM Totals

### ORIGINAL

Rate Class	LRAM \$	SSM \$	TOTAL \$
<u>Third Tranche</u>			
RESIDENTIAL	\$10,726.95	\$1,902.52	\$12,629.47
GENERAL SERVICE < 50kW	\$14,543.93	\$5,985.58	\$20,529.51
-			
<u>OPA Programs</u>			
RESIDENTIAL	\$129,388.26		\$129,388.26
GENERAL SERVICE <50KW	\$11,009.92		\$11,009.92
General Service>50kW to 4,999kW	\$171,695.49		\$171,695.49
	\$337,364.55	\$7,888.10	\$345,252.66
Carrying Charges	\$25,314.51	\$348.26	\$25,662.77
Total Amounts	\$362,679.06	\$8,236.36	\$370,915.43

### LRAM & SSM Totals

### AMENDED

Rate Class	LRAM \$	SSM \$	TOTAL \$
<u>Third Tranche</u>			
RESIDENTIAL	\$6,195.89	\$1,902.52	\$8,098.41
GENERAL SERVICE < 50kW	\$12,748.48	\$5,985.58	\$18,734.06
-			
<u>OPA Programs</u>			
RESIDENTIAL	\$129,376.02		\$129,376.02
GENERAL SERVICE <50KW	\$11,009.92		\$11,009.92
General Service>50kW to 4,999kW	\$171,695.49		\$171,695.49
	\$331,025.81	\$7,888.10	\$338,913.91
Carrying Charges	\$24,957.89	\$348.26	\$25,306.15
Total Amounts	\$355,983.69	\$8,236.36	\$364,220.06

**Evidence:**

Application	Exhibit 10		
Board Staff	Exhibit 11	QT#	43
VECC	Exhibit 11	QT#	15-17
VECC	Exhibit 12	QT#	7

**Supporting parties:** STEI, SEC, Energy Probe and VECC

**Parties taking no position:** None.

**Opposing parties:** None

## **11. General**

11 a. Should STEI develop and implement a more formalized and transparent procedure for its affiliate transfer pricing?

**Complete Settlement:** For the purposes of obtaining complete settlement of all issues, the Parties agree STEI will develop and implement a more formalized and transparent procedure for its affiliate transfer pricing as soon as practical, but no later than the filing of its next cost of service rate application.

**Evidence:**

Application   Exhibit 1      Tab 2   Schedule 4

**Supporting parties:** STEI, SEC, Energy Probe and VECC

**Parties taking no position:** None.

**Opposing parties:** None

# **St. Thomas Energy Inc. (ED-2002-0523)**

**2011 EDR Application (EB-2010-0141 ) version: 10**

**Proposed Settlement Agreement**

**Appendix A**

## **Monthly Rates and Charges Effective July 1st, 2011**

### **Residential**

Service Charge	\$	11.50
Distribution Volumetric Rate	\$/kWh	0.0160
Smart Meter Funding Adder	\$	2.50
LPP Rate Rider - effective until Apr 30, 2012	\$	0.25
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2014	\$/kWh	0.0003
Deferral/Variance Account Disposition - effective until April 30, 2014	\$/kWh	(0.0008)
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2012	\$/kWh	0.0035
Deferral/Variance Account Disposition - effective until April 30, 2012	\$/kWh	0.0001
LRAM Rate Rider - effective until April 30, 2014	\$/kWh	0.0004
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0060
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0052
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

### **General Service Less Than 50 kW**

Service Charge	\$	17.00
Distribution Volumetric Rate	\$/kWh	0.0147
Smart Meter Funding Adder	\$	2.50
LPP Rate Rider - effective until Apr 30, 2012	\$	0.41
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2014	\$/kWh	0.0003
Deferral/Variance Account Disposition - effective until April 30, 2014	\$/kWh	(0.0008)
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2012	\$/kWh	0.0035
Deferral/Variance Account Disposition - effective until April 30, 2012	\$/kWh	(0.0000)
LRAM Rate Rider - effective until April 30, 2014	\$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0059
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0049
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25



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## **Appendix A**

### **General Service 50 to 4,999 kW**

Service Charge	\$	70.35
Distribution Volumetric Rate	\$/kW	3.1490
Smart Meter Funding Adder	\$	2.50
LPP Rate Rider - effective until Apr 30, 2012	\$	5.21
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2014	\$/kW	0.1102
Deferral/Variance Account Disposition - effective until April 30, 2014	\$/kW	(0.3156)
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2012	\$/kW	1.2877
Deferral/Variance Account Disposition - effective until April 30, 2012	\$/kW	(0.0369)
LRAM Rate Rider - effective until April 30, 2014	\$/kW	0.1869
Retail Transmission Rate – Network Service Rate	\$/kW	2.3569
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.9727
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

### **Street Lighting**

Service Charge (per connection)	\$	1.67
Distribution Volumetric Rate	\$/kW	0.0163
LPP Rate Rider - effective until Apr 30, 2012	\$	0.00
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2014	\$/kW	0.0988
Deferral/Variance Account Disposition - effective until April 30, 2014	\$/kW	0.2823
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2012	\$/kW	1.2651
Deferral/Variance Account Disposition - effective until April 30, 2012	\$/kW	(0.0553)
Retail Transmission Rate – Network Service Rate	\$/kW	1.8175
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.5210
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

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### **Sentinel Lighting**

Service Charge (per connection)	\$	3.75
Distribution Volumetric Rate	\$/kW	4.5344
LPP Rate Rider - effective until Apr 30, 2012	\$	0.02
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2014	\$/kW	0.1176
Deferral/Variance Account Disposition - effective until April 30, 2014	\$/kW	(0.2510)
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2012	\$/kW	1.2634
Deferral/Variance Account Disposition - effective until April 30, 2012	\$/kW	0.0154
Retail Transmission Rate – Network Service Rate	\$/kW	1.4816
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.2392
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

### **microFIT Generator Service**

Service Charge	\$	5.25
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### **Specific Service Charges**

#### **Customer Administration**

Arrears certificate	\$	15.00
Statement of account	\$	15.00
Pulling post dated cheques	\$	15.00
Duplicate invoices for previous billing	\$	15.00
Request for other billing information	\$	15.00
Easement letter	\$	15.00
Income tax letter	\$	15.00
Notification charge	\$	15.00
Account history	\$	15.00
Credit reference/credit check (plus credit agency costs)	\$	15.00
Returned cheque charge (plus bank charges)	\$	15.00
Charge to certify cheque	\$	15.00
Legal letter charge	\$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	\$	30.00
Special meter reads	\$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	\$	30.00

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### Appendix A

#### Non-Payment of Account

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

#### Other

Install/Remove load control device - during regular hours	\$	65.00
Install/Remove load control device - after regular hours	\$	185.00
Specific Charge for Access to the Power Poles \$/pole/year	\$	22.35

#### Retail Service Charges (if applicable)

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

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

#### Allowances

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

#### Loss Factors

Secondary Metered < 5000kW	1.0350
Primary Metered < 5000kW	1.0247

# 2011 COST ALLOCATION INFORMATION FILING



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Appendix B

### Sheet 01 Revenue to Cost Summary Worksheet

#### Class Revenue, Cost Analysis, and Return on Rate Base

	Total	1 Residential	2 GS <50	3 GS >50	7 Street Light	8 Sentinel Light
Distribution Revenue (sale)	\$5,818,685	\$3,825,499	\$884,403	\$1,102,596	\$4,603	\$1,584
Miscellaneous Revenue (mi)	\$823,797	\$534,795	\$123,383	\$134,906	\$29,997	\$716
<b>Total Revenue</b>	<b>\$6,642,482</b>	<b>\$4,360,294</b>	<b>\$1,007,786</b>	<b>\$1,237,502</b>	<b>\$34,600</b>	<b>\$2,300</b>
<b>Expenses</b>						
Distribution Costs (di)	\$873,223	\$461,726	\$122,001	\$241,570	\$46,901	\$1,025
Customer Related Costs (cu)	\$1,171,590	\$870,381	\$211,498	\$87,859	\$1,578	\$274
General and Administration (ad)	\$1,526,621	\$980,251	\$244,962	\$257,534	\$42,779	\$1,096
Depreciation and Amortization (dep)	\$1,356,341	\$760,490	\$186,188	\$319,051	\$88,674	\$1,939
PILs (INPUT)	\$377,416	\$210,725	\$51,652	\$89,337	\$25,152	\$550
Interest	\$772,299	\$431,203	\$105,694	\$182,809	\$51,467	\$1,125
<b>Total Expenses</b>	<b>\$6,077,490</b>	<b>\$3,714,776</b>	<b>\$921,994</b>	<b>\$1,178,160</b>	<b>\$256,551</b>	<b>\$6,010</b>
<b>Direct Allocation</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>
Allocated Net Income (NI)	\$914,992	\$510,874	\$125,223	\$216,586	\$60,977	\$1,333
<b>Revenue Requirement (includes NI)</b>	<b>\$6,992,482</b>	<b>\$4,225,650</b>	<b>\$1,047,217</b>	<b>\$1,394,746</b>	<b>\$317,527</b>	<b>\$7,342</b>
<b>Revenue Requirement Input equals Output</b>						
<b>Rate Base Calculation</b>						
<b>Net Assets</b>						
Distribution Plant - Gross	\$44,667,387	\$24,850,596	\$6,128,440	\$10,772,747	\$2,853,236	\$62,368
General Plant - Gross	\$2,603,030	\$1,452,418	\$356,000	\$616,706	\$174,100	\$3,806
Accumulated Depreciation	(\$23,122,207)	(\$12,828,989)	(\$3,181,838)	(\$5,668,297)	(\$1,412,217)	(\$30,867)
Capital Contribution	(\$5,207,529)	(\$2,899,360)	(\$710,603)	(\$1,237,390)	(\$352,470)	(\$7,706)
<b>Total Net Plant</b>	<b>\$18,940,681</b>	<b>\$10,574,665</b>	<b>\$2,591,999</b>	<b>\$4,483,766</b>	<b>\$1,262,649</b>	<b>\$27,602</b>
<b>Directly Allocated Net Fixed Assets</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>
Cost of Power (COP)	\$29,341,836	\$12,239,521	\$3,945,526	\$12,839,596	\$311,516	\$5,677
OM&A Expenses	\$3,571,434	\$2,312,358	\$578,460	\$586,962	\$91,258	\$2,396
Directly Allocated Expenses	\$0	\$0	\$0	\$0	\$0	\$0
<b>Subtotal</b>	<b>\$32,913,270</b>	<b>\$14,551,879</b>	<b>\$4,523,986</b>	<b>\$13,426,558</b>	<b>\$402,774</b>	<b>\$8,073</b>
<b>Working Capital</b>	<b>\$4,936,991</b>	<b>\$2,182,782</b>	<b>\$678,598</b>	<b>\$2,013,984</b>	<b>\$60,416</b>	<b>\$1,211</b>
<b>Total Rate Base</b>	<b>\$23,877,671</b>	<b>\$12,757,447</b>	<b>\$3,270,597</b>	<b>\$6,497,750</b>	<b>\$1,323,065</b>	<b>\$28,813</b>
<b>Rate Base Input equals Output</b>						
<b>Equity Component of Rate Base</b>	<b>\$9,551,069</b>	<b>\$5,102,979</b>	<b>\$1,308,239</b>	<b>\$2,599,100</b>	<b>\$529,226</b>	<b>\$11,525</b>
<b>Net Income on Allocated Assets</b>	<b>\$564,992</b>	<b>\$645,518</b>	<b>\$85,792</b>	<b>\$59,342</b>	<b>(\$221,950)</b>	<b>(\$3,709)</b>
<b>Net Income on Direct Allocation Assets</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>
<b>Net Income</b>	<b>\$564,992</b>	<b>\$645,518</b>	<b>\$85,792</b>	<b>\$59,342</b>	<b>(\$221,950)</b>	<b>(\$3,709)</b>
<b>RATIOS ANALYSIS</b>						
REVENUE TO EXPENSES %	94.99%	103.19%	96.23%	88.73%	10.90%	31.33%
EXISTING REVENUE MINUS ALLOCATED COSTS	(\$350,000)	\$134,644	(\$39,431)	(\$157,243)	(\$282,927)	(\$5,042)
RETURN ON EQUITY COMPONENT OF RATE BASE	5.92%	12.65%	6.56%	2.28%	-41.94%	-32.19%
<b>Revenue to Expense scaled to 100% recovery</b>	<b>100.00%</b>	<b>108.62%</b>	<b>101.31%</b>	<b>93.40%</b>	<b>11.47%</b>	<b>32.98%</b>
Revenue Requirement less Misc Rev	\$6,168,685	\$3,690,855	\$923,834	\$1,259,839	\$287,530	\$6,626
Revenue from Rates at 100% recovery - adjusting rates	\$6,168,685	\$4,055,607	\$937,601	\$1,168,918	\$4,880	\$1,679
Total Revenue at 100% recovery	\$6,992,482	\$4,590,401	\$1,060,984	\$1,303,825	\$34,877	\$2,395
Check		108.63%	101.31%	93.48%	10.98%	32.62%

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Appendix C

**F2 Cost Allocation***Enter selected amounts from sheets 'O1' and 'O2' of Cost Allocation model*

Customer Class Name	REVENUE ALLOCATION (sheet O1)						
	Service Revenue Requirement	%	Miscellaneous Revenue (mi)	%	Base Revenue Requirement *	%	Revenue to Expenses % **
Residential	4,225,650	60.43%	534,795	64.92%	3,690,855	59.83%	108.62%
GS < 50	1,047,217	14.98%	123,383	14.98%	923,834	14.98%	101.31%
GS > 50	1,394,746	19.95%	134,906	16.38%	1,259,840	20.42%	93.40%
Large Use							
Street Light	317,527	4.54%	29,997	3.64%	287,530	4.66%	11.47%
Sentinel	7,342	0.10%	716	0.09%	6,626	0.11%	32.98%
TOTAL (from Column C of sheet O1)	6,992,482	100.00%	823,797	100.00%	6,168,685	100.00%	
	OK	OK	OK	OK	OK	OK	

\* Service Revenue Requirement less Miscellaneous Revenue

\*\* Revenue to cost ratio resulting from a uniform rate increase to recover the 2011 Test Year revenue deficiency

CUSTOMER UNIT COST PER MONTH (sheet O2)					
Customer Class Name	Avoided Costs (Minimum Charge)	Directly Related	Minimum System with PLCC * adjustment	Existing Fixed Rate	Maximum Charge **
Residential	\$3.83	\$6.99	\$12.93	\$10.93	\$12.93
GS < 50	\$8.06	\$14.71	\$23.24	\$15.50	\$23.24
GS > 50	\$35.20	\$60.81	\$70.35	\$72.91	\$72.91
Large Use				\$605.05	\$605.05
Street Light	(\$0.07)	(\$0.04)	\$7.35	\$0.04	\$7.35
Sentinel	\$0.14	\$0.37	\$7.71	\$1.30	\$7.71

\* PLCC = 'Peak Load Carrying Capability'

\*\* Greater of 'Directly Related', 'Minimum System with PLCC adjustment', and Existing Fixed Rate

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### F3 Revenue Requirement Allocation

*Enter allocation of Base Revenue Requirement and RC ratio ranges by customer class*

Customer Class Name	Base Revenue Requirement %			Base Revenue Requirement \$ <sup>3</sup>		
	Cost Allocation <sup>1</sup>	Existing Rates <sup>2</sup>	Rate Application	Cost Allocation	Existing Rates	Rate Application
Residential	59.83%	65.75%	64.39%	3,690,854	4,055,606	3,972,195
GS < 50	14.98%	15.20%	15.15%	923,834	937,601	934,306
GS > 50	20.42%	18.95%	18.84%	1,259,840	1,168,918	1,162,208
Street Light	4.66%	0.08%	1.57%	287,530	4,880	97,014
Sentinel	0.11%	0.03%	0.05%	6,626	1,679	2,962
<b>TOTAL</b>	<b>100.00%</b>	<b>100.00%</b>	<b>100.00%</b>	<b>6,168,684</b>	<b>6,168,684</b>	<b>6,168,684</b>
			<b>OK</b>			<b>OK</b>

<sup>1</sup> from sheet F2

<sup>2</sup> from sheet C3

<sup>3</sup> Base Revenue Requirement (from sheet F1) multiplied by Base Revenue Requirement %

Customer Class Name	Revenue Offsets <sup>4</sup>		Base Revenue Requirement \$			Service Revenue Requirement \$ <sup>5</sup>		
	%	\$	Cost Allocation	Existing Rates	Rate Application	Cost Allocation	Existing Rates	Rate Application
Residential	64.92%	534,795	3,690,854	4,055,606	3,972,195	4,225,650	4,590,402	4,506,990
GS < 50	14.98%	123,383	923,834	937,601	934,306	1,047,217	1,060,984	1,057,689
GS > 50	16.38%	134,906	1,259,840	1,168,918	1,162,208	1,394,746	1,303,824	1,297,114
Street Light	3.64%	29,997	287,530	4,880	97,014	317,527	34,877	127,011
Sentinel	0.09%	716	6,626	1,679	2,962	7,342	2,395	3,678
<b>TOTAL</b>	<b>100.00%</b>	<b>823,798</b>	<b>6,168,684</b>	<b>6,168,684</b>	<b>6,168,684</b>	<b>6,992,482</b>	<b>6,992,482</b>	<b>6,992,482</b>

<sup>4</sup> %s from sheet F2; total \$ from sheet F1

<sup>5</sup> Revenue Offsets plus Base Revenue Requirement

Customer Class Name	Service Revenue Requirement			Cost Allocation	Variance	Target Range	
	Rate Application	Cost Allocation	Revenue to Cost Ratio <sup>6</sup>	Revenue to Cost Ratio <sup>7</sup>		Floor	Ceiling
Residential	4,506,990	4,225,650	1.07	1.09	-0.02	0.85	1.15
GS < 50	1,057,689	1,047,217	1.01	1.01	-0.00	0.80	1.20
GS > 50	1,297,114	1,394,746	0.93	0.93	-0.00	0.80	1.80
Street Light	127,011	317,527	0.40	0.11	0.29	0.70	1.20
Sentinel	3,678	7,342	0.50	0.33	0.17	0.70	1.20
<b>TOTAL</b>	<b>6,992,482</b>	<b>6,992,482</b>	<b>1.00</b>		<b>1.00</b>		

<sup>6</sup> Rate Application value divided by Cost Allocation value

<sup>7</sup> from sheet F2

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**Appendix C**

## F4 Fixed/Variable Rate Design

Enter the proposed fixed monthly rate for each customer class

Customer Class Name	Existing Rates (a)			Cost Allocation - Minimum Fixed Rate (b)			Cost Allocation - Maximum Fixed Rate (b)		
	Rate	Fixed %	Variable %	Rate	Fixed %	Variable %	Rate	Fixed %	Variable %
Residential	\$10.93	49.93%	50.07%	\$3.83	16.85%	83.15%	\$12.93	56.88%	43.12%
GS < 50	\$15.50	35.25%	64.75%	\$8.06	17.35%	82.65%	\$23.24	50.03%	49.97%
GS > 50	\$72.91	15.24%	84.76%	\$35.20	6.98%	93.02%	\$72.91	14.45%	85.55%
Large Use	\$605.05	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	\$605.05		
Street Light	\$0.04	50.41%	49.59%	(\$0.07)	-4.19%	104.19%	\$7.35	439.48%	-339.48%
Sentinel	\$1.30	49.24%	50.76%	\$0.14	2.84%	97.16%	\$7.71	156.18%	-56.18%

(a) per sheet C3

(b) Rates per sheet F2; %s based on # customers/connections (sheet C2) and Base Revenue Requirement allocated to class (sheet F3)

Customer Class Name	Existing Fixed/Variable Split (c)			Rate Application			Base Revenue Requirement \$		
	Rate	Fixed %	Variable %	Fixed Rate	Fixed %	Variable %	Total (d)	Fixed (e)	Variable (f)
Residential	\$11.35	49.93%	50.07%	\$11.50	50.59%	49.41%	3,972,195	2,009,556	1,962,639
GS < 50	\$16.37	35.25%	64.75%	\$17.00	36.59%	63.41%	934,306	341,904	592,402
GS > 50	\$76.85	15.24%	84.76%	\$70.35	13.95%	86.05%	1,162,208	162,086	1,000,121
Large Use		#DIV/0!	#DIV/0!						
Street Light	\$0.84	50.41%	49.59%	\$1.67	99.86%	0.14%	97,014	96,873	140
Sentinel	\$2.43	49.24%	50.76%	\$3.75	75.96%	24.04%	2,962	2,250	712

(c) %s per Existing Rates, Rate based on Fixed % of Total Base Revenue allocated to class (4) and # (e) Based on Rate Application Fixed Rate and # customers/connections (sheet C2)

(d) per sheet F3

(f) Total amount (d) less Fixed amount (e)

Customer Class Name	Transf. Allowance (\$/kW):		Gross \$ Variable (h)	Resulting Variable		Existing Var. Rate (j)	Base Revenue \$	
	kW	Rate		Rate (i)	per		Fixed (k)	Gross (l)
Residential			1,962,639	\$0.0160	kWh	\$0.0156	2,009,556	3,972,195
GS < 50			592,402	\$0.0147	kWh	\$0.0142	341,904	934,306
GS > 50	162,300	\$0.60	97,380	\$3.1490	kW	\$2.9610	162,086	1,259,588
Large Use				#DIV/0!	kW	\$0.7063		
Street Light			140	\$0.0163	kW	\$0.2653	96,873	97,014
Sentinel			712	\$4.5344	kW	\$5.1223	2,250	2,962

(g) kW volume multiplied by Rate

(h) Variable Base Revenue Requirement (f), plus total Transformer Allowances (g)

(i) Gross Variable amount \$ (h), divided by test year volume (sheet C2)

(k) per (e) above

(l) Gross Variable amount (h), plus Fixed Base Revenue (k)

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**Appendix D**

## H4 Bill Impact Summary

*Enter sample volumes and RPP status*

Customer Class Name	Volume		RPP Rate Class	Distribution Charges		Delivery Charges		Total Bill	
	kWh	kW		\$ change	% change	\$ change	% change	\$ change	% change
Residential	800		Summer	\$3.44	14.6%	\$3.46	10.5%	\$4.01	3.5%
GS < 50	2,000		Non-res.	\$5.29	12.2%	\$5.31	8.1%	\$6.20	2.2%
GS > 50	500,000	800	n/a	\$1,296.39	56.7%	\$1,296.39	22.5%	\$1,512.76	2.7%
Street Light	54	0.15	n/a	\$1.85	616.7%	\$1.85	231.3%	\$2.09	33.7%
Sentinel	94	0.26	n/a	\$2.64	92.6%	\$2.64	74.2%	\$2.98	22.6%



**St. Thomas Energy Inc. (ED-2002-0523)**

2011 EDR Application (EB-2010-0141 ) version: 10

Proposed Settlement Agreement

Appendix D

**H5 Customer Bill Impact Analysis**

RPP rates per sheet Y7

*Review detailed bill impacts (no input on this sheet)***Residential****RPP: Summer****800 kWh's**

	Metric	2010 BILL			2011 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge		1	\$10.93	\$10.93	1	\$11.50	\$11.50	\$0.57	5.2%
Distribution	kWh	800	\$0.0156	\$12.48	800	\$0.0160	\$12.80	\$0.32	2.6%
Smart Meters		1	\$0.5200	\$0.52	1	\$2.5000	\$2.50	\$1.98	380.8%
Global Adjustment 2014	kWh		\$0.0002			\$0.0003			
Deferral Account 2014	kWh	800	(\$0.0007)	(\$0.56)	800	(\$0.0008)	(\$0.64)	(\$0.08)	(14.3%)
Global Adjustment 2012	kWh					\$0.0035			
Deferral Account 2012	kWh	800			800	\$0.0001	\$0.08	\$0.08	
LRAM Rate Rider	kWh	800			800	\$0.0004	\$0.32	\$0.32	
Late Payment		1			1	\$0.2500	\$0.25	\$0.25	
SSS Admin Charge		1	\$0.2500	\$0.25	1	\$0.2500	\$0.25		
† <b>Distribution sub-total</b>				<b>\$23.62</b>			<b>\$27.06</b>	<b>\$3.44</b>	<b>14.6%</b>
Electricity (Commodity)	kWh	827	RPP	\$58.73	828	RPP	\$58.81	\$0.08	0.1%
† Transmission - Network	kWh	827	\$0.0060	\$4.96	828	\$0.0060	\$4.97	\$0.01	0.2%
† Transmission - Connection	kWh	827	\$0.0052	\$4.30	828	\$0.0052	\$4.31	\$0.01	0.2%
Wholesale Market Service	kWh	827	\$0.0052	\$4.30	828	\$0.0052	\$4.31	\$0.01	0.2%
Rural Rate Protection	kWh	827	\$0.0013	\$1.08	828	\$0.0013	\$1.08		
Debt Retirement Charge	kWh	800	\$0.0070	\$5.60	800	\$0.0070	\$5.60		
† Low Voltage Charges	kWh	800			800				
<b>Subtotal</b>				<b>\$102.59</b>			<b>\$106.14</b>	<b>\$3.55</b>	<b>3.5%</b>
<b>HST</b>				\$13.34			\$13.80	\$0.46	3.5%
<b>TOTAL BILL</b>				<b>\$115.93</b>			<b>\$119.94</b>	<b>\$4.01</b>	<b>3.5%</b>
† <b>Delivery Only</b>				\$32.88			\$36.34	\$3.46	10.5%

**St. Thomas Energy Inc. (ED-2002-0523)**

2011 EDR Application (EB-2010-0141 ) version: 10

Proposed Settlement Agreement

Appendix D

**H5 Customer Bill Impact Analysis**

RPP rates per sheet Y7

*Review detailed bill impacts (no input on this sheet)***GS < 50****RPP: Non-res.****2,000 kWh's**

	Metric	2010 BILL			2011 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge		1	\$15.50	\$15.50	1	\$17.00	\$17.00	\$1.50	9.7%
Distribution	kWh	2,000	\$0.0142	\$28.40	2,000	\$0.0147	\$29.40	\$1.00	3.5%
Smart Meters		1	\$0.5200	\$0.52	1	\$2.5000	\$2.50	\$1.98	380.8%
Global Adjustment 2014	kWh		\$0.0002			\$0.0003			
Deferral Account 2014	kWh	2,000	(\$0.0007)	(\$1.40)	2,000	(\$0.0008)	(\$1.60)	(\$0.20)	(14.3%)
Global Adjustment 2012	kWh					\$0.0035			
Deferral Account 2012	kWh	2,000			2,000				
LRAM Rate Rider	kWh	2,000			2,000	\$0.0003	\$0.60	\$0.60	
Late Payment		1			1	\$0.4100	\$0.41	\$0.41	
SSS Admin Charge		1	\$0.2500	\$0.25	1	\$0.2500	\$0.25		
† <b>Distribution sub-total</b>				<b>\$43.27</b>			<b>\$48.56</b>	<b>\$5.29</b>	<b>12.2%</b>
Electricity (Commodity)	kWh	2,068	RPP	\$155.11	2,070	RPP	\$155.28	\$0.17	0.1%
† Transmission - Network	kWh	2,068	\$0.0059	\$12.20	2,070	\$0.0059	\$12.21	\$0.01	0.1%
† Transmission - Connection	kWh	2,068	\$0.0049	\$10.13	2,070	\$0.0049	\$10.14	\$0.01	0.1%
Wholesale Market Service	kWh	2,068	\$0.0052	\$10.75	2,070	\$0.0052	\$10.76	\$0.01	0.1%
Rural Rate Protection	kWh	2,068	\$0.0013	\$2.69	2,070	\$0.0013	\$2.69		
Debt Retirement Charge	kWh	2,000	\$0.0070	\$14.00	2,000	\$0.0070	\$14.00		
† Low Voltage Charges	kWh	2,000			2,000				
<b>Subtotal</b>				<b>\$248.15</b>			<b>\$253.64</b>	<b>\$5.49</b>	<b>2.2%</b>
<b>HST</b>				\$32.26			\$32.97	\$0.71	2.2%
<b>TOTAL BILL</b>				<b>\$280.41</b>			<b>\$286.61</b>	<b>\$6.20</b>	<b>2.2%</b>
† <i>Delivery Only</i>				\$65.60			\$70.91	\$5.31	8.1%

**St. Thomas Energy Inc. (ED-2002-0523)**

2011 EDR Application (EB-2010-0141 ) version: 10

Proposed Settlement Agreement

Appendix D

**H5 Customer Bill Impact Analysis**

RPP rates per sheet Y7

*Review detailed bill impacts (no input on this sheet)***GS > 50**

RPP: n/a

500,000 kWh's 800 kW's	Metric	2010 BILL			2011 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge		1	\$72.91	\$72.91	1	\$70.35	\$70.35	(\$2.56)	(3.5%)
Distribution	kW	800	\$2.9610	\$2,368.80	800	\$3.1490	\$2,519.20	\$150.40	6.3%
Smart Meters		1	\$0.5200	\$0.52	1	\$2.5000	\$2.50	\$1.98	380.8%
Global Adjustment 2014	kW	800	\$0.0950	\$76.00	800	\$0.1102	\$88.16	\$12.16	16.0%
Deferral Account 2014	kW	800	(\$0.2894)	(\$231.52)	800	(\$0.3156)	(\$252.48)	(\$20.96)	(9.1%)
Global Adjustment 2012	kW	800			800	\$1.2877	\$1,030.16	\$1,030.16	
Deferral Account 2012	kW	800			800	(\$0.0369)	(\$29.52)	(\$29.52)	
LRAM Rate Rider	kW	800			800	\$0.1869	\$149.52	\$149.52	
Late Payment		1			1	\$5.2100	\$5.21	\$5.21	
SSS Admin Charge		1	\$0.2500	\$0.25	1	\$0.2500	\$0.25		
† <b>Distribution sub-total</b>				<b>\$2,286.96</b>			<b>\$3,583.35</b>	<b>\$1,296.39</b>	<b>56.7%</b>
Electricity (Commodity)	kWh	516,950	\$0.0705	\$36,444.98	517,500	\$0.0705	\$36,483.75	\$38.77	0.1%
† Transmission - Network	kW	800	\$2.3569	\$1,885.52	800	\$2.3569	\$1,885.52		
† Transmission - Connection	kW	800	\$1.9727	\$1,578.16	800	\$1.9727	\$1,578.16		
Wholesale Market Service	kWh	516,950	\$0.0052	\$2,688.14	517,500	\$0.0052	\$2,691.00	\$2.86	0.1%
Rural Rate Protection	kWh	516,950	\$0.0013	\$672.04	517,500	\$0.0013	\$672.75	\$0.71	0.1%
Debt Retirement Charge	kWh	500,000	\$0.0070	\$3,500.00	500,000	\$0.0070	\$3,500.00		
† Low Voltage Charges	kW	800			800				
<b>Subtotal</b>				<b>\$49,055.80</b>			<b>\$50,394.53</b>	<b>\$1,338.73</b>	<b>2.7%</b>
<b>HST</b>				<b>\$6,377.25</b>			<b>\$6,551.29</b>	<b>\$174.03</b>	<b>2.7%</b>
<b>TOTAL BILL</b>				<b>\$55,433.05</b>			<b>\$56,945.82</b>	<b>\$1,512.76</b>	<b>2.7%</b>
† <i>Delivery Only</i>				<i>\$5,750.64</i>			<i>\$7,047.03</i>	<i>\$1,296.39</i>	<i>22.5%</i>

**St. Thomas Energy Inc. (ED-2002-0523)**

2011 EDR Application (EB-2010-0141 ) version: 10

Proposed Settlement Agreement

Appendix D

**H5 Customer Bill Impact Analysis**

RPP rates per sheet Y7

*Review detailed bill impacts (no input on this sheet)***Street Light**

RPP: n/a

54 kWh's

0.15 kW's

	Metric	2010 BILL			2011 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge		1	\$0.04	\$0.04	1	\$1.67	\$1.67	\$1.63	4075.0%
Distribution	kW	0.15	\$0.2653	\$0.04	0.15	\$0.0163		(\$0.04)	(100.0%)
Smart Meters		1			1				
Global Adjustment 2014	kW	0.15	\$0.0852	\$0.01	0.15	\$0.0988	\$0.01		
Deferral Account 2014	kW	0.15	(\$0.2589)	(\$0.04)	0.15	\$0.2823	\$0.04	\$0.08	200.0%
Global Adjustment 2012	kW	0.15			0.15	\$1.2651	\$0.19	\$0.19	
Deferral Account 2012	kW	0.15			0.15	(\$0.0553)	(\$0.01)	(\$0.01)	
LRAM Rate Rider	kW	0.15			0.15				
Late Payment		1			1				
SSS Admin Charge		1	\$0.2500	\$0.25	1	\$0.2500	\$0.25		
† <b>Distribution sub-total</b>				<b>\$0.30</b>			<b>\$2.15</b>	<b>\$1.85</b>	<b>616.7%</b>
Electricity (Commodity)	kWh	56	\$0.0705	\$3.95	56	\$0.0705	\$3.95		
† Transmission - Network	kW	0.15	\$1.8175	\$0.27	0.15	\$1.8175	\$0.27		
† Transmission - Connection	kW	0.15	\$1.5210	\$0.23	0.15	\$1.5210	\$0.23		
Wholesale Market Service	kWh	56	\$0.0052	\$0.29	56	\$0.0052	\$0.29		
Rural Rate Protection	kWh	56	\$0.0013	\$0.07	56	\$0.0013	\$0.07		
Debt Retirement Charge	kWh	54	\$0.0070	\$0.38	54	\$0.0070	\$0.38		
† Low Voltage Charges	kW	0.15			0.15				
<b>Subtotal</b>				<b>\$5.49</b>			<b>\$7.34</b>	<b>\$1.85</b>	<b>33.7%</b>
<b>HST</b>				<b>\$0.71</b>			<b>\$0.95</b>	<b>\$0.24</b>	<b>33.7%</b>
<b>TOTAL BILL</b>				<b>\$6.20</b>			<b>\$8.29</b>	<b>\$2.09</b>	<b>33.7%</b>
† <i>Delivery Only</i>				<i>\$0.80</i>			<i>\$2.65</i>	<i>\$1.85</i>	<i>231.3%</i>

**St. Thomas Energy Inc. (ED-2002-0523)**

2011 EDR Application (EB-2010-0141 ) version: 10

Proposed Settlement Agreement

Appendix D

**H5 Customer Bill Impact Analysis**

RPP rates per sheet Y7

*Review detailed bill impacts (no input on this sheet)***Sentinel**

RPP: n/a

94 kWh's

0.26 kW's

	Metric	2010 BILL			2011 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	\$	%
Monthly Service Charge		1	\$1.30	\$1.30	1	\$3.75	\$3.75	\$2.45	188.5%
Distribution	kW	0.26	\$5.1223	\$1.33	0.26	\$4.5344	\$1.18	(\$0.15)	(11.3%)
Smart Meters		1			1				
Global Adjustment 2014	kW	0.26	\$0.1013	\$0.03	0.26	\$0.1176	\$0.03		
Deferral Account 2014	kW	0.26	(\$0.2302)	(\$0.06)	0.26	(\$0.2510)	(\$0.07)	(\$0.01)	(16.7%)
Global Adjustment 2012	kW	0.26			0.26	\$1.2634	\$0.33	\$0.33	
Deferral Account 2012	kW	0.26			0.26	\$0.0154			
LRAM Rate Rider	kW	0.26			0.26				
Late Payment		1			1	\$0.0200	\$0.02	\$0.02	
SSS Admin Charge		1	\$0.2500	\$0.25	1	\$0.2500	\$0.25		
† <b>Distribution sub-total</b>				<b>\$2.85</b>			<b>\$5.49</b>	<b>\$2.64</b>	<b>92.6%</b>
Electricity (Commodity)	kWh	97	\$0.0705	\$6.84	97	\$0.0705	\$6.84		
† Transmission - Network	kW	0.26	\$1.4816	\$0.39	0.26	\$1.4816	\$0.39		
† Transmission - Connection	kW	0.26	\$1.2392	\$0.32	0.26	\$1.2392	\$0.32		
Wholesale Market Service	kWh	97	\$0.0052	\$0.50	97	\$0.0052	\$0.50		
Rural Rate Protection	kWh	97	\$0.0013	\$0.13	97	\$0.0013	\$0.13		
Debt Retirement Charge	kWh	94	\$0.0070	\$0.66	94	\$0.0070	\$0.66		
† Low Voltage Charges	kW	0.26			0.26				
<b>Subtotal</b>				<b>\$11.69</b>			<b>\$14.33</b>	<b>\$2.64</b>	<b>22.6%</b>
<b>HST</b>				<b>\$1.52</b>			<b>\$1.86</b>	<b>\$0.34</b>	<b>22.6%</b>
<b>TOTAL BILL</b>				<b>\$13.21</b>			<b>\$16.19</b>	<b>\$2.98</b>	<b>22.6%</b>
† <i>Delivery Only</i>				<i>\$3.56</i>			<i>\$6.20</i>	<i>\$2.64</i>	<i>74.2%</i>

# St. Thomas Energy Inc. (ED-2002-0523)

2011 EDR Application (EB-2010-0141 ) version: 10

Proposed Settlement Agreement

Appendix E

## 2011 Settlement - Test Year Revenue Deficiency

Rate Base	\$23,877,673	
Return On Rate Base	7.07%	\$1,687,292
Distribution Expenses & Taxes:		
OM&A	\$3,571,434	
Amortization	1,356,340	
PILs/Taxes	377,416	\$5,305,190
		<hr/>
Service Revenue Requirement		\$6,992,482
Revenue Offsets		-823,798
		<hr/>
Distribution Revenue Requirement		\$6,168,684
		<hr/>
<i>Distribution Revenue at Existing Rates</i>		5,818,684
		<hr/>
Revenue Sufficiency (Deficiency)		\$350,000
		<hr/>



# REVENUE REQUIREMENT WORK FORM

Version: 2.11

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	
<b>1 Rate Base</b>										
Gross Fixed Assets (average)	\$40,302,138		(\$68,360)		\$ 40,233,778				\$40,233,778	
Accumulated Depreciation (average)	(\$21,114,007)	(5)	(\$179,089)		\$ 21,293,096				(\$21,293,096)	
<b>Allowance for Working Capital:</b>										
Controllable Expenses	\$3,875,076		(\$303,642)		\$ 3,571,434				\$3,571,434	
Cost of Power	\$27,758,708		\$1,583,128		\$ 29,341,836				\$29,341,836	
Working Capital Rate (%)	15.00%				15.00%				15.00%	
<b>2 Utility Income</b>										
<b>Operating Revenues:</b>										
Distribution Revenue at Current Rates	\$5,794,876		\$23,808		\$5,818,684		\$0		\$5,818,684	
Distribution Revenue at Proposed Rates	\$6,561,411		(\$392,727)		\$6,168,684		\$0		\$6,168,684	
<b>Other Revenue:</b>										
Specific Service Charges	\$538,827		\$0		\$538,827		\$0		\$538,827	
Late Payment Charges	\$138,817		\$0		\$138,817		\$0		\$138,817	
Other Distribution Revenue	\$71,483		\$0		\$71,483		\$0		\$71,483	
Other Income and Deductions	\$53,672		\$21,000		\$74,672		\$0		\$74,672	
<b>Operating Expenses:</b>										
OM+A Expenses	\$3,753,580		(\$303,642)		\$ 3,449,938				\$3,449,938	
Depreciation/Amortization	\$1,359,074		(\$2,734)		\$ 1,356,340				\$1,356,340	
Property taxes	\$121,496		\$ -		\$ 121,496				\$121,496	
Capital taxes	\$0				\$0				\$0	
Other expenses	\$ -		\$ -		0				\$0	
<b>3 Taxes/PILs</b>										
<b>Taxable Income:</b>										
Adjustments required to arrive at taxable income	\$211,928	(3)			\$214,764				\$214,764	
<b>Utility Income Taxes and Rates:</b>										
Income taxes (not grossed up)	\$321,120				\$282,906				\$282,906	
Income taxes (grossed up)	\$447,554				\$377,416				\$377,416	
Capital Taxes	\$ -	(6)			\$ -	(6)			\$ -	(6)
Federal tax (%)	16.50%				16.50%				16.50%	
Provincial tax (%)	11.75%				8.54%				8.54%	
Income Tax Credits	\$ -				\$ -				\$ -	
<b>4 Capitalization/Cost of Capital</b>										
<b>Capital Structure:</b>										
Long-term debt Capitalization Ratio (%)	56.0%				56.0%				56.0%	
Short-term debt Capitalization Ratio (%)	4.0%	(2)			4.0%	(2)			4.0%	(2)
Common Equity Capitalization Ratio (%)	40.0%				40.0%				40.0%	
Preferred Shares Capitalization Ratio (%)	0.0%				0.0%				0.0%	
	100.0%				100.0%				100.0%	
<b>Cost of Capital</b>										
Long-term debt Cost Rate (%)	5.48%				5.60%				5.60%	
Short-term debt Cost Rate (%)	2.43%				2.46%				2.46%	
Common Equity Cost Rate (%)	9.66%				9.58%				9.58%	
Preferred 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.

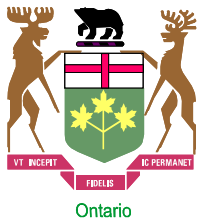
(3) Net of addbacks and deductions to arrive at taxable income.

(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 column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome 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		(\$68,360)		\$40,233,778		\$ -		\$40,233,778
2	Accumulated Depreciation (average)	(3)	(\$21,114,007)		(\$179,089)		(\$21,293,096)		\$ -		(\$21,293,096)
3	Net Fixed Assets (average)	(3)	\$19,188,131		(\$247,449)		\$18,940,682		\$ -		\$18,940,682
4	Allowance for Working Capital	(1)	\$4,745,068		\$191,923		\$4,936,991		\$ -		\$4,936,991
5	Total Rate Base		\$23,933,199		(\$55,526)		\$23,877,673		\$ -		\$23,877,673

(1) Allowance for Working Capital - Derivation									
Controllable Expenses		\$3,875,076		(\$303,642)		\$3,571,434		\$ -	\$3,571,434
Cost of Power		\$27,758,708		\$1,583,128		\$29,341,836		\$ -	\$29,341,836
Working Capital Base		\$31,633,784		\$1,279,486		\$32,913,270		\$ -	\$32,913,270
Working Capital Rate %		(2) 15.00%		0.00%		15.00%		0.00%	15.00%
Working Capital Allowance		\$4,745,068		\$191,923		\$4,936,991		\$ -	\$4,936,991

### 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
<b>Operating Revenues:</b>						
1	Distribution Revenue (at Proposed Rates)	\$6,561,411	(\$392,727)	\$6,168,684	\$ -	\$6,168,684
2	Other Revenue (1)	\$802,798	\$21,000	\$823,798	\$ -	\$823,798
3	Total Operating Revenues	\$7,364,209	(\$371,727)	\$6,992,482	\$ -	\$6,992,482
<b>Operating Expenses:</b>						
4	OM+A Expenses	\$3,753,580	(\$303,642)	\$3,449,938	\$ -	\$3,449,938
5	Depreciation/Amortization	\$1,359,074	(\$2,734)	\$1,356,340	\$ -	\$1,356,340
6	Property taxes	\$121,496	\$ -	\$121,496	\$ -	\$121,496
7	Capital taxes	\$ -	\$ -	\$ -	\$ -	\$ -
8	Other expense	\$ -	\$ -	\$ -	\$ -	\$ -
9	Subtotal (lines 4 to 8)	\$5,234,150	(\$306,376)	\$4,927,774	\$ -	\$4,927,774
10	Deemed Interest Expense	\$757,725	\$14,574	\$772,299	\$ -	\$772,299
11	Total Expenses (lines 9 to 10)	\$5,991,876	(\$291,802)	\$5,700,073	\$ -	\$5,700,073
12	Utility income before income taxes	\$1,372,333	(\$79,925)	\$1,292,408	\$ -	\$1,292,408
13	Income taxes (grossed-up)	\$447,554	(\$70,137)	\$377,416	\$ -	\$377,416
14	Utility net income	\$924,779	(\$9,788)	\$914,992	\$ -	\$914,992

## Notes

(1)	<b>Other Revenues / Revenue Offsets</b>					
	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

### Taxes/PILs

Line No.	Particulars	Application	Settlement Agreement	Per Board Decision
<u>Determination of Taxable Income</u>				
1	Utility net income before taxes	\$924,779	\$914,992	\$914,992
2	Adjustments required to arrive at taxable utility income	\$211,928	\$214,764	\$214,764
3	Taxable income	<u>\$1,136,707</u>	<u>\$1,129,757</u>	<u>\$1,129,757</u>
<u>Calculation of Utility income Taxes</u>				
4	Income taxes	\$321,120	\$282,906	\$282,906
5	Capital taxes	\$ - (1)	\$ - (1)	\$ - (1)
6	Total taxes	<u>\$321,120</u>	<u>\$282,906</u>	<u>\$282,906</u>
7	Gross-up of Income Taxes	<u>\$126,434</u>	<u>\$94,510</u>	<u>\$94,510</u>
8	Grossed-up Income Taxes	<u>\$447,554</u>	<u>\$377,416</u>	<u>\$377,416</u>
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	<u>\$447,554</u>	<u>\$377,416</u>	<u>\$377,416</u>
10	Other tax Credits	\$ -	\$ -	\$ -
<u>Tax Rates</u>				
11	Federal tax (%)	16.50%	16.50%	16.50%
12	Provincial tax (%)	11.75%	8.54%	8.54%
13	Total tax rate (%)	<u>28.25%</u>	<u>25.04%</u>	<u>25.04%</u>

#### 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	5.48%	\$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

Settlement Agreement					
		(%)	(\$)	(%)	(\$)
Debt					
1	Long-term Debt	56.00%	\$13,371,497	5.60%	\$748,804
2	Short-term Debt	4.00%	\$955,107	2.46%	\$23,496
3	Total Debt	60.00%	\$14,326,604	5.39%	\$772,299
Equity					
4	Common Equity	40.00%	\$9,551,069	9.58%	\$914,992
5	Preferred Shares	0.00%	\$ -	0.00%	\$ -
6	Total Equity	40.00%	\$9,551,069	9.58%	\$914,992
7	Total	100.00%	\$23,877,673	7.07%	\$1,687,292

Per Board Decision					
		(%)	(\$)	(%)	(\$)
Debt					
8	Long-term Debt	56.00%	\$13,371,497	5.60%	\$748,804
9	Short-term Debt	4.00%	\$955,107	2.46%	\$23,496
10	Total Debt	60.00%	\$14,326,604	5.39%	\$772,299
Equity					
11	Common Equity	40.00%	\$9,551,069	9.58%	\$914,992
12	Preferred Shares	0.00%	\$ -	0.00%	\$ -
13	Total Equity	40.00%	\$9,551,069	9.58%	\$914,992
14	Total	100.00%	\$23,877,673	7.07%	\$1,687,292

#### Notes

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



# REVENUE REQUIREMENT WORK FORM

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

Version: 2.11

Revenue Sufficiency/Deficiency							
Line No.	Particulars	Initial Application		Settlement Agreement		Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		\$766,535		\$350,001		\$350,001
2	Distribution Revenue	\$5,794,876	\$5,794,876	\$5,818,684	\$5,818,683	\$5,818,684	\$5,818,683
3	Other Operating Revenue Offsets - net	\$802,798	\$802,798	\$823,798	\$823,798	\$823,798	\$823,798
4	<b>Total Revenue</b>	<b>\$6,597,673</b>	<b>\$7,364,209</b>	<b>\$6,642,482</b>	<b>\$6,992,482</b>	<b>\$6,642,482</b>	<b>\$6,992,482</b>
5	Operating Expenses	\$5,234,150	\$5,234,150	\$4,927,774	\$4,927,774	\$4,927,774	\$4,927,774
6	Deemed Interest Expense	\$757,725	\$757,725	\$772,299	\$772,299	\$772,299	\$772,299
	<b>Total Cost and Expenses</b>	<b>\$5,991,876</b>	<b>\$5,991,876</b>	<b>\$5,700,073</b>	<b>\$5,700,073</b>	<b>\$5,700,073</b>	<b>\$5,700,073</b>
7	<b>Utility Income Before Income Taxes</b>	<b>\$605,798</b>	<b>\$1,372,333</b>	<b>\$942,408</b>	<b>\$1,292,408</b>	<b>\$942,408</b>	<b>\$1,292,408</b>
8	Tax Adjustments to Accounting Income per 2009 PILs	\$211,928	\$211,928	\$214,764	\$214,764	\$214,764	\$214,764
9	<b>Taxable Income</b>	<b>\$817,726</b>	<b>\$1,584,261</b>	<b>\$1,157,173</b>	<b>\$1,507,173</b>	<b>\$1,157,173</b>	<b>\$1,507,173</b>
10	Income Tax Rate	28.25%	28.25%	25.04%	25.04%	25.04%	25.04%
11	<b>Income Tax on Taxable Income</b>	<b>\$231,008</b>	<b>\$447,554</b>	<b>\$289,772</b>	<b>\$377,416</b>	<b>\$289,772</b>	<b>\$377,416</b>
12	<b>Income Tax Credits</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ -</b>
13	<b>Utility Net Income</b>	<b>\$374,790</b>	<b>\$924,779</b>	<b>\$652,637</b>	<b>\$914,992</b>	<b>\$652,637</b>	<b>\$914,992</b>
14	<b>Utility Rate Base</b>	<b>\$23,933,199</b>	<b>\$23,933,199</b>	<b>\$23,877,673</b>	<b>\$23,877,673</b>	<b>\$23,877,673</b>	<b>\$23,877,673</b>
	Deemed Equity Portion of Rate Base	\$9,573,280	\$9,573,280	\$9,551,069	\$9,551,069	\$9,551,069	\$9,551,069
15	Income/Equity Rate Base (%)	3.91%	9.66%	6.83%	9.58%	6.83%	9.58%
16	Target Return - Equity on Rate Base	9.66%	9.66%	9.58%	9.58%	9.58%	9.58%
17	Sufficiency/Deficiency in Return on Equity	-5.75%	0.00%	-2.75%	0.00%	-2.75%	0.00%
18	Indicated Rate of Return	4.73%	7.03%	5.97%	7.07%	5.97%	7.07%
19	Requested Rate of Return on Rate Base	7.03%	7.03%	7.07%	7.07%	7.07%	7.07%
20	Sufficiency/Deficiency in Rate of Return	-2.30%	0.00%	-1.10%	0.00%	-1.10%	0.00%
21	Target Return on Equity	\$924,779	\$924,779	\$914,992	\$914,992	\$914,992	\$914,992
22	Revenue Deficiency/(Sufficiency)	\$549,989	\$1	\$262,356	(\$0)	\$262,356	(\$0)
23	<b>Gross Revenue</b>	<b>\$766,535</b>	<b>(1)</b>	<b>\$350,001</b>	<b>(1)</b>	<b>\$350,001</b>	<b>(1)</b>
	<b>Deficiency/(Sufficiency)</b>						

## Notes:

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



## REVENUE REQUIREMENT WORK FORM

Version: 2.11

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	\$3,449,938	\$3,449,938
2	Amortization/Depreciation	\$1,359,074	\$1,356,340	\$1,356,340
3	Property Taxes	\$121,496	\$121,496	\$121,496
4	Capital Taxes	\$ -	\$ -	\$ -
5	Income Taxes (Grossed up)	\$447,554	\$377,416	\$377,416
6	Other Expenses	\$ -	\$ -	\$ -
7	Return			
	Deemed Interest Expense	\$757,725	\$772,299	\$772,299
	Return on Deemed Equity	\$924,779	\$914,992	\$914,992
8	Distribution Revenue Requirement before Revenues	<u>\$7,364,208</u>	<u>\$6,992,482</u>	<u>\$6,992,482</u>
9	Distribution revenue	\$6,561,411	\$6,168,684	\$6,168,684
10	Other revenue	<u>\$802,798</u>	<u>\$823,798</u>	<u>\$823,798</u>
11	<b>Total revenue</b>	<u>\$7,364,209</u>	<u>\$6,992,482</u>	<u>\$6,992,482</u>
12	<b>Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)</b>	<u>\$1 (1)</u>	<u>(\$0) (1)</u>	<u>(\$0) (1)</u>

#### Notes

(1) Line 11 - Line 8