Exhibit 4

OPERATING COSTS

St. Thomas energy inc.
We're Your Local Power Distributor

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Exhibit 4

Tab 1 of 1

Overview

OVERVIEW

INTRODUCTION

STEI's operating costs are comprised of depreciation, amortization and depletions costs as well as operations, maintenance, customer care and administrative costs.

OVERVIEW

STEI is responsible for the delivery of electricity from the transmission system to approximately 16,700 customers in the City of St. Thomas. STEI owns the poles, conduit systems, meters, transformers, wires and substations and is responsible for the construction, expansion, operation and maintenance of the electrical distribution system.

St. Thomas Energy Inc.'s operating costs consists of expenditures required to maintain and operate its distribution assets and the additional costs associated with; customer care including metering, billing and collecting, administrative including property taxes and regulatory, depreciation and taxes. These costs are required to continue with providing the customer with the safe and reliable services that they are accustomed to receiving.

The OM&A costs for the years 2012, 2013 and budget years 2014 and 2015 are presented on a MIFRS basis, whereas 2011 is presented on a CGAAP basis. Prior to 2012 STEI operated as a virtual utility in that STEI had no employees and acquired services from third parties, primarily affiliates via a Master Services Agreement ("MSA"). STEI restructured from a virtual corporation to an operating utility on January 1, 2012. Restructuring of STEI was in the process prior to the 2011 COS application and commenced with the hiring of the President and Chief Operating Officer in 2010. The 2012 restructuring included transferring all utility specific staff and assets from STESI to STEI. With the employee transfer, STEI developed new capitalization policy with respect to administrative costs and at the same time adopted new asset useful life estimates that aligned with the Kinectrics report and MIFRS.

This change from a virtual company to an operating company has changed STEI's cost structure and thus direct comparisons to 2011 are difficult.

Operating, Maintenance and Administrative Costs

The Total operating costs, excluding interest, for the 2015TY are $5,897,001, with Operating, Maintenance and Administration ("OM&A") costs comprising $4,634,620 of the total. Operating Expenses for the period 2011 to 2015 are shown in Table 4-1 below.

Table 4-1

OPERATING EXPENSES

	2011 Approved	2011 Actual	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year
OM&A	3,571,434	3,741,210	5,045,839	4,011,363	4,457,219	4,634,620
Amortization	1,356,340	1,386,336	1,549,248	1,143,709	1,243,196	1,208,219
PILS	377,416	301,471	118,551	25,628	-	54,162
TOTAL	**5,305,190**	**5,429,017**	**6,713,638**	**5,180,700**	**5,700,415**	**5,897,001**
Increase 2015 TY vs 2011 Approved						591,811
% Increase						11.2%

The 2015TY total operating expenses of $5,897,001 are $591,811 greater than the approved 2011 COS Board Approved amount of $5,305,190. Under the previous MSA, which was primarily based upon pre-2000 controllable costs, STEI's OM&A costs were being subsidized by its affiliate AESI. Capital expenditures and amortization has decreased despite the inclusion of smart meters and additional assets due to the change in useful life estimates and a lower STEI labour rate based upon directly attributable costs, as compared to the MSA.

The increased operating cost is also attributed to STEI adopting IFRS like capitalization policies January 1, 2012 as cost that would previously have been capitalized such as Director of

Engineering and Operations labour is now expensed as this time is not directly attributable to capital projects.

The 2015TY costs are based upon direct operating cost required to achieve the operational goals of STEI in a transparent manner. The 2015TY total operating costs of $5,897,001 are $816,637 less than the 2012 actual amount of $6,713,638, the first year of restructuring and $591,881 greater than the 2011 Board Approved COS application.

The 2015TY OM&A costs are based upon the following key economic assumptions:

- Inflation increase of 2.1%
- 70% of Engineering and Linemen chargeable hours have been allocated to the capital program as directly attributed costs without administrative overheads.

Test Year Levels

The proposed OM&A expenditures for the 2015TY are $4,634,620. These funds are required to support STEI's continued efforts to provide effective and efficient distribution system, maintaining system reliability standards, workforce investments ,customer service billing and collecting, a safe work environment for employees and the public, and billing and collecting, operating and financial systems in an effort to achieve increased efficiencies.

Following is a summary of how STEI's 2015TY OM&A costs align with the Board's Renewed Regulatory Framework's four performance outcomes.

1. Customer Service

STEI has made a focused effort to engage its customers in an effort to increase its services and to align with customer expectations. STEI has been using a 3rd party customer engagement survey since 2002 on a bi-annual basis. STEI UtilityPULSE survey was conducted in April 2014, with final result being reported on in June. The 2014 survey continues to contain specific core questions that allow us to benchmark and compare accurately the results from one survey to the next. With the 2014 survey STEI took the opportunity to include some additional questions as a means to gain a better understanding of our customer's desires/plans around conservation programs and web portal abilities to access and manage customer information. Additionally, STEI developed an in-house survey which was conducted in March with 90 customers participating verbally in 10 question survey around social media usage, conservation desires, e-billing and internet usage. In March 2014, STEI launched a newer web portal product called "Customer Connect" which combined two web portal products into one allowing customers to easily access all information from one program. Some highlights of Customer Connect are;

- ✓ TOU price period indicator
- ✓ TOU usage as recent as the day before and going back as far as 2012
- ✓ TOU usage charts with weather overlay
- ✓ Usage chart with associated cost
- ✓ Billing and payment transaction history going back to 2000
- ✓ Electric meter reading history going back to 2000
- ✓ Usage comparison from bill to bill, year to year
- ✓ E-Bill presentment
- ✓ Customer set notifications and alerts based on usage or dollars
- ✓ All data is available for downloading

2. Operational Effectiveness

STEI has been improving its operating and maintenance programs and enhancing its asset management process through the use of a asset condition assessment and asset management plan provided by a 3rd party consultant. The findings of these reports are important planning tools in the development of STEI's long-term plan in establishing STEI's distribution capital and maintenance requirements. STEI is implementing a geographical information system ("GIS"). STEI is also implementing new financial sub-systems such as job costing and work order to interface with the GIS system and eventually the Customer Information System ("CIS"). This will enable STEI to better manage the distribution assets and customer responsiveness through new program initiatives such as an improved outage identification process and customer outage communications.

STEI is forecasting that the current distribution system has ample capacity for renewable generation for the foreseeable future and as such, STEI does not expect to make any network investments within the 5-year planning period. STEI's distribution system capital program continues to focus on distribution system replacement and voltage conversions. Residential rear yard 2.4 kV overhead and secondary lines are being converted 27.6 kV underground in the front boulevards and rebuilding the overhead in rear yards.

STEI is International Standard Organization ("ISO") 9001 certified. The ISO 9000 addresses various aspects of quality management and contains some of ISO's best known standards. The standards provide guidance and tools for companies and organizations who want to ensure that their products and services consistently meet customer's requirements, and that quality is consistently improved. The standard is based on a number of quality management principles including a strong customer focus, the motivation and implication of top management, the process approach and continual improvement. ISO 9001:2008 sets out the requirements of a quality management system and helps ensure that customers get consistent, good quality products and services, which in turn brings many business benefits.

STEI's operations and maintenance programs primarily consist of maintaining its current tree trimming program, reduced substation maintenance (consistent with system conversion capital work which resulted in less work required on 2.4kv substations), planned inspections and responding to customer initiated projects.

The planned inspection program consists of infrared scans, backyard checks, pole sampling, transformer checking, meter verification, service and vegetation management. These inspections are crucial in ensuring that the assets are in proper working condition and that asset life is optimized in order to continue to maintain the system reliability and safety standards that STEI's customers have come accustomed to and rely upon. The results of the inspections often lead to additional unplanned maintenance activities of the distribution system.

As part of STEI's philosophy of continuous improvement and increased operational effectiveness, STEI reviewed its operating and maintenance practices, specifically substation maintenance, which resulted in a new maintenance program with half the stations being scheduled for maintenance on an annual rotating basis, STEI also implemented the Paymentus program a user pay model for credit card payments and brought bank deposit deliveries in house resulting in customer service savings.

STEI is party to a Mutual Assistance Plan between eight distribution companies in the EDA Western District. This Mutual Assistance Plan provides a framework for a coordinated repair and restoration effort by participating utilities. It provides a process to deal with an emergency of a magnitude that requires outside assistance.

STEI is a member of the Utility Collaborative Service ("UCS") group. The UCS model enables LDCs the ability to use class leading CIS and financial software at a shared cost. When STEI joined UCS, the membership was smaller and STEI was paying a higher price for the CIS and financial software, as well as for IT hosting. As the membership grew STEI has achieved savings through economies of scale.

Collaborative efforts of this group include but not limited to:

- Customer Connect Web Portal
- Shared billing and collection systems
- Shared financial systems
- Shared reporting
- Shared Interactive Voice Response (IVR)
- Shared IT Hosting
- Shared back office support

STEI is also a member of a CustomerFirst initiative. This Group consists of 8 non-contiguous LDCs working together to provide ever increasing efficiencies, level of service and preserving the close relationships with our customers. STEI, together with a nearby LDC, is applying to the Ontario Power Authority for a Roving Energy Manager (REM). The shared REM position is a cost effective initiative that will enhance STEI's CDM effort and produce more energy savings which will improve the competitive position of our consumers.

Collaborative efforts of this group include but not limited to:

- Group buying effort
- Sharing CDM resources such as REMs to manage overall costs
- Group effort to update Conditions of Service
- Sharing Asset Management software

STEI also considers the safety of its employees and customers as critical to its overall success. STEI has an excellent safety record with over 18 years and 1.1 million man hours worked without a lost time accident.

STEI is also Occupational Health and Safety Assessment Series ("OHSAS) 18001 certified. OHSAS 18001 assists organizations in managing and controlling their health and safety risks and improving their OH&S performance. The OHSAS 18001 occupational health and safety management system is assessed objectively, certified credibly, and recognized internationally. By controlling the OH&S risks that are consistent with their OH&S policy and objectives, organizations can achieve and demonstrate sound health and safety performance and stewardship.

STEI under the direction of its parent company AGI is tracking all incidents and developing plans to address incident trends. In 2013 an internal Flash Report process was developed to identify incidents and accidents across the company and all incidents and accidents are investigated. In 2013 an analysis of the Corporations safety management system was performed against the Workwell standard. A gap analysis was developed based upon that analysis. However, The WSIB Workwell initiative has since been discontinued; however, the audit process developed was of high quality. In 2014 a determination of Workwell elements will be integrated into the Corporate system including the necessary documentation and training. The Health and Safety Officer, on a Corporate basis, supports training, certifications, workplace inspections and investigations. Additionally, the Corporation is in the process of undergoing a

Presage Safety Survey. Presage is an industry pioneer in safety consulting whose technology reaches into the workplace to predict human behavior with a diagnostic tool that targets the invisible threat of behavioral risk. Presage's technology will allow AGI and STEI to identify, understand and improve upon factors that affect safety performance with their employees and supply chain, thus enhancing their safety culture. Many of our employees work in high voltage electrical environments so safety in the workplace is paramount to the success of our people, our company and our valued customers.

3. ***Public Policy Responsiveness***

STEI and its Board of Directors recognize the importance of adhering to and complying with all public and regulatory policies.

- Smart meter and time-of-use billing was completed in 2011. STEI has worked collaboratively with other LDCs across the Province of Ontario to fulfill the Provincial government's initiative in providing the residents of Ontario with conservation tools. STEI achieved economies of scale where possible and acted prudently in obtaining the best possible pricing. In 2012, STEI applied for and received a smart meter prudence review EB-2012-0348 with rates effective January 3, 2013.

- In response to the Ministry of Energy's directive for Conservation and Demand Management ("CDM") targets, STEI outsourced the management of this activity to Burman Energy. Burman Energy provides energy conservation services, operational and regulatory support including; customer recruitment, program management and administration, marketing and promotional services, application processing, review and approval and project evaluation.

- Renewable generation connections have not materially increased operational costs. STEI has in support of the renewable energy generation program has successfully connected 33 microFIT projects totalling 278.2 kW of capacity, and 2 FIT projects totalling 600 kW of capacity.

In addition to connected projects, STEI has identified the following pending projects;
- o 10 microFIT totalling 85 kW of capacity
- o 4 FIT projects totalling 360 kW of generation capacity

- STEI complies with Measurement Canada regulations with regard to meter seals, accuracy and cost. The agency develops and administers the laws and requirements governing measurement; evaluates, approves and certifies measuring devices; and investigates complaints of suspected inaccurate measurement.

- STEI complies with Electrical Safety Authority ("ESA") regulation 22/04.
  In early 2004 changes in regulation advanced public electrical safety with the approval and introduction of Ontario Regulation 22/04 addressing Electrical Distribution Safety. Ontario Regulation 22/04 - Electrical Distribution Safety established objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. The Electrical Distribution Safety Regulation established a standard for safety performance and offers distribution companies options for achieving compliance. Specifically, the regulation requires the approval of equipment, plans, specifications and inspection of construction before they are put into service.

- On January 1, 2012, as part of STEI's restructuring from a virtual utility to an operational utility, , STEI adopted IFRS like policies for PP&E resulting in no changes to the comparative figures, 2012 to 2015.

- Municipal Freedom of Information and Protection of Privacy Act (MFIPPA)
  In 2004 STEI adopted and implemented a Privacy Policy as required by MFIPPA. Since that time each new employee is trained in the requirements and

made aware of the importance of this Act. The collection, use and disclosure of customers' Personal Information is essential in order to conduct our day-to-day business operations and with this, STEI recognizes and is committed to protecting the privacy and confidentiality of our customers' personal information.

4. ***Financial Performance***

STEI's goal of achieving sustainable shareholder returns also aligns with providing sustainable operating efficiencies, optimizing service levels and cost reductions to mitigate customer rate impacts. The OM&A levels and outcomes are provided below.

Overall Trends in Costs

STEI OM&A costs have increased since its 2011 Cost of Service application. The increase, as previously stated, is attributed to a change from an affiliate subsidized Master Services Agreement when STEI operated as a virtual utility to a largely self-sufficient operating entity in 2012 as well as the impact of the adoption of IFRS like policies on OM&A and reduced capital charge-out rates. As a self-supporting, transparent operating entity, STEI costs where greater than what was provided for under the 2011 Board Approved Cost of Service Application.

January 1, 2012 STEI adopted IFRS like capitalization and depreciation policies in conjunction with the restructuring initiative. The restructuring included the transfer of employee and various assets required to operate the entity as well as incurring additional management expenses related to employee retirement/succession and management fees from AGI. Additionally in 2012 STEI recorded approximately $248,000 of one time smart meter expenses and $419,000 of one time amortization associated with the smart meter disposition. STEI's 2012 financial results were further hampered by a negative PIL decision in which STEI had to return $278,000 to customers.

STEI proposes that 2013 is an appropriate comparison for the 2015TY. In 2013 STEI engaged PricewaterhouseCoopers to provide a transfer pricing study for affiliate transactions; the 2013 actuals are "normalized" and exclude smart meter and staffing impacts. Table 4-2 below shows this normalization process.

Table 4-2

2013 Actual OM&A	**4,011,363**
add back acturarial gain	154,000
Normalized 2013 OM&A	4,165,363
Salary, wages and benefit increase (excluding capital)	242,000
Operational	
Substation Maintenance	30,000
Smart meter seal testing	20,000
increased hour allocation	12,957
Customer	
Bad debts	20,000
Postage incraease	20,000
Administration	
Employee future benefits	10,000
Outside professional services	21,000
Property and facility maintenance	35,000
Office, supplies, material	40,300
Property taxes	18,000
2015TY OM&A	**4,634,620**

Salaries Wages and Benefits

Salary and wages continued an upward trend from 2012 and have increased 2% to 3% annually. STEI employees consist of 7 non-unionized employees and 22 unionized employees.

Union employees received a 3% increase each year in increments from May 1, 2011 to April 30, 2014. STEI is currently in negotiations with its union as the current contract expires April 30, 2014. In addition to annual increases, some employees are entitled to progression rate increases as they acquire more skill and expertise.

Operations and Maintenance Costs

Substation maintenance costs have increased by $30,000 over 2013 as there were fewer substations maintained in 2013 as a decision was made to defer maintenance until 2014. The 2014 and 2015 costs reflect sustained maintenance activities on three substations each year. Customer initiated activities have increased over the last couple years and in response to these activities STEI has increased the labour hours to meet these demands resulting in incremental cost of approximately $13,000, STEI has also forecasted $20,000 for smart meter seal testing. Overall Substation maintenance has decreased $70,627 from the 2011 Board Approved amount of $111,967 to $41,340 in the 2015TY. See above capital conversion plan form 2.4kV resulting in less stations.

Customer Care Costs

There have been substantial changes to the delivery of services to STEI's customers. STEI customers have been impacted by the current economic conditions and as such STEI has incurred greater bad debt expenses. Customer billing costs have also been negatively impacted by the current postage rate increase. The Customer Service department is conducting an internal survey to gauge the public's interest in e-billing.

Administrative Costs

The other administrative cost in support of STEI activities have increased by $127,000. These increases include property taxes, employee future benefits, consultant costs related to employee future benefit valuation, plant maintenance and various office supply and expenses.

SUMMARY AND COST DRIVER TABLES

The budget is a key component of STEI's longer term Business Plan Process which reviews past results and plans future initiatives and ensures that the budgets are prudently planned and financially responsible.

STEI Directors are responsible for preparing capital and operating budgets for their respective areas. Directors are encouraged to seek out operational efficiencies and must prepare a business case for any new hires. Union labour increases are based upon the union contract and the AGI CEO approves non-union labour increase recommendation by the CFO.

STEI has a continuous business planning process which incorporates a future five year business plan which is presented and approved by the Board of Directors annually in December of the year proceeding the plan period. The preceding year is estimated as part of the five year plan.

The focus and rigor of the process is directed to the first of the five year period which is also the budget year. Based on the continuous approach, the budget process effectively begins at the start of the preceding fiscal year.

The process is as follows:

- During the first quarter of the year, the financial results for preceding year end, and monthly are compared against the budget results for capital and income

- Through the second quarter, an overall estimate for the full year ("Latest Estimate") is developed and compared to the budget. Any issues impacting the current year will be considered for the next subsequent year (which will become the new budget at the end of the processes)

- The monthly results are continually compared to budget through the year in order to generate potential trends / issues which will impact the new business plan (and new budget)

- A latest Estimate for the current year is and presented at management strategy review during the third quarter of the year. During this session, any adjustment to the overall strategy will be considered as part of the "top down" review of the new business plan (for subsequent year)

- During the second quarter, a concurrently "bottoms up" process is started for the first year of the new business plan (new budget).

- During the period September to November, there are review points with Sr. Management, and with the Audit Committee. During this time, the "top down" and "bottom up" approaches are used to build the final recommended case.

- The final recommended business plan is then presented to the full Board for approval. The review includes a risk management review of the business plan.

- In December, the Board approves the new Business Plan for the upcoming period which includes the new Budget for the next fiscal year.

- The Audit committee is a three member committee which currently includes two Board members from the STEI Board and one Board member from the Ascent Group Inc. Board.

The business plan incorporates the Capital Spending as an integral component of the process. Moving forward, STEI will be integrating the DS Plan process and capital project documentation into its operating and capital budget process.

2015 TEST YEAR BUDGET

The 2015TY is based upon the 2014BY with adjustments for known changes

The 2015TY operating budget highlights are as follows;

- Hiring of an Engineering Manager, position that is currently vacant.
  - 2014 budget assumes this position will be filled after the first quarter.
- Hiring of an Accountant/Regulatory, position is currently vacant
  - 2014 budget assumes this position will be filled after the second quarter
- Inflation increase, 2.1%
- 70% of linemen chargeable hours are capitalized
- Direct payroll benefits charged to capital, Board Table 2-DA is provided as Appendix
  - 2013 $140,425
  - 2014 $185,000
  - 2015 $189,000

The 2014BY budget was approved by the STEI Board of Directors in December 2013.

The 2014BY is based upon the same 2015TY inflationary and labour assumptions provided above.

DEPARTMENT OVERVIEW

Operations & Maintenance

The operating and maintenance area is comprised of the Engineering, Operations and Purchasing departments. The Engineering, Operations and Purchasing departments are responsible for engineering design, construction, asset management, control room operations, material management and acquisitions and health and safety. Operations is also responsible for fleet maintenance and replacement as well and building and property maintenance.

Engineering

The Engineering Division is responsible for overall electrical distribution system plan and design, electric system protection and adherence to construction standards. Duties include long-range forecasting and planning for the electrical system; short-range planning for individual customer requirements; specification and design of control and protective equipment; detailed design and field engineering for overhead and underground lines, substations and the management of the GIS system. The department is also responsible for the co-ordination of the construction activities and scheduling. This requires that they work closely with the municipal departments, developers and other regulatory agencies such as the Electrical safety Authority. The department strives to provide safe, reliable, cost effective service giving consideration to the environment, economy, and safety.

Operations

Operations involve the physical construction, maintenance and operations of the distribution system including metering. The Line Department staff work closely with the Engineering staff in executing the engineering capital plans, providing reactive and planned operating and maintenance as well as maintaining system reliability is a safe and economical manner.

Maintenance programs are planned around an established cycle with the goal of reducing unplanned outages. Reactive and emergency type work is often after normal working hours and is recoverable from outside parties.

Operations are also responsible for the Control Room which is performs outage restoration planning, dispatching, and device control, switch planning and network management.

Purchasing

The purchasing department is responsible for managing inventory levels, issuing and, receiving inventory including returns. The department is also responsible to ensure that adequate inventory levels are maintained to respond to distribution system requirements.

Customer Service

The customer service department provides STEI's customers with efficient, accurate and timely, customer services, while endeavoring to be the professional, honest and reassuring. The customer service department is responsible for billing, collecting and care activities.

Administration

Administration department includes the President and COO, Finance and Regulatory and Information Technology support. This area provides the strategic direction for STEI, ensures compliance with regulatory codes and legislation and the preparation of regulatory filings, rate applications, audits and financial reporting to internal and external shareholders.

Summary of Recoverable OM&A Expenses

The recoverable OM&A expenses are required to enable STEI to build, operate and maintain a safe, reliable electrical distribution system, to meet legislative requirements and customer expectations. STEI's expenditures enable for the effective maintenance of the distribution assets, to provide efficient and effective customer care, ensure public and employee safety, compliance with the Distribution System Code, environmental requirements, and additional government directives and policies.

STEI's request of $4,634,620 for the 2015TY is based on a business planning process that aimed to ensure the most appropriate cost effective solutions have been implemented.

STEI's OM&A costs have increased since its last Cost of Service Application in 2011. As mentioned previously, STEI restructured from an affiliate subsidized virtual utility in 2011 to a fully operational utility in 2012. As the cost structure has substantially changed, STEI is proposing that historical and the 2011 Cost of Service application structure are not appropriate comparatives.

STEI adopted IFRS like policies upon restructuring in 2012. Specifically, STEI adopted revised useful lives per the Kinectrics report and capitalization policy. The 2011 capital and OM&A costs were previously based upon an activity specific MSA, whereas the 2012 to 2015 labour costs are based upon directly attributable payroll timesheet entries. As STEI adopted IFRS capitalization and PP&E policies only directly attributable cost are capitalized, O&M cost are greater than what they would have typically been under CGAAP and under the previous MSA. STEI is presenting comparable MIFRS costs for the years 2012 to 2015.

A summary of STEI's recoverable OM&A expenses, excluding property taxes for the 2011 Board Approved, 2011 actual, 2012 and 2013 actuals, 2014BY and 2015TY, is provided in Board Appendix 2-JA - replicated below.

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2011 Board-Approved)	Last Rebasing Year (2011 Actuals)	2012 Actuals	2013 Actuals	2014 Bridge Year	2015 Test Year
Reporting Basis						
Operations	$ 493,406	$ 558,853	$ 958,213	$ 868,543	$ 925,270	$ 977,701
Maintenance	$ 423,276	$ 364,438	$ 324,575	$ 274,855	$ 333,832	$ 340,842
SubTotal	**$ 916,682**	**$ 923,291**	**$ 1,282,788**	**$ 1,143,398**	**$ 1,259,102**	**$ 1,318,543**
%Change (year over year)			38.9%	-10.9%	10.1%	4.7%
%Change (Test Year vs Last Rebasing Year - Actual)						42.8%
Billing and Collecting	$ 1,133,130	$ 982,501	$ 1,039,175	$ 869,044	$ 938,833	$ 965,058
Community Relations	$ 19,513	$ 2,684	$ 32,390	$ -	$ -	$ -
Administrative and General	$ 1,502,109	$ 1,832,734	$ 2,691,486	$ 1,998,931	$ 2,259,284	$ 2,351,019
SubTotal	**$ 2,654,752**	**$ 2,817,919**	**$ 3,763,051**	**$ 2,867,975**	**$ 3,198,117**	**$ 3,316,077**
%Change (year over year)			33.5%	-23.8%	11.5%	3.7%
%Change (Test Year vs Last Rebasing Year - Actual)						17.7%
Total	**$ 3,571,434**	**$ 3,741,210**	**$ 5,045,839**	**$ 4,011,373**	**$ 4,457,219**	**$ 4,634,620**
%Change (year over year)			34.9%	-20.5%	11.1%	4.0%

	Last Rebasing Year (2011 Board-Approved)	Last Rebasing Year (2011 Actuals)	2012 Actuals	2013 Actuals	2014 Bridge Year	2015 Test Year
Operations	$ 493,406	$ 558,853	$ 958,213	$ 868,543	$ 925,270	$ 977,701
Maintenance	$ 423,276	$ 364,438	$ 324,575	$ 274,855	$ 333,832	$ 340,842
Billing and Collecting	$ 1,133,130	$ 982,501	$ 1,039,175	$ 869,044	$ 938,833	$ 965,058
Community Relations	$ 19,513	$ 2,684	$ 32,390	$ -	$ -	$ -
Administrative and General	$ 1,502,109	$ 1,832,734	$ 2,691,486	$ 1,998,931	$ 2,259,284	$ 2,351,019
Total	**$ 3,571,434**	**$ 3,741,210**	**$ 5,045,839**	**$ 4,011,373**	**$ 4,457,219**	**$ 4,634,620**
%Change (year over year)			34.9%	-20.5%	11.1%	4.0%

	Last Rebasing Year (2011 Board-Approved)	Last Rebasing Year (2011 Actuals)	Variance 2011 BA – 2011 Actuals	2012 Actuals	Variance 2012 Actuals vs. 2011 Actuals	2013 Actuals	Variance 2013 Actuals vs. 2012 Actuals	2014 Bridge Year	Variance 2014 Bridge vs. 2013 Actuals	2015 Test Year	Variance 2015 Test vs. 2014 Bridge
Operations	$ 493,406	$ 558,853	-$ 65,447	$ 958,213	$ 399,360	$ 868,543	-$ 89,670	$ 925,270	$ 56,727	$ 977,701	$ 52,431
Maintenance	$ 423,276	$ 364,438	$ 58,838	$ 324,575	-$ 39,863	$ 274,855	-$ 49,720	$ 333,832	$ 58,977	$ 340,842	$ 7,010
Billing and Collecting	$ 1,133,130	$ 982,501	$ 150,629	$ 1,039,175	$ 56,674	$ 869,044	-$ 170,131	$ 938,833	$ 69,789	$ 965,058	$ 26,225
Community Relations	$ 19,513	$ 2,684	$ 16,829	$ 32,390	$ 29,706	$ -	-$ 32,390	$ -	$ -	$ -	$ -
Administrative and General	$ 1,502,109	$ 1,832,734	-$ 330,625	$ 2,691,486	$ 858,752	$ 1,998,931	-$ 692,555	$ 2,259,284	$ 260,353	$ 2,351,019	$ 91,735
Total OM&A Expenses	$ 3,571,434	$ 3,741,210	-$ 169,776	$ 5,045,839	$ 1,304,629	$ 4,011,373	-$ 1,034,466	$ 4,457,219	$ 445,846	$ 4,634,620	$ 177,401
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)											
Total Recoverable OM&A Expenses	$ 3,571,434	$ 3,741,210	-$ 169,776	$ 5,045,839	$ 1,304,629	$ 4,011,373	-$ 1,034,466	$ 4,457,219	$ 445,846	$ 4,634,620	$ 177,401
Variance from previous year				$ 1,304,629		-$ 1,034,466		$ 445,846		$ 177,401	
Percent change (year over year)				35%		-21%		11%		4%	
Percent Change: Test year vs. Most Current Actual						15.54%					
Simple average of %variance for all years						23.88%					7%
Compound Annual Growth Rate for all years											4.4%
Compound Growth Rate (2013 Actuals vs. 2011 Actuals)						2.35%					

Note:

1 "BA" = Board-Approved
2 If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.
3 Recoverable OM&A that is included on these tables should be identical to the recoverable OM&A that is shown for the corresponding periods on Appendix 2-JB.

Based upon the above table 2015 TY OM&A expenses have increased by 26.9% from the 2011 Board Approved amount. 2015 TY OM&A expenses have decreased by 10.0% from the 2012 restructuring year.

OM&A Cost Drivers

STEI has gone through a significant restructuring since its 2011 Cost of Service application. Not only has STEI changed from a virtual utility to a fully operational utility, STEI is developing a comprehensive asset management plan while continuing its focus on safety, customer, community and financial results.

The major cost drivers from normalized 2012 actual results are; labour and benefit increases, wage progressions, recruitment, and customer tools to monitor and react to electricity usage regulatory compliance and post-retirement benefits are new to STEI as of 2012.

The following Board Appendix 2-JB details the material changes from the 2011 Board Approved results to the 2015TY

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Appendix 2-JB
Recoverable OM&A Cost Driver Table

OM&A	**2012 Actuals**	**2013 Actuals**	**2014 Bridge Year**	**2015 Test Year**
Reporting Basis				
Opening Balance	$ 3,741,210	$ 5,045,839	$ 4,011,363	$ 4,457,219
Cost Driver # 1 Administration	$ 422,687	-$ 124,524		
Cost Driver # 2 smart meter	$ 248,000	-$ 248,000		
Cost Driver # 3 - management fee	$ 220,000	-$ 305,000	$ -	
Cost Driver # 4 Special Assessment Fee	-$ 58,651	$ -	$ -	
Cost Driver # 5 Plant Maintenance	-$ 135,968	-$ 15,705	$ 35,000	
Cost Driver # 6 Collection Charges	-$ 80,913	$ 6,346		
Cost Driver # 7 Bad Debts	-$ 36,545	-$ 44,270	$ 19,000	
Cost Driver # 8 Community relations, advertising	$ 33,770	-$ 33,485	$ -	
Cost Driver # 9 Office Supplies, Administration	$ 347,121	-$ 71,847	$ 43,239	
Cost Driver # 10 Meter Reading, Collecting	$ 85,161			
Cost Driver # 11 Employee Future benefits	$ 21,407	-$ 175,000	$ 163,575	
Cost Driver # 12 OM&A Direct Charge, includes new lineman hired mid 2013	$ 221,500		$ 50,042	
Cost Driver # 12 Outside services	$ 17,060			
Cost Driver # 13 CS Collection Charges	$ -			
Cost Driver # 14 Paymentus, in house CS activities		-$ 22,991		
Cost Driver # 15, filling Eng Manager and Accounting Analysis positions			$ -	$ 80,000
Cost Driver # 16 Postage Increase			$ 20,000	
Cost Driver # 17 Substation Maintenance			$ 27,000	
Cost Driver # 18 Customer survey, Employee future benefit valuation 2015			$ 21,000	
Cost Driver # 19 property taxes			$ 17,000	
Cost Driver # 20 ICP			$ 50,000	
Smart Meter Testing				$ 20,000
Inflation 2.1%, ICP + OMERS			$ -	$ 73,602
Miscellaneous	$ -		$ -	$ 3,799
Closing Balance	$ 5,045,839	$ 4,011,363	$ 4,457,219	$ 4,634,620

The impacts on the OM&A activities are as follows:

Operations and Maintenance

Based upon the following table, 2015TY O&M expenses have increased by $401,861 over the 2011 Board Approved COS Application and $173,750 over the 2012 actual costs. Table 4-3 below shows the changes from the 2011 Board approved levels and the 2012 actual levels.

Table 4-3

OPERATING and MAINTENANCE EXPENSES

	2011 Approved	2011 Actual	2012 Actual	2013 Actual	2014 Budget	2015 Test Year
Operations	493,406	558,853	958,218	868,543	925,270	977,701
Maintenance	423,276	364,438	324,575	274,855	333,832	340,842
TOTAL	**916,682**	**923,291**	**1,282,793**	**1,143,398**	**1,259,102**	**1,318,543**
Smart Meter adjustment	-	-	(138,000)	-	-	-
Normalized O&M	**916,682**	**923,291**	**1,144,793**	**1,143,398**	**1,259,102**	**1,318,543**
Change from 2011 Approved		**6,609**	**228,111**	**226,716**	**342,420**	**401,861**
Change from 2012 Restructuring				**(1,395)**	**114,309**	**173,750**

The increase over the 2011 Board Approved amount is related to the change from a 2011 fixed charge-out rate based upon a MSA versus directly attributable cost. The 2012 to 2015 operating costs include items that would previously have been included in the capital MSA rate that are now considered an operational expense under IFRS. For example, portions of the Director of Operations and Engineering time in 2011 would have been included in the capital rate from AESI, whereas all this labour in 2012 and beyond is considered an operational expense as it is not directly attributable to the capital installation.

Additionally, the O&M amounts for 2012 to 2015 include the employee payroll and training expenses attributed to the Engineering and Operations staff that is not allocated to capital. These amounts have been charged to O&M so that Management can manage the full costs of supporting these operations. This also aids in variance analysis, for instance, if sick time was charged to administration and if there was a significant change year over year, O&M costs would in theory be under budget but Administration would be over budget due to a labour allocation. Attributing all costs associated with O&M staff avoids this variance analysis. The amount of incremental overheads charged to O&M is as follows: 2012, ($132,000), 2013, ($153,000) 2014 ($77,000) and 2015, ($79,000). The 2014BY increase is attributed to inflation increase of 2.1%, increased hours allocated to O&M activities and substation maintenance that did not occur in 2013.

Additionally in 2013, LDC's were legislated under Bill 8, Ontario Underground Infrastructure Notification System Act, 2012 to use the Government Agency ON1Call to perform all locate requests. Bill 8 has increased STEI's locate costs by approximately $5,000 per year.

The 2015TY amounts are based upon 2014BY activities, with any known changes, and increased by an inflationary amount of 2.1% and increased Engineering Manager labour for a full year vs 3/4 year for 2014.

Billing and Collecting

Based upon the following table, 2015TY B&C expenses have decreased by $168,072 over the 2011 Board Approved COS Application and have increased by $35,883 over the 2012 actual costs. Billing and collection expenses for 2011 to 2015 are shown in Table 4-4 below:

Table 4-4

BILLING and COLLECTING EXPENSES

	2011 Approved	2011 Actual	2012 Actual	2013 Actual	2014 Budget	2015 Test Year
Billing	697,716	654,764	751,778	626,534	726,457	741,713
Collecting	477,456	424,727	456,187	448,814	402,376	410,826
B&C	**1,175,172**	**1,079,491**	**1,207,965**	**1,075,348**	**1,128,833**	**1,152,538**
Bad Debt	81,000	181,401	144,856	100,586	120,000	122,520
Collection Charges	(123,042)	(278,391)	(313,646)	(306,890)	(310,000)	(310,000)
TOTAL	**1,133,130**	**982,501**	**1,039,175**	**869,044**	**938,833**	**965,058**
Smart Meter adjustment	-	-	(110,000)	-	-	-
Normalized O&M	**1,133,130**	**982,501**	**929,175**	**869,044**	**938,833**	**965,058**
Change from 2011 Approved		**(150,629)**	**(203,955)**	**(264,086)**	**(194,297)**	**(168,072)**
Change from 2012 Restructuring				**(60,131)**	**9,658**	**35,883**

The decrease in the 2015TY costs versus the 2011 Board Approved amount is associated with an increase in recoverable collection charges that have been offset by increased bad debts. In conjunction with the 2012 restructuring additional collection charges that were retained by the affiliate have become additional collection charge recoveries to STEI) The 2015TY $35,883 increase over the 2012 normalized actual in attributed to labour increases and a $20,000 increase in postage, reflecting the 37% increase announced March 31, 2014.

Community Relations

STEI is no longer budgeting for community relations expenditure, this activity is being recorded by its affiliate AGI. Approximately $22,000 of community relation costs are included in the AGI annual fee of $450,000. The Community Relations costs from 2011 to 2015 are shown in Table 4-5 below:

Table 4-5

COMMUNITY RELATIONS

	2011 Approved	2011 Actual	2012 Actual	2013 Actual	2014 Budget	2015 Test Year
Community Relations	19,513	2,684	32,390	-	-	-

Administration and General

Based upon the following table, 2015TY Administrative & General expenses have increased by $851,620 over the 2011 Board Approved COS Application and have decreased by $337,757 over the 2012 actual costs. The Administrative and General costs from 2011 to 2015 are shown in Table 4-6 below:

Table 4-6

	2011 Approved	2011 Actual	2012 Actual	2013 Actual	2014 Budget	2015 Test Year
Administration & General	1,502,109	1,832,734	2,691,486	1,998,921	2,259,284	2,353,729
Change from 2011 Approved		330,625	1,189,377	496,812	757,175	851,620
Change from 2012 Restructuring				(692,565)	(432,202)	(337,757)

Administrative costs for the 2013 actual, 2014BY and 2015TY include $450,000 of administration and governance costs allocated from its parent company AGI. STEI receives a number of Corporate, Finance, and Governance services from AGI. The services provided by AGI include corporate functions such as executive management (i.e. CEO and CFO) and enterprise IT services, financial and accounting support for enterprise financial consolidation requirements, as well as governance which includes several Boards of Directors. Additionally, there are other levels of administrative support such as financial/debt management, legal/consulting, and business development services. This fee was independently assessed in 2013 by PricewaterhouseCoopers ("PwC") as a component of the cost allocation study PwC performed on behalf of STEI.

Recoverable OM&A per Customer

STEI recoverable OM&A cost per customer for the 2015TY of $272.58 per customer is $32.30 less than the 2012 actual amount of $304.88. Appendix 2-L from the OEB appendices is replicated below.

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Appendix 2-L
Recoverable OM&A Cost per Customer and per FTE

2015

	Last Rebasing Year - 2011- Board Approved	Last Rebasing Year - 2011- Actual	2012 Actuals	2013 Actuals	2014 Bridge Year	2015 Test Year
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Number of Customers	16,432	16,434	16,550	16,692	16,846	17,003
Total Recoverable OM&A from Appendix 2-JB	$ 3,571,434	$ 3,741,210	$ 5,045,839	$ 4,011,363	$ 4,457,219	$ 4,634,620
OM&A cost per customer	$ 217.35	$ 227.65	$ 304.88	$ 240.32	$ 264.59	$ 272.58
Number of FTEs			29.63	26.75	27.94	28.69
Customers/FTEs			558.59	624.00	602.93	592.65
OM&A Cost per FTE			170,305.25	149,957.50	159,528.24	161,541.29

STEI has calculated its 2015TY OM&A cost per customer, (excluding property tax costs) as $265.52. The property tax has been excluded to be consistent with the OEB methodology.

As provided in the following table 4-7, STEI ranks 9th within its peer group based upon the 2013 OEB 3rd Generation Incentive Regulation Stretch Factor Update. STEI has calculated its peer costs based upon 2012 OEB Year Book OM&A cost per customer increased by an inflation factor of 2% per year. STEI notes that its OM&A cost per customer is based upon IFRS policies which increases OM&A costs based upon more stringent capitalization policy.

Table 4.7

	OM&A Per Customer Mid-Size Southern Medium-High Undergrounding	2015 forecast
1	Westario Power Inc.	218.80
2	E.L.K. Energy Inc.	219.61
3	Essex Powerlines Corporation	227.59
4	Chatham-Kent Hydro Inc. (Entegrus)	234.33
5	Peterborough Distribution Incorporated	237.40
6	Wasaga Distribution Inc.	238.58
7	Kingston Hydro Corporation	249.36
8	Festival Hydro Inc.	255.55
9	**St. Thomas Energy Inc.**	**265.52**
10	Woodstock Hydro Services Inc.	273.29
11	Erie Thames Powerlines Corporation	284.17
12	Welland Hydro-Electric System Corp.	302.57
13	Niagara Peninsula Energy Inc.	307.40
14	COLLUS Power Corp.	327.04
15	Bluewater Power Distribution Corporation	342.07
	Group Average	**265.55**

The 2011 costs from its affiliates were based upon a specific activity charge-out rate vs on an activity based and as such STEI does not have an FTE equivalent for that year. As per the 2011 Cost of Service Application, STESI provided all employee services and management to STEI under a Master Service Agreement, (“MSA”). There were no employee costs resident in STEI and as such no employee FTE was filed.

STEI is not planning any additional hiring for the 2015TY and as such STEI does not expect the OM&A per Customer per FTE to change significantly beyond the 2015TY. STEI has and will continue to apply to the Ontario Energy Board for Service Area Amendments (“SAA”) for new subdivisions being developed within the Municipal boundaries that STEI will be providing water and sewer billing and collection services. Obtaining approval for these developments will contribute to reducing STEI’s cost per customer while continuing to provide a reliable distribution system and efficient and effective billing and customer services to the residents of St. Thomas.

PROGRAM DELIVERY COSTS WITH VARIANCE ANALYSIS

STEI provides a number of programs and activities that are required to continue to provide a safe, reliable, dependable and affordable electricity services and customer services to its customers. The 2011 Board Approved settlement agreed to an envelope reduction approach to the OM&A expenses. STEI allocated the reduction to the OM&A areas identified in the OM&A cost driver section 2.7.2. Due to the material change in how costs are recorded, pre-restructuring 2011 and post restructuring in 2012 – 2015, the variance analysis will focus on the 2015TY versus the 2012 actual results. The 2015TY amount of $4,637,329 is $408,510 less than the 2012 actual and $168,510 less than the 2012 normalized actual amount of $4,805,839 ($5,045,839 less smart meter amount $240,000). Appendix 2-JC from the OEB appendices is replicated below.

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Appendix 2-JC
OM&A Programs Table

Programs	Last Rebasing Year (2011 Board-Approved)	Last Rebasing Year (2011 Actuals)	2012 Actuals	2013 Actuals	2014 Bridge Year	2015 Test Year	Variance (Test Year vs. 2013 Actuals)	Variance (Test Year vs. Last Rebasing Year (2011 Board-Approved)
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	
Program Name O&M								
Operations management	283,657	294,196	454,809	447,318	496,775	507,208	59,890	223,551
Control Room, Purchasing, benefits	87,670	99,571	287,293	343,510	334,398	374,420	30,910	286,750
Substation Maintenance	111,967	84,446	57,657	20,478	40,490	41,340	20,862	-70,627
Tree Trimming	63,030	95,448	69,272	81,254	91,441	93,361	12,107	30,331
Planned Inspections	307,328	245,527	259,450	107,462	123,690	126,035	18,573	-181,293
Customer Initiated	63,030	104,103	154,307	143,366	172,399	176,178	32,812	113,148
							0	0
Sub-Total	916,682	923,291	1,282,788	1,143,388	1,259,193	1,318,542	175,154	401,860
Program Name Customer Service								
Meter Reading & Billing	697,716	654,764	751,778	626,534	726,457	741,713	115,179	43,997
Collecting	477,456	424,727	456,187	448,814	402,376	410,826	-37,988	-66,630
Bad Debt	81,000	181,401	144,856	100,586	120,000	122,520	21,934	41,520
Collection Charges	-123,042	-278,391	-313,646	-306,890	-310,000	-310,000	-3,110	-186,958
							0	0
Sub-Total	1,133,130	982,501	1,039,175	869,044	938,833	965,058	96,015	-168,072
Program Name Administration								
Salary and Expenses	808,635	1,087,252	1,751,489	1,152,125	1,272,193	1,346,002	193,877	537,367
Regulatory	175,896	193,220	184,110	178,327	175,000	178,675	348	2,779
Property taxes	121,496	108,911	83,343	82,987	100,000	102,100	19,113	-19,396
Outside Services	49,987	49,405	66,466	67,154	87,000	88,827	21,673	38,840
General Building and Office	346,095	393,946	606,078	518,338	625,000	635,415	117,077	289,320
Sub-Total	1,502,109	1,832,734	2,691,486	1,998,931	2,259,193	2,351,019	352,088	848,910
Program Name #5								
Community Relations	19,513	2,684	32,390	0	0	0	0	-19,513
							0	0
							0	0
							0	0
							0	0
Sub-Total	19,513	2,684	32,390	0	0	0	0	-19,513
Miscellaneous							0	0
Total	**3,571,434**	**3,741,210**	**5,045,839**	**4,011,362**	**4,457,219**	**4,634,620**	**623,258**	**1,063,186**

OPERATIONS AND MAINTENANCE

Operations and Maintenance for the 2015TY of $1,318,542 are $35,754 greater than the 2012 actual amount of $1,282,788. The 2015TY O&M expenses are $173,754 greater than the normalized 2012, (2012 Actual less smart meter costs of $138,000). The increase includes labour increases of 3% for 2013, forecasted labour and inflation increase of 2.1% for the 2014BY and 2015TY and additional operating hours to support the planned increased inspections and related maintenance work. STEI hired a new lineman in 2013 to support the increased planned O&M activities and the 2.4 kV capital conversion program. The 2015TY does not include smart meter testing. STEI has not included any costs related to smart meter seal testing in the 2015TY O&M expenses. STEI has included $20,000 in the 2015TY for smart meter seal testing, this is an additional cost to the plan in recognition that these meters will need to be re-verified per Measurement Canada requirements.

CUSTOMER FOCUS

Customer initiated 2015TY O&M activities have increased by $133,148 over the 2012 actual and represents 65% of the total increase for this period. Customer initiated activities include; disconnect, reconnect, layouts, meter inquiries and locate activities.

BILLING AND COLLECTING

Billing and Collection cost for the 2015TH $965,058 are $74,117 less than the 2012 actual amount of $1,039,175 or $36,883 greater than the normalized 2012 actual amount of $927,175 (1,039,175 less smart meter of $110,000).

CUSTOMER FOCUS

The greatest increase in this area is a $20,000 increase in postage cost per the increased Canada Post rates announced in March of 2014.

ADMINISTRATIVE

Administration costs for the 2015TY of $2,351,019 are $340,467 less than the 2012 actual amount of $2,691,486. The decrease is attributed to a reduction in the AGI management fee, per the PwC cost allocation study, of $285,000 and reduced salaries and wages associated with restructuring and succession planning.

CUSTOMER FOCUS

To ensure that STEI's customers are not subsidizing any affiliates, STEI engage PwC to perform a transfer pricing study which resulted in a $285,000 reduction in the management fee from AGI to STEI from 2012 the $735,000 paid in 2012 to $450,000 in 2013.

EMPLOYEE COMPENSATION BREAKDOWN

STAFFING

STEI's process for establishing appropriate staffing levels starts with the business planning process which includes a succession plan review. The business planning process includes the CEO and CFO of AGI, the COO of STEI and the Director Finance and Regulatory Compliance STEI which make recommendations to the STEI Board of Directors. New Staff requests are weighted against; continuity and delivery of customer service and distribution system service levels, community and affordability.

As provided in the following Table 4-7, STEI 2015TY employee FTE is 28.69.

Table 4-7

STAFFING LEVELS - FTE

	2012	2013	2014	2015
Management	7.58	5.75	5.75	6.00
Non-Management	20.41	20.33	21.52	22.02
Contract	0.50	0.58	-	-
Co-Op & Summer help	1.63	0.67	0.67	0.67
Staff Totals	**30.12**	**27.33**	**27.94**	**28.69**

STEI has decreased its full time equivalent staffing levels by 1.43 employees from the 2012 restructuring to the 2015TY.

Management has decreased by two positions with the transfer of an IT Supervisor to an affiliate and the elimination of the Finance Manager position which was replaced with a non-management Accounting Analyst position.

Non-management increase included an additional lineman in the fall of 2013 as part of STEI's succession plan. The contract position (Financial Analyst) continued from mid-2012 to mid-2013. The 2014BY includes filing this contract position this with a permanent employee by mid-2014. The 2013 to 2015 staffing levels do not include a Co-Op student.

STEI is forecasting eight potential retirements within the period between the 2015 COS application in the next application, of the eight position, four are non-union and four are union.

COMPENSATION STRATEGY

STEI offers competitive compensation sufficient to attract and retain staff. STEI will have management incentive plans to reward employees when they meet or exceed our corporate objectives. STEI has relied upon independent wage comparison studies performed in 2007 and takes part in confidential surveys such as the on MEARIE provides. Additionally, STEI polls other utilities with regards to wages and benefits for employees.

Changes in salaries and wages for unionized staff are based upon the timing of the negotiated settlement with IBEW. The current union contract, negotiated May 1, 2011, expires April 30, 2014. The expiring contract included wage increases of 2% each May 1 and 1% increase each December 1 of the contract term. The non-unionized employee salaries and grids have been established based upon a market study performed 2007, non-union increases have been 1% for the years 2012 and 2013.

For the 2014BY and the 2015TY, STEI has used inflation rate increase of 2.1% for all staff.

PAY EQUITY

STEI is required by law to comply with Ontario's Pay Equity Act. STEI's pay equity plan in Attachment 2 was updated November 28, 2012. Based upon this current review, no issues are anticipated with the current union negotiations and no additional costs have been added in this Application.

INTERNAL EQUITY

In July 2007, Cyr & Associates was contracted to conduct a compensation review of the management and non-union staff positions in Attachment 1. Each position has been assigned a point value based on an evaluation of the relative value of the position in this organization. To maintain internal equity, all new jobs are evaluated using the same process and job evaluation methodology. Any significant changes or modifications to an existing role triggered a re-evaluation of the position to identify any impact to the existing point value of the job.

STEI engaged Cyr & Associates in 2012 who provided an update to the 2007 study with regards to market-rate comparisons and changes to position descriptions.

No additional costs have been added to this Application with regards to internal equity.

PERFORMANCE PAY

STEI offers an Incentive Compensation Plan ("ICP") to its non-union employees. The plan has two components comprised of corporate objectives and personal goals that are established at the beginning of each year. The ICP payout isn't considered unless a minimum of 80% of the corporate goals are accomplished. The ICP payout is recommended to the Audit Committee which in turn makes a recommendation to the STEI Board of Directors.

BENEFIT COSTS

STEI's benefit coverage includes prescription drugs, vision, dental care, hearing aids, employee assistance, long term disability insurance, life insurance, accidental death and dismemberment and out of country health care coverage in Attachment 3. Benefit costs for union employees are a negotiated item, which changes to the benefit package achieved through negotiations. Benefit coverage is provided by Great West Life.

STATUTORY BENEFITS

The employer portion of statutory benefits; Canada Pension Plan contributions, Employment Insurance, Employer Health Tax and Workers Safety Insurance premiums are also included in benefit expense.

Pension

STEI participates in the OMERS per provincial legislations. Pension contributions have increased as OMERS manages its funding deficit. Contributions increased 1.0% in 2012 and 0.9% in 2013. Table 4-8 below shows the benefit costs from 2012 to 2015.

Table 4-8

BENEFIT COSTS	**2012 Actual**	**2013 Actual**	**2014 BY**	**2015 TY**
Benefit Costs	155,630	141,561	157,766	161,079
Statutory Benefits	169,162	159,112	167,900	172,699
Omers Pension	175,020	195,528	228,619	244,177
Total Benefit Costs	**499,813**	**496,201**	**554,285**	**577,955**

Total benefit costs for the 2015TY of $577,955 have increased by $78,142 from the 2012 actual. The 2014BY and 2015TY OMERS includes costs associated with the replacement of the current Director of Operations and Engineering, who is retired and therefore STEI does not incur OMERS expense.

POST-EMPLOYMENT BENEFIT COSTS

In conjunction with the 2012 restructuring and the transfer of staff into STEI, STEI has recorded post-employment benefit costs. In 2012 STEI recorded $21,407 of post-employment expenses based upon an allocation of transferred employees. In 2013, STEI had an actuarial valuation performed by Collins Barrow Toronto Actuarial Services Inc. The Summary Actuarial Valuation is provided as Attachment 4. STEI does not use the corridor method for recognizing actuarial gains and losses and as such, STEI recorded a net gain of $153,575 in 2013. A new valuation will be performed in conjunction with the transition to IFRS in 2015. STEI has budgeted post-employment benefit costs of $10,000 for the 2014BY and 2015TY.

EMPLOYEE COSTS

Board appendix 2-K is provided below. The number of employees has been expressed as a full time equivalent basis (“FTE”).

Appendix 2-K
Employee Costs

	Last Rebasing Year - 2011- Board Approved	Last Rebasing Year - 2011- Actual	2012 Actuals	2013 Actuals	2014 Bridge Year	2015 Test Year
Number of Employees (FTEs including Part-Time)[1]						
Management (including executive)			7.58	5.75	5.75	6.00
Non-Management (union and non-union)			22.04	21.00	22.19	22.69
Total	-	-	29.63	26.75	27.94	28.69
Total Salary and Wages including ovetime and incentive pay						
Management (including executive)			$ 877,516	$ 683,018	$ 765,371	$ 805,214
Non-Management (union and non-union)			$ 1,309,323	$ 1,284,081	$ 1,404,058	$ 1,504,874
Total	$ -	$ -	$ 2,186,840	$ 1,967,099	$ 2,169,429	$ 2,310,088
Total Benefits (Current + Accrued)						
Management (including executive)			$ 171,114	$ 146,896	$ 180,384	$ 187,358
Non-Management (union and non-union)			$ 328,699	$ 349,305	$ 373,900	$ 390,597
Total	$ -	$ -	$ 499,813	$ 496,201	$ 554,284	$ 577,955
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	$ -	$ -	$ 1,048,630	$ 829,914	$ 945,755	$ 992,572
Non-Management (union and non-union)	$ -	$ -	$ 1,638,023	$ 1,633,386	$ 1,777,958	$ 1,895,471
Total	$ -	$ -	$ 2,686,653	$ 2,463,300	$ 2,723,713	$ 2,888,043

The total compensation amount does not include amounts paid to STEI’s Board of Directors. Board remuneration is paid through the parent company AGI and is included in the management fee of $450,000 that AGI charges STEI. Approximately $40,000 of Board of Director costs is included in the AGI management fee.

Post-employment benefits have not been included in Appendix 2-K.

Attachment 1 of 4

Management Job Evaluation

November 8, 2007

Mr. Brian Hollywood, President
St. Thomas Energy Services Inc.
135 Edward St.
St. Thomas, Ontario
N4P 4A8

Dear Brian,

We are pleased to present the results of the Management job evaluation project work completed to date. While our recommendations provide a new compensation structure for the Management team, you will also note that the overall financial impact of the recommendations is very minimal.

We have developed a compensation structure and process that will provide the Company with flexibility to attract, retain and reward employees using compensation best practices. The project also included a review of utility industry compensation data to ensure the Company is competitively positioned. Should you have any questions, please feel free to contact me directly at (905) 452-3323.

Sincerely,
Cyr & Associates Inc.

Annette Cyr
President

Executive Summary

In July 2007, Cyr & Associates was contracted to conduct a compensation review of the management and non-union staff positions for St. Thomas Energy Services. Cyr & Associates is the industry leader in compensation design and development and is also responsible for the annual industry compensation survey for electrical utilities in Ontario.

Our first step in conducting the review was to collect job data on each of the positions. Each incumbent was provided with a job questionnaire containing questions regarding the primary responsibilities of the role, the managerial and job knowledge required for the role, the level of problem solving, working conditions and the amount of impact the role has on the overall results of the Company. Through the use of this tool, we were then able to use a form of the Hay™ job evaluation methodology to evaluate each position and determine the relative value of the job within the organization. At the same time, comprehensive job descriptions were created for use in the recruitment and performance management processes.

Once the job evaluation process was completed, jobs were grouped into job grades using commonly accepted compensation principles. Jobs were grouped where similar points or clusters of positions existed. The next step was to develop a compensation structure to overlay the job grades, taking into consideration existing pay rates as well as competitive data from industry sources.

We used the 2007 MEARIE Group management survey to provide compensation data for benchmark positions in the Company. Using the 2007 median rates from the benchmark survey data, we were then able to conduct regression analysis of the data to develop a reasonable trend line and formula to assist us in developing pay grades for the Company. The points from the job evaluation were then applied to the equation to develop the midpoints for the salary ranges. We then used a standard compensation design principle to develop a minimum and maximum for the salary range. The minimum is approximately 80% of the midpoint; the maximum is approximately 20% above the midpoint. All incumbents currently fall within the recommended pay ranges. However, incumbent pay may need to be adjusted to reflect the experience, length of service and performance level of the individual to appropriately place them within the range.

The job evaluation process and resulting grades and ranges will comply with existing Pay Equity standards and requirements for legislative compliance.

Maintenance of the Compensation Structure

The recommended job grades and pay band structure must be maintained to ensure internal equity and external competitiveness and to comply with Pay Equity legislation.

Internal Equity: Each position has been assigned a point value based on an evaluation of the relative value of the position in this organization. To maintain internal equity, all new jobs must be evaluated using the same process and job evaluation methodology. Any significant changes or

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modifications to an existing role should also trigger a re-evaluation of the position to identify any impact to the existing point value of the job.

To move through the pay ranges, we recommend that pay adjustments be tied directly to performance contribution and not automatically increased based simply on a match to union pay increases. Management positions have a significant impact on the success, culture and direction of the organization. Linking pay to performance provides a means of communicating what is important to the organization, and then rewarding it accordingly.

Typically, an annual budget for salary increases would be developed and communicated to management during the annual performance review cycle. This cycle is normally aligned with the fiscal year planning and budgeting processes. Department heads are provided a budget allocation (For example 3.25% of department management payroll), and are generally expected to provide increases in pay within their budgets and reflective of the performance contribution of each non-union employee. Employees would receive a performance review and a recommended increase would be submitted to the executive for review and approval. Employees have the potential to move through their pay range at an accelerated rate, based on performance, or may be required to improve performance in order to receive any significant pay increase.

Once the pay ranges have been approved, management would then be required to determine where each incumbent is best positioned within the pay range, based on experience, performance and to some extent, service within the organization. Most companies try to manage base compensation around the midpoint of the range. Pay above the midpoint is generally reserved for high performing individuals or those who are being groomed for career advancement within the organization.

External Competitiveness: Annually, the compensation structure should be reviewed to ensure that it remains competitive with the market. If, on average, the midpoints of the ranges for benchmark positions fall too far above or below salary survey data, there is a potential that the compensation structure may not be competitive or appropriate and may require adjustment.

Commonly, companies will consider projections for average increases for management positions as well as other factors like CPI to identify a percentage rate increase for the entire compensation structure. An adjustment to the salary structure results in a flat percentage increase to the entire structure, to maintain the integrity and equity of the structure. For example, if it is identified that the structure requires a 2% adjustment, then 2% will be applied to the minimum, midpoint and maximum of all of the ranges to bring it to the proper level.

Rates recommended in this report reflect 2007compensation levels. We would recommend that the compensation structure be adjusted by an inflationary factor or at the average level of projected management compensation increases for 2008, whichever is greater. Compensation information of this nature is generally available annually in the fall, from sources such as the MEARIE survey quoted above, or from other compensation consultants such as William Mercer or Watson Wyatt.

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It is important to note that when using a performance-based pay structure that incumbent pay is typically not adjusted along with the structure, unless the incumbent would then fall below the minimum of the range. All employees will move through their pay range based upon performance and contribution to the organization. Goals and objectives as well as performance standards and expectations are normally agreed to at the beginning of the fiscal year, and reviewed for final achievement – at least minimally, at year end.

Pay Equity: The final step in the analysis will be to finalize the Pay Equity plan for management. This is a legislative requirement under the Pay Equity Act. Management are required to have a separate plan for both union and non-union positions and to maintain that plan at all times. With the re-evaluation of the management group, an updated plan will be required upon approval of the recommended compensation structure. Management must ensure ongoing compliance with the legislation through maintenance of the compensation and grading structure as presented – with any future increases to the compensation structure applies consistently.

We recommend the following compensation structure be implemented. We also recommend that the structure be re-evaluated for January 2008 and adjusted as necessary to maintain competitiveness.

St. Thomas Energy Services – Recommended Salary Ranges 2007

BAND	FULL POINTS From	FULL POINTS To	POSITIONS	FULL PTS	CURRENT SALARY	ANNUAL SALARY RANGES - 2007 MINIMUM	MIDPOINT	MAXIMUM
11	899	1061	Pres. & CEO	1031	$123,600	$107,098	$128,517	$154,220
10	761	898	COO	873	$103,000	$93,128	$111,754	$134,105
	761	898	CFO	839	$92,700	$93,128	$111,754	$134,105
9	644	760				$83,971	$100,765	$120,918
8	545	643	Operations Supervisor	604	$91,209	$76,248	$91,497	$109,796
	545	643	Engineering Supervisor	594	$82,400	$76,248	$91,497	$109,796
7	465	544				$69,881	$83,857	$100,628
6	397	464	Information Technology Supervisor	458	$66,950	$64,553	$77,464	$92,957
5	340	396	Line Foreperson	361	$75,608	$60,008	$72,009	$86,411
	340	396	Accounting Supervisor	358	$63,654	$60,083	$72,099	$86,411
4	295	339	Customer Service Supervisor	318	$61,755	$56,435	$67,722	$81,266
			Executive Assistant	315	$62,000	$56,435	$67,722	$81,266
3	254	294						
2	218	253						

Annette Cyr, M.B.A., C. Dir., C.C.P.
Biography

Annette is the President of Cyr & Associates Inc., a boutique Management and Human Resources consulting firm that specializes in strategic planning, leadership development and the creation of leading edge compensation and rewards programs.

Annette has led projects involving organizational change and diagnostics, compensation and incentive design, executive coaching and development in retail, financial services, food services, utilities & municipalities, logistics, not-for-profit, and healthcare sectors. She has assisted clients in establishing leadership development programs, succession management and further assists by formulating HR strategy linked to business objectives. As a certified executive coach, Annette is also provides leadership assessment through the use of a variety of assessment and feedback tools.

Formerly the Vice President of Human Resources for a major international retail company, she has also held executive level positions in financial and food services industries in Canada and the United States prior to establishing her consulting practice. She holds an executive M.B.A, an advanced degree in Business Administration, a Bachelor of Arts degree and is a Certified Compensation Professional (CCP) in Canada & the U.S. She has taught courses in Organizational Strategy, Compensation and Human Resources at York University, and has received the professional designation of Chartered Director from DeGroote School of Management at McMaster University. She is the former Chair of the Board for Burlington Hydro Electric Inc., a member of the Board for Burlington Hydro Inc., a member of the Canadian Internet Registration Authority (CIRA) and a member of the Board if Governors for Joseph Brant Memorial Hospital.

Annette has also made frequent television and radio appearances and is quoted regularly in the Globe & Mail as well as other well known publications. She is a frequent guest speaker for organizations, associations and special events.

Some of her recent projects have included:

- Facilitation and redesign of the strategic planning process for a large industry association.
- Conducting organizational review and workflow analysis and design recommendations for a not-for-profit agency that resulted in streamlined service delivery and cost reduction.
- Facilitating the development of a roles, responsibilities and Board Governance policies for a recently appointed Board of Directors.
- Developing and implementing a new compensation structure, performance management system, organizational competencies and succession management program for two logistics companies and financial services provider.
- Participating in an organizational review for a healthcare provider to identify process improvements, to analyze and recommend a new organizational structure and to assess the quality and delivery of services benchmarked to industry.
- Providing one-on-one executive coaching for a professional engineering management team identified as key successors for the business. Provided executive coaching to a new CEO facing significant growth challenges in the business and a new leadership paradigm.

Attachment 2 of 4

Pay Equity Plan

St. Thomas Energy Inc. /
Ascent Energy Services Inc.
& Local 636 IBEW
Pay Equity Plan

A. Date of Posting

Pay Equity Maintenance Posting – November 28, 2012.

B. Establishment

This plan refers to all employees of St. Thomas Energy Inc. and Ascent Energy Services Inc. represented by Local 636 of the International Brotherhood of Electrical Workers located at 135 Edward Street, St. Thomas, Ontario, N4P 4A8.

C. Jobs Classes Covered by this Plan

Female and Male Dominated Job classes in this bargaining unit, as at December 2012, are listed below:

Female:	Male:
Operations Coordinator	Lineperson
Accounting Clerk – Payroll; Reporting	Engineering Technician
Billing & Customer Service Coordinator	Field Representative
Customer Service Clerk	Purchasing Agent & Stores keeper
Accounting Clerk – A/P	Grounds Keeper

Note: There are no gender-neutral jobs in this bargaining unit as of the date of the plan.

D. Method of Comparison

The original method of comparison used in 1989 was the Hay Chart/Guide method of job evaluation. We have continued to use this plan to evaluate jobs in the organization, with the intention of updating and maintaining the plan. This is a Point Factor Job Evaluation plan incorporating measures of skill, effort, responsibility and working conditions. This method of job evaluation is described in more detail in Appendix A.

Further, each job has been evaluated and rated when the plan was established, or through a maintenance process by the Joint Job Evaluation Committee comprised of employees and representatives of the bargaining unit as well as management trained on job evaluation with the organization. For each unique job class, Job Questionnaires were completed by job incumbents, signed off by managers and incumbents and approved by the Joint Job Evaluation Committee.

To evaluate any position within the organization the position must be scored on all factors. For each factor, a series of degrees has been described. The Job Evaluation Committee must select the most appropriate degree which applies to the job being evaluated. The points awarded for each factor are then summed to produce an overall total score.

It must be remembered that it is the job and *not the employee* which is evaluated. The Job Evaluation Committee assumes that a fully qualified employee with a satisfactory level of performance fills the position when evaluating the job worth. For this reason, it must be recognized that the Job Evaluation System is *not* designed as a standard for determining entry qualifications for selection purposes.

These job evaluation sub factors were applied to each job and used in the process to ensure consistency in application. Each job is rated on current documentation, gathered through the questionnaire, which describes the content of the job and the environment in which it is performed.

The Job Evaluation Committee then worked together to obtain a full understanding of the job. Using the definitions and measures provided in the job evaluation plan document, each job was given a rating on the basis of the sub factors in total, in relation to other jobs in the organization. Final ratings and assignment of points for each job were determined through the evaluation process conducted by the JE Committee.

The final step involved grouping together job classes of comparable or equal value. Job classes of equal or comparable value were determined by placing each job in a representative pay band. Where male and female dominated positions were found within the same band, a male comparator was established, based upon Pay Equity guidelines.

The male comparators for female dominated positions are listed below in Section E. If no appropriate male comparator existed, the Proportional Value method was used. This method normally includes all male job classes or a representative group of male job classes within the pay equity plan and proportionally compares the evaluated points and subsequent pay to those of the female dominated position to determine if any adjustment is required.

E. Pay Equity Maintenance Results

The original Pay Equity plan was created in approximately 1999. As a result of changes in the business and the normal evolution of jobs in the organization, the plan has been updated and revised. Some changes and adjustments were required for maintenance purposes.

The following chart outlines the pay equity maintenance status for job classes effective December 2012:

Job Class and Pay Equity Adjustments as of December 2012:

Female Job Class	Male Comparator	Pay Equity Adjustment Required to Maintain Pay Equity as at December 10th, 2012
Operations Coordinator	No male comparator – Proportional Value Analysis	None
Accounting Clerk-Payroll; Reporting	No male comparator – Proportional Value Analysis	None
Billing & Customer Service Coordinator	Purchasing Agent	$1.91
Customer Service Clerk	No male comparator – Proportional Value Analysis	None
Accounting Clerk – A/P	No male comparator – Proportional Value Analysis	None

Proportional Value Analysis:
If no male comparator is determined from the job to job comparison, the Pay Equity Legislation requires the use of proportional value analysis. To do this, the job value and job rates of all male job classes were plotted on a graph. A representative group of male job classes was selected and statistical method called Regression Analysis was used to determine the relationship between the value of the male jobs and their job rates. This produced a formula which was then used to calculate pay equity job rates for female job classes. Pay equity is achieved when the female job classes are paid the Proportional Value pay equity job rate. Female job classes that are paid less than the pay equity job rate receive an adjustment until pay equity is achieved.

Female job classes that are paid more than the pay equity job rate do not receive a Proportional Value adjustment.

F. Pay Adjustments

Female dominated positions evaluated that were determined to be below the male comparator have been provided an adjustment as indicated in the table above. Where it was determined that the female dominated job was at or above the rate the male comparator or at or above the male comparator pay line (determined through regression analysis), no adjustment was required. Pay adjustments required for Pay Equity purposes as of the date of this plan have been provided. Pay Equity is deemed to be achieved.

G. Permissible Differences

No permissible differences were found between job rates of female and male job classes.

H. Maintaining Pay Equity

Pay Equity rates for new female job classes are determined using the job-to-job method of comparison. This method calculates the pay equity rates for new female job classes by comparing the evaluated points to the values and pay ranges of existing male job classes.

I. Further Information

For further information, please contact the President.

J. Approval

Management:

President | Date: 2012-11-28

IBEW Representative:

Brian Manninger, Business Representative | Date: 2012-11-28

Appendix A - The Hay Method of Job Evaluation

The Hay Method of job evaluation provides a means of measuring the four essential factors specified in the Ontario Pay Equity Act. Each factor, as defined, is free of gender bias and is widely applicable. The focus of the job evaluation process in on the nature and requirements of the job itself - and not on the skills, educational background, personal characteristics or current pay level of the job holder.

The Hay Method is based on the notion that jobs can be measured on the basis of their relative contribution to the overall objectives of the organization. This is reflected in the use of four factors which include the knowledge and skill required to do the job, the thinking needed to solve the problems faced, the answerability for actions and their consequences and the working conditions associated with the job.

The four factors used by Hay are:

A. Know-How
This factor is used to measure the total of every kind of knowledge and skill, however acquired, needed for acceptable job performance by considering three dimensions:

- Practical procedures and knowledge, specialized techniques and learned skills;
- Planning, coordinating, directing and controlling the activities and resources associated with an organizational unit or function;
- Active, practising, person-to-person skills in the area of human relationships.

B. Problem-Solving
This factor measures the thinking required in the job by considering two dimensions:

- The environment in which the thinking takes place; and
- The challenge by the thinking to be done.

C. Accountability
This factor measures the relative degree to which the job performed competently, can affect the end results of the organization or a unit within the organization. The opportunity to contribute to the organization is reflected through several factors:

- The nature and degree of the decision-making or influence of the job; and
- The unit or function most clearly affected by the job and the nature of that effect.

D. Working Conditions
This factor measures the conditions under which the job is performed by considering:

- Physical Effort – jobs require levels of physical activity that vary in intensity, duration and frequency or any combination of these factors that contribute to physical stress and fatigue.
- Physical Environment – jobs may include progressive degrees of exposure of varying intensities to unavoidable physical and environmental factors which increase the risk of accident, ill health or discomfort.
- Sensory Attention – jobs may require levels of sensory attention (seeing, hearing, smelling, tasting or touching), during the work process that vary in intensity, duration and frequency.
- Mental Stress – mental stress refers to progressive degrees of exposure to varying intensities of factors inherent in the work process or environment which increase the risk of such things as tension or anxiety.

By focusing on the important aspects of the content of each job and the context in which it is performed, the Hay Method provides a vehicle for systematically assessing the relationships among various positions and their relative value to the organization. The factor definitions described above have evolved over time to more accurately reflect changing values, perceptions and jobs and legal requirements.

The Weighting of the Factors:
This is a frequently asked question. The answer is there is no universal weighting system as the weighting differs from job to job and organization to organization. In the Hay Method, the Factors and dimensions are assigned pre-established weights in order to remain consistent.

The Joint Job Evaluation Committee works on the basis of consensus in evaluating the jobs. Once trained, each member participates in the rating of the jobs. Each job is rated on current documentation which describes the content of the job and the environment in which it is performed. The Committee works together to obtain a full understanding of the job. Using the definitions and measures provided, each job is given a rating on the basis of the four factors in total, in relation to other jobs in the organization.

Attachment 3 of 4

Benefits Information Package

The MEARIE Group
Employee Benefit Program

Employee Benefit Booklet

St. Thomas Energy Services Inc.
Union Employees

Prepared: 14 June 2011

Notice of Disclaimer

This handbook has been prepared to help you better understand the coverage provided under your employee benefit program. This handbook is not an agreement and it does not create nor confer any contractual or other rights.

The terms and conditions governing your benefit plans are set out in the official contracts between the insurers, your employer and MEARIE Management Inc.

Every effort has been made to ensure that the information in this handbook is accurate. However, if any question should arise, a decision will be made by reference to the official plan contracts and texts.

This handbook has been designed to help you understand and get the most out of your benefits. It gives you most of the information you will generally require regarding your benefits. Separate sections for each benefit plan allow you quick access to the benefit information you want when you want it.

Please keep this handbook in a safe place. If changes are made to your benefits, replacement pages will be provided to you for insertion in this handbook.

Your health, dental, disability and life plans are insured through ***Great-West Life Assurance Company****. The voluntary group home and auto program is insured through* ***AVIVA Traders Insurance Company****.*

Any questions you have about your benefit program should be referred to your Plan Administrator.

General Information

Enrolling In The Benefit Program

Who Can Enroll

If you are an active permanent full-time employee under the age of 65 and working at least 20 hours per week, you are first eligible to enroll in all benefit plans, other than extended health and dental, on the date your employment begins. You are first eligible to enroll in the extended health and dental plans on the first day of the month next following the date your employment begins.

Your dependents, as defined below, are also eligible for coverage under the extended health care and dental care plans. Eligible dependents include your:

Spouse

- the person who you are legally married to, or
- a person who continuously resides with you in a role like that of a marriage partner.

Dependent Children

Dependent children include your natural or legally adopted children, or step-children who:

- are unmarried,
- are not employed on a full-time basis,
- are not eligible for insurance as an employee under this plan or any other group plan, and
- are under 21 years of age, or, if in full-time attendance at an accredited school, college or university, are under 25 years of age.

A child insured under this plan, who is incapacitated due to a mental or physical handicap on the date he reaches the age when he would otherwise no longer be eligible for coverage, will continue to be an eligible dependent subject to written proof of the dependent's condition. A child is considered incapacitated if he is incapable of engaging in any substantially gainful activity and is dependent on you for support, maintenance and care, due to a mental or physical handicap.

A stepchild must be living with you to be an eligible dependent.

General Information

When Coverage Starts

Coverage for you and your eligible dependents commences on the date you first become eligible to enroll. If you are not actively at work on the date your coverage would normally begin, your coverage will not start until you return to active full-time work.

Changing Your Coverage

There are times when you may need to change your coverage under the extended health care and/or dental care plans, either reducing or adding coverage as appropriate. This may be necessary if:

- you acquire a new spouse or dependent child,
- you separate or divorce,
- your spouse or dependent child dies,
- your child no longer qualifies as an eligible dependent, or
- you acquire or lose similar benefits through your spouse's plan.

In all cases, contact your Plan Administrator who will help you make the necessary changes to your coverage.

General Information

When Coverage Terminates

Coverage for you and your dependents will end on:

- the date your employment ends,
- the date you or your dependents cease to qualify for coverage based on the plan's eligibility requirements,
- the date you enter an armed service on full-time duty,
- the date your employer receives a written request from you to terminate the insurance, where permitted,
- the date you fail to make any required premium contribution,
- the date you attain age 65,
- the date your spouse attains age 65 (applies to Spouse’s Optional Life Insurance),
- the date you retire (with the exception of Retirement Life Insurance, as well as Extended Health Care and Dental coverage for eligible Early Retirees – refer to the sub-section, *When You Retire*, for further details), or
- the date the group plan is cancelled.

If you are not actively at work due to **Maternity or Parental Leave of Absence**, coverage may be continued for the period of leave to which you are entitled by legislation provided premiums continue to be paid on your behalf. If you do not intend to continue your coverage during this period, where permitted by law, you must inform your employer in writing on or before the date your leave begins. In this case, coverage for you and your dependents will not be reinstated until you return to active full-time work.

Coverage for you and your dependents will cease on the date you are not actively at work due to **lay-off, leave of absence (other than maternity or parental leave), strike or lock-out**.

General Information

If you are not actively at work due to **illness or injury**:

- your life, accident and disability coverage will continue in accordance with the "Waiver of Premium" provisions described in the applicable sections of this handbook, and
- extended health care and dental care coverage for you and your dependents will continue until your employer terminates such coverage, provided premiums continue to be paid on your behalf and this plan remains in force.

If You Retire

Coverage for you and your dependents will stop on the date you retire. *However*, if you under an Early Retirement pension through OMERS, your dental and extended health coverage will be continued until you reach age 65.

If you retire under an Early Retirement or Normal Retirement pension through OMERS, you may qualify for a reduced amount of life insurance. Coverage details are provided in the Life Insurance section of this handbook.

Dental Care

Your dental care plan has been developed to help you and your family maintain good dental health.

How The Plan Works

Reimbursement of eligible dental services and supplies is based on the fees recommended in the **current** Ontario Dental Association Fee Guide for General Practitioners — updated automatically each year.

There is **no dental care deductible**.

What Is Covered

The plan provides 100% reimbursement for the following basic dental services:

- complete oral examinations (once in any 36-month period),
- full mouth x-rays (once in any 36-month period),
- recall examinations (once in any 9-month period),
- bitewing x-rays (once in any 9-month period),
- routine diagnostic and laboratory procedures,
- one unit of light scaling and one unit of polishing, once in any 9-month period,
- fluoride treatment (once in any 9-month period),
- oral hygiene instruction (once in any 9-month period),
- fillings (amalgam, silicate, acrylic, and composite), retentive pins, and pit and fissure sealants,
- surgical services (excluding implant surgery),
- consultation, anaesthesia, and conscious sedation,
- denture repairs, relines and rebases (minor adjustments are covered only after 3 months have elapsed from the date of insertion),
- injection of antibiotic drugs, when administered by a dentist in conjunction with dental surgery,

- periodontal services for treatment of gum disease and other supporting tissues of the teeth, including:
    1. scaling in excess of one unit, and root planing, up to a combined maximum of 8 units every 12 months;
    2. provisional splinting; and
    3. occlusal equilibration, up to a maximum of 8 units per calendar year, and
- endodontic services which include root canal therapy, root amputation, apexifications, and periapical services.

50% reimbursement is provided for the following removable prosthodontic services and supplies:

- initial provision of a full or partial removable denture,
- denture repairs, relines and rebases, and
- replacement of a removable denture, provided the new denture is necessary due to one of the following:
    1. a natural tooth is extracted and the existing appliance cannot be made serviceable;
    2. the existing appliance is at least 5 years old and cannot be made serviceable; or
    3. the existing appliance is temporary and within 12 months of its installation it is replaced by a permanent denture. The total amount payable for both the temporary and permanent denture is the amount which would have been allowed for a permanent denture.

Dental Care

50% reimbursement is provided for the following fixed prosthodontic and major restorative services:

- crowns, onlays and inlays (only when function is impaired due to cuspal or incisal angle damage caused by trauma or decay), including gold foil restorations (only when approved by the Insurance Company), metal transfers, telescoping and splinting,
- veneers,
- initial provision of fixed bridgework, and
- replacement of a fixed bridgework or addition of teeth to bridgework provided the replacement or addition is due to one of the following:
    1. a natural tooth is extracted and the existing appliance cannot be made serviceable;
    2. the existing appliance is at least 5 years old and cannot be made serviceable; or
    3. the existing appliance is temporary and, within 12 months of its installation, it is replaced by a permanent bridge. The total amount payable for both the temporary and permanent bridge is the amount which would have been allowed for a permanent bridge.

The plan provides 50% reimbursement of the following orthodontic services and supplies:

- space maintainers,
- correction of malocclusion of the teeth,
- observation and adjustment,
- appliances for tooth guidance and uncomplicated tooth movement,
- appliances to control harmful habits,
- retention appliances, and
- fixed or cemented, unilateral and bilateral appliances.

Maximum Benefit

No overall maximum benefit applies for basic or removable prosthodontic dental services. The maximum benefit payable for fixed prosthodontic and major restorative services is $1,500 per person per calendar year. Benefits for orthodontic services are limited to a lifetime maximum of $2,500 per person.

Dental Care

Pre-Treatment Estimate

Whenever the total cost of proposed dental treatment is expected to exceed $500, a treatment plan should be submitted to the Insurance Company in advance to determine how much of your proposed treatment will be covered by the plan. A treatment plan provides a written description of your dental needs, including x-rays; the proposed treatment necessary in the professional judgement of the dentist; and, the cost of the proposed treatment.

Note: *If, for any given dental condition, there are two or more courses of treatment covered under this plan which will produce professionally adequate results, the Insurance Company will pay benefits as if the least expensive course of treatment was used. The Insurance Company retains a professional dental consultant to determine the adequacy of the various courses of treatment available.*

Coordinating Benefits

If both you and your spouse are covered by employer benefit plans, your coverage may overlap; dental services covered by your plan may also be covered by your spouse's plan. "Coordination of Benefits" lets you take advantage of this overlap to recover up to 100% of your eligible expenses.

To coordinate benefits, the person who received the dental treatment makes the claim first — from their employer's plan. (If your child receives dental care, the parent whose birthday falls earliest in the year submits the claim first — to his or her plan). A cheque and explanation of what is being paid comes back from the Insurance Company, and then, if not all of the expense is covered, a second claim is filed with the spouse's plan.

By reviewing your and your spouse's plan to find out when you can receive reimbursement from both plans, you may be able to coordinate benefits and get back as much as 100% of your eligible expenses!

Dental Care

How To Claim Dental Benefits

1. Pick up a claim form from your Plan Administrator before you go to the dentist, or visit www.greatwestlife.com to get printed claim forms with your plan information already filled in.
2. Take the claim form with you to your appointment and ask the dentist to complete the dentist's portion of the claim form. If your dentist agrees to accept payment from the plan instead of directly from you, be sure the claim form shows that the refund should be made payable to the dentist.
3. Fill out the sections of the claim form that ask for information about you (the employee) and the patient (you or your eligible dependent). To ensure prompt processing of your claim, be sure to indicate the name of your employer, your policy account number, your class code and certificate number, in the appropriate boxes provided on the claim form. (This information is provided on your wallet-sized certificate of insurance.)
4. Return your completed claim form for processing to Great-West Life, at the address shown on the claim form.
5. The Insurance Company will review your claim and determine what portion is eligible for reimbursement. You should receive your refund cheque, along with an explanation of the benefits being paid, within 2-3 weeks. If you assign payment of the claim to your dentist, you will receive only a copy of the benefits being paid and the refund cheque will be sent directly to your dentist.

OR

Your dental office may file your claim electronically with Great-West Life. In order to process your claim, the information transmitted by the dental office must be complete, and include the same information required for a paper claim (i.e., your employer's name, your policy number, your class code and certificate number).

Note: *Dental claims must be submitted no later than 12 months from the date the expense is incurred. If your insurance terminates, benefits are payable only if your claim is submitted within 90 days of the date your insurance terminates.*

Dental Care

What's Not Covered

Your dental care plan does not cover:

- services or treatment that are covered under any other plan, government plan or legally mandated program,
- dental care resulting from self-inflicted injuries or illnesses, while sane or insane, war, insurrection, the hostile action of any armed forces, or participation in a riot or civil commotion,
- dental care required as a result of committing or attempting to commit an assault or criminal offense,
- charges for broken appointments, third party examinations, travel to and from appointments, or completion of claim forms,
- charges for services or supplies for which there would have been no charge at all in the absence of insurance, or which are received from a medical or dental department maintained by an employer, association or trade union,
- charges for services or supplies which are performed or provided by an Immediate Family Member or a person who lives with the insured person,
- treatment rendered for a full mouth reconstruction, for a vertical dimension, or for a correction of temporomandibular joint dysfunction,
- cosmetic treatment, unless required due to an accidental injury which occurs while you or your dependent is insured under this plan,
- implants, or any services rendered in conjunction with implants,
- anti-snoring or sleep apnea devices,
- treatment which is not generally recognized by the dental profession as an effective, appropriate and essential form of treatment for the dental condition,
- replacement of removable appliances which are lost, mislaid or stolen, or
- laboratory fees which exceed the reasonable and customary charges, as determined by the Insurance Company.

Dental Care

Extended Benefit For Surviving Dependents

If you should die while insured under this plan, dental coverage will be continued for your dependents who are insured under this plan at the time of your death, provided the required premiums are paid, until the earliest of:

1. attainment of the surviving spouse's 65^{th} birthday, or
2. the date your dependent would otherwise cease to qualify as an eligible dependent, or
3. the date your surviving spouse remarries, or
4. the date your dependents become insured under another group policy, or
5. the date this plan terminates.

Extended Health Care

Under the extended health care plan, you and your family receive financial protection against major medical expenses which are not covered under your provincial health plan.

How The Plan Works

Your extended health care plan reimburses **100%** of the cost of medical services and supplies that are covered under the plan.

The **deductible** under the extended health care plan for employees with **single coverage is $10 per calendar year**. This means that only the first $10 spent on eligible medical services or supplies is *not* reimbursed each year.

If you have **family coverage**, a $10 deductible will be applied only once for each insured family member and not more that twice per family in a calendar year — a **maximum deductible of $20**.

Note: *Eligible* ***Hospital Care, Drugs, Vision Care, Out-of-Country and Travel Assistance*** *expenses are* ***not subject to the deductible***.

*Eligible **drugs and medicines** are subject to a **deductible of $1.00 for each prescription.**

Extended Health Care

What Is Covered

The following medical services and supplies are covered provided they are:

- medically necessary in the treatment of an illness or injury,
- recommended by a physician,
- incurred for the care of a person while insured under this benefit,
- reasonable taking all factors into account,
- not covered under the provincial health plan or any other government-sponsored program, and
- they can legally be insured.

Payment for any covered expenses which may be purchased in large quantities will be limited to the purchase of up to a 3 months' supply at any one time, except for covered Drug expenses.

Hospital Care

Chronic Care: Charges for confinement in a Chronic Care Facility which starts within 14 days of discharge from a Hospital confinement of at least 5 days, to a maximum of $3 per day for up to 120 days per calendar year. Chronic Care utilization fees are not covered expenses.

Convalescent Care: Charges for confinement in a Convalescent Care Facility which starts within 14 days of discharge form a Hospital confinement, to a maximum of $10 per day for up to 120 days per disability.

Note: *The plan does not cover charges for any portion of the cost of Ward accommodation, utilization or copayment fees (or similar charges).*

Extended Health Care

Prescribed Drugs & Medicines — Direct Payment Plan

- drugs or medicines that are prescribed in writing by a physician or dentist for the treatment of an illness or injury, and are dispensed by a licensed pharmacist,
- oral contraceptives,
- preventive vaccines and medicines (oral or injected),
- hematinic vitamins (vitamins to treat blood disorders) that are dispensed by a pharmacist and are properly identified in the Compendium of Pharmaceuticals and Specialties, and
- standard syringes, needles and diagnostic aids, if required for treating diabetes (cotton swabs, rubbing alcohol, automatic jet injectors and similar equipment are not covered).

Fertility Drugs are subject to a maximum of $12,000 per lifetime.

The plan does not cover Anti-smoking drugs, Vitamins (except those which are injected), or Sexual Dysfunction Drugs.

The maximum amount for any covered expense is the price of the lowest cost generic equivalent product that can legally be used to fill the prescription, as listed in the Provincial Drug Benefit Formulary.

If there is no generic equivalent product for the prescribed drug or medicine, the amount covered is the cost of the prescribed product.

Where a prescription contains a written direction from the Physician or dentist that the prescribed drug or medicine is not to be substituted with another product, the full cost of the prescribed product is covered If it is a covered expense under this benefit.

Benefits will be paid directly to the dispensing pharmacist, provided the pharmacist is enrolled in the pay-direct drug plan — simply present your drug card to the pharmacist. The maximum amount allowable towards the prescription drug **dispensing fee is $8.00** per prescription. You will be required to pay a **deductible of $1.00** per prescription plus any portion of the cost that is not covered by the plan, where applicable.

Extended Health Care

Note: *The maximum quantity of Drugs or medicines that will be payable for each prescription will be limited to the lesser of the quantity prescribed by the Physician or Dentist; or, a 34-day supply for non-maintenance drugs or a 100-day supply for maintenance drugs. The drug benefit does not cover charges for dietary supplements, health foods, nutritional products and vitamins (other than injectibles and haematinics). The plan does not cover expenses for the administration of serums, vaccines, or injectable Drugs; or Drugs, biologicals and related preparations which are intended to be administered in Hospital on an in-patient or out-patient basis and are not intended for a patient's use at home.*

Professional Services

Services of a licensed clinical psychologist, up to $35 for the initial visit and $20 for each subsequent visit, limited to an overall maximum of $200 per 12 consecutive months.

Services of a licensed chiropractor, registered physiotherapist or registered massage therapist, up to a combined maximum of **$600 per calendar year**. The services of a physiotherapist or massage therapist will be considered only when recommended in writing by the attending physician.

Services of a certified speech therapist, when recommended in writing by the attending physician, to a maximum of $200 per 12 consecutive months.

Extended Health Care

Vision Care

The following vision care services are covered when prescribed by an ophthalmologist, optometrist, or oculist:

- purchase and fitting of prescription glasses or elective contact lenses, or elective laser vision correction procedures, and one eye examination per 24 month period to a maximum of **$350** every 24 consecutive months (charges for repairs are also included under this maximum).

NOTE – Effective May 1, 2013, coverage will include one eye examination every 24 consecutive months, to a maximum of $75.

Medical Services & Supplies

For all medical equipment and supplies covered under this plan under the following provisions, eligible covered expenses will be limited to the cost of the device or item that adequately meets the patient's fundamental medical needs.

Private Duty Nursing

Private duty nursing services (other than for custodial care, homemaking services and supervision — deemed to be within the practice of nursing) provided in the patient's home by a Registered Nurse (R.N.), Registered Nursing Assistant (R.N.A.), Certified Nursing Assistant (C.N.A.) or Licensed Practical Nurse (L.P.N.) who is not a relative, friend or member of the patient's household, to a maximum of 90 eight-hour shifts per calendar year.

Note: *A detailed treatment plan must be submitted before private duty nursing services begin. The Insurance Company will then advise you of any benefits that are payable under the plan.*

Extended Health Care

Medical Aids, Appliances and Supplies

Charges which are reasonable and customary when incurred on the written authorization of a physician, for the following items when required for therapeutic use only:

1. crutches , cane, and standard type walker;
2. oxygen, and equipment necessary for its administration;
3. respirator (an apparatus used for the purpose of providing artificial respiration over a prolonged period of time, in cases where the respiratory muscles are non-functioning);
4. the rental of, or at the option of the insurer, the purchase of:

   i) a standard type manual hospital bed, including mattress;
   ii) a standard type manual wheelchair

Electric hospital beds, wheelchairs and scooters are excluded unless medically required and recommended in writing by the attending physician.

5. hospital bed, wheelchairs and scooter repairs, when required as a result of normal wear and tear. The cost of replacement batteries is excluded.

Radium Therapy

Charges which are reasonable and customary for radium and radioactive isotope treatments, when authorized in writing by the attending physician.

Blood

Charges which are reasonable and customary for blood transfusions, blood plasma, or other blood products.

Extended Health Care

Non-Dental Prostheses, Supports & Hearing Aids

- artificial limbs and eyes (Note: in the case of myoelectric or sport prostheses, consideration will be limited to the amount that would otherwise be paid for standard type artificial limbs);
- braces, splints, trusses, casts and cervical collars (Note: “Brace” means a rigid or semi-regid supporting device or appliance which fits on and is attached to the body or any part of the body, excluding any brace which is used to correct a dental defect, deficiency or injury);
- catheters and urinary kits;
- external breast prostheses and up to two surgical brassieres per calendar year when required as a result of mastectomy;
- ostomy supplies, where a surgical stoma exists;
- surgical elastic stockings, limited to two pairs per calendar year;
- repairs to prosthetic appliances, when required as a result of normal wear and tear;
- corrective prosthetic lenses and frames, once only, following cataract surgery or when the person lacks an organic lens;
- custom-made orthopaedic shoes or boots which are constructed by a Certified Orthopaedic Footwear Specialist (C.F.S.O.) and are required because of a medical abnormality that, based on medical evidence, cannot be accommodated in a stock-item orthopaedic shoe or a modified stock-item orthopaedic shoe, limited to 2 pairs per calendar year, or the actual cost of modifications and adjustments to stock-item footwear, and
- wigs and hairpieces, required as a result of a temporary hair loss due to medical treatment, limited to $250 per lifetime.

Extended Health Care

Ambulance

Licensed ambulance service provided in the insured person's province of residence, including air ambulance, to and from the nearest hospital where adequate treatment is available.

Accidental Dental Treatment

Services of a dentist for the treatment of damage to natural teeth or the jaw resulting from an external, accidental blow to the mouth which occurs while insured under this plan. The treatment must be received and approved for payment within 12 months of the accident. Injuries due to biting or chewing are *not* covered.

Extended Health Care

Out-of-Province or Out-of-Country

Referrals For Treatment Outside Your Home Province

If a physician in the insured person's home province gives a written referral for treatment that is not performed in that home province, the insurer will cover the cost of the treatment as specified below, if it is provided in Canada or the United States.

The physician must give the insurer full details of the treatment and the insurer must approve it in advance. The insured person must apply and provide the insurance company with a statement from the provincial health plan that describes what it will cover.

The insurer will pay up to $10,000 in the insured person's lifetime for the following:

- Hospital room and board at the ward rate
- Hospital services and supplies, and
- Diagnosis and treatment by physicians

Emergency Out-of-Province / Country Coverage

The insured person must be eligible for benefits under a government health plan in Canada to qualify for emergency out-of-province/country coverage or Travel Assistance coverage.

The insurer will cover the first 60 days of a trip.

Eligible medical services and supplies are covered under this plan for treatment given outside the patient's province of residence if required to provide treatment as a result of a **medical emergency** arising while temporarily outside the home province (including outside Canada), on business or vacation.

> A **medical emergency** is a sudden, unexpected injury which occurs, or an unforeseen illness which begins, during the absence from the patient's home province and which requires immediate medical attention. The plan will not cover emergency treatment while travelling for health reasons.
>
> **Travelling outside Canada while pregnant:** This plan will not cover any pregnancy related costs which are incurred outside of Canada within nine weeks of the expected delivery date. Costs associated with a child born outside Canada within nine weeks of the expected delivery date, or after the expected delivery date, are not covered.

Extended Health Care

The plan will pay up to $1,000,000 for each insured person for all the covered costs related to any one medical emergency. When emergency treatment for a condition is completed, any ongoing treatment related to that condition is not covered.

When used under this emergency out-of-province/country section, hospital means a facility licensed to provide emergency treatment for sick or injured patients. It must have facilities for diagnosis and treatment. Physicians and registered nurses must be in attendance 24 hours a day. It does not include nursing homes, homes for the aged, rest homes, convalescent care facilities or any facility that provides similar care.

The plan will cover the charges for emergency treatment that are over the amount covered by the provincial health plan of the insured person's home province. This coverage includes the cost of:

- Hospital room and board at the ward rate
- Hospital services and supplies, and
- Diagnosis and treatment by physicians

In emergency out-of-province/country situations, other charges included under the Extended Health Care coverage section of this plan are covered to the same extent that they would be in Canada. This includes coverage such as wheelchair rental, crutches and prescription drugs.

In the event of a medical emergency, you or someone acting on your behalf must contact the Travel Assistance Centre prior to seeking medical treatment. If it is not reasonably possible for you to contact the Travel Assistance Centre prior to seeking medical treatment due to the nature of the medical emergency, you must contact the Travel Assistance Centre as soon as possible. Failure to contact the Travel Assistance Centre as described will result in a reduction of benefits in the case of hospitalization of 40% of eligible costs. All costs for such emergency will be limited to your emergency out-of-province/country coverage and Travel Assistance coverage maximum or $25,000, whichever is less.

If a physician or the Travel Assistance provider recommends you or your dependent be moved to a different facility at the destination, and you choose not to go, eligible costs for emergency coverage and Travel Assistance coverage will in the case of hospitalization be reduced by 40% of eligible costs. All costs for such emergency will be limited to your emergency out-of-province/country coverage and Travel Assistance coverage maximum or $25,000, whichever is less.

If a physician or the Travel Assistance provider recommends you or your dependent return to your home province, and you choose not to go, emergency coverage and Travel Assistance coverage will end.

Travel Assistance Coverage

This plan provides travel assistance for you and your eligible dependents, while you are temporarily outside your province of residence (including outside of Canada) because of business or vacation, and not for health reasons. The assistance services are delivered through an international organization, specializing in travel assistance.

The insurer will cover the first 60 days of a trip.

Travelling outside Canada while pregnant: This plan will not cover any pregnancy related costs which are incurred outside of Canada within nine weeks of the expected delivery date. Costs associated with a child born outside Canada within nine weeks of the expected delivery date, or after the expected delivery date, are not covered.

The services under the Travel Assistance coverage include:

- multilingual assistance by telephone, 24 hours a day, 365 days a year, for the insured person or medical providers to obtain aid, assistance, and exchange information, in matters relating to the covered services,
- referrals to physicians or medical facilities, if necessary,
- arrangements for direct payment, wherever possible, for physicians' services, hospitalization and other insured services,
- communication with the physician who is treating the insured person to get an understanding of the situation and monitor the condition,
- telephone interpretation services in most major languages,
- the sending and receiving of urgent messages,
- medical evacuation home or transportation to another medical facility. For transportation home, payment will be made based on an economy fare ticket,
- arrangements for (including all necessary documents) and the cost of transporting the insured person's remains to their home, up to a maximum of $3,500,
- help to locate Embassy or Consulate services,
- help to locate lost documents or luggage.

The Travel Assistance benefit includes the following services, subject to prior approval of the charges:

- the cost of additional commercial accommodation required beyond the original return date, for a companion travelling with the insured person. This includes charges for accommodation, meals, telephone and taxi or rental cars, up to a maximum of $150 per day, not to exceed a total of $1,500,
- the cost of an economy fare ticket home, for a companion who is travelling with the insured person, and who has forfeited their ticket because of a delay caused by the insured person's illness, injury, or death,
- the cost of an economy fare ticket home for each child left alone because of the insured person's illness, injury, or death. The Travel Assistance provider will also arrange for a qualified attendant to accompany the children, if necessary,
- the cost of a round-trip economy fare ticket for a family member to visit an insured person who is travelling alone and must be hospitalized for more than 10 days,
- the cost of returning a vehicle to the insured person's home or the nearest rental agency, up to a maximum of $1,000.

The insurer is not legally responsible for the actions or advice of any physician or attorney that the insured person is referred to.

The Travel Assistance benefit does not cover medical emergencies in the home province.

How To Access The Travel Assistance Plan — Your Travel Assistance Card

Your Travel Assistance card lists the toll free numbers to call in case of an emergency while outside your province. The toll free number will put you in touch with the international travel assistance organization.

Your Travel Assistance card also lists your I.D. number (your certificate number) and your group policy number, which the travel assistance organization needs to confirm that you are covered under the plan.

How to make an out-of-province/country claim

There are special rules for claiming the costs of emergency treatment outside of your home province or Canada.

For all medical expenses, the Travel Assistance provider must be contacted at the time of the emergency. This will enable the Travel Assistance provider to co-ordinate payment directly with the hospital and/or medical provider involved, providing the insured person gives approval to the Travel Assistance provider to co-ordinate payment with the Provincial Health Care plan.

If a medical provider or hospital bills you directly, send the bill along with your claim form to the Travel Assistance provider.

What is not covered for emergency out-of-province/country treatment and travel assistance

The insurer will not pay for any costs resulting directly or indirectly:

- from an accident occurring while you or your dependent was operating a vehicle, vessel or aircraft, if you or your dependent:
    1. were impaired by drugs or alcohol, or
    2. had a blood alcohol level higher than 80 milligrams of alcohol per 100 millilitres of blood
- from the abuse of illegal substances.

Extended Health Care

Maximum Benefit

The maximum dollar amount that is reimbursed for covered medical services and supplies received in your home province is unlimited.

The maximum that is reimbursed for medical treatment received outside your home province or Canada is:

- $1,000,000 for each covered person for all covered costs related to any one emergency under the emergency out-of-province/country and the Travel Assistance coverage; or
- $10,000 during the covered person's lifetime for approved referral treatment.

Coordinating Benefits

If both you and your spouse are covered by employer benefit plans, your coverage may overlap; medical services and supplies covered by your plan may also be covered by your spouse's plan. "Coordination of Benefits" lets you take advantage of this overlap to recover up to 100% of your eligible expenses.

To coordinate benefits, the person who received the service or supply makes the claim first — from their employer's plan. (If your child receives medical care, the parent whose birthday falls earliest in the year submits the claim first — to his or her plan). A cheque and explanation of what is being paid comes back from the Insurance Company, and then, if not all of the expense is covered, a second claim is filed with the spouse's plan.

By reviewing your and your spouse's plan to find out when you can receive reimbursement from both plans, you may be able to coordinate benefits and get back as much as 100% of your eligible expenses!

Extended Health Care

How To Claim Extended Health Care Benefits

To claim benefits for medical services and supplies, *other than* drugs or medicines:

1. Save all your receipts for medical services and supplies, and any bills or receipts received for hospital care. Receipts and bills should show:
   - the patient's name,
   - the date the treatment or supply was provided,
   - the nature of the service or supply, and
   - an item-by-item list of the charges.
2. Pick up a claim form from your Plan Administrator or visit www.greatwestlife.com to get printed claim forms with your plan information already filled in.
3. Fill out the sections of the claim form that ask for information about you (the employee) and the patient (you or your eligible dependent). To ensure prompt processing of your claim, be sure to indicate the name of your employer, your policy number, your class code and certificate number, in the appropriate boxes provided on the claim form. (This information is provided on your wallet-sized certificate of insurance.)
4. Return your completed claim form, with original receipts attached, for processing to Great-West Life at the address shown on the claim form.
5. The Insurance Company will review your claim and determine what portion is eligible for reimbursement. You should receive your refund cheque, along with an explanation of the benefits being paid, within 2-3 weeks.

Note: *Extended health care claims must be submitted no later than 12 months from the date the expense is incurred. If your insurance under this plan terminates, benefits are payable only if your claim is submitted within 90 days of the date your insurance terminates.*

Extended Health Care

To claim benefits for drugs or medicines:

1. Present your drug card to the pharmacist when filling your prescription.
2. Provided the pharmacist is enrolled in the pay-direct drug plan, payment will be made directly to the pharmacist — you do not need to complete any claim forms or wait for the reimbursement.
3. You will be required to pay the deductible, where applicable, to the pharmacist.

Note: *If the prescription is not obtained through the use of your drug card, be sure to get a receipt from the pharmacist. To receive reimbursement of benefits payable, a claim form must be completed and sent to Great-West Life at the address shown on the claim form, along with your original receipts.*

What's Not Covered

Your extended health care plan does not cover any expense which is directly or indirectly related to:

- any illness or injury arising out of or in the course of employment when the person is covered by or is eligible for coverage by Workers' Compensation,
- any illness or injury for which benefits are payable under any government plan or legally mandated program,
- self-inflicted injuries or illnesses, while sane or insane, war, insurrection, the hostile action of any armed forces, or participation in a riot or civil commotion,
- the committing of or the attempt to commit an assault or criminal offense,
- charges for periodic check-ups, broken appointments, third party examinations, travel for health purposes or completion of claim forms,
- charges for services or supplies for which there would have been no charge at all or which would have been reimbursed under a government-sponsored plan in the absence of insurance, or which are received from a medical or dental department maintained by an employer, association or trade union,

- charges for services or supplies which are required for recreation or sports, but which are not medically necessary for regular activities,
- charges which would have been payable by the provincial health plan had proper application been made,
- charges for services or supplies which are performed or provided by an Immediate Family Member or a person who lives with the insured person, or which are provided while confined in a Hospital on an in-patient basis, or
- medical treatment which is not usual and customary, or which is experimental or investigational in nature.

Extended Benefit For Surviving Dependents

If you should die while insured under this plan, extended health care coverage will be continued for your dependents who are insured under this plan at the time of your death, provided the required premiums are paid, until the earliest of:

1. attainment of the surviving spouse's 65th birthday, or
2. the date your dependent would otherwise cease to qualify as an eligible dependent, or
3. the date your surviving spouse remarries, or
4. the date your dependents become insured under another group policy, or
5. the date this plan terminates.

Long Term Disability

Your long term disability plan has been developed to protect you against the financial impact of lost income, if a lengthy illness or injury keeps you from coming to work.

How The Plan Works

Benefits are payable under the long term disability plan after you have been totally and continuously disabled for a period of **120 calendar days**.

Benefits Provided

If you are totally disabled you will receive a monthly income benefit equal to **70% of your regular monthly earnings, to a maximum of $3,500 per month**.

> *To qualify for long term disability benefits you must be "totally disabled". During the first 24 months that you receive long term disability, this means that you are unable to do the essential duties of your normal job and are not otherwise employed. After this 24-month period, you will continue to qualify for long term disability benefits only if you are unable to work at any job for which you are reasonably suited by virtue of your education, training and experience.*

Any benefits you receive from the long term disability plan are taxable if your employer contributes, in whole or in part, towards the cost of providing the plan.

Benefits from the long term disability plan will stop if you:

- recover,
- attain age 65,
- are unable to provide written proof of your disability,
- are no longer under a physician's care,
- fail to undergo an examination by an independent doctor of the Insurance Company's choice,
- in the event of your death.

Long Term Disability

Coordination With Other Disability Benefits

Long term disability benefits are reduced by the amount of income you receive or are entitled to receive as a result of the same disability from:

- Workers' Compensation or similar legislation (excluding any future cost of living adjustments),
- the Canada or Quebec Pension Plan (excluding any future cost of living adjustments or dependent benefits payable to you),
- any other federal, provincial or municipal government plan, excluding any disability benefits available to you through the Ontario Municipal Employees' Retirement System, but not filed on your behalf, and
- any other group insurance plan, or any retirement or pension plan of the employer, excluding any disability benefits available to you through the Ontario Municipal Employees' Retirement System.

The benefit you receive will be further reduced, if necessary, so that the total disability income you receive from this plan and any other source (other than income from a private source) does not exceed 85% of your pre-disability net earnings (if benefits are non-taxable) or gross earnings (if benefits are taxable).

Rehabilitation Benefit

The rehabilitation benefit is designed to help you through an adjustment period of up to 24 months while working part-time, in a reduced capacity or involved in a retraining program approved by the Insurance Company.

While you are participating in an approved rehabilitation program, your long term disability benefit will not be discontinued. However, your monthly long term disability benefit will be reduced by 50% of the compensation you receive from rehabilitative employment.

Long Term Disability

When Disability Recurs

If you recover from total disability, only to become disabled again, the second period of disability will be treated as a continuation of the first unless the second disability is unrelated to the first, or is separated from the first by more than six months.

Waiver of Premium

Premium payments are waived during any period in which you receive benefits from this plan. Long term disability benefits will continue in accordance with the terms of the policy regardless of whether or not this plan remains in effect or your other benefit coverages are subsequently terminated, provided your disability begins while your coverage under this plan is in force.

How To Claim Long Term Disability Benefits

Claim forms are available from your Plan Administrator. Early filing of claims is recommended. Forms should be completed and returned to your Plan Administrator after you have been disabled at least 30 days and do not expect to return to work before the *Elimination Period* expires. Long term disability claims must be submitted no later than 90 days after the date you are eligible for benefits to begin.

Long Term Disability

What's Not Covered

Your long term disability plan does not cover:

- intentionally self-inflicted injury or illness,
- disability resulting from war, or act of war, or while engaged in the armed services,
- any period of disability during which you are not under the regular care and attendance of a legally qualified physician,
- any period of disability which commences while you are not insured under this plan,
- participation in a criminal act, or
- disability, loss or expense which commences or occurs during any period of statutory maternity or parental leave of absence except to the extent:
    1. the continuance of insurance coverage during such period of statutory maternity or parental leave of absence is required by legislation or by written agreement between you and your employer; and
    2. you do not receive or are not entitled to receive any payment, benefit, indemnity or other amount from any source, including any policy, plan or fund provided by any employer, insurer or government (including basic and supplementary unemployment insurance maternity/parental leave benefits).

Life Insurance

Your life insurance plan provides you with a basic benefit and allows you to purchase additional coverage for yourself and/or your spouse. In the event of your death, the plan pays a benefit to your beneficiary. The benefit is payable to you in the event of the death of your covered spouse.

How The Plan Works

If you should die while insured, your plan will pay the amount of your life insurance to the last nominated beneficiary as filed. In the absence of a beneficiary nomination, payment will be made to your estate.

You may name anyone you choose to receive benefits payable under the plan in the event of your death. However, if you name a minor, a trustee must also be appointed. You may change your beneficiary designation at any time, subject to the laws governing such changes, by contacting your Plan Administrator.

If your spouse is insured for life insurance coverage under the spouse's optional life plan, benefits are payable to *you* in the event of the death of your covered spouse.

Life Insurance

Benefits Provided

Employee Life Insurance

Your life insurance plan provides basic and optional coverage, depending on the Option you apply for. You may select coverage under one of the following four Options available under the plan.

Option	Basic Term Insurance (Employer Paid)	Additional Term Insurance (Employee Paid)
1	150% of your annual earnings	Nil
2	175% of your annual earnings	25% of your annual earnings
3	175% of your annual earnings	75% of your annual earnings
4	175% of your annual earnings	125% of your annual earnings

Notes: *All amounts of basic term and additional term insurance are rounded upward to the nearest $1,000.*
Regardless of which Option you select, the total amount of coverage cannot exceed $600,000.
Before selecting (or changing) an Option, it may be important to review the Retirement Life Insurance coverage applicable to you.

Your life insurance coverage begins on the date you complete the eligibility waiting period, provided you make written application for coverage within 31 days of becoming eligible.

If you do not apply within the 31-day deadline, you will automatically be enrolled in the Basic Term Insurance plan only, for a benefit equal to 200% of your annual earnings (Option 1). To enroll in any of the plan Options available which include Additional Term Insurance (Options 2, 3 and 4), you must provide medical evidence — proof that you are insurable — satisfactory to the insurer.

Life Insurance

Spouse's Optional Life Insurance

The purchase of life insurance coverage for your spouse is completely voluntary; you decide whether or not to participate. A **spouse** is the person you are legally married to, or a person who has continuously resided with you in a role like that of a marriage partner for at least one year.

Spouse's optional life insurance coverage is available in **multiples of $10,000 to a maximum of $250,000**. Provided you apply for this coverage within the first 31 days following your eligibility date, only coverage amounts in excess of $10,000 are subject to medical evidence — proof that your spouse is insurable — satisfactory to the insurer. If you apply after the 31-day deadline, **all** coverage applied for will be subject to satisfactory medical evidence.

If you are not actively at work on the date coverage would normally begin, coverage will not begin until you return to active work. If your spouse is hospitalized, coverage will not begin before your spouse is discharged and resumes normal activities.

Changing Your Coverage

There are times when you may need to change your coverage under the employee's and/or spouse's life insurance plan, either reducing or increasing the coverage, as appropriate. (**Note:** For employee life insurance, it may be important to review the Retirement Life Insurance coverage applicable to you before deciding to change your coverage Option.)

You may re-select your Option under the employee's life insurance plan and/or change the amount of your spouse's life insurance benefit, at any time. Your Plan Administrator will provide you with the necessary forms to request a change.

Any request to increase the coverage amount, is subject to medical proof of insurability, satisfactory to the insurer, and will be effective on the date the insurer approves the application, provided you are actively at work (or in the case of your spouse, s/he is not hospitalized).

Any request to reduce or cancel optional life insurance for yourself and/or your spouse, will be effective on the later of the date you request or the first day of the month following the date your request is received. (**Note:** If you subsequently apply to add or increase coverage for yourself and/or your spouse that was previously cancelled or reduced, evidence of insurability, satisfactory to the insurer, will be required.)

Life Insurance

Cost Of The Life Insurance Plan

Your employer pays the entire cost of your Employee Basic Term Life Insurance coverage. All life insurance premiums paid by your employer are a taxable benefit to you.

If you elect Additional Term Life Insurance coverage for yourself and/or Optional Life Insurance coverage for your Spouse, the cost to you will be paid through payroll deduction.

For **Employee Additional Term Life Insurance**, the rates vary by age, gender and smoking status, and are adjusted according to your age on the 1st of January each year, with any required adjustment taking effect at that time. Monthly costs are provided in the chart below.

Employee's Attained Age (as at January 1st)	Male		Female	
	Smoker Monthly Rate (per $1,000)	Non-Smoker Monthly Rate (per $1,000)	Smoker Monthly Rate (per $1,000)	Non-Smoker Monthly Rate (per $1,000)
Under 35	$0.044	$0.022	$0.022	$0.020
35 - 39	$0.060	$0.039	$0.033	$0.028
40 - 44	$0.163	$0.080	$0.099	$0.062
45 - 49	$0.285	$0.142	$0.169	$0.098
50 - 54	$0.445	$0.231	$0.240	$0.151
55 - 59	$0.757	$0.383	$0.395	$0.231
60 - 64	$0.890	$0.480	$0.480	$0.300

Note: *Monthly costs shown above reflect those in effect as of January 1st, 2011.*
The monthly cost schedule is subject to change by the insurer; your employer will notify you prior to any changes taking effect.
Monthly costs shown above are subject to applicable taxes.

Life Insurance

For **Spouse's Optional Life Insurance**, the rates vary based on your spouse's age, gender and smoking status, and are adjusted according to your spouse's age on the 1st of January each year, with any required adjustment taking effect at that time. Monthly costs are provided in the chart below.

Spouse's Attained Age (as at January 1st)	Male		Female	
	Smoker Monthly Rate (per $1,000)	Non-Smoker Monthly Rate (per $1,000)	Smoker Monthly Rate (per $1,000)	Non-Smoker Monthly Rate (per $1,000)
Under 30	$0.042	$0.032	$0.042	$0.026
30 - 39	$0.069	$0.035	$0.054	$0.032
40 - 49	$0.187	$0.094	$0.113	$0.069
50 - 59	$0.615	$0.307	$0.312	$0.187
60 – 64	$1.200	$0.599	$0.653	$0.390

Note: *Monthly costs shown above reflect those in effect as of January 1st, 2011.*
The monthly cost schedule is subject to change by the insurer; your employer will notify you prior to any changes taking effect.
Monthly costs shown above are subject to applicable taxes.

When Coverage Ends

Employee Life Insurance (Basic Term and Additional Term) coverage ceases on the earliest of the following dates:

- the date your employment ends, other than by retirement on pension or cessation of active employment due to total disability;
- the last day of the month in which you reach age 65; or
- the date the group plan is cancelled.

(**Note:** If your employment ends due to retirement on pension, you will continue to be insured for a reduced Retirement Life Insurance benefit — refer to the sub-section, *Retirement Life Insurance*.)

Your Spouse's Optional Life Insurance coverage ends on the earliest of the following dates:

- the date your employment ends;
- the date of your death;
- the date you retire or reach age 65;
- the date your spouse no longer qualifies as an eligible spouse; or
- the date of your spouse's 65th birthday.

Waiver Of Premium

If you become totally disabled while insured and before your 65th birthday or earlier retirement, your life insurance coverage under the Basic Term, Additional Term and Spouse's Optional Life plan will be continued without further payment of premiums. Your coverage will continue until you are no longer disabled, retire or reach age 65, whichever occurs first. (Your spouse's life insurance coverage will continue until you are no longer disabled, die, retire or reach age 65, or your spouse reaches age 65 — whichever occurs first.)

Proof that you are totally disabled must be submitted to Great-West Life within 12 months from the onset of the disability, and periodically as requested by Great-West Life thereafter.

Totally Disabled means that you are prevented from performing any work for compensation or profit or from following any gainful occupation. (However, if you are insured for Long Term Disability benefits by Great-West Life under this same master policy, the definition of total disability used to determine your eligibility for disability benefits, as described in this booklet, shall also apply when assessing your life insurance waiver of premium benefit.)

Life Insurance

Conversion Privilege

If **your** life insurance coverage ceases or reduces as a result of termination of employment, retirement or attainment of age 65, you may apply to convert your cancelled or reduced insurance to an individual policy — *without* having to provide medical evidence. You must make written application for the individual policy to Great-West Life accompanied by payment of the first premium within 31 days of the date your life insurance terminates or reduces. If you should die during the 31-day conversion period, a death benefit equal to the amount of life insurance eligible for conversion will be paid, regardless of whether application for conversion has been made.

You may choose an individual policy plan which provides coverage comparable to the coverage for which you were insured under this Plan, but without disability benefits, or you may choose any other individual policy which Great-West Life is willing to offer, but without disability benefits. The amount of the individual policy will not exceed the lesser of $200,000 ($400,000 for employees residing in Quebec[1]) or the excess of the amount of your life insurance in force under this Plan immediately prior to the termination or reduction over the amount of life insurance provided by any group policy of your employer or any other employer for which you are eligible on the effective date of the individual policy. The premium rate will be based on your age and gender, and the type of policy plan you select.

[1]For a Quebec plan Member to convert, his or her convertible amount must be at least $10,000 or 25 percent of group coverage (whichever is greater).

Your **spouse's** life insurance coverage ceases on the date your employment terminates. You may, however, apply to convert your spouse's insurance, on or before your spouse's 65th birthday, to an individual policy — *without* having to provide medical evidence. You must make written application for the individual policy to Great-West Life accompanied by payment of the first premium within 31 days of the date your employment ends. If your spouse should die during the 31-day conversion period, a death benefit equal to the amount of insurance eligible for conversion will be paid, regardless of whether application for conversion has been made.

Life Insurance

Retirement Life Insurance

On the last day of the month in which you reach age 65, or retire on pension under a Normal Retirement, Early Retirement or Total Disability Retirement — whichever occurs first — your life insurance coverage under the Option you selected will cease. However, you will continue to be insured for a reduced Retirement Life Insurance benefit based on your years of service in this plan and your Option selection(s) prior to retirement, as set out in the chart on the following page.

Life Insurance

Classification	Amount of Retirement Life Insurance
A. If you retire with less than 10 Years of Service in this Plan	$2,000
B. If you were not insured under the Superseded Plan* and retire with 10 or more Years of Service in this Plan **or** if you were insured under the Superseded Plan* but at any time prior to retirement elected coverage under Options 2, 3 or 4	50% of your final annual earnings, reducing by 2-1/2% of final annual earnings on the anniversary of your retirement date each year following for ten years, to a minimum of 25% of your final annual earnings
C. If you were insured under the Superseded Plan*:	
1. If at **any time** you elected coverage under Options 2, 3 or 4;	Amount will be determined in accordance with provision B above
2. If you were hired on or after May 1, 1967 and never elected coverage under Options 2, 3 or 4 at any time prior to retirement; or	50% of your final annual earnings
3. If you were hired prior to May 1, 1967 and never elected coverage under Options 2, 3 or 4 at any time prior to retirement	70% of the amount of coverage you were insured for immediately prior to your retirement date

Notes

All amounts of retirement life insurance are rounded upward to the nearest $1.00.

**Superseded Plan* means the prior life insurance plan which this Plan replaced effective March 1, 1980.

Years of Service means your service in this Plan or the Superseded Plan with your current employer you retire from, together with service credited to you in this Plan or the Superseded Plan by reason of your prior service with any other employer participating in this Plan, where the transfer occurs without intervening employment.

Life Insurance

How To Claim Death Benefits

Your Plan Administrator will furnish all the required claim forms to your beneficiary in the event of your death. In the event of the death of your covered spouse, the required claim forms will be furnished to you. Claims for death benefits must be submitted no later than 12 months after the date of death.

What's Not Covered

No amount will be paid for that part of your spouse's optional life insurance benefit that has been in force for less than 2 years, if loss of life results from suicide, while sane or insane. However, Great-West Life will refund all applicable premiums paid.

Supplementary Life Insurance

The supplementary life insurance plan enables you to purchase additional life insurance coverage for yourself.

How The Plan Works

The purchase of supplementary life insurance is completely voluntary; you decide whether or not to participate.

In the event of your death, your supplementary life insurance plan will pay a benefit to your appointed beneficiary.

You may name anyone you choose to receive benefits payable under the plan in the event of your death. However, if you name a minor, a trustee must also be appointed. You may change your beneficiary designation at any time by contacting your Plan Administrator.

Benefits Available

Supplementary life insurance coverage is available in **multiples of $10,000, to a maximum of $250,000**. All coverage is subject to medical evidence — proof that you are insurable, satisfactory to the insurer.

(**Note:** All amounts of life insurance under the term life, optional life and supplementary life plans are subject to a combined overall maximum of $600,000.)

Supplementary Life Insurance

Cost of Supplementary Life Insurance

Your cost, paid through payroll deduction, depends on your gender, your age and on whether or not you smoke. (You are considered a “non-smoker” if you have not smoked for the last 12 months.) Monthly costs are provided in the table below.

Employee’s Attained Age (as at January 1st)	Male		Female	
	Smoker Monthly Rate (per $1,000)	Non-Smoker Monthly Rate (per $1,000)	Smoker Monthly Rate (per $1,000)	Non-Smoker Monthly Rate (per $1,000)
Under 35	$0.044	$0.022	$0.022	$0.020
35 - 39	$0.060	$0.039	$0.033	$0.028
40 - 44	$0.163	$0.080	$0.099	$0.062
45 - 49	$0.285	$0.142	$0.169	$0.098
50 - 54	$0.445	$0.231	$0.240	$0.151
55 - 59	$0.757	$0.383	$0.395	$0.231
60 - 64	$0.890	$0.480	$0.480	$0.300

Note: *Monthly costs shown above reflect those in effect as of January 1st, 2011.*
The monthly cost schedule is subject to change by the insurer; your employer will notify you prior to any changes taking effect.
Monthly costs shown above are subject to applicable taxes.

Supplementary Life Insurance

Waiver of Premium

If you become totally disabled while insured and before your 65th birthday or earlier retirement, your life insurance coverage under the Supplementary Life plan will be continued without further payment of premiums. Your coverage will continue until you are no longer disabled, retire or reach age 65, whichever occurs first.

Proof that you are totally disabled must be submitted to Great-West Life within 12 months from the onset of the disability, and periodically as requested by Great-West Life thereafter.

Totally Disabled means that you are prevented from performing any work for compensation or profit or from following any gainful occupation. (However, if you are insured for Long Term Disability benefits by Great-West Life under this same master policy, the definition of total disability used to determine your eligibility for disability benefits, as described in this booklet, shall also apply when assessing your life insurance waiver of premium benefit.)

Conversion Privilege

Your supplementary life insurance coverage ceases on the date your employment terminates. However, if you are under age 65, you may apply to convert your insurance to an individual policy — *without* having to provide medical evidence. You must make written application for the individual policy to Great-West Life accompanied by payment of the first premium within 31 days of the date your supplementary life insurance terminates. The amount of the individual policy will not exceed the lesser of $200,000 ($400,000 for employees residing in Quebec[1]) or the total amount of your life insurance in force under all life insurance plans provided under this policy immediately prior to the termination of your coverage. If you should die during the 31-day conversion period, a death benefit will be paid, regardless of whether or not application for conversion has been made.

[1]For a Quebec plan Member to convert, his or her convertible amount must be at least $10,000 or 25 percent of group coverage (whichever is greater).

Supplementary Life Insurance

How To Claim Death Benefits

Your Plan Administrator will furnish all the required claim forms to your beneficiary in the event of your death. Claims for death benefits must be submitted no later than 12 months after the date of death.

What's Not Covered

No amount will be paid for that part of your Supplementary Life Insurance benefit that has been in force for less than 2 years, if loss of life results directly or indirectly, while sane or insane, from suicide, attempted suicide or purposely self-inflicted injury.

Group Home & Automobile Insurance Program

The group home and automobile insurance program is a voluntary, employee-paid plan, that gives you access to preferred group home & automobile insurance rates.

How The Plan Works

To enhance your overall benefits package, your employer has endorsed The MEARIE Group's Home & Automobile Insurance Program*.

This Program is available to you on a completely voluntary basis, with all associated premiums being paid by you.

The Program, sponsored by The MEARIE Group, is insured through AVIVA Traders Insurance Company. AVIVA has been providing group home and automobile insurance to groups and associations for over 50 years.

AVIVA's financial strength and stability ensures that their claims-paying ability is second-to-none in the Canadian insurance marketplace.

Products Available

Residential

- Homeowners
- Tenants
- Condominium
- Seasonal/Secondary/Rented Residences
- Recreational Watercraft
- Personal Articles

Personal Automobiles

- Automobiles
- Trailers
- Campers/Motor Homes
- Snowmobiles
- Other Recreational Vehicles

Group Home & Automobile Insurance Program

Value-Added Products & Services

AVIVA Traders has a variety of value-added products and services, including:

AVIVA Roadside Assist

This value-added service provides emergency roadside assistance for up to four vehicles per policy. The annual membership fee provides a variety of services, including:

- Emergency towing
- Battery boosts
- Emergency winching
- Fuel Delivery
- Trip Planning

Vehicle Anti-theft Device

Policyholders will have the option of purchasing an ignition disabler at a discounted price. Policyholders will receive a discount on their auto policy, which could be equal to or greater than the cost of the Anti-theft device.

Six Star Protector

Is an easy way to protect policyholders from possible premium increases as a result of an accident, even if they are at fault. For a nominal fee, policyholders can protect their "Six Star" driving record and their claims free discount in the event they have an accident in the future.

Payment Options

- Multi-pay plans, or, monthly payment plan with no interest or service fees.

Hours Of Operation

- Extended service hours: 8:00 a.m. to 8:00 p.m., Monday to Friday.

Group Home & Automobile Insurance Program

How To Obtain A Quote

To obtain a no-obligation quote or to get more information on your home and auto insurance needs, call The MEARIE Group's toll free number 1-877-4MEARIE (1-877-463-2743), or visit AVIVA's website at www.avivacanada.com (click on Traders - password: grquote).

** Administered by Alternative Risk Services Inc.*

The MEARIE Group

3700 Steeles Avenue West, Suite 1100
Vaughan, Ontario L4L 8K8
905.265.5300
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Attachment 4 of 4

Estimated Benefit Expense

St. Thomas Energy Services Inc.
STEI
ESTIMATED BENEFIT EXPENSE (CICA 3461)
Final

	Calendar Year 2013	Projected** Calendar Year 2014
Discount Rate at December 31	4.50%	4.50%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*

A. Determination of Benefit Expense

	Calendar Year 2013	Projected** Calendar Year 2014
Current Service Cost	31,918	26,599
Interest on Benefits	58,240	47,952
Expected Interest on Assets	-	-
Past Service Cost/(Gain)	-	-
Transitional Obligation/(Asset)	-	-
Actuarial (Gain)/Loss	-	(162,204)
Benefit Expense	90,158	(87,653)

B. Reconciliation of Prepaid Benefit Asset (Liability)

	Calendar Year 2013	Projected** Calendar Year 2014
Accrued Benefit Obligation (ABO) as at December 31	1,081,373	1,071,164
Assets as at December 31	-	-
Unfunded ABO	(1,081,373)	(1,071,164)
Unrecognized Loss/(Gain)	(162,204)	-
Unrecognized Past Service Cost/(Gain)	-	-
Prepaid Benefit Asset (Liability)	(1,243,577)	(1,071,164)
Prepaid Benefit/(Liability) as at January 1	(1,234,948)	(1,243,577)
Benefit Income/(Expense)	(90,158)	87,653
Contributions/Benefit Payments by the Employer	81,529	84,760
Prepaid Benefit Asset (Liability)	(1,243,577)	(1,071,164)

* based on estimated employer benefit payments for those expected to be eligible for benefits

** CY 2014 figures are provided for management's informational purposes only as these figures are subject to change based on the results of the January 1, 2014 full actuarial valuation which will be completed in 2014.

St. Thomas Energy Services Inc.
STEI
ESTIMATED BENEFIT EXPENSE (CICA 3461)
Final

	Calendar Year 2013	Projected** Calendar Year 2014
Discount Rate at December 31	4.50%	4.50%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*

C. Calculation of Component Items

	Calendar Year 2013	Projected** Calendar Year 2014
Calculation of the Service Cost		
- Current Service Cost	31,918	26,599
Interest on Benefits		
- ABO at January 1	1,234,948	1,081,373
- Current Service Cost	31,918	26,599
- Benefit Payments	(40,764)	(42,380)
- Accrued Benefits	1,226,101	1,065,592
- Interest	58,240	47,952
Expected Interest on Assets		
- Assets at January 1	-	-
- Funding	40,764	42,380
- Benefit Payments	(40,764)	(42,380)
- Expected Assets	-	-
- Interest	-	-
Expected ABO as at December 31		
- ABO at January 1	1,234,948	1,081,373
- Current Service Cost	31,918	26,599
- Interest on Benefits	58,240	47,952
- Benefit Payments	(81,529)	(84,760)
- Expected ABO at December 31	1,243,577	1,071,164
Expected Assets as at December 31		
- Assets at January 1	-	-
- Funding	81,529	84,760
- Interest on Assets	-	-
- Benefit Payments	(81,529)	(84,760)
- Expected Assets at December 31	-	-

* based on estimated employer benefit payments for those expected to be eligible for benefits

** CY 2014 figures are provided for management's informational purposes only as these figures are subject to change based on the results of the January 1, 2014 full actuarial valuation which will be completed in 2014.

St. Thomas Energy Services Inc.
STEI
ESTIMATED BENEFIT EXPENSE (CICA 3461)
Final

	Calendar Year 2013	Projected** Calendar Year 2014
Discount Rate at December 31	4.50%	4.50%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*

D. Actuarial (Gain)/Loss

	Calendar Year 2013	Projected** Calendar Year 2014
(Gain)/Loss on ABO as at January 1		
- Prepaid Benefit/(Liability)	1,234,948	1,243,577
- Unamortized (Gain)/Loss From Prior Year	-	-
- Expected ABO	1,234,948	1,243,577
- Actual ABO	1,234,948	1,081,373
- (Gain)/Loss on ABO	-	(162,204)
(Gain)/Loss on assets as at January 1		
- Expected Assets	-	-
- Actual Assets	-	-
- (Gain)/Loss on Assets	-	-
Total (Gain)/Loss as at January 1	-	(162,204)
10% of ABO as at January 1	123,495	108,137
Total (Gain)/Loss in Excess of 10%	-	(54,066)
Expected Average Remaining Service Life (Years)	10	9
Minimum Amortization for Current Year	-	(6,007)
Actual Amortization for Current Year	-	(162,204)
(Gain)/Loss on ABO at December 31 (due to change in management's best estimate assumptions - discount rate, salary scale, and health and dental benefit cost levels, and demographic changes)		
- Expected ABO - December 31	1,243,577	
- Actual ABO - December 31	1,081,373	
- (Gain)/Loss on ABO at December 31	(162,204)	
Unamortized (Gain)/Loss as at December 31	(162,204)	-

* based on estimated employer benefit payments for those expected to be eligible for benefits

** CY 2014 figures are provided for management's informational purposes only as these figures are subject to change based on the results of the January 1, 2014 full actuarial valuation which will be completed in 2014.

SHARED SERVICES AND CORPORATE COST ALLOCATION

HISTORICAL

St. Thomas Energy Inc. is 100% owned by its parent company, Ascent Group Inc., which in turn is 100% owned by the Corporation of the City of St. Thomas. As noted previously, prior to 2012 STEI received all services from STESI based upon Master Service Agreement ("MSA"). The MSA pricing provided for existing services, at the inception of the MSA, was provided under a fixed fee per customer that declined annually based upon pre 2000 services, variable pricing for new services required by STEI after May 1, 20014 and capital and regulatory expenditure pricing. Under this agreement STESI assumed all financial risks with the provision of these services.

CURRENT

STEI provides and receives services from its affiliates in order to benefit from cost savings due to increased efficiencies and economies of scale. STEI also provides water and sewer billing and collecting services to the City of St. Thomas. A summary of these services is provided in Board Appendix 2-N (complete). As part of STEI's restructuring and the 2015 Cost of Service application, STEI obtained an independent third party study to review the cost allocations. This study was prepared by PricewaterhouseCoopers and is provided in Appendix A to this Exhibit. A copy of the City of St. Thomas service level agreement in provided as Appendix B to this exhibit and the AGI service level agreement is provided as Appendix C to this Exhibit.

SERVICES PROVIDED BY STEI

- **Engineering services to Ascent**.
  Engineering work performed by STEI on behalf of affiliates is done on an ad-hoc basis. The type of work performed can vary from project to project (e.g. MEC Calculations, Site Specific

Loss Calculations) and is performed by STEI's Engineering Manager. Time spent on each project by the Engineering Manager is tracked and charged at an hourly rate.

WATER AND SEWER BILLING, CITY OF ST. THOMAS

STEI provides water and sewer billing and collecting services to the City of St. Thomas. By providing these services STEI has been able to share cost and increase efficiency and effectiveness. Under the Service Level Agreement (Attachment 2), all specific third party costs are recovered 100%, staffing costs are allocated based upon a time study and shared costs such as postage is not charged to the City as the joint bill does not increase STEI's costs in these areas and there would be not cost reduction if STEI was not billing the water and sewer. For those municipal customers that receive water and sewer billing that are not STEI customers the City pays the full costs.

Services received by STEI from Ascent Group Inc.

- **Corporate and Governance Oversight**

  Through their parent company Ascent Group Inc. (AGI), STEI receives a number of Corporate, Finance, and Governance services. These services are provided to all subsidiaries of AGI (i.e. STEI, AESI, ASI, ARI). The services provided by AGI include corporate functions such as executive management (i.e. CEO and CFO) enterprise IT services as well as governance which includes several Boards of Directors. Additionally, there are other various levels of administrative support such as financial/debt management, treasury, management legal/consulting, community relations and business development services.

- **Locates**

  Locates services include work performed in order to determine where underground facilities or lines are situated throughout a given area. This service profile includes all costs related to

Locates work performed by AESI on behalf of STEI. Costs include an hourly labour charge (tracked through daily timesheets), as well as any charges related to vehicles used in the performance of the service by AESI.

- **Meter Service Locates**

  Meter Service Layouts provide customers with diagrams/drawings of where meters should be situated as well as other specifications related to the placement/installation of meters. This service profile includes costs related to Meter Service Layouts performed by AESI on behalf of STEI. As with Locates, costs include both an hourly labour charge (tracked through timesheets) and vehicles charges incurred to perform the service.

- **Service Layouts**

  Meter Technician services include meter maintenance work such as repairs, connections, inspections, and disconnections. This service profile includes all costs related to Meter Technician Services performed by AESI on behalf of STEI. As with the other service profiles, costs include an hourly labour charge as well as any vehicle charges incurred while performing repairs/maintenance of meters.

COST DRIVER STUDY

As part of the 2011 Cost of Service Settlement Agreement, STEI agreed to develop and implement a more formalized and transparent procedure for its transfer pricing as soon as practical, but no later than the filing of the next cost of service rate application.

In an effort for full transparency, a restructuring occurred on January 1, 2012 in which all operational staff and related assets where transferred to STEI. In addition STEI engaged PriceWaterhouseCoopers to prepare a Cost Driver Study (Attachment 1) to analyze the transfer pricing between STEI (regulated) and their affiliates. The study is to ensure that Article 340 of the Ontario Energy Board (OEB)'s Accounting Procedures Handbook and the Affiliate Relationship Code (ARC) is being adhered within STEI.

STEI identified specific inter-affiliate services that were under review. The scope included services received from STEI's affiliates (i.e. Meter Technician Services, Meter Service Layouts, Locates, and Corporate/Finance/Governance) as well as services provided by STEI to its affiliates (i.e. Engineering Services, and Water/Sewer Billing and Collections).

VARIANCE ANALYSIS

The 2011 Board Approved corporate allocations have not been provided as the amount is difficult to determine. The following Table 4-9 provides the actual cost of services received and provided from 2011 to 2013 actual per audited financial statements to the 2014BY and 2015TY.

Table 4-9

Corporate Allocations - OM&A

Item	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual
Services Provided To STEI	5,201,947	969,058	527,321	520,000	529,450
Services Provided By STEI	-	342,564	343,589	342,000	329,000
2015TY vs 2011 Actual					
Services Provided To STEI					(4,672,497)
Services Provided By STEI					329,000

2011 actual services provided to STEI were based upon STEI as a virtual utility receiving cost per a Master Service Agreement.

2012 Actual vs 2013 Actual

2012 services provided to STEI were based upon Management's best efforts base upon internal resource allocations that resulted in $969,058 of cost being allocated. 2013 cost allocation are based upon the PwC costing study and are consistent for the 2014BY and 2015TY.

Services provided by STEI are mainly attributed to the water and sewer billing agreement that was inherited by STEI upon restructuring. For the 2014BY and 2015TY the water and sewer billing revenues are supported by a service level agreement based upon the PwC costing study.

Board Appendix 2-N for the 2011, 2012 and 2013 Historical Year, 2014 Bridge Year and 2015 Test year are provided in the following pages.

Corporate Cost Allocation - 2011

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
STESI	STEI	All services to	Master service Agreement		5,201,947
		build, maintain			
		its capital infrastructure			
		Billing, collecting, financial			
		Capital			2,031,855
					7,233,802

Corporate Cost Allocation - 2012

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
STEI	*City of St Thomas*	water & sewering billing	Historical		306,065
STEI	*AESI*	labour and equipment support	labour $65/hr vehicle $10 or $45/ hr		34,499
STEI	*AESI*	Engineering Support	Fixed Price $100/hr		2,000
AESI	*STEI*	Locates	labour $65/hr vehicle $10 or $45/ hr		85,525
AESI	*STEI*	Meter Work	labour $65/hr vehicle $10 or $45/ hr		27,150
AESI	*STEI*	Layouts	labour $65/hr vehicle $10 or $45/ hr		16,940
AESI	*STEI*	Building and Maintenance support	labour $65/hr vehicle $10 or $45/ hr		78,573
AGI	*STEI*	Corporate Governance and oversight	Internal Allocation	43.50%	707,878
AGI	*STEI*	Board of Directors	Internal Allocation	45.00%	52,992

Corporate Cost Allocation - 2013

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
STEI	*City of St Thomas*	water & sewering billing	Glen?		296,184
STEI	*AESI*	labour and equipment support	labour $65/hr vehicle $10 or $45/ hr		45,455
STEI	*AESI*	Engineering Support	Fixed Price $100/hr		1,950
AESI	*STEI*	Locates	labour $65/hr vehicle $10 or $45/ hr		82,990
AESI	*STEI*	Meter Work	labour $65/hr vehicle $10 or $45/ hr		24,670
AESI	*STEI*	Layouts	labour $65/hr vehicle $10 or $45/ hr		10,777
AGI	*STEI*	Corporate Governance and oversight	PwC Study		429,768
AGI	*STEI*	Board of Directors	PwC Study		26,521

Corporate Cost Allocation 2014

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
STEI	*City of St Thomas*	water & sewering billing	PwC study & SLA		272,000
STEI	*AESI*	labour and equipment support	Fixed Price		70,000
AESI	*STEI*				70,000
AGI	*STEI*	Corporate Governance and oversight	PwC Study		409,600
AGI	*STEI*	Board of Directors	PwC Study		38,900
		Audit Committee			1,500

Corporate Cost Allocation - 2015

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
STEI	*City of St Thomas*	water & sewering billing	PwC study & SLA		294,000
STEI	*AESI*	labour and equipment support	Fixed Price		35,000
AESI	*STEI*				70,000
AGI	*STEI*	Corporate Governance and oversight	PwC Study		419,050
AGI	*STEI*	Board of Directors	PwC Study		38,900
		Audit Committee			1,500

BOARD OF DIRECTOR COSTS

In the 2011 Cost of Service Application, STEI's Board of Directors consisted of 6 members that met on a quarterly basis. There has been no change to the number of STEI Board of Directors. The total Board costs includes remuneration, training and insurance.

Attachment 1 of 2

Cost Driver Study

www.pwc.com/ca

Cost Driver Study for St. Thomas Energy Inc.

September 2013

Contents

Limitations

PricewaterhouseCoopers (PwC) represents and warrants in its final report that:

- The material contained reflects PwC's efforts to accurately represent our findings in light of the information available at the time of report preparation.

- Our work does not constitute an audit opinion issued pursuant to CICA standards or any other statutory reporting standards.

- The overall definition and scope of the work to be performed and its adequacy in addressing your needs are the responsibility of St. Thomas Energy Inc. The ultimate decision to accept, proceed with, and implement any specific recommendations made by PwC related to this engagement rests with St. Thomas Energy Inc.

- We have not provided any specific review or recommendations related to individual staff members currently working for St. Thomas Energy Inc.

- We have based our analysis and findings on information provided to us by St. Thomas Energy Inc. staff through interviews and documents. While we have reviewed the documents provided to us, we have not independently validated or audited the information provided to us. Furthermore, the benchmark is an indicative market price as of August 2013.

- This report has been prepared for the sole use of St. Thomas Energy Inc.

- Any use that a third party makes of this report or reliance thereon, or any decisions made based on it, is the responsibility of such third party. PwC accepts no responsibility for damages, if any, suffered by any third party as a result of decisions made or actions based on the report.

- PwC will not audit or otherwise verify the information contained in its benchmarking database as well as the information supplied to PwC by St. Thomas Energy Inc. in connection with this engagement, from whatever source, except as specified in the Engagement Letter, and the procedures performed by PwC will not constitute an audit in accordance with CICA standards or any other statutory reporting standards.

Executive Summary

PricewaterhouseCoopers (PwC) has been engaged by St. Thomas Energy Inc. (STEI) for the purpose of performing a Cost Driver Study to analyse the transfer pricing between STEI (regulated) and their affiliates. The study is to ensure that Article 340 of the Ontario Energy Board (OEB)'s Accounting Procedures Handbook and the Affiliate Relationship Code (ARC) is being adhered within STEI. The ARC provides guideline options to LDCs in providing transparency on its transfer pricing between the affiliated companies. The objective of the ARC is to ensure that costs of services exchanged between affiliates should be at reasonable and fair in order to ensure that cross-subsidization does not occur between unregulated and regulated businesses.

STEI management identified specific inter-affiliate services that were under the scope of this review. The scope includes services received from STEI's affiliates (i.e. Meter Technician Services, Meter Service Layouts, Locates, and Corporate/Finance/Governance) as well as services provided by STEI to its affiliates (i.e. Engineering Services, and Water/Sewer Billing and Collections). Of the identified services, for services that have an annual value of less than $100,000 (Meter Technician Services, Meter Service Layouts, Locates, and Engineering Services), PwC has performed a benchmarking analysis by surveying seven Ontario Local Distribution Companies (LDCs) and extrapolated data to calculate the mean, median, and range for comparison purposes. Based on our analysis, much of the rates that STEI is paying (Locates, Meter Service Layouts, and Meter Technician Services), and charging (Engineering Services) are at or slightly above industry average. This may imply that STEI costs are relatively less competitive than the prices that other LDCs are paying. Since Locates, Meter Service Layouts, and Meter Technician Services are all performed by the same technician from the affiliate service company, STEI's costs may be higher than other LDCs that can leverage its resources for economies of scale. Additionally, the rate that STEI is charging for Engineering Services (at $100/hr) is well above the industry range. Since only $2,000 or 5 requests of Engineering Services has been rendered during the year of 2012, a higher hourly rate may be reasonable.

Benchmark results are as follows:

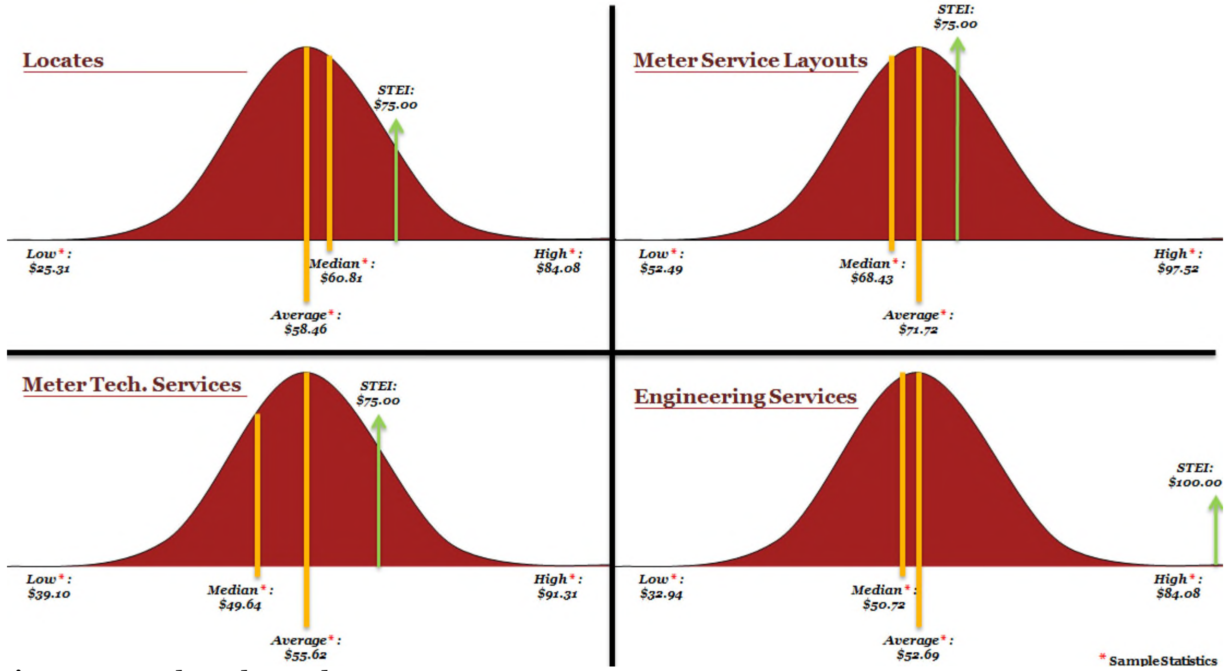


Figure 1 - Benchmark Result Summary

In regards to the Corporate/Finance/Governance and Water/Sewer Billing and Collection, PwC performed a detailed analysis on the costs involved in provisioning the services.

Costs of Water/Sewer Billing and Collection services were reviewed to ensure that STEI is recovering the incremental cost of service and affiliates are not cross-subsidizing business operations. Incremental costs were identified as costs which are incurred in addition to the costs incurred to service Hydro customers of STEI. For instance, postage charges will be incurred by STEI when sending bills to customers on a monthly basis. There are synergies that could be leveraged by mailing both Hydro and Water/Sewer bills together while without incurring additional charges. However the postage costs incurred for sending bills to Water/Sewer-only customers will be deemed as incremental cost.

Based on the incremental costs, STEI should be recovering $322,750/year (or $1.80/bill) for the Water/Sewer Billing and Collection services. Under the current Master Service Agreement (MSA), the City of St. Thomas is charged $275,000 in addition to late payment interests collected (estimated at $43,000 per year) which totals to $318,000 per annum. Therefore the current annual service fee charged by STEI is only slightly undercharged by approximately $5,000.

Rates Charged Per Monthly Bill			
Mean	**Median**	**Proposed**	**Current**
$2.78	$2.87	$1.80	$1.54

Figure 2 - Benchmark of Current and Proposed Water/Sewer Billing and Collection Service Charge

PwC has also obtained pricing data from four Ontario LDCs that are also providing Water/Sewer Billing and Collection services for other municipalities. As depicted in the table above, the current and proposed fee are well below the industry average of $2.78 per bill.

With respect to the Corporate/Finance/Governance service provided by AGI, parent company of STEI, costs include corporate overhead expenses such as senior executives and IT personnel that provide oversight and support functions to the organizations under the AGI umbrella, as well as Board of Directors expenses, conferences, training, and professional services. Support function personnel costs were allocated based on management estimates on their actual contributions to each company (e.g. Enterprise IT support are rarely utilized by STEI as they have their own IT support resources). Other expenses were allocated based on the proportion of revenues generated within the Ascent consortium of companies. Based on the analysis, a service fee of $444,348 ($2.22 per customer/month) should be charged to STEI for Corporate/Finance/Governance services provided by AGI.

Cost Driver Study

St. Thomas Energy Inc. (STEI) has engaged the services of PricewaterhouseCoopers (PwC) in August 2013 to perform a Cost Driver Study to analyse transfer pricing between STEI and its affiliates in accordance with the Ontario Energy Board's (OEB) Affiliate Relationship Code (ARC).

The ARC provides guideline options to LDCs in providing transparency on its transfer pricing for transactions, products, and services exchanged between the distributor and its affiliates. The objective of the rule is to ensure that cross-subsidization does not exist among affiliate companies.

Services for which a reasonably competitive market exists, the cost should be no more than the market price when acquiring services or products from an affiliate. A competitive tendering or bidding process is not required for services with an annual value of less than the greater of $100,000 or 0.1% of the utility's net revenue with the presence of satisfactory benchmarking. For services where a reasonably competitive market does not exist, the utility should recover its costs incurred to provide the service.

Based on discussion with STEI management, there are six services exchanged between the distribution company and its affiliates that are in scope of this report. Services that are procured from affiliates include; Locates, Meter Technician Services, Meter Service Layout, and Corporate/Finance/Governance. The remaining services are provided by STEI to its affiliates which include Water/Sewer Billing and Collection and Engineering Services. Of the aforementioned services, Locates, Meter Technician Services, Meter Service Layout, and Engineering Services each have an annual value of less than $100,000. Hence the costs of providing these services were benchmarked with industry peers in Ontario. This was done by aggregating survey data as well as leveraging the 2012 Management Salary Survey of Local Distribution Companies in Ontario that was performed by The Mearie Group. Since the City of St. Thomas is considered an "arm's length" affiliate, the Water/Sewer Billing and Collection services provided by STEI on behalf of the City should be charged at STEI's incremental cost to allow full recovery of additional costs incurred. For this reason, costs incurred in providing the services were analysed and a reasonable methodology was derived in identifying incremental costs between STEI and its affiliates. With respect to the Corporate/Finance/Governance services provided by STEI's parent company, AGI, it is deemed that a reasonably competitive market for senior management and enterprise support does not exist. For this service, AGI's costs were analysed to determine an appropriate methodology and cost to STEI.

Organizational Structure

Ascent Group Inc. (AGI)

A for-profit, taxable entity wholly owned by the City of St. Thomas. The Ascent Group Inc. (AGI) was formed on January 1, 2012, strategically rebranded from St. Thomas Holding Inc. which was originally incorporated on November 3, 2000 as a result of the deregulation of the electrical industry.

St. Thomas Energy Inc. (STEI)

St. Thomas Energy Inc. (STEI) is a wholly owned subsidiary of Ascent Group Inc. (AGI). STEI is the local distribution company (LDC) of St. Thomas and is regulated by the Ontario Energy Board.

Ascent Energy Services Inc. (AESI)

Ascent Energy Services Inc. (AESI) provides reliable, cost-effective electrical distribution, traffic signal, street lighting, and fibre optic services. AESI performs installations, preventative maintenance, and offers various solutions for LED conversion projects. AESI has also been involved in revenue metering for over a century.

Ascent Solutions Inc. (ASI)

Ascent Solutions Inc. (ASI) was formed through the merger of several like-minded, forward-thinking companies and has grown to become one of the largest high voltage contractors in Ontario. ASI provide leading edge solutions for the energy sector including the planning, engineering, design, construction, commissioning and maintenance of substations, power distribution system services, automation and control solutions, security systems, green energy, renewable energy technologies, and technology services.

Ascent Renewables Inc. (ARI)

Ascent Renewables is a dormant subsidiary that is currently not generating revenue and does not hold any assets.

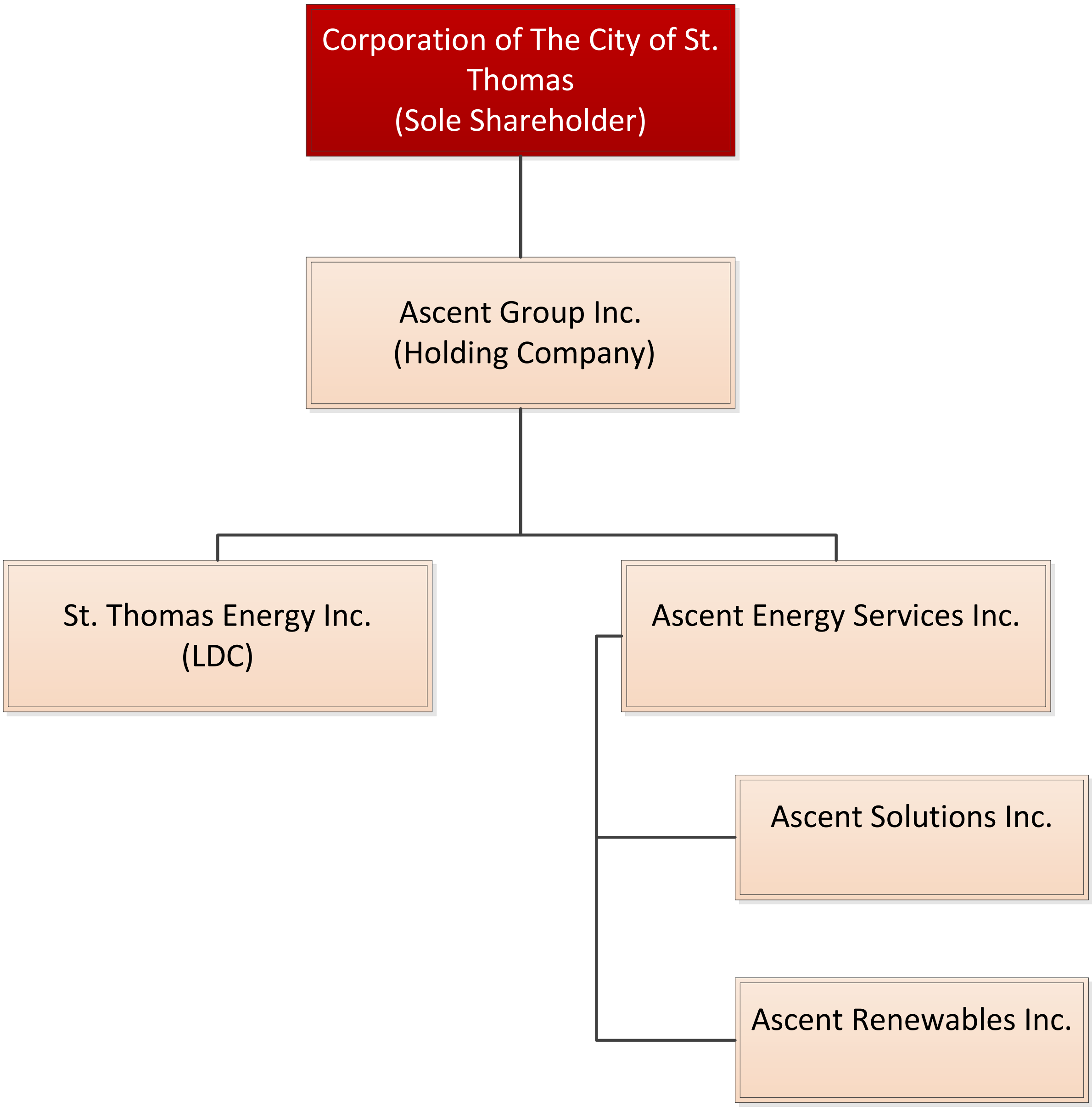


Figure 3 - Organization Structure of Ascent Group Inc.

Service Cost Benchmarking

STEI provides and receives a number of services from AESI (see Services Description section below). In order to determine STEI's compliance with Article 340, PwC surveyed a sample of seven Ontario LDCs that operate within the same industry as STEI. PwC compiled the survey response data as well as the survey results from The Mearie Group's 2012 Management Salary Survey of Local Distribution Companies in order to derive the average, median, and range for comparative analytics.

Services Description

Services Provided by Affiliates

Locates

- Locates services include work performed in order to determine where underground facilities or lines are situated throughout a given area. This service profile includes all costs related to Locates work performed by AESI on behalf of STEI. Costs include an hourly labour charge (tracked through daily timesheets), as well as any charges related to vehicles used in the performance of the service by AESI.

Meter Service Layouts

- Meter Service Layouts provide customers with diagrams/drawings of where meters should be situated as well as other specifications related to the placement/installation of meters. This service profile includes costs related to Meter Service Layouts performed by AESI on behalf of STEI. As with Locates, costs include both an hourly labour charge (tracked through timesheets) and vehicles charges incurred to perform the service.

Meter Technician Services

- Meter Technician services include meter maintenance work such as repairs, connections, inspections, and disconnections. This service profile includes all costs related to Meter Technician Services performed by AESI on behalf of STEI. As with the other service profiles, costs include an hourly labour charge as well as any vehicle charges incurred while performing repairs/maintenance of meters.

Services Provided to Affiliates

Engineering

- Engineering work performed by STEI on behalf of AESI is done on an ad-hoc basis. The type of work performed can vary from project to project (e.g. MEC Calculations, Site Specific Loss Calculations) and is performed by STEI's Engineering Manager. Time spent on each project by the Engineering Manager is tracked and charged at an hourly rate to AESI.

Methodology

Since each of the four services (Locates, Meter Technician Services, Meter Service Layouts, and Engineering) have an annual value of less than $100,000, we will be performing a benchmarking study to compare cost in procuring such services to and from STEI and its affiliates. Our approach is outlined below:

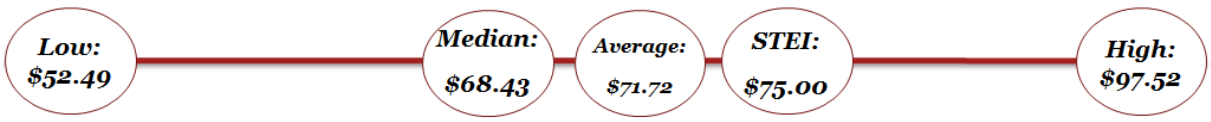
- For each of the services defined above, (i.e. Locates, Meter Service Layouts, Meter Technician Services and Engineering) service profiles and definitions were developed. Within each of these categories the charges between STEI and AESI related almost exclusively to hourly labour charges.
- PwC developed a survey and distributed to participating LDCs, defining each of the services in scope and requesting relevant cost data (e.g. labour rates) incurred at each of the LDCs.
- Responses were gathered and costs from other LDCs were benchmarked against those of STEI. Along with the LDC market data, salary information from The Mearie Group's 2012 Management Salary Survey of Local Distribution Companies was also used for applicable services. An understanding of the scope of services at other LDCs was obtained in order to ensure comparability of data with STEI. Where applicable, annualized costs were converted to hourly rates through use of Full Time Equivalents (FTEs) provided by LDCs.

Benchmark Results

Locates

- In 2012, AESI performed 1,389 Locates on behalf of STEI with a total cost of $88,000.
- The Locates hourly rate of $75 ($65 labour/per hour, $10 vehicle/per hour) charged by AESI to STEI is above average market rates. The industry average and median rates are $58.46 and $60.81 per hour respectively.
- The same personnel (from affiliate) who perform Locates also perform Meter Service Layouts and Meter Technician Services, which may cause higher rates compared to other LDCs.

Meter Service Layouts



- In 2012, AESI performed 168 meter service layouts on behalf of STEI with a total cost of $18,000.
- The Meter Service Layouts hourly rate of $75 ($65 labour/per hour, $10 vehicle/per hour) charged by AESI to STEI is slightly above average and median market rates of $71.72 and $68.43 respectively. As the rate is only approximately $3 above market averages, STEI's rate would be considered competitive.
- The same personnel (from affiliate) who perform Meter Service Layouts also perform Locates and Meter Technician Services, which may cause higher rates compared to other LDCs.

Meter Technician Services

- In 2012, STEI spent a total of $24,000 on Meter Technician Services provided by AESI.
- Although the STEI hourly rate of $75 ($65 labour/per hour, $10 vehicle/per hour) is well below the highest surveyed cost of ($91.31), it is still above market average and median rates of $55.62 and $49.64 respectively. The rate incurred at STEI would be considered less competitive compared to other LDCs.
- The same personnel (from affiliate) who perform Meter Technician Services also perform Meter Service Layouts and Locates, which may cause higher rates compared to other LDCs.

Engineering Services

- In 2012, STEI provided approximately $2,000 of Engineering Services to AESI.
- The STEI hourly rate of $100 is much greater than the average and median market rates of $52.69 and $50.72 respectively.
- However, since STEI's Engineering Services are ad-hoc in nature and a rarely requested service (5 requests made in 2012) by AESI, a slightly higher rate is therefore reasonable.

Incremental Cost of Water/Sewer Billing and Collection

The services performed by STEI on behalf of its affiliate, the City of St. Thomas, with respect to Water/Sewer Billing and Collections should be charged at STEI's incremental cost in providing such services. The costs of services performed have therefore been analysed in detail to identify incremental costs that STEI is incurring in the rendering of the services.

In order to develop the analysis of Water/Sewer Billing and Collection services, a listing of all relevant costs was compiled. The listing included both direct and indirect costs that were incurred while performing the Billing and Collection processes. These costs were then analysed to identify incremental costs to arrive at a cost per customer that STEI should recover from the City of St. Thomas.

A number of different cost drivers were also used to develop a total cost of services provided to the City of St. Thomas. Cost drivers for Water/Sewer Billing and Collections would include:

Postage

- Postage charges are driven primarily by the number and frequency of customer bills. STEI is currently being charged per parcel of mail with a bill being mailed once per month.

Labour

- Labour is primarily being driven by both hours and salary for relevant personnel involved in the Billing and Collections services. Depending on the employee, resources typically work between 35 to 40 hours/week. The cost of these hours is dependent upon the salary and benefits which the applicable employee earns.

Meter Readings

- The cost of meter readings is driven by both the frequency of meter reads as well as the type of meter being read. This service is currently outsourced to a third party provider, Olameter, who charges STEI a rate per read based upon the type of meter (i.e. commercial/residential, inside/outside/etc.)

Third Party Services

- Third party services such as cost incurred with respect to Utility Collaborative Services (UCS) systems and STEI's Customer Information System, are primarily driven by the number of customer accounts as UCS charges STEI for the majority of their costs on the basis of the number of customer accounts served each month.

- Ecaliber, which provides bill printing services, has costs that are driven by the number of bills printed.

- In addition to meter readings mentioned above, Olameter also performs disconnections, reconnections, and account delinquency notices deliveries on behalf of STEI. These three services are all driven by the number of instances performed as Olameter charges a rate for each service occurrence.

Incremental Cost

With respect to incremental cost, all costs that are expected to be incurred by STEI regardless of Water/Sewer services have been excluded in the analysis. This is under the assumption that certain costs would have to be incurred to service STEI's Hydro customers regardless of whether they are serving Water/Sewer customers. Examples of these costs include building facilities, postage machine leases, as well as internal systems.

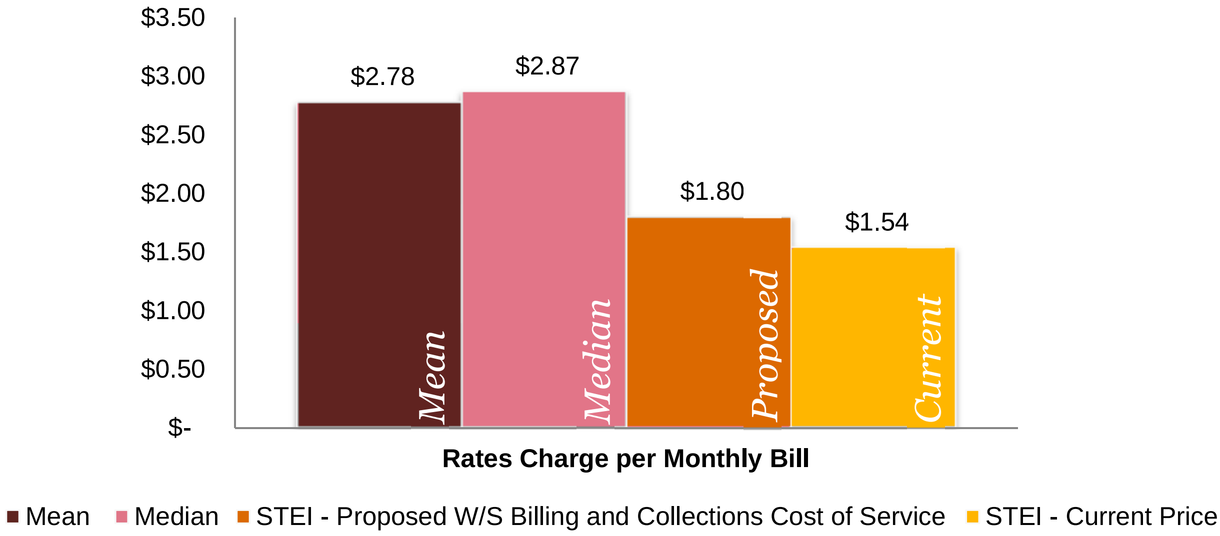
Incremental costs include additional resources, manual walk-by meter reading service, delivery of disconnection notices, postage, billing materials, bill printing services, and banking fees. As per STEI management estimates Customer Service Representatives spends approximately 51% of their available capacities on Water/Sewer Billing and Collection processes. By extrapolating the workload and maximizing resource utilization, we would assume that approximately 50% of the workforce or about three Customer Service Representatives would be fully utilized by Water/Sewer services. Manual walk-by meter reading services as well as delivery of disconnection notices are performed by Olameter, third party vendor, and service charges are assessed for each incident. Since STEI has implemented the AMI/Smart Meter infrastructure, walk-by meter reading service would only be necessary to perform Water/Sewer Billing services. For customers that have both Water/Sewer as well Hydro accounts, Water/Sewer bills could be sent in the same envelope as the Hydro bills to reduce postage costs. However for the customers that only have Water/Sewer-only services, additional postage will be incurred for each bill sent. Billing materials and bill printing are expensed for each additional Water/Sewer bill. While banking fees are charged based on the number of customers paying through credit/debit machines, and thus would be incurred based on the additional number of Water/Sewer customers served.

Under this scenario, the incremental costs incurred to provide the Water/Sewer Billing and Collection services would be $21.59/year per customer or $1.80 per bill. This would represent $322,750 per year in total charge to the City of St. Thomas for the Water/Sewer Billing and Collections services.

Results

Under the current Master Service Agreement (MSA), the City of St. Thomas is charged $275,000 in addition to late payment interests collected (estimated at $43,000 per year) which totals to $318,000 per annum. From the analysis above, the total incremental cost incurred to provide the City of St. Thomas with Water/Sewer Billing and Collection services amounts to $322,750. Therefore the current annual service fee charged by STEI is undercharged by approximately $5,000.

Additionally, PwC obtained pricing data from four sources for Water/Sewer Billing and Collection services from other Ontario LDCs. A comparison was made between the current and proposed pricing for STEI as well as the pricing of similar services by other Ontario LDCs.



Although the new proposed charge of $1.80/customer each month is lower than the average and median rates charged by other LDC's in Ontario, it is important to note that that cost structures may differ significantly between entities. As an example, STEI utilized third parties partners as well as sharing resources with affiliates and therefore had lower operating cost when compared to another LDC that maintains its own resources and services. As depicted in the chart above, both of the current fee of $1.54 per bill and proposed fee of $1.80 per bill are below the industry average of $2.78 per bill. Thus the current fee structure is very competitive in comparison with the industry.

Cost Allocation - Corporate, Finance, and Governance

Through their parent company Ascent Group Inc. (AGI), STEI receives a number of Corporate, Finance, and Governance services. These services are provided to all subsidiaries of AGI (i.e. STEI, AESI, ASI, ARI). The services provided by AGI include corporate functions such as executive management (i.e. CEO and CFO) and enterprise IT services, financial and accounting support for enterprise financial consolidation requirements, as well as governance which includes several Boards of Directors. Additionally, there are other various levels of administrative support such as financial/debt management, legal/consulting, and business development services.

As these services are received from an affiliate, it is important that STEI have in place a methodology to derive a reasonable rate charged amongst the various companies in accordance to Article 340 of the OEB's Accounting Policy Handbook. Given this, PwC has undertaken a detailed analysis of the costs involved in providing the Corporate, Finance, and Governance service in order to determine a reasonable fee to STEI.

Costs

The costs involved in providing the Corporate, Finance, and Governance services have been identified in order to determine a reasonable fee amongst the various subsidiaries of AGI. A significant portion of the costs relate to enterprise senior management and IT compensation. Other expenses include the Board of Directors for the various companies under the AGI umbrella, as well as professional services such as legal/professional fees and banking fees, as these expenditures are consolidated at the holding company and managed for all subsidiaries.

Methodology

To provide a robust methodology in allocating costs to respective entities within the Ascent Group of Companies, costs incurred during the provision of this service (e.g. CEO and CFO providing strategic oversight of the group of companies) have been allocated to each subsidiary respectively based on each entity's total revenue as a portion of the consortium of the Ascent Group of Companies. Since only two of the Ascent Group of Companies generate revenue (STEI and ASI), revenue numbers for those entities were extracted from their most recent financial statements (FY 2012). For those resources that provide support to the Ascent Group of Companies but have less of a focus on STEI operations, these will be allocated based on STEI management estimates of the resource time spent on STEI relevant matters. For example, the Enterprise IT Services personnel are less utilized by STEI since it has its own dedicated IT resource to help with day-to-day operations and troubleshooting. This will allow us to allocate costs accordingly to STEI in order to reflect a more realistic time/effort spent in STEI by those resources.

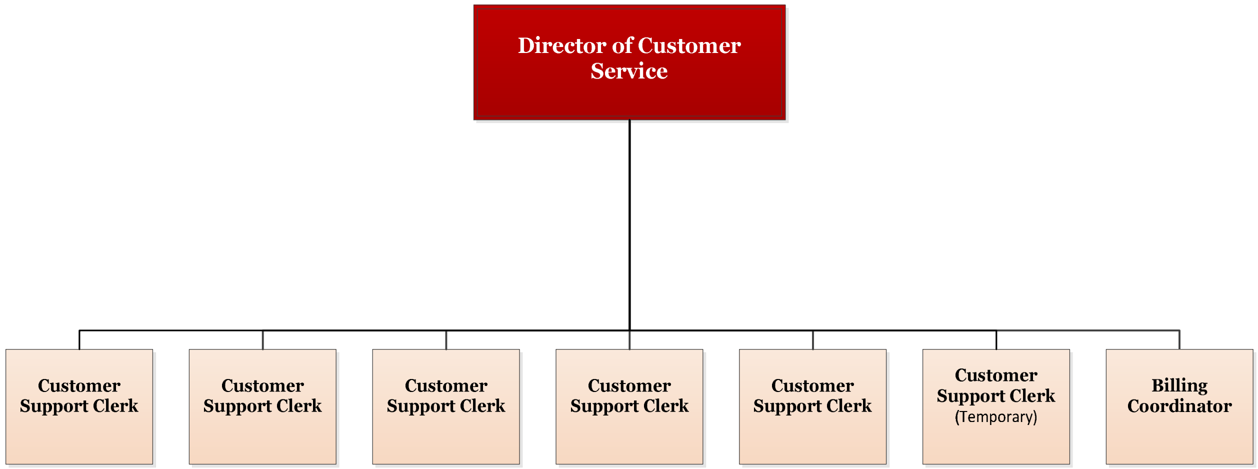
Results

By applying the methodology mentioned above, the result is that $444,348 ($2.22 per customer/month) should be charged to STEI for Corporate, Finance and Governance services.

	STEI	Ascent Services Inc.	Total
Revenue:	$8,499,437	$22,340,774	$30,840,211
Allocation Percentage:	27.56%	72.44%	100.00%

Appendices

Appendix A –CSR Department Organizational Structure



Appendix B – Customer Account Breakdown

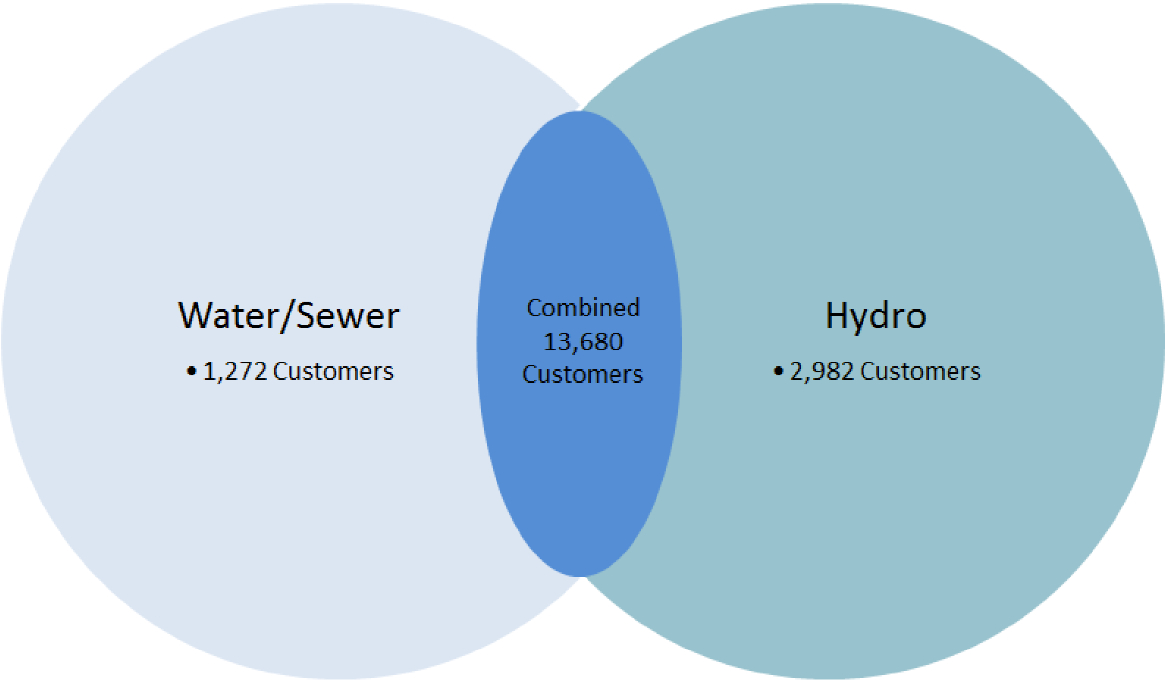


Figure 4 - Number of Customers in Hydro and Water/Sewer

Appendix C –Incremental Costs of Water/Sewer Billing and Collection Services

Cost	Incremental Portion
Olameter Meter Reading	100% Cost considered incremental to Water/Sewer as manual readings done on water meters only
Customer Support Labour	51% of Customer Support Clerk time (Approximately 3 FTE's) considered incremental to Water/Sewer based on STEI management estimate
Postage Costs	Customer account distribution split into three categories. Hydro-only, Water/Sewer-only, and Both. Incremental postage costs are equal to postage costs incurred on Water/Sewer-only portion of customer account distribution
Bill Printing	Incremental bill printing costs are equal to costs incurred for each Water/Sewer customer.
Olameter Collection Notices	Portion incremental to the Water/Sewer process is equal to the estimated notices attributable to Water/Sewer accounts.
Customer Information System	Customer account distribution split into three categories. Hydro-only, Water/Sewer-only, and Both. Incremental Customer Information System costs include costs that are incurred on a per customer account basis and hence are equal to the Water/Sewer portion of customer accounts.

Attachment 2 of 2

SLA-Water and Sewer

JOHN G. DEWANCKER, P.Eng.
Director, Environmental Services &
City Engineer

Michael Campbell P. Eng.
Manager of Operations & Compliance

BRIAN CLEMENT, MASc. P.Eng
Manager of Engineering

THE CORPORATION OF THE CITY OF
ST. THOMAS

All correspondence
to be addressed to:
PO Box 520 - City Hall Annex
St. Thomas, Ontario
N5P 3V7
Telephone (519) 631-1680
Fax (519) 631-2130

RECEIVED Mar 12/14

March 10, 2014

St. Thomas Energy Inc.
P.O. Box 460 Stn. Main
135 Edward St.
St. Thomas ON N5P 3V2

Attention: Ms. Jennifer Shannon-Mousseau

Dear Ms. Shannon-Mousseau:

RE: Signing of "Billing and Accounts Management Services Agreement"

Please find enclosed four (4) signed copies of the above noted agreement. Could you please see that these copies are signed by the appropriate individual and return two (2) signed copies to us?

Thank you for your assistance in this matter. If you have any questions, please do not hesitate to contact me at 519-631-1680 ext. 4161.

Yours very truly

Ginny Chapman

Ginny Chapman
Administrative Assistant/Office Coordinator

Encl.

BILLING AND ACCOUNTS MANAGEMENT SERVICES AGREEMENT

THIS AGREEMENT effective as of the 1st day of January, 2014

BETWEEN:

ST. THOMAS ENERGY INC.
(hereinafter referred to as "STEI")

OF THE FIRST PART

- and -

THE CORPORATION OF THE CITY OF ST. THOMAS

(hereinafter referred to as the "Municipality")

OF THE SECOND PART

WHEREAS the Municipality and STEI (collectively, the "Parties") are entering this Agreement to clarify and set out their respective rights and obligations with respect to the provision of Billing and Accounts Management Services;

NOW THEREFORE IN CONSIDERATION of mutual covenants and agreements as set forth, and for other good and valuable consideration (the receipt and sufficiency of which is hereby expressly acknowledged), the Parties do hereby covenant and agree with each other, as follows:

Definitions

"Effective Date" means start date.

"Parties" means STEI and the Municipality.

"Services" means the meter reading, billing and collection, account management services for water and waste water charges.

"Term" has the meaning described thereto in Section 3.01

"Base Service Escalation" means that once the base service customer thresholds have been exceeded the fee will be increased as outlined in Schedule A Fees and Charges, Fees and Charges subject to the escalation factors.

"Customers" refers to water and wastewater customers of the Municipality and the identified designated Central Elgin and Southwold Township customers.

"Escalation Factors" means that January 1 of each year the Billing and Accounts Management Services agreement will be increased by an inflation factor, a material 3rd party cost adjustment or an increase in base service above 1,350 water and sewer specific customer accounts or 14,600 joint water, sewer and electric accounts.

"Estimate" refers to a reading attributed to an account in the absence of an actual reading.

"Inflation Factor" refers to the percentage change in the All-items Consumer Price Index for Ontario as published by Statistics Canada for the most recent twelve (12) months ending December 31 over the same index for the immediately preceding twelve (12) months.

"Material 3rd Party Cost Adjustment" refers to any 3rd party water and sewer specific pass through cost in excess of the inflation factor.

"Remote" refers to the device outside the premise that is attached to the water meter and is capable of communicating the read from the water meter to water reader.

Meter Reading

1.1. Regular Readings

1.1.1. The 3rd party meter reading contractor shall conduct all readings within the municipal boundaries and some rural areas on behalf of STEI for the purposes needed to full fill this agreement. Readings will be obtained from the remote reading device or in the case of non-remote locations from the water meter inside the premise.

1.2. Frequency of Regular Readings

1.2.1. The 3rd party meter reading contractor shall attempt to read the meters or remotes of customers not less than every month or such other periodic basis mutually agreed to between the parties of this agreement.

1.3. Final Readings

1.3.1. In the case where the customer for the premise is to change, the meter reader shall ensure that a final meter reading is obtained for the service location.

1.4. Non-Remote Locations (Direct Reads)

1.4.1. In the event the customer does not have a remote; the meter reader shall make a reasonable effort to enter the premises to take a Direct Reading from the water meter. If there is no response from the customer, the meter reader shall leave a "self read card" for the customer in a place where the customer would be reasonably expected to see it.

1.5. Re-Reading

1.5.1. When a concern over reading accuracy has been raised a re-read of the meter will be done. In the event that there is an error in the meter reading, the customer's original bill, based on the erroneous reading, will be cancelled and a new bill issued.

1.6. Municipal By-law

1.6.1. STEI shall have regard for the municipal by-law regarding the regulations of water supply as found in By-law 17-2002 and as amended form time to time. By-law 17-2002 shall be attached as Schedule "B" as it relates to meter readings, billings and collection activities.

2. **Billing**

2.1. General

2.1.1. From receipt of the meter readings the billing will be calculated based on water consumption for the period and in accordance with the latest billing rates and charges as provided by the Municipality. STEI will be responsible for producing and distributing the invoice to the customer.

2.2. Estimates

2.2.1. In the event the meter appears to have malfunctioned an estimate amount of consumption will be determined based on the customers past history and billed accordingly with the latest billing rates.

2.3. Billing Adjustments

2.3.1. STEI will seek direction from the Municipality for all unusual circumstances causing the need for a billing adjustment. Billing adjustments are communicated to the customer and as such noted on the customer's account within the CIS system. Re-payment terms equal to the time related to the adjustment are to be offered to the customer.

2.3.2. In general, all related meter readings, billings and collection activities must be in compliance with the Municipality's Water By-Law 44-2000, as amended.

3. **Customer Service**

3.1. STEI will provide customer services to the Municipalities water and waste water customers in the same fashion as their electric services, providing the appropriate response in a courteous and timely fashion for the following situations:

3.1.1.1. Explaining charges on a customer's account;

3.1.1.2. Inform the customer of rates, billing and collection practices;

3.1.1.3. Logging a service request for broken meters and remotes and forwarding it to the Municipality

3.1.1.4. Update customer accounts with required information (move in/out, change of banking information etc.);

3.1.1.5. STEI shall not be required to defend or justify the Municipalities' water and wastewater policies.

3.1.2. Customer Service Hours of Operation

3.1.2.1. STEI shall provide contact ability during standard office hours. Voicemail and email capabilities shall be available twenty four (24) hours a day, seven (7) days a week.

4. Cash Collection

4.1. STEI shall provide convenient destination points for water and wastewater customer payments.

4.2. STEI's payment processes shall have the capability to facilitate the following;

4.2.1. Ensure internal controls and audit trails for accuracy and completeness;

4.2.2. Process all cash, cheque, post-dated cheque, pre-authorized, electronic banking files and debit payments.

5. Overdue Accounts

5.1. Overdue interest penalty charge as prescribed by STEI shall be imposed on all water and wastewater accounts not paid in full by the due date specified on the customer invoice. Any revenue therefrom shall be retained by STEI.

5.2. STEI shall be responsible for making every reasonable effort to collect past due accounts including but not limited to the imposition of overdue interest.

6. Reporting

6.1. Each month STEI will provide to the Municipality the following information;

6.1.1. Number of customers billed by account type (residential, commercial, industrial etc.);

6.1.2. Total usage by account type for the municipality and two townships;

6.1.3. Total dollar (usage and fixed) amount by account type for the municipality and two townships;

6.1.4. Listing of uncollectable accounts, with service address, end date, by service and applicable dollar amount owing

6.1.5. Statement of total monthly billings by service, less uncollectable accounts

7. **Term of Agreement**

7.1. The term of this Agreement shall be from the Effective Date to and including December 31, 2016 and the Term shall extend automatically for a further period(s) of one year unless either Party gives the other notice in writing not less than forty five (45) days prior to the end of the Term, or the end of any renewal of the Term, as the case may be.

7.2. During the Term, the Municipality shall have the option of cancelling this agreement on the anniversary of the Effective Date by providing notice in writing to St. Thomas Energy Inc. not less than forty five (45) days prior to the end of the anniversary of the Effective Date.

8. **Covenants of the Municipality**

8.1. *Purchase of Services* - The Municipality agrees to purchase the Services for the Term.

8.2. *User Rates* - The Municipality will determine the user rates for water and waste water use by-law. The Municipality will provide STEI thirty (30) days written notice before implementing new rates.

8.3. *Maintenance and Servicing of Meters* - The Municipality will be responsible for the maintenance and servicing of water meters. STEI will promptly report to the water and waste water department of the Municipality, or such other department as the Municipality may direct, any unusual or irregular meter readings which indicate that there may be a problem with a meter.

9. Covenants of STEI

9.1. *Provision of Services* – STEI agrees to provide the Services for the Term in a competent and professional manner. Subject to the obligations hereunder, STEI shall be free to offer services to any other person.

9.2. *Meter Reading and Billing* - STEI either directly or through a 3rd party, will read the water meters of the customers and bill the Customers monthly based on the readings for the water and waste water charges. In the event that STEI is unable to read a Customer's meter, for whatever reason, the Customer's usage will be estimated by STEI, based on previous usage, and billed according to the estimate.

9.3. *Change of Occupancy Meter Reading* – Any change of occupancy meter reading requests by Customers will be the responsibility of STEI.

9.4. *Change of Meter* – STEI will be responsible for processing all meter changes within the billing system up to a maximum of 3,000 annually based on information provided by the Municipality.

9.5. *Occupancy/New Accounts* – STEI will be responsible for setting up new accounts within the billing system for new Customers.

9.6. *New Service Accounts*- STEI will be responsible for setting up new service accounts based on information provided by the Municipality.

9.7. *Payment to the Municipality* - STEI will pay to the Municipality the water and waste water charges billed to the Customers by the end of the month following the date of invoicing.

9.8. *Accounts Receivable* –STEI will have no liability for unpaid Customer accounts receivable or Customer accounts receivable that are in arrears.

9.9. *Uncollectable Accounts Receivable* - In the event STEI does not receive payment in respect to a final account within 1 month from the date of billing, the account receivable will be considered uncollectable and deducted from that month's payment to the Municipality. Such uncollectable accounts will be listed and provided to the Municipality monthly via a report indicating the details of the write off.

9.10. *Customer Inquiries* - STEI will direct any Customer inquiries regarding rates, meters and installation to the staff of the Municipality.

9.11. *Non-disclosure of Information* - STEI will not (either during the term of this Agreement or at any time thereafter) disclose any confidential Customer information or confidential information regarding the Municipality, disclosed to STEI pursuant to this Agreement, to any person other than with the consent of the Municipality or pursuant to a court order. STEI may disclose the confidential information referred to above to a professional advisor who is under a duty of confidentiality provided that STEI informs the professional advisor of the confidential nature of the information.

9.12. *Insurance* - STEI shall pay and maintain, for the benefit of STEI, appropriate insurance covering the operations and liabilities of STEI relevant to this Agreement, including, without limiting the generality of the foregoing, worker's compensation and employment insurance in conformity with applicable statutory requirements in respect of any remuneration payable by STEI to any employee and public liability and property damage insurance. For clarity, STEI shall maintain a minimum of $5 million of liability insurance (Commercial General Liability) and the Municipality shall be named as an additional insured on the policy. Further, STEI shall maintain a minimum of $2 million of owned/non-owned automobile liability insurance.

9.13. *Indemnity* – STEI, its contractors and subcontractors, shall indemnify and save the Municipality harmless from and against all claims, actions, losses, expenses, costs or damages of every nature and kind whatsoever which the Municipality or its officers, employees or agents may suffer as a result of the negligence or breach of STEI in the performance or non-performance of this Agreement.

9.14. *Limitation of Liability* –Except as agreed from time to time, STEI shall have no liability for billing errors, unpaid or overdue bills or uncollectable bills in carrying out the Services.

9.15. *Other Services* – STEI shall provide such other services as may be reasonably requested by the Municipality from time to time for such remuneration as agreed to between the parties.

10. <u>Fees</u>

10.1. *STEI's Fees* –The Municipality shall pay to STEI the fees and charges set forth in **<u>Schedule A</u>** attached hereto as they may be amended from time to time in relation to the costs of providing the Services. The fees and charges set forth in Schedule A will be adjusted annually commencing in year two (2) by the Escalation Factor. The Escalation Factor will be calculated when the Inflation Factor becomes available and will be applied retroactively to the most recent anniversary date.

10.2. *Occupancy Charges* – STEI may charge Customers occupancy charges/new account set up fees. STEI is not required to remit these charges and fees to the municipality.

10.3. *Change of Meter* – STEI will charge for time and material for all meter changes within the billing system over and above the 3,000 annual amounts included in this Agreement. All additional charges will be supported by payroll time sheet entry and 3rd party invoices.

10.4. *Interest Charges* – STEI may charge the Customers interest charges for late payment of Customer bills and STEI is not required to remit these interest charges to the Municipality but applied to the City Payment per schedule A.

10.5. *Invoicing of Fees* - The fees and charges referred to in Schedule A will be invoiced to the Municipality by STEI within five (30) days from the end of each month and shall provide reasonable detail of the fees and charges incurred. The Municipality shall pay all invoices within ten (10) days from the date of receipt.

10.6. *Extra-Ordinary Costs* – STEI will submit to the Municipality fees incurred which is not included on Schedule A prior to invoicing the Municipality for these fees and costs. STEI will have regard for the Municipality's Purchasing By-laws related to such matters.

11. <u>Termination</u>

11.1. In the event of non-performance by either Party of its obligations under this Agreement, the other Party may at its sole option elect to terminate this Agreement provided that the defaulting Party shall be given written notice of the default and shall be given ninety (90) days to cure the default, and then only upon failure to cure the default this Agreement may be terminated.

12. Notices

12.1. All notices required to be given to either of the Parties under this Agreement shall be in writing and delivered to the following:

In the case of STEI, to:

St. Thomas Energy Inc.
135 Edward St.
St. Thomas, Ontario
N5P4A8
Attention: President & Chief Operating Officer
Telephone: (519) 631-5550 ext. 5229
Fax: (519) 631-5193

In the case of the Municipality, to:

The Corporation of the City of St. Thomas
545 Talbot St.
St. Thomas, Ontario
N5P 3V7
Attention: CAO
Telephone: (519) 631-1680
Fax: (519) 631-3836

13. Relationship

13.1. STEI's obligations in connection with this Agreement are contractual in nature only. The legal relationship between the Parties established by this Agreement is that of STEI serving solely as an independent contractor providing specified services to the Municipality on an arm's length basis and, without limitation, the relationship is not intended to be, and shall not be deemed or considered to be, one of joint venture, co-venture, agency or trustee-beneficiary and therefore neither Party will owe any fiduciary or similar duty to the other Party under this Agreement, all of which are expressly disclaimed.

14. Arbitration

14.1. The Parties agree to consult with each other and to negotiate in good faith to resolve any differences or disputes which either Party may have relating to the interpretation, application or implementation of this Agreement, or any dispute which may arise over any costs, fees or other costs incurred and failing agreement the Parties agree to resolve their disputes by arbitration as provided in this Article 10.

14.2. Arbitration of a dispute shall be commenced by written notice by a party requesting arbitration to the other, which notice shall identify the issue or issues it wishes to submit to arbitration. Within thirty (30) days of the date of the notice, the Parties shall agree upon a single arbitrator and failing agreement then each Party shall appoint an arbitrator and the two appointees shall within 45 days of the date of the notice of arbitration appoint a third person who shall act as Chair of the arbitration panel, and failing agreement the Chair shall be appointed by a judge of the Ontario Supreme Court of Justice pursuant to the provisions of the *Arbitration Act*, R.S.O. 1991, c.A.17.

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

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

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

15. General Provisions

15.1. *Negligence* – STEI including its contractors and subcontractors, shall be responsible for any errors attributable to STEI's negligence or by the negligence of its servants, agents or representatives and STEI shall be responsible for any errors due to the breach of this Agreement by STEI. Limitation of Liability – STEI shall not be responsible or otherwise liable for any injury, loss, or damage resulting from, occasioned to or suffered by any person or persons or to any property, through the provisions of the Services, attributable to STEI, its servants, agents, or representatives unless the injury, loss, or damage arises as a result of the negligence of STEI, its servants, agents or representatives or as a result of a breach of this Agreement by STEI.

15.2. This Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns.

15.3. The division of this Agreement into Articles and Sections and the insertion of headings are for the convenience of reference only and shall not affect the construction or interpretation of this Agreement. The terms "this Agreement", "hereof", "hereunder" and similar expressions refer to this Agreement and not to any particular Article, Section or other portion hereof and include any agreement or instrument supplemental or ancillary hereto. Unless something in the subject matter or context is inconsistent therewith, references herein to Articles and Sections are to Articles and Sections of this Agreement.

15.4. In this Agreement words importing the singular number only include the plural and vice versa, words importing any gender include all genders and words importing persons include individuals, partnerships, associations, trusts, unincorporated organizations and corporations and vice versa.

15.5. This Agreement constitutes the entire agreement between the Parties with respect to the subject matter hereof and cancels and supersedes any prior understanding and agreements between the Parties hereto with respect thereto. There are no representations, warranties, forms, conditions, undertakings or collateral agreements, express, implied or statutory between the Parties other than as expressly set forth in this Agreement.

15.6. No amendment to this Agreement shall be valid or binding unless set forth in writing and duly executed by both of the Parties hereto. No waiver of any breach of any term or provision of this Agreement shall be effective or binding unless made in writing and signed by the Party purporting to give the same and, unless otherwise provided in the written waiver, shall be limited to the specific breach waived.

15.7. Except as may be expressly provided in this Agreement, neither Party hereto may assign its rights or obligations under this Agreement without the prior written consent of the other Party hereto.

15.8. If any provision of this Agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability shall attach only to such provision or part thereof and the remaining part of such provision and all other provisions hereof shall continue in full force and effect.

15.9. Each Party must from time to time execute and deliver all such further documents and instruments and do all acts and things as the other Party may reasonably require to effectively carry out or better evidence or perfect the full intent and meaning of this Agreement.

15.10. This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

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

St. Thomas Energy Inc.

Per:

Gary Tobin

President & Chief Operating Officer

Gary Tobin

The Corporation of the City of St. Thomas

Per:

Heather Jackson

Mayor

Mayor Heather Jackson
The Corporation of the City of St. Thomas

Per:

CAO/Clerk

W.S. GRAVES
C.A.O./CLERK

Schedule A

BASE SERVICES	
Billing, Collection and Meter Reading	$337,000 / year
Additional Base Services Fees for customer accounts exceeding thresholds defined in Escalation Factors	
1. Water and sewer only accounts 2014 rate	$39.60 / year
2. Combined water, sewer and electric, 2014 rate	$20.76 / year

(For greater certainty the Inflation Factor and Material 3rd Party Cost Adjustment factors apply to the Base Services charge and Additional Base Services Fees for customer accounts exceeding thresholds)

Incremental Costing Summary

Item	# of Accounts	Cost $
Water meter reading & collection	15,064	110,244
Postage, envelopes, notices	1,274	18,108
Bill print	1,274	5,800
Administration, IT	15,064	32,737
Customer Service	15,064	170,111
Total Billing & Service Costs		337,000
Interest earned on overdue accounts		(43,000)
Amount due from City of St. Thomas		294,000

ADDITIONAL CHARGES/ADJUSTMENTS	
Interest Charges Sec 10.4	Reduce overall fees by monthly amount collected
Other Services Sec 9.14	If/as agreed
Extra-Ordinary Services Sec 10.5	If/as agreed
Ancillary	If/as agreed
Meter Changes Sec 9.4	Time & material for meter changes in excess of 3,000/year

PURCHASE OF NON-AFFILIATE SERVICES

St. Thomas Energy Inc. purchases supplies and services from third parties in order to distribute electricity to its customers. St. Thomas Energy Inc.'s expenditures on purchased products and services in 2012 and 2013 in excess of $50,000 from any single supplier is provided below. While spending projections are not prepared on this basis, St. Thomas Energy Inc. expects its pattern of expenditures to remain generally consistent with recent history, except for material variances in expenses for Operations, Maintenance and Administration.

St. Thomas Energy Inc.'s procurement policy appears as Attachment 1 to this Exhibit. St. Thomas Energy Inc. purchases equipment, materials and services in a cost effective manner with full consideration given to price as well as product quality, the ability to deliver on time, reliability, compliance with engineering specifications and quality of services. Vendors are screened to ensure knowledge, reputation, and the capability to meet St. Thomas Energy Inc.'s needs. The procurement of goods and services for St. Thomas Energy Inc. is done consistent with its procurement policy and carried out with the highest of ethical standards and consideration to the public nature of the expenditures. Table 4-10 below shows the Non-Affiliate Services and Products for 2012 and 2013.

Table 4-10

2012 STEI NON-AFFILIATE SERVCIES and PRODUCTS

Vendor Name	Product and Service	Methodology of Selection	$ Value
Anixter Canada Inc	Wire	Tender	89,224
Automated Solutions	GIS Project	Tender	177,638
Burman Energy Consultants	OPA CDM programs	Tender	332,300
C.E.S. Transformer	Transformers	Tender	1,900
Canada Post Corp	Postage	Sole source	114,382
Cyril J Demeyere Ltd	Consulting services	Sole source, specialized knowledge	48,336
Davey Tree Expert Co	Tree trimming/maintenance	2011 tender (3 yrs)	45,506
Elster Metering	Electric meters	London buying group (Tender)	60,867
Harris Computer Systems	Maintenance/licence fees, software upgrades to system	Sole source/UCS Group	25,521
HD Supply Power Solutions	Line hardware, load break elbows, lugs, cutouts, fuse links, cable adaptors, etc.	Tender	97,705
LDA Construction(2011)Inc	Construction services - Capital Project	Tender	127,321
Olameter Inc	Meter reading services	Tender	159,133
Pachecos Contractors Ltd.	Construction services - Capital Project	Tender	83,317
POSI+	Aerial devices for vehicles	Tender	85,616
Utilismart	Web-site presentment of wholesale, retail, micro-fit, embedded generation, totalized/aggregated prints, IESO bill verification	Tender	53,775
Utility Collaborative Service	Billing, Hosting of various services - EIS, mCARE, EBT spokes, financial, Tele-Works	2010 tender	269,866

2013 STEI NON-AFFILIATE SERVCIES and PRODUCTS

Vendor Name	Product and Service	Methodology of Selection	$ Value
Attache Group Inc.	Computer hardware/software parts, maintenance agreements	Tender	192,886
Automated Solutions	GIS Project	Tender	81,148
Burman Energy Consultants	OPA CDM programs	Tender	474,093
C.E.S. Transformer	Transformers	Tender	122,903
Canada Post Corp	Postage	Sole source	121,106
Commercial Truck Equipment	Vehicle repairs	Tender	68,644
Davey Tree Expert Co	Tree trimming/maintenance	2011 tender (3 yrs)	56,005
Doug Tarry Limited	Construction services - Capital Project	Tender	135,435
Elster Metering	electric meters	London buying group (Tender)	61,426
Guelph Utility Pole Co Ltd	Wood poles	Buying Group	52,321
HD Supply Power Solutions	Line hardware, load break elbows, lugs, cutouts, fuse links, cable adaptors, etc.	Tender	140,776
LDA Construction(2011)Inc	Electrical underground, padmount transformers and vaults installation	Tender	132,496
Olameter Inc	Meter reading services	Tender	162,167
Pachecos Contractors Ltd.	Construction services - Capital Project	Tender	531,088
POSI+	Single bucket line truck aerial device and body	Tender	153,419
PWC	Professional services re: 2015 Rate application	Tender	51,947
Utilismart	Web-site presentment of wholesale, retail, micro-fit, embedded generation, totalized/aggregated prints, IESO bill verification	Tender	53,850
Utility Collaborative Service	Billing, Hosting of various services - EIS, mCARE, EBT spokes, financial, Tele-Works	2010 tender	285,275
Wajax Equipment	Vehicle repairs	Tender	85,950

Attachment 1 of 1

Procurement Policy

7.4 Purchasing

Purpose:

St. Thomas Energy Inc. has established and maintained procedures to control the quality of purchased products or services through the use of supplier assessment and monitoring, purchasing document data and verification of incoming product.

Scope:

These procedures apply to the purchase of all energy, parts, materials and subcontracted services required to supply products or services. St. Thomas Energy Inc. purchases fall into two major categories:

1. Electrical energy purchased from the Independent Electricity System Operator (IESO) on a daily spot price and regulated by the Ontario Energy Board (OEB).
2. All other materials, supplies, vehicles, equipment and services required to supply products and services to the customer. These procedures deal primarily with this category of purchases.

Responsibility:

The Director of Engineering and Operations has the responsibility for implementing and maintaining these procedures.

Definitions:

To distinguish between different categories of Suppliers the following definitions apply:

- Suppliers who deliver catalogue products,
- Subcontractors who design and/or manufacture products or provide services in accordance with specifications provided by St. Thomas Energy Inc.

7.4.1 Purchasing control

7.4.1.1 A copy of the approved suppliers list is available to personnel preparing and authorizing the company's purchasing documents. Materials, supplies, equipment or services incorporated in a company's products or services may not be purchased from suppliers that are not on the Approved Suppliers List, except for the special situations as outlined in subsection 7.4.1.7 of this procedure. Furthermore, Ontario Regulation 22/04 requires that all materials and equipment purchased used to build and construct an electrical distribution system must meet Ontario Electrical Code Rule 2-024 which means the material and equipment must be approved by an acceptable certification agency such as the Canadian Standards Association (CSA). Ontario Regulation 22/04 also allows material and equipment to be approved by the distributor. The product review and approval process must be similar to the requirements under Ontario Electrical Code Rule 2-024. This can be achieved by using material and equipment with: applicable industry standards recognized by the Electrical Safety Authority (ESA) including an assurance that the equipment presents no undue hazard to persons or equipment; or distributor developed equipment specifications approved by a professional engineer for a specific use on a distribution system including an assurance that the equipment presents no undue hazards to persons or property; or by good utility practice where material and equipment (other than new major equipment) are approved by a competent person for specific use on the distribution system including an assurance that the equipment presents no undue hazards to persons or property. The product review and approval process must also be documented.

7.4.1.2 All Suppliers who have been supplying the company under the current quality system and whose performance is deemed to be satisfactory are considered to be qualified and approved. Regardless of the past quality history, there are no exemptions from continuous quality performance monitoring as described in subsection 7.4.1.9 of this procedure.

7.4.1.3 New suppliers may only be approved by satisfactorily completing a Supplier Approval Form (Form 15). The form may be completed by the supplier or St. Thomas Energy Inc.

7.4.1.4 The Department Manager will use Form 15 to determine the method and acceptance criteria for new suppliers. Upon completion of all the required information listed on the form the Department Manager will approve or reject the supplier.

7.4.1.5 It is the responsibility of the Department Managers to forward all supplier approval information to the Purchasing Agent so that the Approved Supplier List (ASL) can be updated.

7.4.1.6 It is the responsibility of the Purchasing Agent to ensure that the ASL is current and maintained.

7.4.1.7 On occasion a situation may arise that requires St. Thomas Energy Inc. to purchase materials or services from a supplier not on the Approved Supplier List due to emergency reasons (approved supplier is out of product, supplier is sole supplier, etc.) The Department Manager will approve any purchases from suppliers not on the Approved Suppliers List. St. Thomas Energy Inc. will take appropriate precautions at the receiving inspection phase when this situation occurs. Following delivery of the product or service, the supplier should apply to be added to the Approved Supplier list.

7.4.1.8 Supplier's performance will be reviewed based on nonconformance identified against the supplier. Data is summarized for the management review meetings at least annually.

7.4.1.9 Suppliers, who repeatedly fail to deliver satisfactory products, and/or do not deliver on time despite earlier complaints and requests for corrective actions, are removed from the Approved Supplier List. The reason for removal will be recorded and placed in the supplier's file.

7.4.2 Purchasing information

7.4.2.1 It is the responsibility of any employee requiring non-inventory products or services to complete a Requisition (Form 22), have it approved by their supervisor and forward it to the Purchasing Agent. For office supplies an Office Supplies Blanket Requisition (Form 98) is to be used.

7.4.2.2 The Department Manager or Supervisor has the option of completing a Requisition (Form 22) or sending an email directly to the Purchasing Agent with their purchase request.

7.4.2.3 A Purchase Order (Form 47) is to be issued for every purchase unless an alternative method is approved and authorized by the Department Manager (e.g. credit card, petty cash etc.). This will include any open purchase orders placed with suppliers for miscellaneous items. The appropriate paperwork and/or receipts for each purchase must be promptly submitted to the Purchasing Agent.

7.4.2.4 In order to maintain competitive pricing, the Purchasing Agent will normally obtain pricing from at least two suppliers.

7.4.2.5 Purchase orders (Form 47) shall contain data clearly describing the product ordered, including where applicable:

a) the type, class, grade or other precise identification;
b) the title or other positive identification, and applicable issues of specifications, drawings, process requirements, inspection instructions and other relevant technical data, including requirements for approval or qualifications of product, procedure, process equipment and personnel;
c) the title number and issue of the quality system standard to be applied. Currently, St. Thomas Energy Inc. does not require that any supplier maintains a registered quality system.

7.4.2.6 The employee completing and/or approving the purchase document will review it for adequacy of specified requirements prior to release and verify such by his/her initials. Approval limits for purchase orders are identified in the purchasing work instruction.

7.4.2.7 It is the responsibility of the Purchasing Agent to monitor and maintain inventory levels using the Critical Inventory Report.

7.4.2.8 Any employee performing purchasing functions is responsible to ensure that a copy of the purchasing documents is forwarded to the Purchasing Agent so that he/she can verify that items received meet the purchasing requirements.

7.4.3 Verification of purchased product

7.4.3.1 The Purchasing Agent is responsible to ensure that purchased product is inspected as required to verify that it meets specified requirements.

7.4.3.2 The Purchasing Agent is responsible to ensure that all required paperwork is received with purchase product.

7.4.3.3 The Purchasing Agent is responsible to ensure that all purchased products are properly identified and labeled and stored. He/She is also responsible to segregate and identify parts and materials purchased for specific jobs.

7.4.3.4 The Purchasing Agent or any employee performing receiving functions is responsible to initiate a nonconformance as outlined in “Control of Nonconforming Product PRO

8.3" if any purchased product fails incoming inspection.

7.4.3.5 St. Thomas Energy Inc. will specify verification arrangements and the method of product release on the purchasing documents when it proposes to verify purchased product at the supplier's premises.

7.4.4 Promotion or Use of New Equipment and Material

7.4.4.1 When new equipment and material that has not been previously used in the construction of the electrical distribution system is being promoted by vendors or manufactures, an evaluation must be completed to ensure the equipment meets the requirements of regulation 22/04 and meets STEI operations requirements.

7.4.4.2 When new equipment and material that has not been previously used, is being proposed to staff, it must be brought to the attention of the Distribution Engineer and Director of Engineering & Operations to ensure regulatory and operations requirements are satisfied.

7.4.5 Vendor Monitoring

7.4.5.1 The Purchasing Agent/Stores Keeper and/or the applicable Department Manager have the responsibility to ensure that suppliers' performance is monitored.

7.4.5.2 The Purchasing Agent and/or Stores Keeper and/or Department Manager will record in the database non-conformances regarding quality, on time delivery, order accuracy and any nonconformance. The intent of this recording is for tracking purposes to monitor performance over time to see if there are trends that should be reviewed and discussed with the supplier or that may require the issuance of a corrective action request. (If a problem is deemed significant a corrective action request may be issued for the one event at the discretion of the Purchasing Agent and/or Quality Management Rep.)

7.4.5.3 Suppliers' performance will be reviewed annually to determine the quality of service. The Purchasing Agent reviews the data base and creates a brief summary covering problematic vendors. This summary is present to the Quality Management Rep. (or Delegate) for inclusion and discussion at the Management Review meeting.

Reference Documents:

Work Instruction 7.4.1 – Request for Pricing and Ordering Material
Work Instruction 7.4.2 – Inventory Control
Work Instruction 7.4.3 – Corporate Credit Card Policy

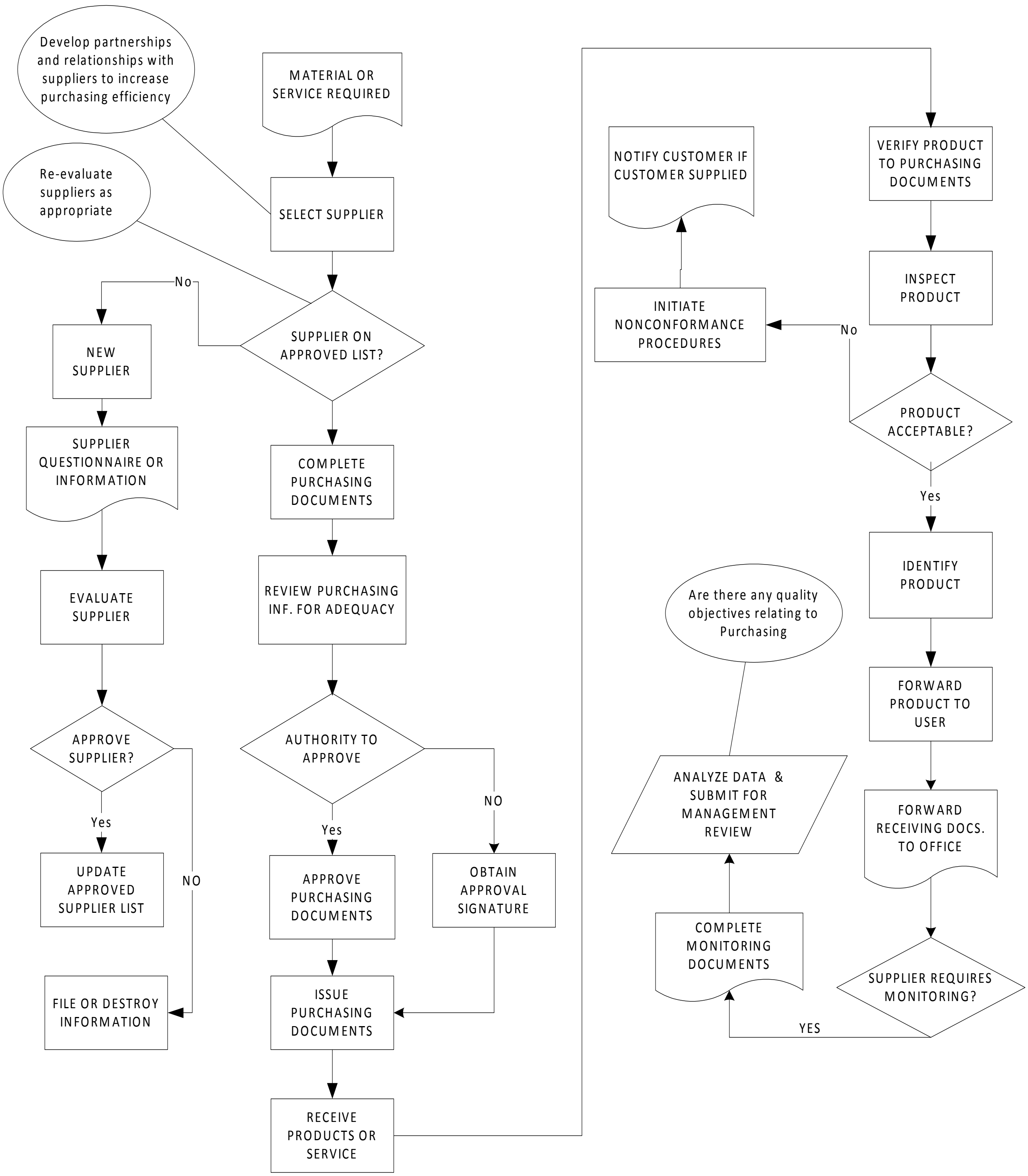
Document History:

September 2011 – Document history section added and 7.4.1.8 edited to remove reference to data analysis procedure; 7.4.1.7 edited to remove exemptions for financial institutions, law firms, consultants etc.

January 31, 2012 - Vendor monitoring added; rewritten from PRO 8.4-Analysis of Data that no longer exists due to quality manual rewrite – Changed reference from Operations Manager to Director of Engineering & Operations.

April 8, 2013 – Add process for Product Review as per ESA Audit, ‘Needing Improvement’.

Appendix I - St Thomas Energy Services Inc.'s Purchasing Process



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ONE-TIME COSTS

STEI has included one-time cost or non-annual costs of $20,000 in its 2015TY. This amount is related to the customer engagement survey that is done every-other year. This amount is then used for the actuarial valuation of the post-employment benefit liability that is also performed every other year, in the customer engagement survey “off years”.

REGULATORY COSTS

STEI's Finance Department is responsible to prepare all regulatory filings, rate application, audits and inputs in the Ontario Energy Board ("OEB"), the Independent Electrical Systems Operator ("IESO") and other regulatory agencies. The Finance Department is the main conduit for communication, educating and informing employees of new requirements for the agencies noted above.

The 2015TY Regulatory Costs do not include staff labour costs but is comprised of Ontario Energy Board annual cost assessments, cost awards, costs associated with rate filings and rate orders and one-time costs associated with this Cost of Service Application.

STEI will incur significant costs for the preparation, processing and approval of the 2015 Cost of Service Application. These costs are identified in Board Appendix 2-M. The costs include consultant fees, legal fees and intervenor cost awards. STEI requests approval of these costs to be recovered over a five year period until STEI's next scheduled Cost of Service Application. Therefore, in the 2015 Test Year, STEI has included $178,675 representing $92,675 of ongoing cost and one-fifth (or $86,000) of the total Cost of Service Application costs. Board Appendix 2-M is shown below:

Appendix 2-M
Regulatory Cost Schedule

On-Going
One-Time

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2011 Board Approved)	Most Current Actuals Year 2013	2014 Bridge Year	Annual % Change	2015 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 40,000	$ 39,932	$ 43,000	7.68%	$ 45,000	4.65%
2	OEB Section 30 Costs (Applicant-originated)									
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going		$ 1,500	$ 1,500	0.00%	$ 2,000	33.33%
4	Expert Witness costs for regulatory matters						$ -		$ -	
5	Legal costs for regulatory matters	5655		One-Time	$ 100,000		$ 125,000			-100.00%
6a	Consultants' costs for regulatory matters	5655		One-Time	$ 237,400	$ 77,000	$ 143,000	85.71%		-100.00%
6b	Consultants' costs for regulatory matters	5655		On-Going		$ 12,684	$ 6,024	-52.51%	$ 15,000	149.00%
7	Operating expenses associated with staff resources allocated to regulatory matters, OEB initiatives, conferences, etc.			On-Going	$ 32,796		$ -		$ 27,675	
8a	Operating expenses associated with other resources allocated to regulatory matters , New paper add	5655		On-Going		$ 545	$ 1,000	83.49%	$ 1,000	0.00%
8b	Operating expenses associated with other resources allocated to regulatory matters, additional expenses for rate hearing, etc	5655		One-Time		$ 3,000	$ 7,000	133.33%		-100.00%
9	Other regulatory agency fees or assessments									
10	Any other costs for regulatory matters (please define)									
11a	Intervenor costs	5655		On-Going		$ 190		-100.00%	$ 2,000	
11b	Intervenor costs	5655		One-Time	$ 75,000		$ 75,000			-100.00%
12	Sub-total - Ongoing Costs [3]		$ -		$ 72,796	$ 54,851	$ 51,524	-6.07%	$ 92,675	79.87%
13	Sub-total - One-time Costs [4]		$ -		$ 412,400	$ 80,000	$ 350,000	337.50%	$ -	-100.00%
14	Total		$ -		$ 485,196	$ 134,851	$ 401,524	197.75%	$ 92,675	-76.92%

Please fill out the following table for all <u>one-time</u> costs related to this cost of service application to be amortized over the test year plus the IRM period.

		Historical Year(s)	2014 Bridge Year	2015 Test Year
4	Expert Witness costs			
5	Legal costs	$ -	$ 125,000	$ -
6	Consultants' costs	$ 77,000	$ 143,000	$ -
7	Incremental operating expenses associated with staff resources allocated to this application.		$ -	
8	Incremental operating expenses associated with other resources allocated to this application. [1]	$ 3,000	$ 7,000	
11	Intervenor costs		$ 75,000	

1 Please identify the resources involved.
2 Where a category's costs include both one-time and ongoing costs, the applicant should prove a separate breakdown between one-time and ongoing costs.
3 Sum of all ongoing costs identified in rows 1 to 11 inclusive.
1 4 Sum of all one-time costs identified in rows 1 to 11 inclusive.

LOW-INCOME ENERGY ASSISTANCE PROGRAMS (LEAP)

In 2008, the Ontario Energy Board started consultation with stakeholders to consider the need for, and the nature of, policies that could assist low-income energy consumers. Through that consultation, the OEB identified three components of a "Low-Income Energy Assistance Program" (LEAP), that could assist low-income energy customers better manage their bill payments and energy costs. These components are: (1) emergency financial assistance; (2) customer service rules; and, (3) targeted conservation and demand management programs.

The delivery of LEAP relies heavily on the cooperation between utilities and social service agencies. It is expected that as agencies screen and assess applicants in need, that they may refer customer not only for LEAP, but also for customer service measures and/or conservation programs.

STEI acknowledges that Account 6205 Donations is general non-recoverable. However, STEI has included $7,500 in its 2015TY as the sub account LEAP funding of Account 6205 is generally recoverable. The LEAP funding represents 0.12% of the 2015TY total distribution revenues. The actual amount will differ based upon STEI's Board Approve application.

STEI confirms that there are no amounts included in the 2015 TY revenue requirement for Legacy Programs, such as Winter Wormth.

CHARITABLE AND POLITICAL DONATIONS

St. Thomas Energy Inc. does not make any charitable or political donations other than the approved LEAP funding based upon distribution revenues. Therefore, the 2015TY does not include any donation costs.

DEPRECIATION/AMORTIZATION/DEPLETION

St. Thomas Energy Inc.'s Depreciation Policy can be found in Exhibit 2, Tab 1, Schedule 11. Until the end of 2011, amortization is consistent with Canadian GAAP, the requirements of the CICA, and the requirements of the OEB.

In 2012, St. Thomas Energy Inc. restructured from a virtual utility to a fully staffed, operational utility. At that time, STEI reviewed it capitalization and amortization policies and aligned them with MIFRS guidelines. For the years 2012 to 2015, St. Thomas Energy Inc.'s amortization will be consistent with MIFRS.

STEI did not close out the accumulated depreciation and contributed capital to the capital assets account, but did change the estimated useful lives to an average remaining useful life based upon the OEB sponsored Kinectrics study as a guide. St. Thomas Energy Inc. confirms that the useful lives for its asset group's fall within the range allowed in the Board sponsored Kinectrics study.

The following Table 4-11 illustrates the change in the amotization period of STEI's assets from 2011 pre-restructuring to 2012-2015 restructuring changes.

Table 4-11

STEI ASSETS and USEFUL LIVES		2011 CGAAP	Kinectrics Range	Kinectrics Typical UFL	2012-2015 IFRS
1820.0000	Distribution Station Equipment	30	10-65	20-55	45
1830.0000	Poles, Towers & Fixtures	25	35-75	45	45
1835.0000	Overhead Conductors & Devices	25	15-75	20-60	60
1840.0000	Underground Conduit	25	20-85	30-60	40
1845.0000	Underground Conductors & Devices	25	20-55	30-40	40
1850.1000	Underground Transformers	25	20-60	35-40	40
1850.2000	Overhead Transformers	25	25-60	35-45	40
1855.1000	Overhead Services	25	25-85	35-60	40
1855.2000	Underground Services	25	25-85	35-60	40
1860.1500	Smart Meters	15	15	n/a	15
1860.2000	Interval Meters	25	15-35	n/a	15
1860.3000	Wholesale Meters	25	15-35	n/a	30
1908.0000	Building & Fixtures, General Plant	50	50-75	n/a	60
1908.1000	Security System	10	n/a	n/a	10
1915.0000	Office Furniture & Equipmet	10	5-15	n/a	10
1920.0000	Computer Equipment	5	3-5	n/a	5
1925.0000	Computer Software	5	2-5	n/a	5
1925.1000	Cayenta/Harris Software	10	2-5	n/a	10
1930.0000	Transportation Equipment	5-8	5-20	n/a	5-15
1940.0000	Tools and Equipment	10	5-10	n/a	10
1955.0000	Communication Equipment	5	5-15	n/a	5
1960.1000	Mobile Substation	30	5-20	n/a	15
1980.0000	System Supervisory Equipment (SCADA)	15	15-30	20	20
1980.1000	Geographic Information System (GIS)	15	10-65	20-45	15

Contained in the following Tables 12 – 16 are STEI asset continuity schedules for the 2011,2012 and 2013 Actual Years, 2014 Bridge year and 2015 Test Year. STEI's internal continuity schedules reconcile with the Rate Base Board Appendices, 2-BA. STEI internal continuity schedules include the adoption of the half-year rule in 2015.

Table4-12

2011 ASSET CONTINUITY SCHEDULE -CGAAP

		COST				Accumulated Depreciation				Book Value			
GL Acct	Description	Opening	Additions	Removals	Ending	Opening	Additions	Removals	Ending	Opening	Additions	Acc Dep	Ending
1806.0000	Land Rights / Right of Way	6,733.79	-	-	6,733.79	-	-	-	-	6,733.79	-	-	6,733.79
1820.0000	Distribution Station Equipment	850,124.96	-	-	850,124.96	(826,606.66)	(4,668.96)	-	(831,275.62)	23,518.30	-	(4,668.96)	18,849.34
1830.0000	Poles, Towers & Fixtures	7,783,182.57	675,463.56	-	8,458,646.13	(3,571,192.63)	(305,413.39)	-	(3,876,606.02)	4,211,989.94	675,463.56	(305,413.39)	4,582,040.11
1835.0000	Overhead Conductors & Devices	7,161,738.96	321,075.38	-	7,482,814.34	(3,648,531.81)	(284,618.93)	-	(3,933,150.74)	3,513,207.15	321,075.38	(284,618.93)	3,549,663.60
1840.0000	Underground Conduit	3,822,469.11	114,142.60	-	3,936,611.71	(1,773,048.68)	(133,231.58)	-	(1,906,280.26)	2,049,420.43	114,142.60	(133,231.58)	2,030,331.45
1845.0000	Underground Conductors & Devices	7,760,133.68	257,423.03	-	8,017,556.71	(3,453,990.34)	(295,519.46)	-	(3,749,509.80)	4,306,143.34	257,423.03	(295,519.46)	4,268,046.91
1850.1000	Underground Transformers	1,453,452.47	153,726.65	-	1,607,179.12	(212,322.95)	(64,287.16)	-	(276,610.11)	1,241,129.52	153,726.65	(64,287.16)	1,330,569.01
1850.2000	Overhead Transformers	7,392,916.55	153,093.14	-	7,546,009.69	(4,352,947.82)	(263,849.02)	-	(4,616,796.84)	3,039,968.73	153,093.14	(263,849.02)	2,929,212.85
1855.1000	Overhead Services	3,981,176.41	116,099.94	-	4,097,276.35	(1,999,173.67)	(149,740.42)	-	(2,148,914.09)	1,982,002.74	116,099.94	(149,740.42)	1,948,362.26
1855.2000	Underground Services	1,029,553.32	78,010.91	-	1,107,564.23	(142,349.53)	(44,302.57)	-	(186,652.10)	887,203.79	78,010.91	(44,302.57)	920,912.13
1860.1000	Stranded Meters	2,272,023.44	6,483.80	-	2,278,507.24	(1,426,919.38)	(68,960.50)	-	(1,495,879.88)	845,104.06	6,483.80	(68,960.50)	782,627.36
1860.1500	Smart Meters	-	-		-	-	-	-	-	-	-	-	-
1860.2000	Interval Meters	83,282.61	6,235.14	-	89,517.75	(8,983.61)	(3,580.71)	-	(12,564.32)	74,299.00	6,235.14	(3,580.71)	76,953.43
1860.3000	Wholesale Meters	73,618.78	-	-	73,618.78	(7,873.81)	(2,944.74)	-	(10,818.55)	65,744.97	-	(2,944.74)	62,800.23
DISTRIBUTION SYSTEM		43,670,406.65	1,881,754.15	-	45,552,160.80	(21,423,940.89)	(1,621,117.44)	-	(23,045,058.33)	22,246,465.76	1,881,754.15	(1,621,117.44)	22,507,102.47
1905.0000	Land and General Plant	174,187.53		-	174,187.53	-		-	-	174,187.53	-	-	174,187.53
1908.0000	Building & Fixtures, General Plant	2,385,249.78	-	-	2,385,249.78	(850,574.08)	(49,632.81)	-	(900,206.89)	1,534,675.70	-	(49,632.81)	1,485,042.89
1908.1000	Building and Fixtures, Security System	-		-	-	-	-	-	-	-	-	-	-
1915.0000	Office Furniture & Equipmet	-		-	-	-	-	-	-	-	-	-	-
1920.0000	Computer Equipment	-		-	-	-	-	-	-	-	-	-	-
1925.0000	Computer Software	-		-	-	-	-	-	-	-	-	-	-
1925.1000	Harris/Cayenta Software	-		-	-	-	-	-	-	-	-	-	-
1930.0000	Vehicles						-		-		-	-	-
1940.0000	Tools and Equipment	-		-	-	-	-	-	-	-	-	-	-
1955.0000	Communication Equipment	-		-	-	-	-	-	-	-	-	-	-
1960.1000	Mobile Substation	-		-	-	-	-	-	-	-	-	-	-
1980.0000	System Supervisory - SCADA	43,592.36	-		43,592.36	(28,788.48)	(2,906.13)		(31,694.61)	14,803.88	-	(2,906.13)	11,897.75
1980.1000	GIS System	-	-	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
OTHER ASSETS		2,603,029.67	-	-	2,603,029.67	(879,362.56)	(52,538.94)	-	(931,901.50)	1,723,667.11	-	(52,538.94)	1,671,128.17
CONTRIBUTED CAPITAL		ADDITIONS				ACCUMULATED DEPRECIATION				Book Value			
		Opening	Additions	Removals	Ending					Opening	Additions	Acc Dep	Ending
1820.0000	Distribution Station Equipment	-				-							
1830.0000	Poles, Towers & Fixtures	(1,315,066.48)	(3,374.99)	-	(1,318,441.47)	309,901.92	52,778.09	-	362,680.01	(1,005,164.56)	(3,374.99)	52,778.09	(955,761.46)
1835.0000	Overhead Conductors & Devices	(1,129,322.67)	(1,301.51)	-	(1,130,624.18)	265,755.15	45,259.64	-	311,014.78	(863,567.53)	(1,301.51)	45,259.64	(819,609.40)
1840.0000	Underground Conduit	(715,170.98)	(36,392.52)	-	(751,563.50)	176,656.29	30,085.59	-	206,741.87	(538,514.70)	(36,392.52)	30,085.59	(544,821.63)
1845.0000	Underground Conductors & Devices	(1,286,055.51)	(43,748.03)	-	(1,329,803.54)	312,572.60	53,232.92	-	365,805.51	(973,482.92)	(43,748.03)	53,232.92	(963,998.03)
1850.1000	Underground Transformers	(660,485.90)	(167,713.75)	-	(828,199.65)	194,669.74	33,153.38	-	227,823.13	(465,816.16)	(167,713.75)	33,153.38	(600,376.52)
1850.2000	Overhead Transformers	(528,856.84)	-	-	(528,856.84)	124,308.70	21,170.49	-	145,479.20	(404,548.14)	-	21,170.49	(383,377.64)
1855.1000	Overhead Services	(590,059.48)	(6,658.41)	-	(596,717.89)	140,259.56	23,887.01	-	164,146.57	(449,799.92)	(6,658.41)	23,887.01	(432,571.32)
1855.2000	Underground Services	(395,830.39)	(7,173.97)	-	(403,004.36)	94,726.86	16,132.53	-	110,859.40	(301,103.52)	(7,173.97)	16,132.53	(292,144.96)
1860.1000	Stranded Meters	(269,171.40)	-	-	(269,171.40)	63,269.20	10,775.11	-	74,044.31	(205,902.20)	-	10,775.11	(195,127.09)
1860.1500	Smart Meters	(21,119.01)	-	-	(21,119.01)	6,257.39	845.41	-	7,102.80	(14,861.62)	-	845.41	(14,016.21)
1860.2000	Interval Meters	-	-	-	-		-	-	-	-	-	-	-
1860.3000	Wholesale Meters	-	-	-	-		-	-			-	-	-
		(6,911,138.67)	(266,363.18)	-	(7,177,501.85)	1,688,377.41	287,320.17	-	1,975,697.58	(5,222,761.26)	(266,363.18)	287,320.17	(5,201,804.27)
							287,320.17						
Cost		39,362,297.65	1,615,390.97	-	40,977,688.62	(20,614,926.04)	(1,386,336.21)	-	(22,001,262.25)	18,747,371.61	1,615,390.97	(1,386,336.21)	18,976,426.37
WIP		-	150,101.00	-	150,101.00	-	-	-	-	-	150,101.00	-	150,101.00
		39,362,297.65	1,765,491.97	-	41,127,789.62	(20,614,926.04)	(1,386,336.21)	-	(22,001,262.25)	18,747,371.61	1,765,491.97	(1,386,336.21)	19,126,527.37

Table 4-13

2012 ASSET CONTINUITY SCHEDULE - CGAAP Adopted Kinectrics Study

GL Acct	Description	COST Opening	COST Additions	COST Removals	COST Ending	Accumulated Depreciation Opening	Accumulated Depreciation Additions	Accumulated Depreciation Removals	Accumulated Depreciation Ending	Book Value Opening	Book Value Additions	Book Value Acc Dep	Book Value Ending
1806.0000	Land Rights / Right of Way	6,733.79	904.09	-	7,637.88	-	-	-	-	6,733.79	904.09	-	7,637.88
1820.0000	Distribution Station Equipment	850,124.96	-	-	850,124.96	(831,275.62)	(835.90)	-	(832,111.52)	18,849.34	-	(835.90)	18,013.44
1830.0000	Poles, Towers & Fixtures	8,458,646.13	188,797.41	-	8,647,443.54	(3,876,606.02)	(120,686.08)	-	(3,997,292.10)	4,582,040.11	188,797.41	(120,686.08)	4,650,151.44
1835.0000	Overhead Conductors & Devices	7,482,814.34	195,298.31	-	7,678,112.65	(3,933,150.74)	(69,636.30)	-	(4,002,787.04)	3,549,663.60	195,298.31	(69,636.30)	3,675,325.61
1840.0000	Underground Conduit	3,936,611.71	459,743.43	-	4,396,355.14	(1,906,280.26)	(83,918.58)	-	(1,990,198.84)	2,030,331.45	459,743.43	(83,918.58)	2,406,156.30
1845.0000	Underground Conductors & Devices	8,017,556.71	559,389.01	-	8,576,945.72	(3,749,509.80)	(141,840.07)	-	(3,891,349.87)	4,268,046.91	559,389.01	(141,840.07)	4,685,595.85
1850.1000	Underground Transformers	1,607,179.12	245,580.75	-	1,852,759.87	(276,610.11)	(43,351.77)	-	(319,961.88)	1,330,569.01	245,580.75	(43,351.77)	1,532,797.99
1850.2000	Overhead Transformers	7,546,009.69	93,154.06	-	7,639,163.75	(4,616,796.84)	(105,756.68)	-	(4,722,553.52)	2,929,212.85	93,154.06	(105,756.68)	2,916,610.23
1855.1000	Overhead Services	4,097,276.35	82,538.83	-	4,179,815.18	(2,148,914.09)	(60,322.47)	-	(2,209,236.56)	1,948,362.26	82,538.83	(60,322.47)	1,970,578.62
1855.2000	Underground Services	1,107,564.23	76,011.95	-	1,183,576.18	(186,652.10)	(27,602.57)	-	(214,254.67)	920,912.13	76,011.95	(27,602.57)	969,321.51
1860.1000	Stranded Meters	2,278,507.24	-	-	2,278,507.24	(1,495,879.88)	(66,603.36)	-	(1,562,483.24)	782,627.36	-	(66,603.36)	716,024.00
1860.1500	Smart Meters	-	3,100,868.84		3,100,868.84	-	(571,776.51)	-	(571,776.51)	-	3,100,868.84	(571,776.51)	2,529,092.33
1860.2000	Interval Meters	89,517.75	4,237.61	-	93,755.36	(12,564.32)	(7,035.54)	-	(19,599.86)	76,953.43	4,237.61	(7,035.54)	74,155.50
1860.3000	Wholesale Meters	73,618.78	-	-	73,618.78	(10,818.55)	(2,385.30)	-	(13,203.85)	62,800.23	-	(2,385.30)	60,414.93
DISTRIBUTION SYSTEM		**45,552,160.80**	**5,006,524.29**	-	**50,558,685.09**	**(23,045,058.33)**	**(1,301,751.13)**	-	**(24,346,809.46)**	**22,507,102.47**	**5,006,524.29**	**(1,301,751.13)**	**26,211,875.63**
1905.0000	Land and General Plant	174,187.53		-	174,187.53	-		-	-	174,187.53	-	-	174,187.53
1908.0000	Building & Fixtures, General Plant	2,385,249.78	-	-	2,385,249.78	(900,206.89)	(35,275.13)	-	(935,482.02)	1,485,042.89	-	(35,275.13)	1,449,767.76
1908.1000	Building and Fixtures, Security System	-	15,493.24	-	15,493.24	-	(1,695.67)	-	(1,695.67)	-	15,493.24	(1,695.67)	13,797.57
1915.0000	Office Furniture & Equipment	-	71,936.87	-	71,936.87	-	(7,193.64)	-	(7,193.64)	-	71,936.87	(7,193.64)	64,743.23
1920.0000	Computer Equipment	-	136,793.63	-	136,793.63	-	(40,378.55)	-	(40,378.55)	-	136,793.63	(40,378.55)	96,415.08
1925.0000	Computer Software	-	122,966.23	-	122,966.23	-	(62,622.65)	-	(62,622.65)	-	122,966.23	(62,622.65)	60,343.58
1925.1000	Harris/Cayenta Software	-	353,134.18	-	353,134.18	-	(35,313.42)	-	(35,313.42)	-	353,134.18	(35,313.42)	317,820.76
1930.0000	Vehicles		679,340.00		679,340.00	-	(136,811.04)		(136,811.04)		679,340.00	(136,811.04)	542,528.96
1940.0000	Tools and Equipment	-	377,238.90	-	377,238.90	-	(43,345.89)	-	(43,345.89)	-	377,238.90	(43,345.89)	333,893.01
1955.0000	Communication Equipment	-	12,465.77	-	12,465.77	-	(2,493.15)	-	(2,493.15)	-	12,465.77	(2,493.15)	9,972.62
1960.1000	Mobile Substation	-	200,000.00	-	200,000.00	-	(13,333.33)	-	(13,333.33)	-	200,000.00	(13,333.33)	186,666.67
1980.0000	System Supervisory - SCADA	43,592.36	14,408.85	-	58,001.21	(31,694.61)	(5,261.31)		(36,955.92)	11,897.75	14,408.85	(5,261.31)	21,045.29
1980.1000	GIS System	-	397,907.52	-	397,907.52	-	(26,527.17)	-	(26,527.17)	-	397,907.52	(26,527.17)	371,380.35
				-	-	-		-	-	-	-	-	-
OTHER ASSETS		**2,603,029.67**	**2,381,685.19**	-	**4,984,714.86**	**(931,901.50)**	**(410,250.95)**	-	**(1,342,152.45)**	**1,671,128.17**	**2,381,685.19**	**(410,250.95)**	**3,642,562.41**
CONTRIBUTED CAPITAL		**ADDITIONS** Opening	Additions	Removals	Ending	**ACCUMULATED DEPRECIATION**				**Book Value** Opening	Additions	Acc Dep	Ending
1820.0000	Distribution Station Equipment	-	-	-	-	-	-	-	-	-	-	-	-
1830.0000	Poles, Towers & Fixtures	(1,318,441.47)	(3,954.18)	-	(1,322,395.65)	362,639.58	23,982.92	-	386,622.50	(955,801.89)	(3,954.18)	23,982.92	(935,773.15)
1835.0000	Overhead Conductors & Devices	(1,130,624.18)	(1,524.86)	-	(1,132,149.04)	310,980.11	14,928.03	-	325,908.14	(819,644.07)	(1,524.86)	14,928.03	(806,240.90)
1840.0000	Underground Conduit	(751,563.50)	(42,637.90)	-	(794,201.40)	206,718.83	19,853.70	-	226,572.53	(544,844.67)	(42,637.90)	19,853.70	(567,628.87)
1845.0000	Underground Conductors & Devices	(1,329,803.54)	(51,255.70)	-	(1,381,059.24)	365,764.74	29,635.47	-	395,400.21	(964,038.80)	(51,255.70)	29,635.47	(985,659.03)
1850.1000	Underground Transformers	(828,199.65)	(196,495.39)	-	(1,024,695.04)	227,797.73	21,590.21	-	249,387.94	(600,401.92)	(196,495.39)	21,590.21	(775,307.10)
1850.2000	Overhead Transformers	(528,856.84)	-	-	(528,856.84)	145,462.98	13,220.48	-	158,683.46	(383,393.86)	-	13,220.48	(370,173.38)
1855.1000	Overhead Services	(596,717.89)	(7,801.07)	-	(604,518.96)	164,128.28	12,918.25	-	177,046.53	(432,589.61)	(7,801.07)	12,918.25	(427,472.43)
1855.2000	Underground Services	(403,004.36)	(8,405.11)	-	(411,409.47)	110,847.04	8,325.61	-	119,172.65	(292,157.32)	(8,405.11)	8,325.61	(292,236.82)
1860.1000	Stranded Meters	(295,792.75)	-	-	(295,792.75)	81,358.30	16,269.78	-	97,628.08	(214,434.45)	-	16,269.78	(198,164.67)
1860.1500	Smart Meters	-	-	-	-	-	-	-	-	-	-	-	-
1860.2000	Interval Meters	-	(6,446.60)	-	(6,446.60)		2,029.53	-	2,029.53	-	(6,446.60)	2,029.53	(4,417.07)
1860.3000	Wholesale Meters	-	-	-	-		-	-	-	-	-	-	-
		(7,183,004.18)	**(318,520.81)**	-	**(7,501,524.99)**	**1,975,697.58**	**162,753.98**	-	**2,138,451.56**	**(5,207,306.60)**	**(318,520.81)**	**162,753.98**	**(5,363,073.43)**
Cost		40,972,186.29	7,069,688.67	-	48,041,874.96	(22,001,262.25)	(1,549,248.10)	-	(23,550,510.35)	18,970,924.04	7,069,688.67	(1,549,248.10)	24,491,364.61
WIP		150,101.00	114,689.00	(150,101.00)	114,689.00	-	-	-	-	150,101.00	(35,412.00)	-	114,689.00
ENDING (balance to note 6.)		**41,122,287.29**	**7,184,377.67**	**(150,101.00)**	**48,156,563.96**	**(22,001,262.25)**	**(1,549,248.10)**	-	**(23,550,510.35)**	**19,121,025.04**	**7,034,276.67**	**(1,549,248.10)**	**24,606,053.61**

Table 4-14

2013 ASSET CONTINUITY SCHEDULE - MIFRS (Consistent with 2012 CGAAP)

		COST				Accumulated Depreciation				Book Value			
GL Acct	**Description**	**Opening**	**Additions**	**Removals**	**Ending**	**Opening**	**Additions**	**Removals**	**Ending**	**Opening**	**Additions**	**Acc Dep**	**Ending**
1806.0000	Land Rights / Right of Way	7,637.88	-	-	**7,637.88**	-	-	-	-	7,637.88	-	-	**7,637.88**
1820.0000	Distribution Station Equipment	850,124.96	-	-	**850,124.96**	(832,111.52)	(835.90)	-	**(832,947.42)**	18,013.44	-	(835.90)	**17,177.54**
1830.0000	Poles, Towers & Fixtures	8,647,443.54	286,820.42	-	**8,934,263.96**	(3,997,292.10)	(127,059.87)	-	**(4,124,351.97)**	4,650,151.44	286,820.42	(127,059.87)	**4,809,911.99**
1835.0000	Overhead Conductors & Devices	7,678,112.65	192,086.61	-	**7,870,199.26**	(4,002,787.04)	(72,837.74)	-	**(4,075,624.78)**	3,675,325.61	192,086.61	(72,837.74)	**3,794,574.48**
1840.0000	Underground Conduit	4,396,355.14	284,762.55	-	**4,681,117.69**	(1,990,198.84)	(91,037.64)	-	**(2,081,236.48)**	2,406,156.30	284,762.55	(91,037.64)	**2,599,881.21**
1845.0000	Underground Conductors & Devices	8,576,945.72	314,372.51	-	**8,891,318.23**	(3,891,349.87)	(149,699.38)	-	**(4,041,049.25)**	4,685,595.85	314,372.51	(149,699.38)	**4,850,268.98**
1850.1000	Underground Transformers	1,852,759.87	271,743.59	-	**2,124,503.46**	(319,961.88)	(50,145.36)	-	**(370,107.24)**	1,532,797.99	271,743.59	(50,145.36)	**1,754,396.22**
1850.2000	Overhead Transformers	7,639,163.75	75,678.16	-	**7,714,841.91**	(4,722,553.52)	(107,648.53)	-	**(4,830,202.05)**	2,916,610.23	75,678.16	(107,648.53)	**2,884,639.86**
1855.1000	Overhead Services	4,179,815.18	92,393.69	-	**4,272,208.87**	(2,209,236.56)	(62,632.31)	-	**(2,271,868.87)**	1,970,578.62	92,393.69	(62,632.31)	**2,000,340.00**
1855.2000	Underground Services	1,183,576.18	54,237.77	-	**1,237,813.95**	(214,254.67)	(28,958.51)	-	**(243,213.18)**	969,321.51	54,237.77	(28,958.51)	**994,600.77**
1860.1000	Stranded Meters	2,278,507.24	-	-	**2,278,507.24**	(1,562,483.24)	(65,451.01)	-	**(1,627,934.25)**	716,024.00	-	(65,451.01)	**650,572.99**
1860.1500	Smart Meters	3,100,868.84	46,474.95		**3,147,343.79**	(571,776.51)	(209,822.92)	-	**(781,599.43)**	2,529,092.33	46,474.95	(209,822.92)	**2,365,744.36**
1860.2000	Interval Meters	93,755.36	456.30	-	**94,211.66**	(19,599.86)	(7,065.96)	-	**(26,665.82)**	74,155.50	456.30	(7,065.96)	**67,545.84**
1860.3000	Wholesale Meters	73,618.78	-	-	**73,618.78**	(13,203.85)	(2,385.30)	-	**(15,589.15)**	60,414.93	-	(2,385.30)	**58,029.63**
DISTRIBUTION SYSTEM		**50,558,685.09**	**1,619,026.55**	**-**	**52,177,711.64**	**(24,346,809.46)**	**(975,580.43)**	**-**	**(25,322,389.89)**	**26,211,875.63**	**1,619,026.55**	**(975,580.43)**	**26,855,321.75**
1905.0000	Land and General Plant	174,187.53	-	-	**174,187.53**	-	-	-	-	174,187.53	-	-	**174,187.53**
1908.0000	Building & Fixtures, General Plant	2,385,249.78	11,302.49	-	**2,396,552.27**	(935,482.02)	(35,463.50)	-	**(970,945.52)**	1,449,767.76	11,302.49	(35,463.50)	**1,425,606.75**
1908.1000	Building and Fixtures, Security System	15,493.24	6,670.85	-	**22,164.09**	(1,695.67)	(2,362.76)	-	**(4,058.43)**	13,797.57	6,670.85	(2,362.76)	**18,105.66**
1915.0000	Office Furniture & Equipment	71,936.87	-	-	**71,936.87**	(7,193.64)	(7,193.64)	-	**(14,387.28)**	64,743.23	-	(7,193.64)	**57,549.59**
1920.0000	Computer Equipment	136,793.63	165,763.17	-	**302,556.80**	(40,378.55)	(60,511.34)	-	**(100,889.89)**	96,415.08	165,763.17	(60,511.34)	**201,666.91**
1925.0000	Computer Software	122,966.23	15,135.00	-	**138,101.23**	(62,622.65)	(27,620.25)	-	**(90,242.90)**	60,343.58	15,135.00	(27,620.25)	**47,858.33**
1925.1000	Harris/Cayenta Software	353,134.18	-	-	**353,134.18**	(35,313.42)	(35,313.42)	-	**(70,626.84)**	317,820.76	-	(35,313.42)	**282,507.34**
1930.0000	Vehicles	679,340.00	247,083.48	(38,000.00)	**888,423.48**	(136,811.04)	(85,343.27)	7,600.00	**(214,554.31)**	542,528.96	209,083.48	(77,743.27)	**673,869.17**
1940.0000	Tools and Equipment	377,238.90	22,888.40	-	**400,127.30**	(43,345.89)	(40,012.73)	-	**(83,358.62)**	333,893.01	22,888.40	(40,012.73)	**316,768.68**
1955.0000	Communication Equipment	12,465.77	-	-	**12,465.77**	(2,493.15)	(2,493.10)	-	**(4,986.25)**	9,972.62	-	(2,493.10)	**7,479.52**
1960.1000	Mobile Substation	200,000.00	-	-	**200,000.00**	(13,333.33)	(13,333.33)	-	**(26,666.66)**	186,666.67	-	(13,333.33)	**173,333.34**
1980.0000	System Supervisory - SCADA	58,001.21	-		**58,001.21**	(36,955.92)	(5,261.31)		**(42,217.23)**	21,045.29	-	(5,261.31)	**15,783.98**
1980.1000	GIS System	397,907.52	69,794.85	-	**467,702.37**	(26,527.17)	(31,180.16)	-	**(57,707.33)**	371,380.35	69,794.85	(31,180.16)	**409,995.04**
				-	-	-		-	-	-	-	-	-
OTHER ASSETS		**4,984,714.86**	**538,638.24**	**(38,000.00)**	**5,485,353.10**	**(1,342,152.45)**	**(346,088.81)**	**7,600.00**	**(1,680,641.26)**	**3,642,562.41**	**500,638.24**	**(338,488.81)**	**3,804,711.84**
CONTRIBUTED CAPITAL		**ADDITIONS**				**ACCUMULATED DEPRECIATION**				**Book Value**			
		Opening	**Additions**	**Removals**	**Ending**					**Opening**	**Additions**	**Acc Dep**	**Ending**
1820.0000	Distribution Station Equipment	-	-	-	-								
1830.0000	Poles, Towers & Fixtures	(1,322,395.65)	(10,620.18)	-	**(1,333,015.83)**	386,622.50	24,218.92	-	**410,841.42**	(935,773.15)	(10,620.18)	24,218.92	**(922,174.41)**
1835.0000	Overhead Conductors & Devices	(1,132,149.04)	(6,651.30)	-	**(1,138,800.34)**	325,908.14	15,038.89	-	**340,947.03**	(806,240.90)	(6,651.30)	15,038.89	**(797,853.31)**
1840.0000	Underground Conduit	(794,201.40)	(130,564.84)	-	**(924,766.24)**	226,572.53	23,117.82	-	**249,690.35**	(567,628.87)	(130,564.84)	23,117.82	**(675,075.89)**
1845.0000	Underground Conductors & Devices	(1,381,059.24)	(5,978.26)	-	**(1,387,037.50)**	395,400.21	29,784.93	-	**425,185.14**	(985,659.03)	(5,978.26)	29,784.93	**(961,852.36)**
1850.1000	Underground Transformers	(1,024,695.04)	(386,050.18)	-	**(1,410,745.22)**	249,387.94	31,241.46	-	**280,629.40**	(775,307.10)	(386,050.18)	31,241.46	**(1,130,115.82)**
1850.2000	Overhead Transformers	(528,856.84)	(29,037.03)	-	**(557,893.87)**	158,683.46	13,946.41	-	**172,629.87**	(370,173.38)	(29,037.03)	13,946.41	**(385,264.00)**
1855.1000	Overhead Services	(604,518.96)	(9,112.82)	-	**(613,631.78)**	177,046.53	13,146.07	-	**190,192.60**	(427,472.43)	(9,112.82)	13,146.07	**(423,439.18)**
1855.2000	Underground Services	(411,409.47)	(8,813.98)	-	**(420,223.45)**	119,172.65	8,545.96	-	**127,718.61**	(292,236.82)	(8,813.98)	8,545.96	**(292,504.84)**
1860.1000	Stranded Meters	(295,792.75)	-	-	**(295,792.75)**	97,628.08	16,269.78	-	**113,897.86**	(198,164.67)	-	16,269.78	**(181,894.89)**
1860.1500	Smart Meters	-	(2,842.06)	-	**(2,842.06)**	-	189.47	-	**189.47**	-	(2,842.06)	189.47	**(2,652.59)**
1860.2000	Interval Meters	(6,446.60)	(6,473.13)	-	**(12,919.73)**	2,029.53	2,461.07	-	**4,490.60**	(4,417.07)	(6,473.13)	2,461.07	**(8,429.13)**
1860.3000	Wholesale Meters	-	-	-	-	-	-	-	-	-	-	-	-
		(7,501,524.99)	**(596,143.78)**	**-**	**(8,097,668.77)**	**2,138,451.56**	**177,960.78**	**-**	**2,316,412.34**	**(5,363,073.43)**	**(596,143.78)**	**177,960.78**	**(5,781,256.43)**
Cost		48,041,874.96	1,561,521.01	- 38,000.00	**49,565,395.97**	(23,550,510.35)	(1,143,708.46)	7,600.00	**(24,686,618.81)**	24,491,364.61	1,523,521.01	(1,136,108.46)	**24,878,777.16**
WIP		114,689.00	88,742.06	(114,689.00)	**88,742.06**	-	-	-	-	114,689.00	(25,946.94)	-	88,742.06
ENDING (balance to note 6.)		**48,156,563.96**	**1,650,263.07**	**(152,689.00)**	**49,654,138.03**	**(23,550,510.35)**	**(1,143,708.46)**	**7,600.00**	**(24,686,618.81)**	**24,606,053.61**	**1,497,574.07**	**(1,136,108.46)**	**24,967,519.22**

Table 4-15

2014 ASSET CONTINUITY SCHEDULE

		COST				Accumulated Depreciation				Book Value			
GL Acct	Description	Opening	Additions	Removals	Ending	Opening	Additions	Removals	Ending	Opening	Additions	Acc Dep	Ending
1806.0000	Land Rights / Right of Way	7,637.88	-	-	**7,637.88**	-	-	-	-	7,637.88	-	-	**7,637.88**
1820.0000	Distribution Station Equipment	850,124.96	-	-	**850,124.96**	(832,947.42)	(835.90)	-	**(833,783.32)**	17,177.54	-	(835.90)	**16,341.64**
1830.0000	Poles, Towers & Fixtures	8,934,263.96	337,027.00	-	**9,271,290.96**	(4,124,351.97)	(134,549.36)	-	**(4,258,901.33)**	4,809,911.99	337,027.00	(134,549.36)	**5,012,389.63**
1835.0000	Overhead Conductors & Devices	7,870,199.26	276,757.00	-	**8,146,956.26**	(4,075,624.78)	(77,450.36)	-	**(4,153,075.14)**	3,794,574.48	276,757.00	(77,450.36)	**3,993,881.12**
1840.0000	Underground Conduit	4,681,117.69	338,922.00	-	**5,020,039.69**	(2,081,236.48)	(99,510.69)	-	**(2,180,747.17)**	2,599,881.21	338,922.00	(99,510.69)	**2,839,292.52**
1845.0000	Underground Conductors & Devices	8,891,318.23	291,948.00	-	**9,183,266.23**	(4,041,049.25)	(156,998.08)	-	**(4,198,047.33)**	4,850,268.98	291,948.00	(156,998.08)	**4,985,218.90**
1850.1000	Underground Transformers	2,124,503.46	278,524.00	-	**2,403,027.46**	(370,107.24)	(57,108.46)	-	**(427,215.70)**	1,754,396.22	278,524.00	(57,108.46)	**1,975,811.76**
1850.2000	Overhead Transformers	7,714,841.91	118,961.00	-	**7,833,802.91**	(4,830,202.05)	(110,622.66)	-	**(4,940,824.71)**	2,884,639.86	118,961.00	(110,622.66)	**2,892,978.20**
1855.1000	Overhead Services	4,272,208.87	114,977.00	-	**4,387,185.87**	(2,271,868.87)	(65,506.74)	-	**(2,337,375.61)**	2,000,340.00	114,977.00	(65,506.74)	**2,049,810.26**
1855.2000	Underground Services	1,237,813.95	29,866.00	-	**1,267,679.95**	(243,213.18)	(29,705.16)	-	**(272,918.34)**	994,600.77	29,866.00	(29,705.16)	**994,761.61**
1860.1000	Stranded Meters	2,278,507.24		-	**2,278,507.24**	(1,627,934.25)	(62,443.42)	-	**(1,690,377.67)**	650,572.99	-	(62,443.42)	**588,129.57**
1860.1500	Smart Meters	3,147,343.79	13,018.00		**3,160,361.79**	(781,599.43)	(210,690.79)	-	**(992,290.22)**	2,365,744.36	13,018.00	(210,690.79)	**2,168,071.57**
1860.2000	Interval Meters	94,211.66	-	-	**94,211.66**	(26,665.82)	(7,065.96)	-	**(33,731.78)**	67,545.84	-	(7,065.96)	**60,479.88**
1860.3000	Wholesale Meters	73,618.78	-	-	**73,618.78**	(15,589.15)	(2,385.30)	-	**(17,974.45)**	58,029.63	-	(2,385.30)	**55,644.33**
DISTRIBUTION SYSTEM		**52,177,711.64**	**1,800,000.00**	**-**	**53,977,711.64**	**(25,322,389.89)**	**(1,014,872.88)**	**-**	**(26,337,262.77)**	**26,855,321.75**	**1,800,000.00**	**(1,014,872.88)**	**27,640,448.87**
1905.0000	Land and General Plant	174,187.53	-	-	**174,187.53**	-	-	-	-	174,187.53	-	-	**174,187.53**
1908.0000	Building & Fixtures, General Plant	2,396,552.27	100,000.00	-	**2,496,552.27**	(970,945.52)	(37,130.17)	-	**(1,008,075.69)**	1,425,606.75	100,000.00	(37,130.17)	**1,488,476.58**
1908.1000	Building and Fixtures, Security System	22,164.09	-	-	**22,164.09**	(4,058.43)	(2,362.76)	-	**(6,421.19)**	18,105.66	-	(2,362.76)	**15,742.90**
1915.0000	Office Furniture & Equipment	71,936.87	70,000.00	-	**141,936.87**	(14,387.28)	(14,193.64)	-	**(28,580.92)**	57,549.59	70,000.00	(14,193.64)	**113,355.95**
1920.0000	Computer Equipment	302,556.80	19,500.00	-	**322,056.80**	(100,889.89)	(64,411.34)	-	**(165,301.23)**	201,666.91	19,500.00	(64,411.34)	**156,755.57**
1925.0000	Computer Software	138,101.23	76,500.00	-	**214,601.23**	(90,242.90)	(42,920.25)	-	**(133,163.15)**	47,858.33	76,500.00	(42,920.25)	**81,438.08**
1925.1000	Harris/Cayenta Software	353,134.18	20,000.00	-	**373,134.18**	(70,626.84)	(37,313.42)	-	**(107,940.26)**	282,507.34	20,000.00	(37,313.42)	**265,193.92**
1930.0000	Vehicles	888,423.48	352,792.06		**1,241,215.54**	(214,554.31)	(94,676.61)	-	**(309,230.92)**	673,869.17	352,792.06	(94,676.61)	**931,984.62**
1940.0000	Tools and Equipment	400,127.30	28,000.00	-	**428,127.30**	(83,358.62)	(42,812.73)	-	**(126,171.35)**	316,768.68	28,000.00	(42,812.73)	**301,955.95**
1955.0000	Communication Equipment	12,465.77		-	**12,465.77**	(4,986.25)	(2,493.15)	-	**(7,479.40)**	7,479.52	-	(2,493.15)	**4,986.37**
1960.1000	Mobile Substation	200,000.00		-	**200,000.00**	(26,666.66)	(13,333.33)	-	**(39,999.99)**	173,333.34	-	(13,333.33)	**160,000.01**
1980.0000	System Supervisory - SCADA	58,001.21	-		**58,001.21**	(42,217.23)	(5,261.31)		**(47,478.54)**	15,783.98	-	(5,261.31)	**10,522.67**
1980.1000	GIS System	467,702.37	150,000.00	-	**617,702.37**	(57,707.33)	(35,833.15)	-	**(93,540.48)**	409,995.04	150,000.00	(35,833.15)	**524,161.89**
				-	-	-	-	-	-	-	-	-	-
OTHER ASSETS		**5,485,353.10**	**816,792.06**	**-**	**6,302,145.16**	**(1,680,641.26)**	**(392,741.86)**	**-**	**(2,073,383.12)**	**3,804,711.84**	**816,792.06**	**(392,741.86)**	**4,228,762.04**
CONTRIBUTED CAPITAL		**ADDITIONS**				**ACCUMULATED DEPRECIATION**				**Book Value**			
		Opening	**Additions**	**Removals**	**Ending**					**Opening**	**Additions**	**Acc Dep**	**Ending**
1820.0000	Distribution Station Equipment	-	-	-	-	-				-	-	-	-
1830.0000	Poles, Towers & Fixtures	(1,333,015.83)	(3,000.00)	-	**(1,336,015.83)**	410,841.42	24,285.59	-	**435,127.01**	(922,174.41)	(3,000.00)	24,285.59	**(900,888.82)**
1835.0000	Overhead Conductors & Devices	(1,138,800.34)	(4,000.00)	-	**(1,142,800.34)**	340,947.03	15,105.56	-	**356,052.59**	(797,853.31)	(4,000.00)	15,105.56	**(786,747.75)**
1840.0000	Underground Conduit	(924,766.24)	(22,000.00)	-	**(946,766.24)**	249,690.35	23,667.82	-	**273,358.17**	(675,075.89)	(22,000.00)	23,667.82	**(673,408.07)**
1845.0000	Underground Conductors & Devices	(1,387,037.50)	(34,000.00)	-	**(1,421,037.50)**	425,185.14	30,634.93	-	**455,820.07**	(961,852.36)	(34,000.00)	30,634.93	**(965,217.43)**
1850.1000	Underground Transformers	(1,410,745.22)	(16,000.00)	-	**(1,426,745.22)**	280,629.40	31,641.46	-	**312,270.86**	(1,130,115.82)	(16,000.00)	31,641.46	**(1,114,474.36)**
1850.2000	Overhead Transformers	(557,893.87)	(2,000.00)	-	**(559,893.87)**	172,629.87	14,021.41	-	**186,651.28**	(385,264.00)	(2,000.00)	14,021.41	**(373,242.59)**
1855.1000	Overhead Services	(613,631.78)	(3,000.00)	-	**(616,631.78)**	190,192.60	13,221.07	-	**203,413.67**	(423,439.18)	(3,000.00)	13,221.07	**(413,218.11)**
1855.2000	Underground Services	(420,223.45)	(7,000.00)	-	**(427,223.45)**	127,718.61	8,720.96	-	**136,439.57**	(292,504.84)	(7,000.00)	8,720.96	**(290,783.88)**
1860.1000	Stranded Meters	(295,792.75)	-	-	**(295,792.75)**	113,897.86	16,269.78	-	**130,167.64**	(181,894.89)	-	16,269.78	**(165,625.11)**
1860.1500	Smart Meters	(2,842.06)	(9,000.00)	-	**(11,842.06)**	189.47	389.47	-	**578.94**	(2,652.59)	(9,000.00)	389.47	**(11,263.12)**
1860.2000	Interval Meters	(12,919.73)	-	-	**(12,919.73)**	4,490.60	2,794.40	-	**7,285.00**	(8,429.13)	-	2,794.40	**(5,634.73)**
1860.3000	Wholesale Meters	-	-	-	-	-	-	-	-	-	-	-	-
		(8,097,668.77)	**(100,000.00)**	-	**(8,197,668.77)**	**2,316,412.34**	**180,752.45**	-	**2,497,164.79**	**(5,781,256.43)**	**(100,000.00)**	**180,752.45**	**(5,700,503.98)**
Cost		49,565,395.97	2,516,792.06	-	**52,082,188.03**	(24,686,618.81)	(1,226,862.29)	-	**(25,913,481.10)**	24,878,777.16	2,516,792.06	(1,226,862.29)	**26,168,706.93**
WIP		88,742.06	(88,742.06)	-	-	-	-	-	-	88,742.06	(88,742.06)	-	-
ENDING (balance to note 6.)		**49,654,138.03**	**2,428,050.00**	-	**52,082,188.03**	**(24,686,618.81)**	**(1,226,862.29)**	-	**(25,913,481.10)**	**24,967,519.22**	**2,428,050.00**	**(1,226,862.29)**	**26,168,706.93**

Table 4-16

2015 ASSET CONTINUITY SCHEDULE

		COST				Accumulated Depreciation				Book Value			
GL Acct	Description	Opening	Additions	Removals	Ending	Opening	Additions	Removals	Ending	Opening	Additions	Acc Dep	Ending
1806.0000	Land Rights / Right of Way	7,637.88	-	-	7,637.88	-	-	-	-	7,637.88	-	-	7,637.88
1820.0000	Distribution Station Equipment	850,124.96	-	-	850,124.96	(833,783.32)	(835.90)	-	(834,619.22)	16,341.64	-	(835.90)	15,505.74
1830.0000	Poles, Towers & Fixtures	9,271,290.96	326,655.00	-	9,597,945.96	(4,258,901.33)	(138,178.86)	-	(4,397,080.19)	5,012,389.63	326,655.00	(138,178.86)	5,200,865.77
1835.0000	Overhead Conductors & Devices	8,146,956.26	268,280.00	-	8,415,236.26	(4,153,075.14)	(79,686.03)	-	(4,232,761.17)	3,993,881.12	268,280.00	(79,686.03)	4,182,475.10
1840.0000	Underground Conduit	5,020,039.69	329,925.00	-	5,349,964.69	(2,180,747.17)	(103,634.76)	-	(2,284,381.93)	2,839,292.52	329,925.00	(103,634.76)	3,065,582.77
1845.0000	Underground Conductors & Devices	9,183,266.23	285,377.00	-	9,468,643.23	(4,198,047.33)	(160,565.30)	-	(4,358,612.63)	4,985,218.90	285,377.00	(160,565.30)	5,110,030.61
1850.1000	Underground Transformers	2,403,027.46	270,632.00	-	2,673,659.46	(427,215.70)	(60,491.36)	-	(487,707.06)	1,975,811.76	270,632.00	(60,491.36)	2,185,952.40
1850.2000	Overhead Transformers	7,833,802.91	115,271.00	-	7,949,073.91	(4,940,824.71)	(112,063.55)	-	(5,052,888.26)	2,892,978.20	115,271.00	(112,063.55)	2,896,185.65
1855.1000	Overhead Services	4,387,185.87	111,533.00	-	4,498,718.87	(2,337,375.61)	(66,900.91)	-	(2,404,276.52)	2,049,810.26	111,533.00	(66,900.91)	2,094,442.36
1855.2000	Underground Services	1,267,679.95	29,353.00	-	1,297,032.95	(272,918.34)	(30,072.08)	-	(302,990.42)	994,761.61	29,353.00	(30,072.08)	994,042.54
1860.1000	Stranded Meters	2,278,507.24	-	(2,278,507.24)	-	(1,690,377.67)	-	1,690,377.67	-	588,129.57	(2,278,507.24)	1,690,377.67	-
1860.1500	Smart Meters	3,160,361.79	12,974.00		3,173,335.79	(992,290.22)	(211,555.72)	-	(1,203,845.94)	2,168,071.57	12,974.00	(211,555.72)	1,969,489.85
1860.2000	Interval Meters	94,211.66	-	-	94,211.66	(33,731.78)	(7,065.96)	-	(40,797.74)	60,479.88	-	(7,065.96)	53,413.92
1860.3000	Wholesale Meters	73,618.78	-	-	73,618.78	(17,974.45)	(2,385.30)	-	(20,359.75)	55,644.33	-	(2,385.30)	53,259.03
DISTRIBUTION SYSTEM		53,977,711.64	1,750,000.00	(2,278,507.24)	53,449,204.40	(26,337,262.77)	(973,435.71)	1,690,377.67	(25,620,320.81)	27,640,448.87	(528,507.24)	716,941.97	27,828,883.59
1905.0000	Land and General Plant	174,187.53	-	-	174,187.53	-	-	-	-	174,187.53	-	-	174,187.53
1908.0000	Building & Fixtures, General Plant	2,496,552.27	100,000.00	-	2,596,552.27	(1,008,075.69)	(37,963.51)	-	(1,046,039.20)	1,488,476.58	100,000.00	(37,963.51)	1,550,513.08
1908.1000	Building and Fixtures, Security System	22,164.09	-	-	22,164.09	(6,421.19)	(2,362.76)	-	(8,783.95)	15,742.90	-	(2,362.76)	13,380.14
1915.0000	Office Furniture & Equipment	141,936.87	70,000.00	-	211,936.87	(28,580.92)	(17,693.64)	-	(46,274.56)	113,355.95	70,000.00	(17,693.64)	165,662.31
1920.0000	Computer Equipment	322,056.80	85,000.00	-	407,056.80	(165,301.23)	(69,586.54)	-	(234,887.77)	156,755.57	85,000.00	(69,586.54)	172,169.03
1925.0000	Computer Software	214,601.23	13,000.00	-	227,601.23	(133,163.15)	(27,931.45)	-	(161,094.60)	81,438.08	13,000.00	(27,931.45)	66,506.63
1925.1000	Harris/Cayenta Software	373,134.18	-	-	373,134.18	(107,940.26)	(37,313.42)	-	(145,253.68)	265,193.92	-	(37,313.42)	227,880.50
1930.0000	Vehicles	1,241,215.54	125,000.00		1,366,215.54	(309,230.92)	(100,926.61)		(410,157.52)	931,984.62	125,000.00	(100,926.61)	956,058.02
1940.0000	Tools and Equipment	428,127.30	20,000.00	-	448,127.30	(126,171.35)	(43,812.73)	-	(169,984.08)	301,955.95	20,000.00	(43,812.73)	278,143.22
1955.0000	Communication Equipment	12,465.77	-	-	12,465.77	(7,479.40)	(2,493.15)	-	(9,972.55)	4,986.37	-	(2,493.15)	2,493.22
1960.1000	Mobile Substation	200,000.00	-	-	200,000.00	(39,999.99)	(13,333.33)	-	(53,333.32)	160,000.01	-	(13,333.33)	146,666.68
1980.0000	System Supervisory - SCADA	58,001.21	50,000.00		108,001.21	(47,478.54)	(6,511.31)		(53,989.85)	10,522.67	50,000.00	(6,511.31)	54,011.36
1980.1000	GIS System	617,702.37	50,000.00	-	667,702.37	(93,540.48)	(40,833.15)	-	(134,373.63)	524,161.89	50,000.00	(40,833.15)	533,328.74
				-	-	-		-	-	-	-	-	-
OTHER ASSETS		6,302,145.16	513,000.00	-	6,815,145.16	(2,073,383.12)	(400,761.59)	-	(2,474,144.71)	4,228,762.04	513,000.00	(400,761.59)	4,341,000.45
CONTRIBUTED CAPITAL		ADDITIONS				ACCUMULATED DEPRECIATION				Book Value			
		Opening	Additions	Removals	Ending					Opening	Additions	Acc Dep	Ending
1820.0000	Distribution Station Equipment	-	-	-	-	-				-	-	-	-
1830.0000	Poles, Towers & Fixtures	(1,336,015.83)	(3,000.00)	-	(1,339,015.83)	435,127.01	24,318.93	-	459,445.94	(900,888.82)	(3,000.00)	24,318.93	(879,569.89)
1835.0000	Overhead Conductors & Devices	(1,142,800.34)	(4,000.00)	-	(1,146,800.34)	356,052.59	15,138.90	-	371,191.49	(786,747.75)	(4,000.00)	15,138.90	(775,608.85)
1840.0000	Underground Conduit	(946,766.24)	(22,000.00)	-	(968,766.24)	273,358.17	23,942.82	-	297,300.99	(673,408.07)	(22,000.00)	23,942.82	(671,465.25)
1845.0000	Underground Conductors & Devices	(1,421,037.50)	(34,000.00)	-	(1,455,037.50)	455,820.07	31,059.93	-	486,880.00	(965,217.43)	(34,000.00)	31,059.93	(968,157.50)
1850.1000	Underground Transformers	(1,426,745.22)	(16,000.00)	-	(1,442,745.22)	312,270.86	31,841.46	-	344,112.32	(1,114,474.36)	(16,000.00)	31,841.46	(1,098,632.90)
1850.2000	Overhead Transformers	(559,893.87)	(2,000.00)	-	(561,893.87)	186,651.28	14,058.91	-	200,710.19	(373,242.59)	(2,000.00)	14,058.91	(361,183.68)
1855.1000	Overhead Services	(616,631.78)	(3,000.00)	-	(619,631.78)	203,413.67	13,258.57	-	216,672.24	(413,218.11)	(3,000.00)	13,258.57	(402,959.54)
1855.2000	Underground Services	(427,223.45)	(7,000.00)	-	(434,223.45)	136,439.57	8,808.46	-	145,248.03	(290,783.88)	(7,000.00)	8,808.46	(288,975.42)
1860.1000	Stranded Meters	(295,792.75)	-	295,792.75	-	130,167.64	-	(130,167.64)	-	(165,625.11)	295,792.75	(130,167.64)	-
1860.1500	Smart Meters	(11,842.06)	(9,000.00)	-	(20,842.06)	578.94	589.47	-	1,168.41	(11,263.12)	(9,000.00)	589.47	(19,673.65)
1860.2000	Interval Meters	(12,919.73)	-	-	(12,919.73)	7,285.00	2,961.07	-	10,246.07	(5,634.73)	-	2,961.07	(2,673.67)
1860.3000	Wholesale Meters	-	-	-	-	-	-	-	-	-	-	-	-
		(8,197,668.77)	(100,000.00)	295,792.75	(8,001,876.02)	2,497,164.79	165,978.51	(130,167.64)	2,532,975.65	(5,700,503.98)	195,792.75	35,810.86	(5,468,900.37)
Cost		52,082,188.03	2,163,000.00	- 1,982,714.49	52,262,473.54	(25,913,481.10)	(1,208,218.79)	1,560,210.03	(25,561,489.86)	26,168,706.93	180,285.51	351,991.24	26,700,983.68
WIP		-	-	-	-	-	-	-	-	-	-	-	-
ENDING (balance to note 6.)		52,082,188.03	2,163,000.00	(1,982,714.49)	52,262,473.54	(25,913,481.10)	(1,208,218.79)	1,560,210.03	(25,561,489.86)	26,168,706.93	180,285.51	351,991.24	26,700,983.68

ASSET RETIREMENT OBLIGATIONS

STEI does not have any Asset Retirement Obligations ("AROs"), associated depreciation or accretion expenses in relation to the AROs to report as part of this Application.

"HALF-YEAR" RULE

STEI's amortization policy has been to record a full year of depreciation expense on capital additions during the year that the asset was placed in service. STEI will be adopting the half-year rule in 2015 with the adoption of IFRS.

DEPRECIATION AND AMORTIZATION POLICY

STEI's amortization policy is in accordance with the Canadian Institute of Chartered Accountants (the "CICA") Handbook which states that amortization should be recognized in a rational and systematic manner appropriate to the nature of the property, plant and equipment (with a limited life) and to its use by the enterprise. The CICA Handbook recognizes that different methods of amortizing a capital asset result in different patterns of charges to income.

In accordance with the CICA Handbook, STEI uses the straight-line method of amortization. Capital assets are recorded at cost, and amortized over their estimated remaining service lives where construction in progress assets are not amortized until the project is complete and in service.

STEI does not capitalize any interest to the cost of constructed assets.

Contributions in aid of construction ("contributed capital") consist of third party contributions toward the cost of constructing distribution assets. Some of this contributed capital may be refunded by STEI based on future economic evaluations and in accordance with the Board's Distribution System Code ("DSC"). Contributed capital is accounted for as a reduction to the cost of related capital assets and is amortized at rates corresponding with the useful lives of the related capital assets.

SUMMARY OF CHANGES SINCE LAST COST OF SERVICE APPLICATION

In 2011 under CGAAP, STEI followed the guidelines provided in the Board's 2006 Electricity Distribution Rate Handbook ("EDR Handbook") and the Accounting Procedures Handbook for Electric Distribution Utilities ("APH"). This method was permitted under CGAAP, as the prescribed useful lives of the APH represented the "estimated service lives" of assets under the regulatory framework.

Under IFRS, specifically under International Accounting Standard ("IAS") 16, each significant part of an item of PP&E must be depreciated separately. This is referred to as component accounting. The rationale for component accounting is that since not all components of an item of PP&E have the same useful life, they will depreciate at different rates.

STEI will continue to prepare financial statements under CGAAP and is not transitioning to IFRS until January 1st, 2015. On January 1, 2012, STEI implemented changes to depreciation rates that would have been implemented under IFRS. This change is in accordance with the Board's guidelines (Board Letter, July 17, 2012 "Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies in 2012 and 2013"). STEI also adopted IFRS like capitalization policies in conjunction with the restructuring and has not been capitalizing administrative costs that would have been allowed under CGAAP. Depreciation has been calculated for the 2012 and 2013 Actuals and the 2014 Bridge Year and 2015 Test Year based upon the new methodology.

STEI will be adopting the half-year rule for capital additions in 2015 with the adoption of IFRS.

COMPONENTIZATION

In 2010, in preparation for the original (before deferral) conversion to IFRS, STEI contracted KPMG to provide an IFRS conversion impact assessment and Kinectrics to provide a useful Life of Asset Study. The Kinetrics analysis recommended a range of useful life of each component within the STEI specific study. STEI has componentized its asset based upon July 31, 2010 Kinetrics study. The KPMG and Kinetrics studies are provided as attachments one and two to this exhibit.

Board Appendix 2-BB is provided below:

Appendix 2-BB
Service Life Comparison
Table F-1 from Kinetrics Report[1]

Parent*	#	Asset Details: Category| Component | Type			Useful Life: MIN UL	TUL	MAX UL	USoA Account Number	USoA Account Description	Current: Years	Current: Rate	Proposed: Years	Proposed: Rate
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers and Fixtures	25	4%	45	2%
			Cross Arm	Wood	20	40	55						
				Steel	30	70	95						
	2	Fully Dressed Concrete Poles	Overall		50	60	80						
			Cross Arm	Wood	20	40	55						
				Steel	30	70	95						
	3	Fully Dressed Steel Poles	Overall		60	60	80						
			Cross Arm	Wood	20	40	55						
				Steel	30	70	95						
	4	OH Line Switch			30	45	55	1855	OH Services	25	4%	40	3%
	5	OH Line Switch Motor			15	25	25						
	6	OH Line Switch RTU			15	20	20						
	7	OH Integral Switches			35	45	60						
	8	OH Conductors			50	60	75	1835	Overhead Conductors and Devices	25	4%	60	2%
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Overhead Transformers	25	4%	40	3%
	10	OH Shunt Capacitor Banks			25	30	40						
	11	Reclosers			25	40	55						
TS & MS	12	Power Transformers	Overall		30	45	60	1820	Distribution Station Equipment	30	3%	45	2%
			Bushing		10	20	30						
			Tap Changer		20	30	60						
	13	Station Service Transformer			30	45	55						
	14	Station Grounding Transformer			30	40	40						
	15	Station DC System	Overall		10	20	30						
			Battery Bank		10	15	15						
			Charger		20	20	30						
	16	Station Metal Clad Switchgear	Overall		30	40	60						
			Removable Breaker		25	40	60						
	17	Station Independent Breakers			35	45	65						
	18	Station Switch			30	50	60	1820	Distribution Station Equipment	30	3%	45	2%
	19	Electromechanical Relays			25	35	50						
	20	Solid State Relays			10	30	45						
	21	Digital & Numeric Relays			15	20	20						
	22	Rigid Busbars			30	55	60						
	23	Steel Structure			35	50	90						
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75						
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25						
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30						
	27	Primary Non-TR XLPE Cables in Duct			20	25	30						
	28	Primary TR XLPE Cables Direct Buried			25	30	35						
	29	Primary TR XLPE Cables in Duct			35	40	55	1840	Underground Conduit	25	4%	40	3%
	30	Secondary PILC Cables			70	75	80						
	31	Secondary Cables Direct Buried			25	35	40	1855	UG Services	25	4%	40	3%
	32	Secondary Cables in Duct			35	40	60						
	33	Network Tranformers	Overall		20	35	50	1850	Underground Transformers	25	4%	40	3%
			Protector		20	35	40						
	34	Pad-Mounted Transformers			25	40	45						
	35	Submersible/Vault Transformers			25	35	45						
	36	UG Foundation			35	55	70	1845	Underground Conductor and Devices	25	4%	40	3%
	37	UG Vaults	Overall		40	60	80						
			Roof		20	30	45						
	38	UG Vault Switches			20	35	50	1845	Underground Conductor and Devices	25	4%	40	3%
	39	Pad-Mounted Switchgear			20	30	45	1845	Underground Conductor and Devices	25	4%	40	3%
	40	Ducts			30	50	85						
	41	Concrete Encased Duct Banks			35	55	80						
	42	Cable Chambers			50	60	80						
S	43	Remote SCADA			15	20	30	1980	SCADA	15	7%	20	5%

Table F-2 from Kinetrics Report[1]

#	Asset Details: Category| Component | Type		Useful Life Range	USoA Account Number	USoA Account Description	Current: Years	Current: Rate	Proposed: Years	Proposed: Rate
1	Office Equipment		5-15	1915	Office Equipment	10	10%	10	10%
2	Vehicles	Trucks & Buckets	5-15	1930	Vehicles			15	7%
		Trailers	5-20	1930	Vehicles			20	5%
		Vans	5-10	1930	Vehicles			10	10%
3	Administrative Buildings		50-75	1908	Administrative Buildings	50	2%	60	2%
4	Leasehold Improvements		Lease dependent						
5	Station Buildings	Station Buildings	50-75						
		Parking	25-30						
		Fence	25-60						
		Roof	20-30						
6	Computer Equipment	Hardware	3-5	1925	Hardware	5	20%	5	20%
		Software	2-5	1925	Software	5	20%	5	20%
7	Equipment	Power Operated	5-10						
		Stores	5-10						
		Tools, Shop, Garage Equipment	5-10	1940	Tools, Shop, Garage Equipment	10	10%	10	10%
		Measurement & Testing Equipment	5-10						
8	Communication	Towers	60-70						
		Wireless	2-10	1955	Wireless	5	20%	5	20%
9	Residential Energy Meters		25-35						
10	Industrial/Commercial Energy Meters		25-35	1860	Interval Meters	25	4%	15	7%
11	Wholesale Energy Meters		15-30	1860	Wholesasle Meters	25	4%	30	3%
12	Current & Potential Transformer (CT & PT)		35-50						
13	Smart Meters		5-15	1860	Smart Meters	15	7%	15	7%
14	Repeaters - Smart Metering		10-15						
15	Data Collectors - Smart Metering		15-20						

Depreciation Expenses

STEI recalculated the average remaining useful life of the opening balance of assets as at January 1st, 2012, the effective date of STEI's change to depreciation rates and capitalization upon restructuring from a virtual utility. STEI recalculated the remaining useful life for the January 1, 2012 opening balances by adjusting continuity schedules for the years 2000 to 2011 by the new UFL and taking a weighted average of the years.

STEI's did not adjust the opening BV and clear out the accumulated depreciation and contributed capital. The contributed capital opening remaining useful lives were adjusted to match the corresponding asset.

Board Appendix 2-CB is provided below, which provides remaining useful life estimates. Appendix 2-CB is as of January 1, 2012.

Appendix 2-CB
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2012

Year **2012** **MIFRS**

Account	Description	Opening NBV as at Jan 1, 2012 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2012 Depreciation Expense (k) = (j) + (h)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (k) - (l)	Depreciation Expense on 2012 Full Year Additions (n) = (d)/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2012 Full Year Depreciation [6] (p) = (j) + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 108,703	$ 367,397	9.00	5.00	20.00%	$ 12,078	$ 36,740	$ 48,818	$ 97,936	-$ 49,118	$ 73,479		$ 85,558
1612	Land Rights (Formally known as Account 1906)	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1805	Land	$ 6,734	$ 904			0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1808	Buildings	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1810	Leasehold Improvements	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 18,849		24.00	45.00	2.22%	$ 785	$ -	$ 785	$ 836	-$ 51	$ -		$ 785
1825	Storage Battery Equipment	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 4,582,040	$ 188,797	39.00	45.00	2.22%	$ 117,488	$ 2,098	$ 119,586	$ 120,687	-$ 1,101	$ 4,195		$ 121,684
1835	Overhead Conductors & Devices	$ 3,549,663	$ 195,298	52.00	60.00	1.67%	$ 68,263	$ 1,627	$ 69,890	$ 69,636	$ 254	$ 3,255		$ 71,518
1840	Underground Conduit	$ 2,030,332	$ 459,743	29.00	40.00	2.50%	$ 70,011	$ 5,747	$ 75,758	$ 83,914	-$ 8,156	$ 11,494		$ 81,505
1845	Underground Conductors & Devices	$ 4,268,047	$ 559,389	36.00	40.00	2.50%	$ 118,557	$ 6,992	$ 125,549	$ 141,840	-$ 16,291	$ 13,985		$ 132,542
1850	Line Transformers	$ 4,259,782	$ 338,735	30.00	40.00	2.50%	$ 141,993	$ 4,234	$ 146,227	$ 149,109	-$ 2,882	$ 8,468		$ 150,461
1855	Services (Overhead & Underground)	$ 2,869,274	$ 158,551	34.00	40.00	2.50%	$ 84,390	$ 1,982	$ 86,372	$ 87,925	-$ 1,553	$ 3,964		$ 88,354
1860	Meters	$ 933,200	$ 4,238	13.00	15.00	6.67%	$ 71,785	$ 141	$ 71,926	$ 76,025	-$ 4,099	$ 283		$ 72,067
1860	Meters (Smart Meters)	$ 3,082,487	$ 18,382	15.00	15.00	6.67%	$ 205,499	$ 613	$ 206,112	$ 571,777	-$ 365,665	$ 1,225		$ 206,725
1905	Land	$ 174,188		-	15.00	6.67%	$ -	$ -	$ -		$ -	$ -		$ -
1908	Buildings & Fixtures	$ 1,485,043	$ 15,493	43.00	60.00	1.67%	$ 34,536	$ 129	$ 34,665	$ 36,971	-$ 2,306	$ 258		$ 34,794
1910	Leasehold Improvements	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 48,475	$ 23,462	10.00	10.00	10.00%	$ 4,848	$ 1,173	$ 6,021	$ 7,194	-$ 1,173	$ 2,346		$ 7,194
1915	Office Furniture & Equipment (5 years)	$ -				0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ 136,794	5.00	5.00	20.00%	$ -	$ 13,679	$ 13,679	$ 40,379	-$ 26,700	$ 27,359		$ 27,359
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1930	Transportation Equipment	$ -	$ 679,340	10.00	10.00	10.00%	$ -	$ 33,967	$ 33,967	$ 136,811	-$ 102,844	$ 67,934		$ 67,934
1935	Stores Equipment	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 28,110	$ 349,129	10.00	10.00	10.00%	$ 2,811	$ 17,456	$ 20,267	$ 43,346	-$ 23,079	$ 34,913		$ 37,724
1945	Measurement & Testing Equipment	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1950	Power Operated Equipment	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1955	Communications Equipment	$ -	$ 12,466	15.00	15.00	6.67%	$ -	$ 416	$ 416	$ 2,493	-$ 2,077	$ 831		$ 831
1955	Communication Equipment (Smart Meters)	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -	$ 200,000	15.00	15.00	6.67%	$ -	$ 6,667	$ 6,667	$ 13,333	-$ 6,666	$ 13,333		$ 13,333
1970	Load Management Controls Customer Premises	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1980	System Supervisor Equipment	$ 43,592	$ 412,316	12.00	15.00	6.67%	$ 3,633	$ 13,744	$ 17,377	$ 31,788	-$ 14,411	$ 27,488		$ 31,120
1985	Miscellaneous Fixed Assets	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1990	Other Tangible Property	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1995	Contributions & Grants	-$ 1,975,697	-$ 318,520	20.00	40.00	2.50%	-$ 98,785	-$ 3,982	-$ 102,766	-$ 162,754	$ 59,988	-$ 7,963		-$ 106,748
etc.						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
	Total	$ 25,512,821	$ 3,801,915				$ 837,892	$ 143,424	$ 981,316	$ 1,549,246	-$ 567,930	$ 286,848	$ -	$ 1,124,739
	Depreciation exp. adj. from gain or loss on the retirement of assets (pool of like assets)								$ -					

STEI adopted new accounting policies upon restructuring January 1, 2012 including asset UFL estimates. STEI adopted, under CGAAP, useful life estimates reflective of the Kinectrics report and IFRS requirements. Additionally, STEI had to develop a PP&E capitalization policy as previously all costs were capitalized as third party whereas in 2012 STEI had to make a determination as to appropriate capitalization rates and overheads. STEI adopted IFRS like PP&E capitalization policies in that only directly attributed costs are capitalized. The adoption of new PP&E and capitalization policies did not require restatement of 2011 financial results and as such, STEI is presenting the required Board Appendices as of 2012. This provides the basis for the 2013 Actual, 2014BY and 2015TY Board Depreciation Amortization schedules, 2-CB, 2-CD and 2-CE.

STEI provided internal continuity schedules that reconcile to the RRR filings and included those amounts in depreciation expenses columns "Expense per Appendix 2-B".

Board Appendix 2-CA, 2012 CGAAP Depreciation and Amortization is shown below.

Appendix 2-CA
Depreciation and Amortization Expense
Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2012
Year 2012 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2012 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 108,703		$ 108,703	$ 367,397	$ 292,402	5.00	20.00%	$ 58,480	$ 97,936	-$ 39,456
1612	Land Rights (Formally known as Account 1906)			$ -		$ -		0.00%	$ -		$ -
1805	Land	$ 6,734		$ 6,734	$ 904	$ 7,186	-	0.00%	$ -		$ -
1808	Buildings		$ -	$ -		$ -		0.00%	$ -		$ -
1810	Leasehold Improvements			$ -		$ -		0.00%	$ -		$ -
1815	Transformer Station Equipment >50 kV			$ -		$ -		0.00%	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 850,125	$ 831,276	$ 18,849		$ 18,849	45.00	2.22%	$ 419	$ 836	-$ 417
1825	Storage Battery Equipment			$ -		$ -		0.00%	$ -		$ -
1830	Poles, Towers & Fixtures	$ 8,458,646	$ 3,876,606	$ 4,582,040	$ 188,797	$ 4,676,439	45.00	2.22%	$ 103,921	$ 120,687	-$ 16,766
1835	Overhead Conductors & Devices	$ 7,482,814	$ 3,933,151	$ 3,549,663	$ 195,298	$ 3,647,312	60.00	1.67%	$ 60,789	$ 69,636	-$ 8,847
1840	Underground Conduit	$ 3,936,612	$ 1,906,280	$ 2,030,332	$ 459,743	$ 2,260,204	40.00	2.50%	$ 56,505	$ 83,914	-$ 27,409
1845	Underground Conductors & Devices	$ 8,017,557	$ 3,749,510	$ 4,268,047	$ 559,389	$ 4,547,742	40.00	2.50%	$ 113,694	$ 141,840	-$ 28,146
1850	Line Transformers	$ 9,153,189	$ 4,893,407	$ 4,259,782	$ 338,735	$ 4,429,149	40.00	2.50%	$ 110,729	$ 149,109	-$ 38,380
1855	Services (Overhead & Underground)	$ 5,204,840	$ 2,335,566	$ 2,869,274	$ 158,551	$ 2,948,550	40.00	2.50%	$ 73,714	$ 87,925	-$ 14,211
1860	Meters	$ 2,441,644	$ 1,508,444	$ 933,200	$ 4,238	$ 935,318	15.00	6.67%	$ 62,355	$ 76,025	-$ 13,670
1860	Meters (Smart Meters)	$ 3,082,487	$ -	$ 3,082,487	$ 18,382	$ 3,091,678	15.00	6.67%	$ 206,112	$ 571,777	-$ 365,665
1905	Land	$ 174,188	$ -	$ 174,188		$ 174,188		0.00%	$ -		$ -
1908	Buildings & Fixtures	$ 2,385,250	$ 900,207	$ 1,485,043	$ 15,493	$ 1,492,789	60.00	1.67%	$ 24,880	$ 36,971	-$ 12,091
1910	Leasehold Improvements			$ -		$ -		0.00%	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 48,475		$ 48,475	$ 23,462	$ 60,206	10.00	10.00%	$ 6,021	$ 7,194	-$ 1,173
1915	Office Furniture & Equipment (5 years)			$ -		$ -		0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware			$ -		$ -		0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -	$ 136,794	$ 68,397	5.00	20.00%	$ 13,679	$ 40,379	-$ 26,700
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -		$ -		0.00%	$ -		$ -
1930	Transportation Equipment			$ -	$ 679,340	$ 339,670	5.00	20.00%	$ 67,934	$ 136,811	-$ 68,877
1935	Stores Equipment			$ -		$ -		0.00%	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 28,110		$ 28,110	$ 349,129	$ 202,674	10.00	10.00%	$ 20,267	$ 43,346	-$ 23,079
1945	Measurement & Testing Equipment			$ -		$ -		0.00%	$ -		$ -
1950	Power Operated Equipment			$ -		$ -		0.00%	$ -		$ -
1955	Communications Equipment			$ -	$ 12,466	$ 6,233	5.00	20.00%	$ 1,247	$ 2,493	-$ 1,246
1955	Communication Equipment (Smart Meters)			$ -		$ -		0.00%	$ -		$ -
1960	Miscellaneous Equipment			$ -	$ 200,000	$ 100,000	10.00	10.00%	$ 10,000	$ 13,333	-$ 3,333
1970	Load Management Controls Customer Premises			$ -		$ -		0.00%	$ -		$ -
1975	Load Management Controls Utility Premises			$ -		$ -		0.00%	$ -		$ -
1980	System Supervisor Equipment	$ 43,592		$ 43,592	$ 412,316	$ 249,751	15.00	6.67%	$ 16,650	$ 31,788	-$ 15,138
1985	Miscellaneous Fixed Assets			$ -		$ -		0.00%	$ -		$ -
1990	Other Tangible Property			$ -		$ -		0.00%	$ -		$ -
1995	Contributions & Grants	-$ 7,183,004	-$ 5,207,307	-$ 1,975,697	-$ 318,520	-$ 2,134,957	40.00	2.50%	-$ 53,374	-$ 162,754	$ 109,380
etc.				$ -		$ -		0.00%	$ -		$ -
				$ -		$ -		0.00%	$ -		$ -
	Total	**$ 44,239,962**	**$ 18,727,140**	$ 25,512,821	$ 3,801,915	$ 27,413,779			$ 954,020	$ 1,549,246	-$ 595,226

Board Appendix 2-CA results in 2012 depreciation expense of $954,020 for the half-year rule which is $595,226 less than the 2012 actual amount of $1,549,246. STEI actual amortization included $419,000 related to smart meter disposition including historical amortization of $182,000 related to 2010 and $237,000 for 2011. STEI did not adopt the half-year rule in 2012, resulting in an additional variance of approximately $180,000. The impact of the half-year rule is more prevalent in 2012 as STEI acquired $1,407,737 of assets from an affiliate upon restructuring, these were not "new additions", but a transfer of ownership of existing assets in support of STEI operations.

Board Appendix 2-CB 2012 MIFRS Depreciation and Amortization Expense is shown below.

Appendix 2-CB
Depreciation and Amortization Expense
Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2012

Year 2012 **MIFRS**

Account	Description	Opening NBV as at Jan 1, 2012 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2012 Depreciation Expense (k) = (j) + (h)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (k) - (l)	Depreciation Expense on 2012 Full Year Additions (n) = (d)/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2012 Full Year Depreciation [6] (p) = (j) + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 108,703	$ 367,397	9.00	5.00	20.00%	$ 12,078	$ 36,740	$ 48,818	$ 97,936	-$ 49,118	$ 73,479		$ 85,558
1612	Land Rights (Formally known as Account 1906)	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1805	Land	$ 6,734	$ 904			0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1808	Buildings	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1810	Leasehold Improvements	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 18,849		24.00	45.00	2.22%	$ 785	$ -	$ 785	$ 836	-$ 51	$ -		$ 785
1825	Storage Battery Equipment	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 4,582,040	$ 188,797	39.00	45.00	2.22%	$ 117,488	$ 2,098	$ 119,586	$ 120,687	-$ 1,101	$ 4,195		$ 121,684
1835	Overhead Conductors & Devices	$ 3,549,663	$ 195,298	52.00	60.00	1.67%	$ 68,263	$ 1,627	$ 69,890	$ 69,636	$ 254	$ 3,255		$ 71,518
1840	Underground Conduit	$ 2,030,332	$ 459,743	29.00	40.00	2.50%	$ 70,011	$ 5,747	$ 75,758	$ 83,914	-$ 8,156	$ 11,494		$ 81,505
1845	Underground Conductors & Devices	$ 4,268,047	$ 559,389	36.00	40.00	2.50%	$ 118,557	$ 6,992	$ 125,549	$ 141,840	-$ 16,291	$ 13,985		$ 132,542
1850	Line Transformers	$ 4,259,782	$ 338,735	30.00	40.00	2.50%	$ 141,993	$ 4,234	$ 146,227	$ 149,109	-$ 2,882	$ 8,468		$ 150,461
1855	Services (Overhead & Underground)	$ 2,869,274	$ 158,551	34.00	40.00	2.50%	$ 84,390	$ 1,982	$ 86,372	$ 87,925	-$ 1,553	$ 3,964		$ 88,354
1860	Meters	$ 933,200	$ 4,238	13.00	15.00	6.67%	$ 71,785	$ 141	$ 71,926	$ 76,025	-$ 4,099	$ 283		$ 72,067
1860	Meters (Smart Meters)	$ 3,082,487	$ 18,382	15.00	15.00	6.67%	$ 205,499	$ 613	$ 206,112	$ 571,777	-$ 365,665	$ 1,225		$ 206,725
1905	Land	$ 174,188		-	15.00	6.67%	$ -	$ -	$ -		$ -	$ -		$ -
1908	Buildings & Fixtures	$ 1,485,043	$ 15,493	43.00	60.00	1.67%	$ 34,536	$ 129	$ 34,665	$ 36,971	-$ 2,306	$ 258		$ 34,794
1910	Leasehold Improvements	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 48,475	$ 23,462	10.00	10.00	10.00%	$ 4,848	$ 1,173	$ 6,021	$ 7,194	-$ 1,173	$ 2,346		$ 7,194
1915	Office Furniture & Equipment (5 years)	$ -				0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ 136,794	5.00	5.00	20.00%	$ -	$ 13,679	$ 13,679	$ 40,379	-$ 26,700	$ 27,359		$ 27,359
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1930	Transportation Equipment	$ -	$ 679,340	10.00	10.00	10.00%	$ -	$ 33,967	$ 33,967	$ 136,811	-$ 102,844	$ 67,934		$ 67,934
1935	Stores Equipment	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 28,110	$ 349,129	10.00	10.00	10.00%	$ 2,811	$ 17,456	$ 20,267	$ 43,346	-$ 23,079	$ 34,913		$ 37,724
1945	Measurement & Testing Equipment	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1950	Power Operated Equipment	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1955	Communications Equipment	$ -	$ 12,466	15.00	15.00	6.67%	$ -	$ 416	$ 416	$ 2,493	-$ 2,077	$ 831		$ 831
1955	Communication Equipment (Smart Meters)	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -	$ 200,000	15.00	15.00	6.67%	$ -	$ 6,667	$ 6,667	$ 13,333	-$ 6,666	$ 13,333		$ 13,333
1970	Load Management Controls Customer Premises	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1980	System Supervisor Equipment	$ 43,592	$ 412,316	12.00	15.00	6.67%	$ 3,633	$ 13,744	$ 17,377	$ 31,788	-$ 14,411	$ 27,488		$ 31,120
1985	Miscellaneous Fixed Assets	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1990	Other Tangible Property	$ -				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1995	Contributions & Grants	-$ 1,975,697	-$ 318,520	20.00	40.00	2.50%	-$ 98,785	-$ 3,982	-$ 102,766	-$ 162,754	$ 59,988	-$ 7,963		-$ 106,748
etc.						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
	Total	$ 25,512,821	$ 3,801,915				$ 837,892	$ 143,424	$ 981,316	$ 1,549,246	-$ 567,930	$ 286,848	$ -	$ 1,124,739
	Depreciation exp. adj. from gain or loss on the retirement of assets (pool of like assets)								$ -					
	Total								$ 981,316					

Board Appendix 2-CB results in 2012 depreciation expense of $981,316 for the half-year rule and $1,124,739 for a full year as compared to the 2012 actual amount of $1,549,246. In theory the half-year amount in this table should equal the amount in Board Appendix 2-CA as the treatment under CGAAP and IFRS is the same for STEI. The difference between the results on this Appendix and 2012 actual is attributed to the same rationale as provided in Appendix 2-BA.

Board Appendix 2-CC 2013 MIFRS Depreciation and Amortization Expense is shown below.

Appendix 2-CC
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2012

2013 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2013 Depreciation Expense [1] (h)=2011 Full Year Deprecation + ((d)*0.5)/(f)	2013 Depreciation Expense per Apppendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)	Depreciation Expense on 2013 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2013 Full Year Depreciation [3] (p) = 2012 Full Year Depreciation + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 15,135	5.00	20.00%	$ 87,071	$ 62,934	$ 24,137	$ 3,027		$ 88,585
1612	Land Rights (Formally known as Account 1906)			0.00%	$ -		$ -	$ -		$ -
1805	Land		-	0.00%	$ -		$ -	$ -		$ -
1808	Buildings			0.00%	$ -		$ -	$ -		$ -
1810	Leasehold Improvements			0.00%	$ -		$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV			0.00%	$ -		$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ -	45.00	2.22%	$ 785	$ 836	-$ 51	$ -		$ 785
1825	Storage Battery Equipment			0.00%	$ -		$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 286,820	45.00	2.22%	$ 124,871	$ 127,060	-$ 2,189	$ 6,374		$ 128,057
1835	Overhead Conductors & Devices	$ 192,087	60.00	1.67%	$ 73,118	$ 72,838	$ 281	$ 3,201		$ 74,719
1840	Underground Conduit	$ 284,763	40.00	2.50%	$ 85,065	$ 91,038	-$ 5,973	$ 7,119		$ 88,624
1845	Underground Conductors & Devices	$ 314,373	40.00	2.50%	$ 136,471	$ 149,699	-$ 13,228	$ 7,859		$ 140,401
1850	Line Transformers	$ 347,422	40.00	2.50%	$ 154,804	$ 157,794	-$ 2,990	$ 8,686		$ 159,147
1855	Services (Overhead & Underground)	$ 146,631	40.00	2.50%	$ 90,187	$ 91,591	-$ 1,404	$ 3,666		$ 92,020
1860	Meters	$ 456	15.00	6.67%	$ 72,082	$ 74,902	-$ 2,820	$ 30		$ 72,098
1860	Meters (Smart Meters)	$ 46,475	15.00	6.67%	$ 208,274	$ 209,823	-$ 1,549	$ 3,098		$ 209,823
1905	Land			0.00%	$ -		$ -	$ -		$ -
1908	Buildings & Fixtures	$ 17,973	60.00	1.67%	$ 34,944	$ 37,826	-$ 2,882	$ 300		$ 35,094
1910	Leasehold Improvements			0.00%	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)		10.00	10.00%	$ 7,194	$ 7,194	$ 0	$ -		$ 7,194
1915	Office Furniture & Equipment (5 years)			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equipment - Hardware			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 165,763	5.00	20.00%	$ 43,935	$ 60,511	-$ 16,576	$ 33,153		$ 60,511
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	$ -		$ -	$ -		$ -
1930	Transportation Equipment	$ 209,083	15.00	6.67%	$ 74,903	$ 85,343	-$ 10,440	$ 13,939		$ 81,873
1935	Stores Equipment			0.00%	$ -		$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 22,888	10.00	10.00%	$ 38,868	$ 40,013	-$ 1,144	$ 2,289		$ 40,013
1945	Measurement & Testing Equipment			0.00%	$ -		$ -	$ -		$ -
1950	Power Operated Equipment			0.00%	$ -		$ -	$ -		$ -
1955	Communications Equipment		5.00	20.00%	$ 831	$ 2,493	-$ 1,662	$ -		$ 831
1955	Communication Equipment (Smart Meters)			0.00%	$ -		$ -	$ -		$ -
1960	Miscellaneous Equipment		10.00	10.00%	$ 13,333	$ 13,333	$ 0	$ -		$ 13,333
1970	Load Management Controls Customer Premises			0.00%	$ -		$ -	$ -		$ -
1975	Load Management Controls Utility Premises			0.00%	$ -		$ -	$ -		$ -
1980	System Supervisor Equipment	$ 69,795	15.00	6.67%	$ 33,447	$ 36,441	-$ 2,995	$ 4,653		$ 35,773
1985	Miscellaneous Fixed Assets			0.00%	$ -		$ -	$ -		$ -
1990	Other Tangible Property			0.00%	$ -		$ -	$ -		$ -
1995	Contributions & Grants	-$ 596,144	40.00	2.50%	-$ 114,200	-$ 177,961	$ 63,761	-$ 14,904		-$ 121,651
				0.00%	$ -		$ -	$ -		$ -
				0.00%	$ -		$ -	$ -		$ -
	Total	**$1,523,521**			**$ 1,165,984**	**$ 1,143,708**	**$ 22,276**	**$ 82,490**	**$ -**	**$ 1,207,229**
	Depreciation exp. adj. from gain or loss on the retirement of assets (pool of like assets)				$ -					
	Total				**$ 1,165,984**					

Board Appendix 2-CC results in 2013 depreciation expense of $1,165,984 for the half-year rule and $1,207,229 for a full year as compared to the 2013 actual amount of $1,143,708. The difference on a full year basis is that STEI 2013 actual amortization was $63,521 less than the Appendix. The difference is attributed to a number of asset items, the largest difference being computer software (actual $25,651 less than the Appendix).

Board Appendix 2-CD 2014 MIFRS Depreciation and Amortization Expense is shown below.

Appendix 2-CD
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2012

2014 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2014 Depreciation Expense [1] (h)=2012 Full Year Deprecation + ((d)*0.5)/(f)	2014 Depreciation Expense per Apppendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)	Depreciation Expense on 2014 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2014 Full Year Depreciation [3] (p) = 2013 Full Year Depreciation + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 96,500	5.00	20.00%	$ 98,235	$ 80,234	$ 18,001	$ 19,300		$ 107,885
1612	Land Rights (Formally known as Account 1906)			0.00%	$ -		$ -	$ -		$ -
1805	Land		-	0.00%	$ -		$ -	$ -		$ -
1808	Buildings			0.00%	$ -		$ -	$ -		$ -
1810	Leasehold Improvements			0.00%	$ -		$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV			0.00%	$ -		$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV		45.00	2.22%	$ 785	$ 836	-$ 51	$ -		$ 785
1825	Storage Battery Equipment			0.00%	$ -		$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 337,027	45.00	2.22%	$ 131,802	$ 134,549	-$ 2,747	$ 7,489		$ 135,547
1835	Overhead Conductors & Devices	$ 276,757	60.00	1.67%	$ 77,025	$ 77,450	-$ 425	$ 4,613		$ 79,332
1840	Underground Conduit	$ 338,922	40.00	2.50%	$ 92,861	$ 99,511	-$ 6,650	$ 8,473		$ 97,097
1845	Underground Conductors & Devices	$ 291,948	40.00	2.50%	$ 144,050	$ 156,998	-$ 12,948	$ 7,299		$ 147,700
1850	Line Transformers	$ 397,485	40.00	2.50%	$ 164,115	$ 167,731	-$ 3,616	$ 9,937		$ 169,084
1855	Services (Overhead & Underground)	$ 144,843	40.00	2.50%	$ 93,831	$ 95,212	-$ 1,381	$ 3,621		$ 95,641
1860	Meters		15.00	6.67%	$ 72,098	$ 71,895	$ 203	$ -		$ 72,098
1860	Meters (Smart Meters)	$ 13,018	15.00	6.67%	$ 210,257	$ 210,691	-$ 434	$ 868		$ 210,691
1905	Land			0.00%	$ -		$ -	$ -		$ -
1908	Buildings & Fixtures	$ 100,000	60.00	1.67%	$ 35,927	$ 39,493	-$ 3,566	$ 1,667		$ 36,760
1910	Leasehold Improvements			0.00%	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 70,000	10.00	10.00%	$ 10,694	$ 14,194	-$ 3,500	$ 7,000		$ 14,194
1915	Office Furniture & Equipment (5 years)			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equipment - Hardware			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 19,500	5.00	20.00%	$ 62,461	$ 64,411	-$ 1,950	$ 3,900		$ 64,411
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	$ -		$ -	$ -		$ -
1930	Transportation Equipment	$ 352,792	15.00	6.67%	$ 93,633	$ 94,677	-$ 1,044	$ 23,519		$ 105,392
1935	Stores Equipment			0.00%	$ -		$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 28,000	10.00	10.00%	$ 41,413	$ 42,813	-$ 1,400	$ 2,800		$ 42,813
1945	Measurement & Testing Equipment			0.00%	$ -		$ -	$ -		$ -
1950	Power Operated Equipment			0.00%	$ -		$ -	$ -		$ -
1955	Communications Equipment	$ -	5.00	20.00%	$ 831	$ 2,493	-$ 1,662	$ -		$ 831
1955	Communication Equipment (Smart Meters)			0.00%	$ -		$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -	10.00	10.00%	$ 13,333	$ 13,333	$ 0	$ -		$ 13,333
1970	Load Management Controls Customer Premises			0.00%	$ -		$ -	$ -		$ -
1975	Load Management Controls Utility Premises			0.00%	$ -		$ -	$ -		$ -
1980	System Supervisor Equipment	$ 150,000	15.00	6.67%	$ 40,773	$ 41,094	-$ 321	$ 10,000		$ 45,773
1985	Miscellaneous Fixed Assets			0.00%	$ -		$ -	$ -		$ -
1990	Other Tangible Property			0.00%	$ -		$ -	$ -		$ -
1995	Contributions & Grants	-$ 100,000	40.00	2.50%	-$ 122,901	-$ 180,752	$ 57,851	-$ 2,500		-$ 124,151
etc.				0.00%	$ -		$ -	$ -		$ -
				0.00%	$ -		$ -	$ -		$ -
	Total	**$2,516,792**			**$ 1,261,222**	**$ 1,226,862**	**$ 34,360**	**$ 107,986**	**$ -**	**$ 1,315,215**
	Depreciation exp. adj. from gain or loss on the retirement of assets (pool of like assets)				$ -					
	Total				**$ 1,261,222**					

Board Appendix 2-CD results in 2014 depreciation expense of $1,261,222 for the half-year rule and $1,315,215 for a full year as compared to the 2014BY amount of $1,226,862. The difference on a full year basis is that STEI 2014BY amortization is $88,353 less than the Appendix. The difference is attributed to a number of asset items, the largest difference being computer software is $27,665 less than the Appendix and net distribution asset amortization, including contributed capital is $46,970 less than the Appendix.

Board Appendix 2-CE 2015 MIFRS Depreciation and Amortization Expense is shown below:

Appendix 2-CE
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2012

2015 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2015 Depreciation Expense [1] (h)=2013 Full Year Depreciation + ((d)*0.5)/(f)	2015 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 13,000	5.00	20.00%	$ 109,185	$ 65,243.00	$ 43,942
1612	Land Rights (Formally known as Account 1906)			0.00%	$ -		$ -
1805	Land		-	0.00%	$ -		$ -
1808	Buildings			0.00%	$ -		$ -
1810	Leasehold Improvements			0.00%	$ -		$ -
1815	Transformer Station Equipment >50 kV			0.00%	$ -		$ -
1820	Distribution Station Equipment <50 kV		45.00	2.22%	$ 785	$ 836.00	-$ 51
1825	Storage Battery Equipment			0.00%	$ -		$ -
1830	Poles, Towers & Fixtures	$ 326,655	45.00	2.22%	$ 139,176	$ 138,179.00	$ 997
1835	Overhead Conductors & Devices	$ 268,280	60.00	1.67%	$ 81,567	$ 79,686.00	$ 1,881
1840	Underground Conduit	$ 329,925	40.00	2.50%	$ 101,221	$ 103,635.00	-$ 2,414
1845	Underground Conductors & Devices	$ 285,377	40.00	2.50%	$ 151,267	$ 160,565.00	-$ 9,298
1850	Line Transformers	$ 385,903	40.00	2.50%	$ 173,908	$ 172,555.00	$ 1,353
1855	Services (Overhead & Underground)	$ 40,886	40.00	2.50%	$ 96,152	$ 96,973.00	-$ 821
1860	Meters		15.00	6.67%	$ 72,098	$ 9,451.00	$ 62,647
1860	Meters (Smart Meters)	$ 12,974	15.00	6.67%	$ 211,123	$ 211,555.00	-$ 432
1905	Land			0.00%	$ -		$ -
1908	Buildings & Fixtures	$ 100,000	60.00	1.67%	$ 37,594	$ 40,325.00	-$ 2,731
1910	Leasehold Improvements			0.00%	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 70,000	10.00	10.00%	$ 17,694	$ 17,694.00	-$ 0
1915	Office Furniture & Equipment (5 years)			0.00%	$ -		$ -
1920	Computer Equipment - Hardware			0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 85,000	5.00	20.00%	$ 72,911	$ 69,587.00	$ 3,324
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	$ -		$ -
1930	Transportation Equipment	$ 125,000	10.00	10.00%	$ 111,642	$ 100,927.00	$ 10,715
1935	Stores Equipment			0.00%	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 20,000	10.00	10.00%	$ 43,813	$ 43,812.00	$ 1
1945	Measurement & Testing Equipment			0.00%	$ -		$ -
1950	Power Operated Equipment			0.00%	$ -		$ -
1955	Communications Equipment	$ -	5.00	20.00%	$ 831	$ 2,493.00	-$ 1,662
1955	Communication Equipment (Smart Meters)			0.00%	$ -		$ -
1960	Miscellaneous Equipment	$ -	10.00	10.00%	$ 13,333	$ 13,333.00	$ 0
1970	Load Management Controls Customer Premises			0.00%	$ -		$ -
1975	Load Management Controls Utility Premises			0.00%	$ -		$ -
1980	System Supervisor Equipment	$ 100,000	15.00	6.67%	$ 49,107	$ 47,345.00	$ 1,762
1985	Miscellaneous Fixed Assets			0.00%	$ -		$ -
1990	Other Tangible Property			0.00%	$ -		$ -
1995	Contributions & Grants	-$ 100,000	40.00	2.50%	-$ 125,401	-$ 165,979.00	$ 40,578
etc.				0.00%	$ -		$ -
				0.00%	$ -		$ -
	Total	**$ 2,063,000**			**$ 1,358,006**	**$ 1,208,215**	**$ 149,791**
	Depreciation exp. adj. from gain or loss on the retirement of assets (pool of like assets)						
	Total Depreciation expense to be included in the test year revenue requirement				**$ 1,358,006**		

Board Appendix 2-CE results in 2015 depreciation expense of $1,358,006 for the half-year rule as compared to the 2015TY STEI requested amount $1,208,218 resulting in a variance of $149,791.

2015 Appendix amount includes stranded meter amortization of approximately $59,000 which has been excluded from the STEI 2015TY amount. The other significant variance continues to be related to software in the amount of $43,942.

Attachment 1 of 2

KPMG-IFRS Conversion Impact Assesment

IFRS Advisory Services

St. Thomas Energy Group

IFRS Conversion Impact Assessment

August 2010

ADVISORY

AUDIT ▪ TAX ▪ ADVISORY

Disclaimer

This IFRS conversion impact assessment report is provided to St. Thomas Energy Inc. ("St. Thomas Energy") pursuant to our engagement letter, dated March 5, 2010 and is subject in all respects to the terms and conditions of those engagement letters, specifically:

- Our services under this engagement are not intended to be an audit, examination, attestation, special report or agreed-upon procedures engagement as those services are defined in the CICA Handbook applicable to such engagements conducted by independent auditors. Accordingly, our services for this engagement will not result in the issuance of a written communication to third parties by KPMG directly reporting on financial data or internal control or expressing a conclusion or any other form of assurance.
- This engagement contemplates providing general advice on the application of IFRS.
- The deliverables presented as part of this engagement are for the internal use of St. Thomas Energy management, the Audit Committee, and Board of Directors. St. Thomas Energy acknowledges and understands that any use of the deliverable by a third party in subsequent phases of St. Thomas Energy's IFRS conversion project, will first require an indemnification to be provided to KPMG by St. Thomas Energy and the third party. We disclaim any responsibility or liability for losses, damages, or costs incurred by anyone as a result of the unauthorized circulation, publication, reproduction, or use of our deliverables contrary to the provisions of this letter. Our deliverables will reflect our observations as of the date of our report.
- There is no guarantee that all accounting and disclosure differences will be identified in our report. Certain accounting and disclosure differences can be identified only by detailed review of transaction contracts and other underlying documentation.
- Actions and decisions taken by St. Thomas Energy based on recommendations and analysis provided by KPMG during the course of this engagement remain the responsibility of St. Thomas Energy's management.
- GAAP and IFRS pronouncements and applied interpretations are subject to revision by the respective authoritative accounting bodies in Canada and by the International Accounting Standards Board ("IASB"). Accounting advice provided by KPMG will be based on our understanding of current pronouncements and interpretations at the time and such advice may therefore change materially in response to subsequent changes or, revisions to, the pronouncements or interpretations.
- Each accounting gap identified in the "Summary of Key Findings" tables will need resolution in the next phase of St. Thomas Energy's project. The section entitled "Considerations for Next Phase" identifies some specific considerations or activities in the next phase, but is not an exhaustive list. Management must use their discretion in identifying all activities that are necessary to determine IFRS consistent accounting policies, resolve business and training issues and design systems, processes and controls that are needed to obtain the data required to prepare IFRS financial statements.

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PRIVATE & CONFIDENTIAL
Glen Farrow
Chief Financial Officer
St. Thomas Energy Ltd.
135 Edward Street
St. Thomas, ON, N5P 4A8

December 1, 2010

Dear Mr. Farrow,

KPMG LLP has appreciated the opportunity to assist St. Thomas Energy Ltd. ("St. Thomas Energy") in the conduct of the Detailed Assessment Phase of your IFRS Project. As part of the Detailed Assessment Phase deliverables, we present to you herein the IFRS Conversion Impact Assessments as of August 2010 for the following entities in accordance with our terms of our engagement letter dated March 5, 2010, including their Standard Terms and Conditions.

- St. Thomas Energy Ltd. ("STEI")
- St. Thomas Services Ltd. ("STESI")
- Tiltran Services Inc. ("Titran")
- Lizco Sales Inc. ("Lizco")
- Tal Trees Inc. ("Tal Trees")

This report is designed to meet STEI's objective of examining its accounting policies and procedures to determine differences between IFRS and STEI's current practices in order to formulate and construct an IFRS transition plan. This analysis was done by performing the detailed systematic accounting gap analysis between STEI's application of Canadian Generally Accepted Accounting Principles ("Canadian GAAP" or "CGAAP") and International Financial Reporting Standards ("IFRS"); specifically by:

- addressing accounting policy changes that must be applied retrospectively or prospectively.
- assessing the impact the accounting changes may have on St. Thomas Energy's policies, procedures and information technology and data systems.
- identifying the impacts to systems, processes, business and people.

It has been our privilege to have this opportunity to work with your team and we look forward to continuing to serve STEI through the next phases of your IFRS project. If you have any questions or would like to discuss our final report further; please contact Ian Jeffreys at (519) 660-2137 or Sara Girgis at (519) 251-3528.

Yours very truly,

KPMG LLP

Ian Jeffreys, CA
Partner

Table of Contents

Introduction

Beginning with the financial year 2011(subject to change based on the outstanding Exposure Draft), St. Thomas Energy is required to prepare its financial statements in accordance with International Financial Reporting Standards ("IFRS). There has been and Exposure Draft released by the Accounting Standards Board which if approved would allow rate regulated companies to delay the transition until the 2012 fiscal year. This exemption would only be applicable for the rate regulated company.

Therefore, management of St. Thomas Energy initiated a project for the conversion from Canadian Generally Accepted Accounting Principles ("CGAAP") to IFRS.

In March 2010, KPMG was engaged to assist management with this conversion project.

The IFRS project has focused on the following entities:

- St. Thomas Energy Ltd. ("STEI")
- St. Thomas Energy Services Inc. ("STESI")
- Tiltran Services Inc. ("Tiltran")
- Lizco Sales Inc. ("Lizco")
- Tal Trees Inc. ("Tal Trees")

These entities are collectively referred to as St. Thomas Energy.

Working in conjunction with key management, KPMG has completed a detailed systematic gap analysis of the accounting and reporting differences between CGAAP and IFRS, and has considered the potential high level impact of the differences on St. Thomas Energy's IT systems and business processes, and its personnel. Our key findings are presented in this report.

We have also included as Appendices, our completed draft Accounting and Disclosure matrixes (downloaded word version for ease of review). The Accounting and Disclosure Matrix has been completed in full for St. Thomas Energy. For others, the relevant sections have been highlighted in this report. This sets out the detailed requirements of IFRS along with a comparison to the current applications of CGAAP by the entities.

This report substantially completes phase 2 of the conversion project.

In preparing this report KPMG has completed the following:

- Held a kick off session with key management personnel to raise awareness of key project issues.
- Conducted various interviews with key finance and business personnel to gather information and assess St. Thomas Energy's current application for CGAAP against the IFRS requirements.
- Conducted an interview with St. Thomas Energy management focused on key business processes that would be impacted by IFRS.
- Met with the representatives from IT to assess the high level impact of accounting and reporting differences on IT systems and business processes.

- Completed the Accounting and Disclosure Matrix and documented St. Thomas Energy's current application of CGAAP.

Our assessment is based on IFRS standards and regulatory reporting requirements in place as at August 30, 2010. We note, however, that there are several areas of IFRS that are subject to future amendment by the IASB. The anticipated future changes are particularly challenging in that should the revisions to any of the proposed standards be approved during St. Thomas Energy's period of IFRS conversion, this will impact the results and findings of the detailed assessment. Therefore, it is critical that St. Thomas Energy stays abreast of the IFRS developments and establishes processes to manage all future changes.

The next phases of the conversion project, Design and Implementation, will be challenging. The focus of the design phase should be to build the tools required for the conversion based on management's decisions around accounting choices and related disclosures both at the transition date (January 1, 2010) and on an ongoing basis. This will involve the interpretation of accounting policy principles to support accounting policy decisions and the quantification of the impact of such choices and decisions. In addition, this phase involves designing the new business processes and IT systems (as applicable) in order to capture new data, and carry out reporting procedures.

We look forward to working with you through the next phase of this project.

Executive Summary

This report summarizes the key findings from our detailed impact assessment. We have summarized, by topic area, the key accounting and reporting gap differences and the impact that each key difference has on St. Thomas Energy's current accounting policy, IT and processes, other business areas and people. Included in each topic area is also an analysis of the available accounting policy choices and options under IFRS. In addition, we have highlighted specific considerations for the next phase of this project.

There is considerable uncertainty with respect to rate regulated accounting. This standard is under development by the IASB and will address accounting for regulatory assets and liabilities. It is expected that the standard will also address transition issues and differences arising in various other standards such as PP&E. It is not known whether this standard will eliminate all differences, some differences or whether all differences will have to be quantified and presented as a regulatory asset or liability. The new standard is not expected to be approved and issued until after January 1, 2011. The ACSB has released an exposure draft for comment *Adoption of IFRSs by Entities with Rate-regulated Activities* for comment, which would allow the applicable entities to defer transition to IFRS until periods beginning on or after January 1, 2012. Management will need to continue to monitor the status of this project and build flexibility into the IFRS conversion project plan.

The AcSB exposure draft on IFRS implementation has not been approved and as there is some risk that it may not be approved the project should continue to move forward. To qualify for the deferral an entity must have activities subject to rate regulation and have disclosed that it has accounted for a transaction differently than it would have in the absence of rate regulation. Therefore distribution companies and the holding company consolidated meet the criteria to qualify while the services company and other entities would not. If deferral is chosen, there will be implications for consolidation, as all companies to be consolidated must be using the same accounting standards. St. Thomas Energy will have to consider the options available and consider the impact on the consolidated entity.

In summary, the conversion to IFRS will have a high impact on St. Thomas Energy. The conversion will result in significant accounting policy changes with resulting impacts for IT systems and business processes. This is summarized in the figure below:

Accounting and Reporting

The conversion will result in significant accounting policy changes, most notably with respect to the following standards:

- IFRS 1, First time Adoption
- IAS 16, Property Plant and Equipment (PP&E)
- Regulatory Assets and Regulatory Liabilities
- IAS 23, Borrowing Costs
- IFRIC 18, Transfers of Assets from Customers

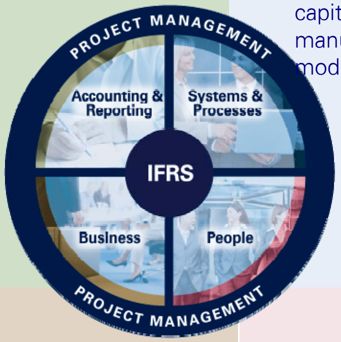
The high level accounting and reporting impacts are discussed in the following pages.

Systems and Processes

The high level IT impact has been assessed as at June 29, 2010. Our preliminary view is that the current version of the Harris Financials system has limited functionality to deal with the requirements of IFRS. We anticipate significant work effort will be required in building new business processes to record transactions under IFRS, and some system changes may be required as well.

As Harris Financials does not have a fixed asset subledger / module, with fixed assets being tracked in Excel spreadsheets, the PP&E requirements for increased records and changes to capitalization and depreciation policies can be addressed via manual process changes, or by implementing the fixed asset module within the new version of the system.

The Harris system does not support dual reporting and the requirements for multiple separate ledgers to support CGAAP, OEB and IFRS reporting, though alternatives are available to track IFRS related adjustments and amounts.



Business

The uncertainty of the responses to the IFRS conversion by the OEB, as well as current deliberations of the IASB on regulatory accounting matters, increases the conversion effort and resources required.

The accounting policy changes and resulting impact to financial results will require communication to stakeholders.

People

Changes to accounting policies and the above-noted impacts to business processes will require technical and transactional level process training of employees, not only in the accounting / finance department, but also in the regulatory, and engineering and operations departments.

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Summary of Key Findings

First time adoption of IFRS – IFRS 1

STEI and its related entities will prepare their financial reports under IFRS for the first time for the year ended December 31, 2011, unless the exposure draft is passed and the election to defer is taken, with comparatives required to be restated. As a consequence, STEI and its related entities will be required to prepare opening balance sheets at January 1, 2010 in accordance with IFRS.

In the preparation of this opening balance sheet, STEI and its related entities must adopt those standards and those accounting policies that will be effective for the first annual IFRS financial statements. Any adjustments arising from the restatement of the opening balance sheet is recognized directly in retained earnings, or if appropriate, another component of equity.

Under IFRS 1, retrospective application of IFRS accounting policies as at January 1, 2010 is required for most balances. However, upon first time adoption there are a number of exceptions to this general rule and certain elections provide STEI and its related parties with a range of options.

An analysis of the key exceptions and elections available to STEI and its related entities are set out in the following table. We have not highlighted those options (either elective or mandatory) that are not believed to be applicable to STEI and/or its related entities.

The next phase of STEI and it's related entities IFRS conversion project should take into account the following planning considerations:

- Consider the elective exemptions applicable to STEI and its related entities in conjunction with the related topic areas discussed below.
- Strategize and decide on which exemptions to apply.
- Be ready to apply mandatory exceptions.
- Prepare the opening balance sheet as at January 1, 2010 and related IFRS 1 disclosures.

The following exemptions apply to STEI and/or its related entities:

Elective Exemptions

Property, Plant and Equipment Fair Value or revaluation as "Deemed Cost"	**Brief Description of Key Elective Exemption** ● Permits the cost of an item of PP&E to be measured based on a deemed cost either: – (a) fair value at date of transition – (b) a previous CGAAP revaluation (if broadly comparable to fair value or cost, or depreciated cost) – (c) net book value, available for assets that are used, or were previously used, in operations subject to rate regulation. ● Available on asset by asset basis. ● Arises at transition only; is separate from on-going accounting policy choice. **If Exemption Elected** ● The fair value, revalued value, or current NBV becomes the deemed cost as at January 1, 2010 and is the starting point for subsequent accounting (depreciation, replacement, etc). ● Any corresponding adjustment amount is booked to retained earnings. ● Avoids need to reconstruct historical cost. **If Exemption Not Elected** ● Need to reconstruct historical cost and net book value of PP&E using IFRS standards. **Relevant Considerations** ● Availability of historical records to reconstruct costs. ● Resource effort to reconstruct cost. ● Any increase in values may offset negative adjustments arising from other conversion adjustments. ● Higher future depreciation charges and/or lower gain on future sale. ● External costs/difficulties of determining fair value. ● Use of the exemption does not eliminate the need to identify components.

Property, Plant and Equipment Borrowing Costs	**Brief Description of Key Elective Exemption** • Adopt a policy of capitalizing interest on qualifying projects commencing after January 1, 2010. **If Exemption Elected** • Prospectively capitalize interest for all projects commencing after January 1, 2010 and reverse any capitalized interest previously recognized under Canadian GAAP. There is however a proposed amendment that will allow entities not to reverse interest capitalized under CGAAP and would prospectively capitalize interest from the date of transition on ongoing qualified assets. **If Exemption Not Elected** • Retroactively capitalize interest for all qualifying projects i.e. o Identify all qualifying projects o Determine direct borrowing costs o Calculate interest to be capitalized • Adjust amortization to reflect adjustment to PP&E. **Relevant Considerations** • Availability of historical records to retroactively calculate interest amounts to be capitalized (for example, TS funding received if these assets are not sold or retired before then). • Likely to be an increase in retained earnings – level of retained earnings at January 1, 2010 to be assessed. • For STEI, impact on rate–setting process. • If any of the deemed costs exemptions are used, then retrospective restatement of amounts previously capitalized may not be required. • Monitor status of IASB annual improvement project for 2011 in which further clarification of the application of this IFRS 1 election has been proposed which would expand the scope of the prospective application of capitalizing interest to include qualifying assets for which commencement of capitalization occurs prior to the date of transition and which relieve the requirement to reverse previous capitalized interest under existing Canadian GAAP up to the date of transition.

First time adoption of IFRS – IFRS 1 (continued)

Property, Plant and Equipment **Transfers of Assets from Customers**	**Brief Description of Key Elective Exemption** ● Exemption would allow IFRIC 18 to be applied to transfers of assets from customers received on or after January 1, 2010. ● Any date before the date of transition (January 1, 2010) can be designated as the date to apply IFRIC 18. **If Exemption Elected** ● No requirement to apply IFRIC 18 to account for assets contributed by customers prior to the date of transition to IFRS. **If Exemption Not Elected** ● Retrospectively apply interpretation to all past customer contributions. **Relevant Considerations** ● Availability of historical records to retrospectively apply IFRIC 18. ● Impact on rate setting process.
Property, Plant and Equipment **Decommissioning Liabilities**	**Brief Description of Key Elective Exemption** ● Allows changes in decommissioning, restoration and similar liabilities to be added to or deducted from the cost of the asset at transition date, and for this adjusted value to be depreciated prospectively. **If Exemption Elected** ● Liability is measured at the date of transition. ● Estimate amount that would have been in PP&E when liability first arose, by discounting liability to that date using best estimate of historical non-adjusted discount rate. ● Estimate accumulated depreciation that would have been recorded as at transition date. ● Adjustments made to retained earnings. **If Exemption Not Elected** ● Retrospectively adjust liability, PP&E and depreciation each period for any changes made (i.e. change in estimate in timing and/or amount of payments and changes to discount rates). **Relevant Considerations** ● This exemption will only apply if asset retirement obligations are identified (examples for consideration: pole or transformer disposal). ● Availability of historical information to retrospectively construct a record of all adjustments in each period.
Business Combinations	**Brief Description of Key Elective Exemption** ● Allows an entity not to restate business combinations that occurred prior to the date of transition. ● Can choose any date prior to transition to apply election. If so, must restate all business combinations subsequent to the chosen date. **If Exemption Elected** ● No changes to existing business combinations. ● May recognize additional assets/liabilities. ● Adjust balance sheet/retained earnings only for these assets/liabilities that do not qualify for recognition under IFRS. **If Exemption Not Elected** ● All business combinations pre transition date must be restated for new IFRS requirements. ● Carrying values of assets/liabilities may change.

	• May recognize additional assets/liabilities. • Acquisition costs will generally be expensed, except for debt/equity issue costs. • Other impacts on value of share consideration, purchase price and restructuring liabilities. **Relevant Considerations** • Availability of historical records. • Nature of past business combinations • Impact on retained earnings. • Impact on rate setting process.
Employee Benefits **Actuarial gains/losses**	**Brief Description of Key Elective Exemption** • Permits recognition of all cumulative unrecognized actuarial gains and losses at transition date in equity. • The election must be applied consistently across all employee benefit plans and all entities. **If Exemption Elected** • Recognize in full, at transition, all previously unrecognized actuarial gains and losses through equity (i.e. reset unamortized actuarial gains and losses to zero by adjusting opening equity). • Avoids need to re-measure unrecognized actuarial gains and losses as if IFRS had always been applied. • Avoids the future amortization of previous unamortized actuarial losses to the P&L. **If Exemption Not Elected** • Need to re-measure unrecognized actuarial gains and losses as if IFRS had always been applied. **Relevant Considerations** • Availability of historical records for plans. • Impact on rate setting process (for St. Thomas Energy).
Employee Benefits Disclosures	**Brief Description of Key Elective Exemption** • Permits an entity not to disclose historical /trend information regarding defined benefit plan arrangements. **If Exemption Elected** • Can choose to disclose such amounts from date of transition only (i.e. the first annual IFRS financial statements will include two periods of disclosures for employee benefit plans, being the first IFRS reporting period and the restated comparative period). An additional disclosure period will be added each year until the five periods required by IAS 19 are provided. **If Exemption not Elected** • An entity must disclose significant information for the current annual period (2011) and the previous four annual periods. **Relevant Considerations** • Availability of historical records for plans.

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Mandatory Exemptions

Estimates	**Brief Description of Exceptions to Retrospective Application** • Estimates at January 1, 2010 under IFRS must be consistent with estimates at same date made under CGAAP, unless there is evidence those estimates were in error or where there are differences between CGAAP and IFRS as to determination of such measurements. • If new estimates are required under IFRS at January 1, 2010 then estimates must reflect conditions that existed at that date and cannot reflect conditions arising after that date. **Comments** • For the transition year, STEI and related entities should calculate its estimates under both CGAAP and IFRS, based on evidence available at that time.

STEI – Summary of Key Findings

1. STEI – First Time Adoption of IFRS – IFRS 1

Property, Plant and Equipment Proposed exemption Net Book Value as Deemed Cost	**Brief Description of Key Elective Exemption** • The ED on the new IFRS 1 exemption for rate regulated entities permits the net book value of PP&E (used for general reporting purposes) at January 1, 2010 to be the basis of "deemed cost". **If Exemption Elected** • No requirement to restate historical cost or obtain a fair value. **If Exemption Not Elected** • Restate historical costs or obtain fair values. **Relevant Considerations** • Assess whether there are differences between CGAAP net book value and regulated accounting net book value.

2. STEI – Property, Plant and Equipment and Borrowing Costs

Key GAAP Differences	**Capital vs. Expense** • Under both IFRS and CGAAP, costs of PP&E include all expenditures directly attributable to bringing the asset to the location and working condition for its intended use. • IFRS provides specific guidance as to the types of costs that are directly attributable. IFRS specifically prohibits capitalization of administrative and general overhead and training, while CGAAP is not as explicit (no specific prohibitions). • Normally, feasibility studies are not capitalized under IFRS as these costs do not always result in asset construction, and therefore may not meet the criteria of providing a future economic benefit. • Abnormal amounts of wasted labour and wasted materials incurred during construction of an asset are not included in the cost of the asset. • Third party compensation for damaged assets should be recognized as revenue when receivable, the replacement asset should be capitalized and an impairment charge recognized on the damaged asset. **Borrowing Costs** • Under IFRS, borrowing costs related to "qualifying" assets must be capitalized if certain conditions are met. IFRS also provides specific guidance, as follows, on the capitalization rate and timing of capitalization, whereas CGAAP is silent. - Under IFRS the capitalization rate includes a debt component only. - Interest on both general and specific borrowings is eligible for capitalization under IFRS. However, the amount capitalized is limited to the actual interest expense incurred. - Capitalization is suspended when development is interrupted for extended periods, and ceases when the asset is ready for its intended use. **Dismantlement or Decommissioning Costs** • IFRS requires legal and constructive obligations to be considered in determining dismantling or decommissioning costs, compared to CGAAP where asset retirement obligations are based on legal obligations only. The measurement of decommissioning obligations is also

different under IFRS.

Cost Model vs. Revaluation Model

- IFRS allows two models for measuring PP&E after recognition: the cost model and the revaluation model (based on fair value).

Component Accounting

- Separate accounting for "significant" components of PP&E is more rigorously applied and broader under IFRS. CGAAP is less specific than IFRS about the level at which component accounting is required.
- Under IFRS, components include non-physical components such as a major inspection or overhaul, while CGAAP does not provide guidance on non-physical components.

De-recognition

- IFRS requires that the carrying amount of a replaced asset or part of an asset be de-recognized (even if not treated as a separate component) and the cost of the replacement asset be capitalized. CGAAP does not provide explicit guidance on the replacement of components or parts of an asset.

Depreciation

- IFRS requires that component depreciation be taken based on its cost less its residual value over its estimated useful life which is similar to CGAAP. However, IFRS also requires an annual review of the method of depreciation, residual value and useful life, where CGAAP requires review periodically or when events or changes in circumstances indicate that the current estimates may no longer be appropriate.
- IFRS allows assets to be grouped for purposes of determining the depreciation charge only where the significant part of an item of PP&E has the same useful life and depreciation method of another significant part of the same item. It may be appropriate to aggregate individually insignificant items.
- IFRS requires idle assets to be depreciated.

Transfer of Assets

- IFRIC 18, "Transfer of Assets from Customers", was recently approved by the IASB. Customer contributions are recognized at fair value to PP&E and revenue over the period of service. It is necessary therefore to identify the services required to be provided to a customer in exchange for the contribution. If the service is merely connection to a network, then the credit is recognized in full to revenue at the date of connection. However, if the services involve ongoing access to the supply of electricity on an ongoing basis at a price lower than would be charged without the customer contribution, then the revenue would be recognized over the period of ongoing supply or the useful life of the asset (if earlier).

Major spare parts

- IFRS and Canadian GAAP standards on inventory are harmonized. In this industry and in practice, however, some variation in treatment can occur regarding cyclical and insurance spares. Cyclical spares refer to major spare parts that are expected to be replaced during the life of the asset, whereas insurance spare parts refer to major spare parts that are not expected to be used, but where it is necessary to keep the spare available in the event it is required. Depreciation of the insurance spares follows the depreciation period of the asset it is in place for, while cyclical spares are depreciated when they are put into use.

Classification and Presentation

- An asset which incorporates both intangible and tangible elements should be accounted for in accordance with the more significant element of the asset.
- Investment Properties, which are assets held to earn rental income or held for capital appreciation, are to be separately classified and accounted for either at cost or fair value.

Impact on St. Thomas Energy's

Capital vs. Expense

- Under IFRS, the criteria to capitalize material burden in inventory includes costs directly attributable to bringing the asset to the location and

CurrentAccounting Policy / Application

working condition for its intended use. All construction is performed by St. Thomas Energy Services ("STESI"). STESI applies several burden rates to capital; labour burden, building overheads, general admin overhead, stores overhead, vehicle overheads, operations overheads and engineering overhead . STESI's labour burden applied to capital is comprised of payroll and benefits, engineering, training, sick days and holidays. The building overhead includes building rent and other building expenses. General administrative overhead includes director and management expense, office costs, telephone, IT expense and other costs. The vehicle overhead includes repairs and amortization, operations overheads include management expense and mobile phone costs, engineering overheads include engineering hourly expense and supplies costs. These burdens include a variety of costs, some of which may be viewed as administrative overhead costs or may not be considered to be directly attributable to bringing the asset to the location and working condition for its intended use. Management should review the components of STESI's burdens to determine if they meet these criteria.

- The labour burden is comprised of employee benefits including CPP, EI, sick time and down time as well as meetings, conferences and travel. Some of the costs included in the payroll burden may not be considered to be directly attributable to the construction of an asset. Down time may be considered to be abnormal amounts of wasted labour that would be expensed as incurred. Management should analyze the components of payroll burden to determine if all costs can continue to be capitalized.
- The building overhead includes building rent and other building expenses. Management should take a careful look to determine if these costs are directly attributable.
- General administration overheads include director salaries and community relation costs, management salaries, office supplies, property taxes, legal and consulting fees, insurance, IT expense and bad debt expense. Under IFRS general administration cost can not be capitalized.
- Stores overhead includes inventory adjustments.
- Vehicle overheads include fuel, repair and maintenance and amortization. Management should analyze the components to determine if all costs can continue to be capitalized.
- Engineering overhead includes management salaries. These management employees do not complete time sheets, which makes it difficult to determine what part of their time is directly attributable.
- Under IFRS, pre-construction activities generally do not qualify for capitalization as design work does not generate expected future economic benefits. In addition, start-up and pre-operating costs such as feasibility studies are generally expensed as incurred because they are not linked to a specific item of PP&E at the time they are incurred. Some of these types of costs may be included in the labour burden. Management should determine whether these types of costs have been included in the general administration burden and determine the proper treatment as required under IFRS.
- Under IFRS, compensation from third parties for damaged PP&E should be recorded as revenue when it is receivable. Management should develop a process to recognize this compensation as revenue, record the asset impairment as an expense and capitalize the replacement asset.

Borrowing Costs

- Under IFRS, borrowing costs have three components: qualifying assets, capitalization rates and timing of capitalization.
- Qualifying Asset: STEI and STESI do not capitalize any interest on construction in progress balances. A qualifying asset is defined as an asset that takes a substantial period of time to get ready for its intended use. In KPMG's view a substantial period of time would represent an asset construction extending well in excess of six months. Management will need to ensure that interest is capitalized for any asset construction projects with a duration well in excess of six months.
- Capitalization rate: Under IFRS the borrowing costs capitalized must reflect the weighted average of the actual borrowing costs applicable to general borrowings, where specific borrowings for construction are not in evidence. This may not be the same as the imputed carrying charge currently included in the material burden.
- Timing of capitalization: STEI will need to determine if there are periods of inactivity during which interest capitalization should be suspended. STEI will also have to determine when capitalization should cease.

Dismantlement or Decommissioning Costs

- STEI currently does not have any Asset Retirement Obligations (AROs) recorded under Canadian GAAP. Under IFRS, the broader provision requirements surrounding legal or constructive obligations related to past events may require recognition of a liability for decommissioning or dismantlement activities. Therefore management needs to consider whether the estimated costs related to replacement of assets, such as replacement of old meters with smart meters, old poles with new poles, etc., meets the criteria for liability recognition and what the appropriate measurement amount is for any liability that might need to be accrued.
- STEI, in general, will decommission an asset only to replace it with another (substations and poles). No provision for the cost of removing assets is currently recorded at the inception of the asset; and all costs of removal and replacement are capitalized (expensed as appropriate) at the time of replacement. Management will need to determine if a liability should be recorded under IFRS.

Cost Model vs. Revaluation Model

- STEI may elect to use the revaluation model to measure its PP&E or continue to use the cost model. If the revaluation method is adopted this may lead to higher future depreciation changes. Management will need to consider the impact of revaluation on rate setting.

Component Accounting

- IFRS requires different individual components of an asset that require different depreciation methods or rates to be accounted for separately. Although STEI identifies individual components within its assets to some extent, management will need to analyze its current policy/method of identifying components to determine whether it is in compliance with IFRS requirements. Management should analyze the nature of the assets in the overhead lines, underground line, and buildings (IT infrastructure) in order to determine the appropriate useful life for each component in the class.
- STEI does not currently segregate non-physical components such as a major inspection or overhauls for depreciation purposes. Current inspection, testing and overhaul programs are performed as part of STEI's repair and maintenance program. Management should give consideration to identifying major inspections, or overhauls that entail major expenditures, which occur at regular intervals over the life of an asset, as distinct from costs associated with routine repairs and maintenance. In addition, management should consider inspection costs related to transformers and substations.

De-recognition

- Assets, or components or parts of assets, are tested and replaced by STEI regularly; specifically poles, meters and transformers, all of which are grouped assets. Where inspections lead to major replacement or refurbishment of transformers, STEI will capitalize the related material and labour through a work order. However, the asset that is replaced is not derecognized, unless specifically identifiable, and no gain or loss is recognized on the replacement of PP&E. Management needs to review this policy as it is inconsistent with IFRS.

Depreciation

- STEI depreciates assets on a straight-line basis over a useful life that has been prescribed / mandated by the OEB through the Electricity Distribution Rate Handbook, Appendix E Capitalization Rates. STEI will need to demonstrate that these useful lives truly reflect the useful lives of the assets to STEI.
- STEI depreciates assets using a group life methodology. STEI will need to demonstrate that these methodologies truly reflect the useful lives of the assets to STEI.
- St. Thomas Energy does not review the depreciation method, useful lives or residual values on an annual basis. This needs to be done under IFRS.

Transfer of Assets

- Currently customer contributions are recorded as a contra account to PP&E. Under IFRIC 18, Transfers of Assets from Customers, this treatment of customer contributions in a contra account in PP&E would not be appropriate, and the credit would depend on the nature of the identifiable services provided. In accordance with paragraph 13 of IAS 18, STEI will be required to identify the separately identifiable services included in the agreement. The credit is recognized in revenue immediately upon connection if the service is merely a connection to a network. If the service involves ongoing access to the supply of electricity on an ongoing basis at a price lower than would be charged without the customer contribution, then the revenue would be recognized over the period of ongoing supply or the useful life of the asset.

STEI - Property, Plant and Equipment and Borrowing Costs (continued)

Major Spare Parts

- STEI carries a limited quantity of major spare parts for its transformers, meters, poles and parts for the substation that they believe are critical to their ability to provide emergency services quickly and efficiently in the event of a power failure or emergency. These spare parts are also put into use when the asset undergoes maintenance or is tested so there is no overall loss of power to customers. Transformers are included in PP&E and are depreciated, though there are usually no spares at year end. The remaining spares are included in inventory and depreciated when used and transferred to PP&E. Management needs to review the nature of their major spare parts to determine if they are cyclical spares or insurance spares as these two different classifications of assets are subject to different depreciation methodologies.

Additional IFRS Disclosures

Classification and Presentation

- The financial statements shall disclose, for each class of PP&E, a reconciliation of the cost and accumulated depreciation at the beginning and end of the period showing items including additions, disposals and depreciation.
- If STEI elects to use fair value in its opening IFRS statement of financial position as deemed cost for an item of PP&E, its first IFRS financial statements should disclose, for each line item in the opening statement of financial position (a) the aggregate of those fair values; and (b) the aggregate adjustment to the carrying amounts reported under previous CGAAP.
- If STEI chooses the revaluation model for measurement of PP&E on an ongoing basis, significant differences in disclosure would result, and new disclosures would be necessary.
- The following additional disclosures are recommended but not required under IFRS:
  - Carrying amount of idle PP&E
  - Gross carrying amount of fully depreciated PP&E that is still in use
  - Carrying amount of PP&E retired from active use and not classified as "held for sale"
  - Where the cost model is used for measurement of PP&E, disclose the fair value of PP&E when it is materially different from the carrying amount.

Impact on IT Systems and Processes

New Processes

- STEI will need to develop new processes to support the data capture and recording of transactions in accordance with new IFRS accounting policies, such as:
  - Overheads – change in process to have overheads reflect costs that can be capitalized under IFRS
  - Borrowing Costs – identify qualifying assets as those construction in progress accounts that extend well in excess of 6 months and implement a process to determine the interest to be capitalized
  - Pre-construction activities – change the process to capitalize only those costs that provide a future economic benefit to St. Thomas Energy.
  - Customer Contributions – change the process for journalizing customer contributions to map to revenue or deferred revenue as needed.
  - Decommissioning / Dismantling – pending determination of material dismantlement costs, change the process to measure and capitalize dismantlement costs related to replacements of poles, meters, transformers etc.
  - Major Spare Parts – changes to the procurement process may be required to capture major spare parts that are to be recorded in fixed assets as individual asset records as opposed to grouping them in asset pools. Process changes will also be required with respect to major spare parts temporarily taken out of service.
  - Depreciation – a process will have to be developed to identify major assets that become idle, to determine if the asset is

impaired and a write down is required or if depreciation should continue. Componentization will also need to be considered.

IT Systems

Capital vs. Expense

- STEI will need to configure its fixed asset module to accommodate any changes to STEI's capitalization of burden rates related to labour, building, general admin, stores, vehicle, operations and engineering. This is an issue not only during the parallel accounting period (CGAAP and IFRS financial statements for 2010), but also ongoing if the regulators (OEB) require non-IFRS balances for rate setting purposes. If requirements for capitalized burden costs differ, then this will lead to a different cost basis for regulatory purposes for the same asset and therefore different capitalization amounts.
- All self-constructed assets are managed in Harris using the Work Order module. Amounts are not capitalized until they are transferred to STEI when construction is completed, or year end.
- Harris is used to automatically calculate the amount of burden to be capitalized based on a fixed rate, over a range of accounts, for every unit that is billed to a work order (each truck for the truck charge, each employee hour for labour burden, each issue to a cost centre for material burden, etc). The system does not have the capability to apply multiple burden rates to transactions (i.e. for OEB vs. IFRS reporting). During the parallel accounting period, a new process may be required to calculate adjustments for IFRS differences, or system changes may be required to accommodate the use of multiple burden rates. Changes will also be required on a go-forward basis if two sets of transactional data are required, i.e. OEB and IFRS.

Borrowing Costs

- Changes in fixed asset values for capitalized interest would have to be manually calculated and included within the work order pertaining to the related asset, or affected via a manual journal entry after the fact.

Component Accounting

- The system impact of component accounting can be addressed by implementing the fixed asset module within the Harris system (as STEI is not currently using a fixed asset module). Each serialized item can be set up as a separate fixed asset record and multiple fixed asset records can be linked together (in a parent child relationship) within the system. From a business process perspective, the impact of this change is high, as each component must be set up in the system with its own master record. As well, as all the fixed asset component costs are built up within the STESI company database, system changes may be required (e.g. creation of an interface), or a new process created, in order to transfer the asset component details over to the STEI company database, for capitalization purposes.
- It must be determined during the blueprinting phase how a single capital work order comprised of costs related to multiple asset components will be settled to multiple asset records.
- As a result of accounting differences, there could be two different cost bases for each asset added during the parallel accounting period, in addition to possible different cost bases for OEB purposes vs. IFRS books. The Harris fixed asset module does not have the capability to report fixed assets multiple ways / for multiple purposes. System changes or changes in business processes will be required to address this requirement.

Cost Model vs. Revaluation Model

- As STEI is not currently utilizing a fixed asset module within the Harris system, revaluations of fixed assets would need to be affected via a manual process of posting adjusting entries. Upon implementing a fixed asset module within the Harris system, revaluations of fixed assets can be recorded within the fixed asset subledger and amortization of these amounts can then be performed.

Depreciation

- As Excel spreadsheets are currently used to calculate fixed asset depreciation, requirements for changes in depreciable amount, useful life and depreciation method can be addressed within the spreadsheet. Upon implementing a fixed asset module within the Harris system, depreciation rules can be configured to address changes in useful life and depreciation method for each fixed asset class / record.
- Changes can be made to capture material fixed asset scrap / residual values within the fixed asset spreadsheet and adjust the depreciation amounts accordingly. Upon implementing a fixed asset module within the Harris system, residual values can be record and changed within

the system and depreciation automatically calculated based on the established scrap / residual values.

De-recognition

- De-recognition of an asset can be achieved through the fixed asset spreadsheet and Harris Financials G/L via a manual adjustment process. The business process impact of this requirement will be high for assets that are currently pooled within the system (i.e. there is not an individual fixed asset record for each item in the system) as a specific asset within the pool cannot be identified for de-recognition.

Disclosure

- Existing reports and/or spreadsheets will need to be configured to create continuity schedules as required for disclosure under IFRS.

Other Impacts (Business and People Impacts)	**Financial Impact:** ● Changes as a result of introducing IFRS will: o Affect the timing of expense recognition –administrative and other general overheads, interest expense, depreciation o Affect the timing of revenue recognition for customer contributions o Affect the net book value ("NBV") of PP&E o Introduce volatility to the P&L **Regulatory Reporting:** ● Further consideration must be given to the impact on the rate application process. ● STEI may need to maintain two sets of books (IFRS and OEB), and reconcile them where required. This will depend on the ultimate settlement of the IASB on how regulatory assets and liabilities should be accounted for. **Other Business Impacts:** ● Volatility in the P&L will affect key performance measures reviewed by management, the audit committee and the board such as return on net income, cash flow, OM&A per customer and capital expenditures. ● Volatility in the P&L will affect key inputs to the debt covenant calculations for debt to capitalization such as net income and retained earnings. ● Volatility in the P&L will affect overall results and thus consideration should be given to changes to how the bonus is determined. **Budget Impact:** ● Changes in the P&L will affect the budget process to the extent that IFRS-based figures are used in establishing budget amounts (as most entities will establish a 2010 budget under old Canadian GAAP or OEB driven processes, comparison of budget to actual during 2010 should be clearly communicated as to which rules have been applied in displaying actuals on management reporting. ● Changes in the P&L will affect peer comparisons used to assess reasonableness of the budget, such as cost per customer. **Tax Impact:** ● The impact on taxable income will have to be assessed once Canada Revenue Agency's guidelines are fully developed. **People Impact:** ● As a result of changes to PP&E and what can and can't be capitalized, the engineering / operations crew will need to be trained on new capitalization processes (i.e. what can and cannot be included in a work order, such as start-up costs). ● Training for accounting and finance teams on new processes as described above. ● Training for rate regulation staff regarding use of a second ledger for OEB books, and resulting reconciliation processes.
Considerations for Next Phase (Conversion Plan Activities)	**Strategic Planning** ● Engagement of the OEB to ensure plans for changes to rate-regulated processes is clearly understood and regulatory impacts identified. ● Plan and design function of the second set of books, identify primary vs. secondary basis of accounting; IFRS vs. Canadian GAAP/OEB. **Capital vs. Expense** ● Identify the components of the pre-construction activities that would not qualify as providing expected future economic benefits to STEI, and quantify materiality of currently capitalized costs (feasibility studies and other pre-construction activities). ● Identify the components of the material burden that would not qualify as directly attributable costs for capitalization under IFRS. ● Conclude on appropriateness to capitalize current labour, material, and trucking burdens to PP&E as costs directly attributable to the construction of the asset.

STEI - Property, Plant and Equipment and Borrowing Costs (continued)

- Once accounting conclusions are reached regarding the burden rates, design changes to the system as necessary.
- Conclude on whether a decommissioning / dismantling cost should be recognized for constructive obligations. If asset retirement obligations are identified, then it will be necessary to consider the related IFRS 1 exemption.
- Develop a process to identify constructive obligations for decommissioning / dismantling costs that may occur in the future.
- Design changes to the process for recording replacement of damaged equipment and third party compensation.

Component Accounting

- Determine appropriateness of current level of PP&E componentization.
- Conclude on whether significant non-physical components exist.
- Once conclusions are reached regarding the appropriate level of componentization under IFRS:
  - o quantify non-physical components if they exist;
  - o calculate new carrying values for new components;
  - o conclude on the need to retrospectively apply new component level based on materiality; If utilizing the NBV as deemed cost exemption, the entity will only be required to apply componentization on a go forward basis.
  - o develop business processes to create new master file records as necessary for each new component.

De-recognition, Depreciation and Borrowing Costs

- Investigate appropriateness of current estimates of useful lives and residual values. Design process for updating the Harris system and/or fixed asset spreadsheets for changes to useful lives (i.e. depreciable period) to ensure changes can be made on a prospective basis.
- Consider appropriateness of current useful lives of significant components under IFRS.
- Consider appropriateness of current depreciation method and residual values.
- Design new process for annual review of useful lives, depreciation method and residual values.
- Design new processes for de-recognition requirements when assets, components, or parts of assets are replaced.
- Design new policies and processes for capitalizing borrowing costs with respect to the capitalization rates and qualifying assets.

IFRS 1

- Conclude on policy for assessing opening balance of PP&E at transition.
- Conclude on option for treatment of borrowing costs on transition.
- Conclude on option for treatment of past contributions of contributions from customers.
- If asset retirement obligations exist, conclude on option to depreciate changes to decommissioning liabilities on transition prospectively.

Transfers of assets

- Conclude on whether service associated with customer contributions is a connection to a network or involves the ongoing access to the supply of electricity on an ongoing basis at a price lower than would be charged without the customer contribution.

Classification and Presentation

- Conclude on the practical treatment for major spare parts, as either insurance or cyclical spares.
- Design new processes for any change in treatment of major spare parts.

Other

- Consider changes to incentive compensation programs such as the bonus plan.
- Determine communication strategy with stakeholders (shareholders, bondholders) regarding volatility in the P&L as a result of conversion to IFRS.
- Determine specific training requirements of various staff.
- Consider the need for documentation of technical conclusions through draft accounting policies.

	• Design financial reporting processes and procedures, and draft accounting policies.
Index of Additional Topics of Interest	• Refer to IFRS 1. • Refer to Impairments. • Refer to Investment Property (see Miscellaneous Topics). • Refer to Provisions, Contingent Assets and Contingent Liabilities for consideration given to decommissioning and dismantling costs. • Refer to Intangibles.

3. STEI – Regulatory Accounting

Key GAAP Differences	• Under IFRS, all items recognized in the financial statements must meet the definition of a financial statement element as defined in the IFRS framework. CGAAP previously exempted rate regulated entities from applying these definitions to balances resulting from rate regulation. Commencing in 2009, CGAAP permits, through the GAAP hierarchy, rate regulated entities to apply specific industry guidance (FAS 71), which can give rise to regulatory assets and liabilities. • On July 20, 2010 the IASB discussed the analysis of the Rate-regulated Activities project (the "RRA ED"). The IASB discussed the issue and was "divided on whether to develop a standard to amend IFRSs to permit or require the recognition of regulatory assets and liabilities and if so, how to measure those regulatory assets and liabilities." A new timeline was not discussed, in light of the lack of decision on the RRA ED, the Accounting Standards Board (AcSB) released an exposure draft (ED) for comment. The ED proposes to amend the Introduction to Part 1 of the CICA Handbook to require the adoption of IFRSs by qualifying entities with rate-regulated activities, for interim or annual periods beginning on or after January 1, 2012.
Impact on STEI's Current Accounting Policy / Application	• Certain aspects of FAS 71 are inconsistent with the IFRS framework; for instance, regulatory assets and liabilities may be excluded from the definition of assets and liabilities under IFRS if they do not meet the definition of a financial statement element. Management will need to review the classification of regulatory assets and liabilities to determine if the current accounting presentation will be appropriate under IFRS. • The difference between the cost of power and revenue arising in connection with the IESO settlement arrangements for price variances is currently recorded as a regulatory asset/liability with adjustments to revenue. • Interest revenue and expense have been accrued on the regulatory balances.
Impact on IT Systems and Processes	**New Processes** • STEI will need to develop new processes to support potential separate regulatory reporting and rate setting requirements. **IT Systems** • Regulatory asset / liability amounts are calculated via the use of Excel spreadsheets, with adjustments to the amounts carried out via standard journal entry functionality within Harris Financials. In the event that accounting for regulatory assets and liabilities ultimately differs between IFRS and OEB reporting requirements, two sets of reporting will be required. • Harris Financials does not have dual reporting functionality and thus does not have the capability to report amounts under both CGAAP and IFRS for the 2010 fiscal period. St. Thomas Energy will need to explore alternative means for IFRS reporting such as the use of additional IFRS adjustment G/L accounts or the creation of another reporting company within the system. • As fixed assets are recorded and tracked within an Excel spreadsheet, fixed asset transactions can be reported multiple ways for each financial reporting requirement (CGAAP, OEB, IFRS) by making changes to the spreadsheet. The Harris system fixed asset module does not have the capability to report fixed assets multiple ways for each financial reporting requirement. A system change or change in business processes will be required to address this requirement.

STEI - Regulatory Accounting (continued)

Other Impacts (Business and People Impacts)	**Financial Impact:** ● The introduction of IFRS may result in the recognition of additional revenues and expenses and impact the amount of certain revenues recognized. **Regulatory Reporting:** ● Where the financial impacts noted above are not resolved, STEI may need to maintain two sets of books, IFRS and OEB, and reconcile them where required. This is currently the subject of OEB deliberation. **Tax Impact:** ● The impact on taxable income will have to be assessed. **People Impact:** ● Training for accounting and finance staff regarding the application of definitions contained in the IFRS framework to regulatory amounts. ● Training for rate regulation staff regarding the application of the definitions of Regulatory Assets and Regulatory Liabilities under the IFRS framework.
Considerations for Next Phase (Conversion Plan Activities)	● Evaluate the regulatory assets and liabilities against the definitions contained in the current IFRS framework. ● Monitor IASB developments –the IASB has continued to work on the regulated accounting project but has not come to a decision as of September 2010. ● Monitor OEB developments. ● Consider the need for documentation of technical conclusions through draft accounting policies. ● Design financial reporting processes and procedures, and draft accounting policies.
Index of Additional Topics of Interest	● Refer to Revenue.

4. STEI – Revenue

Key GAAP Differences	**Revenue Recognition** • Under IFRS, service revenue is recognized when the outcome of the transaction can be estimated reliably. Certain sources of revenue are not recognized as revenue under rate regulated accounting. • IFRS requires revenue to be measured at the fair value of the consideration received or receivable. Rate regulated accounting allows certain revenues to be recorded at approved amounts. • Rate regulated utilities argue that under CGAAP, following the GAAP hierarchy, they can use FAS 71 to account for rate regulated transactions. • IFRS requires revenue to be presented on a gross or net basis depending on the assessment of terms and risk. Billable work is presented on a net basis in the financial statements.
Impact on STEI's Current Accounting Policy / Application	• Customer billings for smart meters and recovery of regulatory assets have not been reported as revenue. Under IFRS, service revenue is recognized when the outcome of the transaction can be estimated reliably and revenue should be measured at the fair value of the consideration received. Management should review the nature of these billings and determine the appropriate classification (i.e. as revenue) and confirm that the amounts should therefore be recorded at fair value. • IESO settlement arrangements - the adjustment at month end to make expense equal revenue may not meet the recognition criteria under IFRS as an asset/liability with a corresponding impact on revenue. • Ontario Power Authority (OPA) – St. Thomas Energy will have to determine if they act as principal or agent for the programs operated through OPA funding. A determination will have to be made whether the funding received from the OPA is in the nature of a government grant.
Additional IFRS Disclosures	• Accounting policies for the presentation of government grants may need to be developed and disclosed. • No other material disclosure differences noted.
Impact on IT Systems and Processes	**New Processes** • STEI will need to develop new processes to support revenue recognition in accordance with IFRS. **IT Systems** • Billing, collections and cash processing of utility bills are processed through the Harris Financials Customer Information System ("CIS"), which is integrated with the G/L. Should accounting policies regarding revenue recognition on utility billing be changed, St. Thomas Energy may need to review the mapping of CIS transactions to the GL chart of accounts and assess other potential implications (i.e. whether proceeds from customer contributions to fixed assets will be recorded as revenue in one set of books and a contra asset in another).
Other Impacts (Business and People Impacts)	**Financial Impact:** • The introduction of IFRS may result in the recognition of additional revenue sources and impact the amount, timing and recognition of certain revenues and expenses. **Regulatory Reporting:** • Where the financial impacts noted above are not accepted by the OEB, St. Thomas Energy may need to maintain two sets of books, IFRS

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	and OEB, and reconcile them where required. This is currently the subject of deliberation. **Other Business Impacts:** • Changes to the amount and timing of revenue and expense recognition will affect the key performance measures reviewed by management, the audit committee and the board such as net income and cash flow. The changes will impact retained earnings and as a result the debt covenant calculations. **Budget Impacts:** • Consideration will have to be given to changes required in the budgeting process with respect to the amount and timing of revenue recognition. **Tax Impact:** • Additional revenue sources will be included in accounting income. Tax impacts will have to be considered. **People Impact:** • Accounting and finance staff will require training on the application of revenue recognition principles under IFRS.
Considerations for Next Phase (Conversion Plan Activities)	• Design new processes for the recognition of all customer billings as revenue while tracking revenue and associated costs and approved recoveries for rate setting purposes, if required. • Conclude on whether STEI is acting as agent or principal with respect to the billing, collection and payment of retailer billings and the debt retirement charge as well as other “pass through” activities. • May need to design new processes to capture debt retirement charges as revenue and record the related expense to the OEFC. • May need to redesign the budget process to reflect the changes to revenue recognition. • Determine communication strategy with stakeholders regarding changes to amount and timing of revenue recognition. • Determine specific training requirements for finance staff. • Consider the need for documentation of technical conclusions through draft accounting policies. • Design financial reporting processes and procedures, and draft accounting policies. • May need to negotiate with lenders any potential impacts on financial covenants
Index of Additional Topics of Interest	• Refer to Regulatory Assets and Liabilities.

5. STEI – Impairments

Key GAAP Differences	
Key GAAP Differences	• Similar to CGAAP, long lived assets other than goodwill or indefinite life intangible assets, are tested for impairment when there has been a triggering event. However, impairment testing under IFRS involves a one stage process where the carrying value of the asset (or group of assets) is compared to the recoverable amount, which is defined as the higher of the value-in-use (discounted cash flows) or fair value less cost to sell. In contrast, CGAAP first determines whether an impairment exists by comparing the carrying value to the undiscounted cash flows, and, if a write-down is necessary, the carrying value is then compared to fair value of the asset. • Value-in-use is a new concept under IFRS; it represents the discounted future cash flows of an entity (entity specific). • Under IFRS, impairment testing is conducted for a Cash Generating Unit (“CGU”), the smallest group of assets that generates cash inflows from continuing use that largely are independent of the cash inflows of other assets or groups thereof. Generally, a CGU is at a lower level than an asset group used under CGAAP. • Impairment losses, other than from goodwill, are reversed if there has been a change in the estimate used to determine the assets’ recoverable amount.
Impact on STEI’s Current Accounting Policy / Application	• Management believes that so long as STEI can recover costs on its PP&E through rates it will never trigger the requirement to review impairment. For this reason, St. Thomas Energy has not recorded an impairment loss on its long lived assets to date as no triggering events have occurred to warrant impairment testing. Management needs to review the impairment triggering events under IFRS to determine that this approach is still appropriate. • STEI receives transfers of assets from customers. Any impacts on the recoverable value of these assets given the current regulatory treatment must be considered. (i.e. they are not included in rate base). • STEI includes all assets in the regulated business in its asset groups for impairment testing. However, under IFRS, a CGU is often at a lower level than an asset group under CGAAP. Determination of a CGU under IFRS depends largely on whether the asset is separable and whether the asset has largely independent cash inflows. STEI has done a preliminary assessment and believes that its rate regulated operations represent one cash generating unit.

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STEI - Impairments (continued)

Additional IFRS Disclosures	• If impairments of Long-lived Assets and Intangible Assets are recorded, then the following disclosures would be required for each class of asset: o the amount of impairment losses recognized or reversed in profit or loss during the period, and the line item it was recorded to; o the amount of impairment losses on revalued assets recognized (or reversed) in other comprehensive income during the period. • For each material impairment loss recognized or reversed during the period, disclose the following: o the events and circumstances that led to the recognition or reversal; o the amount; o the nature of any individual assets or a description of the CGU, where applicable; o any changes to the assets comprising a CGU; o whether the recoverable amount is the fair value less cost to sell or value–in-use, with discount rates used if the latter. • Disclose, in aggregate, the main classes of assets affected by, and the main events and circumstances that led to, an impairment loss or reversal.
Impact on IT Systems and Processes	**New Processes** • STEI will need to develop processes in accordance with new IFRS accounting policies, such as: o Determining CGU's; o Gathering fair value and cost to sell information; o Gathering cash flow details and calculating other estimates (i.e. discount rate); o Allocating an impairment loss across the assets in a CGU; o Tracking assets that are impaired for potential future impairment reversals. • Reconciling OEB balances to IFRS long lived asset balances to determine whether assets are recoverable; where the OEB balance is less than the IFRS balance, a triggering event may exist as the recoverable amount (through rates) would be limited to the OEB balance. **IT Systems** • Impairments of assets within the Harris system fixed asset module should be created using parent and child functionality to establish an impairment as a 'child' of the asset, such that a history of asset value changes is retained in the event the original carrying value needs to be recreated for an impairment reversal.

Other Impacts (Business and People Impacts)	**Financial Impact and Regulatory Reporting:** • In general, the new requirements give rise to more frequent impairment. However, in rate regulated industries, impairment losses would generally be dependent on the differences between the asset balances submitted to the OEB (i.e. the recoverable rate base) and the IFRS balances. • To the extent that impairment losses are recorded, the impact on regulatory reporting will have to be determined. **Other Business Impact:** • Key performance indicators such as OM&A cost per customer may be impacted if an impairment loss is recognized. **Tax Impact:** • The impact on taxable income will have to be assessed once Canada Revenue Agency's guidelines are fully developed. **People Impact:** • Training accounting and finance teams on new processes as described above. • Training for finance teams on methods and concepts used in impairment testing under IFRS.

Considerations for Next Phase (Conversion Plan Activities)	• Determine if there are separable assets within the regulated business and determine the assets to be included in each CGU.
	• Develop a policy and processes for impairment testing including:
	  o Determining CGU's;
	  o Gathering fair value and cost to sell information;
	  o Gathering cash flow details and calculating other estimates (i.e. discount rate);
	  o Allocating an impairment loss across the assets in a CGU;
	  o Tracking assets that are impaired for potential future impairment reversals.
	• Configure reports or design new processes to address new disclosure requirements under IFRS.
	• Consider the need for documentation of technical conclusions through draft accounting policies.
	• Design financial reporting processes and procedures, and draft accounting policies.

Index of Additional Topics of Interest	• Refer to PP&E. • Refer to Intangible Assets.

6. STEI – Provisions, Contingent Liabilities and Contingent Assets

Key GAAP Differences	• IFRS requires both legal and constructive obligations to be assessed in determining dismantling or decommissioning costs, compared to CGAAP where asset retirement obligations are based on legal obligations only. • The measurement of a decommissioning provision differs under IFRS whereby the accretion on the liability is required to be treated as interest expense. • In determining whether a provision should be recognized, both CGAAP and IFRS look to past events and the probability of future outflows of resources. However, the probability threshold is different: IFRS uses a "more likely than not" threshold (greater than 50%), while CGAAP uses a "likely" recognition threshold (greater than 70%). • If there is a large population and a continuous range of equally possible outcomes, then the obligation is measured at the mid-point of the range under IFRS. CGAAP requires that where no amount within a range is a better estimate than any other, then the obligation is measured at the low end of the range. • IFRS requires discounting of provisions if the effect would be material.
Impact on STEI's Current Accounting Policy / Application	• STEI may have decommissioning provisions recognized under IFRS whereas they have recognized no such Asset Retirement Obligations under CGAAP. Decommissioning provisions may relate to the dismantling of transmission and distribution equipment and to old meters for the mandatory replacement by smart meters. • All of STEI's transformers have PCB levels that are less than the provincial standard • STEI may have additional provisions to be recognized under IFRS based on the lower probability threshold for a provision.
Additional IFRS Disclosures	• IFRS requires additional disclosures for each class of provisions, as follows: o the carrying amount at the beginning and end of the period; o additional provisions made in the period, including increases to existing provisions; o amounts used (i.e. incurred and charged against the provision) during the period; o unused amounts reversed during the period; o the increase during the period in the discounted amount arising from the passage of time and the effect of any change in the discount rate, where applicable. • For each class of provision, STEI shall disclose: o a brief description of the nature of the obligation and the expected timing of any resulting outflows of economic benefits; o an indication of the uncertainties about the amount or timing of those outflows. Where necessary to provide adequate information, disclose the major assumptions made concerning future events; o the amount of any expected reimbursement, stating the amount of any asset that has been recognized for that expected reimbursement, where applicable.

STEI - Provisions, Contingent Liabilities and Contingent Assets (continued)

Impact on IT Systems and Processes	• Process changes to identify and measure provisions and contingent assets and liabilities. • Design new process to create continuity schedules as required for disclosure under IFRS. • No system configuration impact is expected
Other Impacts (Business and People Impacts)	**Financial Impacts** • The introduction of IFRS may result in the increased recognition of provisions which will impact results. **Regulatory Reporting:** • Further consideration to be given to the impact on rate setting. • IFRS could impact rate base to the extent that asset retirement obligations and decommissioning provisions are required. • IFRS may impact revenue requirement to the extent that recorded provisions increase depreciation and operations and maintenance expense. **Other Business Impact:** • If additional provisions are recorded, STEI will have to assess the impact on cost per customer used as key performance indicators. **Tax Impact:** • The impact on taxable income will have to be assessed once Canada Revenue Agency's guidelines are fully developed. **People Impact:** • Training accounting and finance teams on recognition and measurement of provisions and any changes in processes resulting. • Training regulatory team on the differences that may arise under IFRS.
Considerations for Next Phase (Conversion Plan Activities)	• Conclude on whether a decommissioning / dismantling cost should be recognized for constructive obligations, for example replacement costs of old meters for smart meters and transmission and distribution equipment. • Further analyze the current or potential liabilities to determine if a provision should be recognized under IFRS, by applying a lower threshold than applied under CGAAP. • Configure reports or design new processes to address new disclosure requirements under IFRS. • Develop a process to reassess estimates (i.e. discount rates) where discounting of provisions is required and determine appropriate mapping of accretion (unwinding of the discount).
Index of Additional Topics of Interest	• Refer to PP&E and discussions on Decommissioning Costs.

7. STEI – General Financial Statement Topics

Key GAAP Differences	**Form and Components of Financial Statements** • Under IFRS, a statement of changes in equity and a statement of comprehensive income are required. Under CGAAP, a statement of retained earnings is presented instead of the statement of changes in equity. • Under IFRS, an analysis of expenses by nature or by function is required in the income statement or in the notes, and the chosen classification must be applied consistently. • Under IFRS, if there is a change in accounting policy three statements of financial position are required. This will be required in the year of transition. • Under IFRS, a reporting entity has an accounting policy choice of classifying interest and dividends received as operating or investing activities and interest and dividends paid as operating and financing activities on the statement of cash flows. Under CGAAP, interest received and paid, and dividends received are treated as operating activities, while dividends paid are part of financing activities. • IFRS makes no distinction between ordinary and extraordinary activities, and the presentation, disclosure or characterization of items as "extraordinary items" in the income statement or notes is prohibited. **Presentation of financial statements** • Current and non-current classification of certain items can be different between CGAAP and IFRS. Under IFRS all deferred tax assets/liabilities are non-current. Under CGAAP, the current vs. non-current classification is determined based on the nature of the asset/liability giving rise to deferred tax balance.
Impact on STEI's Current Accounting Policy / Application	**Form and Components of Financial Statements** • STEI will need to: o reconsider the format of its Income Statement and determine its policy for presenting expenses by nature or function; o present a separate statement of changes in equity instead of a statement of retained earnings; o make an accounting policy choice on whether interest and dividends paid and received are financing or operating activities.
Additional IFRS Disclosures	• Accounting policy notes will be required to contain more details regarding policy elections and key judgments and estimates that have been made in preparing the financial statements.
Impact on IT Systems and Processes	**Form and Components of Financial Statements** • Design new processes to gather the information necessary to present a statement of equity. • Design changes to process and present interest and dividends, paid or received, in financing or operating activities based on policy chosen by management. **IT Systems** • St. Thomas Energy generates its financial statements using Excel spreadsheets populated with data from the Harris Financials system. These spreadsheets will have to be modified to reflect changes in the presentation of the components of the financial statements and application of accounting policies.
Other Impacts	**People Impact:**

STEI - General Financial Statement Topics (continued)

(Business and People Impacts)	• Training for accounting and finance teams on new processes and requirements as described above.
Considerations for Next Phase (Conversion Plan Activities)	• Develop a template or draft Financial Statements with related notes. • Consider disclosures and accounting policy choices of peers in the industry. • Configure reports or design new processes to address new disclosure requirements under IFRS.

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8. STEI – Miscellaneous Topics

Key GAAP Differences	There are often issues that arise due to differences in practice on the application of IFRS and CGAAP. Some of these are set out below. **<u>Leases:</u>** ● Under IFRS, a lease is classified as either a finance (capital) lease or an operating lease. The classification depends on whether substantially all of the risks and rewards incidental to ownership of a leased asset have been transferred from the lessor to the lessee. A number of indicators are used to assist classification. However, under CGAAP, in practice the quantitative thresholds included in the indicators generally are interpreted as "bright lines." **<u>Inventory:</u>** ● Effective January 1, 2008, STEI adopted CICA HB s 3031, which harmonized CGAAP with IFRS. Major spare parts and standby equipment have been reclassified from inventory to fixed assets upon adoption of s3031. Although the standards have been harmonized, there may still be differences in practice and interpretation. St. Thomas Energy will need to review the classifications in light of the IFRS guidance. **<u>Related Party Transactions:</u>** ● IFRS includes key management (including directors), their close family members, and post-employment benefit plans as related parties, whereas CGAAP does not address whether a post-employment benefit plan is a related party. ● Under CGAAP, there are special recognition and measurement requirements for related party transactions, whereas IFRS does not have specific requirements.
Impact on STEI's Current Accounting Policy / Application	**<u>Leases</u>** ● STEI has entered into leases for vehicles which it currently accounts for as operating leases. **<u>Related Party Transactions:</u>** ● There are a number of disclosure requirements for related parties of STEI. Examples of STEI's related parties would include: o Parent: 2154310 Ontario Inc. o Key management personnel, including the board of directors, and their close family members; o OMERS; o Other related parties, including all parties controlled by the parent (St. Thomas Energy Services Inc., Tiltran, Lizco, Tal Trees) ● The IASB issued an exposure draft that proposes amending IAS 24 to provide an exemption from requirements to disclose related party transactions in respect of related party relationships that arise through common control by the state, except if indicators of influence exist between the entities. This will need to be assessed.
Additional IFRS Disclosures	**<u>Leases</u>** ● There are different lease disclosure requirements that STEI may be subject to pending materiality and classification as operating or finance, and lessee or lessor. **<u>Related Party Transactions:</u>** ● IFRS requires specific disclosure of related party relationships between a parent and its subsidiaries, while CGAAP does not. ● Compensation of key management personnel must be disclosed and categorized as short-term employee benefits, post-employment benefits, other long-term benefits, and termination benefits.

	• Comprehensive disclosures of related party transactions are required under both standards, however, IFRS requires the disclosure to be grouped into categories of related parties. • IFRS requires disclosure of the details of any guarantees given or received for outstanding balances resulting from related party transactions. • IFRS requires disclosure of the provisions for doubtful debts related to the amount of outstanding related party balances. • Under IFRS, the expense recognized during the period in respect of bad or doubtful accounts due from related parties is disclosed.
Impact on IT Systems and Processes	**New Processes** • Leases: Design new processes to gather lease commitment information if required. • Related Party Transactions: Design processes to gather information necessary for the related party disclosure requirements.

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Other Impacts **(Business and People Impacts)**	**People Impact:** • Training for accounting and finance teams on new processes and requirements as described above. • Communication plan regarding disclosure of compensation of key management personnel.
Considerations for Next Phase **(Conversion Plan Activities)**	• Design new processes as set out above. • Configure reports or design new processes to address new disclosure requirements under IFRS. **Leases** • Re-evaluate existing leases to determine the proper classification under IFRS. **Insurance Contracts:** • Determine if participation in MEARIE falls within the scope of the Insurance Contract standard under IFRS (which is not applicable solely to Insurance companies). **Related Party Transactions:** • Follow resolution of exposure draft to amend IAS 24. The entity will need to determine who "key management personnel" is for compensation disclosure.
Index of Additional Topics of Interest	• Refer to PP&E.

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St. Thomas Energy Service Inc. - Summary of Key Findings

1. St. Thomas Energy Services Inc. – Employee Benefits

Key GAAP Differences	• Under both IFRS and CGAAP, where insufficient information is provided regarding a multi-employer defined benefit pension plan then the plan may be recorded as a defined contribution plan. While there is a presumption under CGAAP that insufficient information is available, there is no such presumption under IFRS. However, even if the multi-employer plan is accounted for as a defined contribution plan, IFRS may require recognition of an additional pension asset/liability if there is a contractual arrangement to share/fund any plan surplus/deficit. • Under IFRS, actuarial gains and losses may be recognized in profit or loss, or alternatively recognized immediately through equity. The policy chosen for the recognition of actuarial gains and losses is applied consistently to all defined benefit plans and from period to period. CGAAP does not permit recognition through equity and does not explicitly require the policy chosen to be applied consistently to all defined benefit plans. • Under IFRS, past service costs for benefits that have not yet vested are amortized straight-line over the period until they vest. Vested past service costs are recognized directly in the statement of profit and loss. Under CGAAP, past service costs are amortized on a straight-line basis over the expected average remaining service life of employees. • Under IFRS, guidance exists for post employment benefits funded through insurance policies. Whether this guidance is applicable to insured long term employee benefits is currently being debated. Application of this guidance would require companies to account for insured long term employee benefits under defined benefit accounting where risks are retained, directly or indirectly, by the organization. • Under IFRS, short term employee benefits which are accumulating compensated absences are recognized when the employees render service, which increases their entitlement to future compensated absences. Accumulating compensated absences that do not vest must include a forfeiture factor when measuring the obligation. Under CGAAP, no liability is recorded for accumulating compensated absences that do not vest.
Impact on STESI' Current Accounting Policy / Application	• OMERS has determined that it is unable to provide sufficient information for STESIs to account for their pension plan as a defined benefit pension plan, as opposed to a defined contribution plan. • Under IFRS, any future past service costs must be recognized immediately (if vested) or amortized over the period until they vest. . • Under IFRS, a liability may need to be recorded for accumulating compensated absences that do not vest (i.e. sick pay).

Additional IFRS Disclosures	• STESI shall disclose the employee benefits for key management personnel and employee benefits expense.
	• As sufficient information cannot be provided by OMERS of STESI's participation in the multi-employer plan, the pension plan is accounted for as a defined contribution plan, the following disclosures are required:
	    o the fact that the plan is a defined benefit plan;
	    o the reason why sufficient information is not available to enable the entity to account for the plan as a defined benefit plan;
	    o to the extent that a plan surplus or deficit may affect the amount of future contributions, the following additional disclosures are required:
	        ▪ any available information about that surplus or deficit;
	        ▪ the basis used to determine that surplus or deficit;
	        ▪ the implications, if any, for the entity.
	• Disclose the employer's best estimate, as soon as it can reasonably be determined, of contributions expected to be paid to the plan during the annual period beginning after the balance sheet date.

Impact on IT Systems and Processes	**New Processes** • STESI will need to develop processes in accordance with new IFRS accounting policies, such as gathering information required for additional disclosure including new requirements to disclose employee benefits of key management personnel and employee benefits expense. **IT Systems** • No system configuration impact is expected

Other Impacts (Business and People Impacts)	**Financial Impact:**
	• Changes in timing of expense recognition as a result of conversion to IFRS.
	Regulatory Reporting:
	• Further consideration to be given to the impact on rate setting, if any.
	• IFRS could impact revenue requirement to the extent that operating expenses change as a result of the timing of recognition of employee benefits.
	Other Business Impact:
	• Changes in the timing of expense recognition, due to changes in the amortization period (average remaining service life to vesting period) or accounting under defined benefit plans will affect:
	    o Key performance measures reviewed such as net income and cash flow;
	    o Debt covenant calculation to the extent that total capitalization is impacted by changes to retained earnings;
	• Changes to assumptions made by actuaries to incorporate IFRS requirements, where necessary.

Considerations for Next Phase (Conversion Plan Activities)	• Communications with actuaries regarding impact to Services' actuarial valuations as a result of IFRS conversion. • Monitor developments on whether risks are indirectly retained by Services with respect to its long term disability program, as risks may be retained through the mechanism of setting future insurance premiums. Identify all long term employee benefits funded through insurance policies. • Determine liability to be recorded for accumulating compensated absences that do not vest (i.e. sick pay). This calculation may need to be done in conjunction with the actuary.

- Configure reports or design new processes to address new disclosure requirements under IFRS.
- Conclude on elective exemption regarding recognizing unamortized actuarial losses in equity.
- Consider the need for documentation of technical conclusions through draft accounting policies.
- Design financial reporting processes and procedures, and draft accounting policies.

2. St. Thomas Energy Services Inc – Intangible Assets

Key GAAP Differences	• The new Canadian GAAP HB S3064 Goodwill and Intangible Assets was effective for STESI on January 1, 2009. This new Canadian guidance is largely harmonized with IFRS, except IAS 38 which: o permits intangible assets to be measured subsequently using fair value (if specific criteria are met) or the cost method; o provides more detailed guidance on estimating an asset's useful life, selecting and reviewing an amortization period and method, and reviewing retirements and disposals. • An asset which incorporates both intangible and tangible elements should be accounted for in accordance with the more significant element of the asset.
Impact on STESI.'s Current Accounting Policy / Application	• Services' computer software (2009 NBV of $13,235) is currently classified as deferred charges as the system is only leased and only the data is owned by the company. • Depending on which component of an asset is more significant, the tangible or non-tangible component, some computer software may be reclassed to Intangible Assets. Computer software would represent a finite life intangible asset.
Additional IFRS Disclosures	• Disclosures of intangible assets include: o Indefinite vs. finite useful lived intangible assets; o Amortization methods and useful lives/amortization rates where the intangible asset has a finite life; o Gross carrying amount and accumulated amortization; o The line to which the amortization expense has been recorded; o A reconciliation of the cost and accumulated amortization of each class at the beginning and end of the period including additions, disposals, held for sale assets, changes due to revaluations, impairment losses & reversals, amortization recognized during the period; o For intangible assets with indefinite useful lives, the carrying amount and the reason for assessing the asset as an indefinite lived intangible; o A description, the carrying amount and remaining amortization period of any individual intangible asset that is material to the financial statements.
Impact on IT Systems and Processes	**New Processes** • A new business process should be developed to identify whether future purchases of software should be classified as PP&E or Intangible Assets. **IT Systems** • Whether computer software is classified as PP&E or Intangible assets, the existing fixed asset spreadsheet (and later the Harris system fixed asset module) can be used to calculate amortization and to process transactions. • System configuration changes may be necessary to map Intangible Assets recorded in Harris Financials to separate accounts in the chart of accounts, and ultimately the financial statements via separate account mappings / groupings.
Other Impacts	**Regulatory Reporting:**

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(Business and People Impacts)	• Further consideration to be given to the impact on rate setting, if any. • Rate base could be impacted to the extent that computer software is moved to intangible assets. **Other Business Impact:** • Consider impact of the accounting treatment for land rights and a change in useful life or depreciation method on key performance measures such as net income and cash flow and on the debt covenants. **People Impact:** • Determine training necessary for accounting and finance teams on new accounting requirements and any new financial reporting processes. • Communicate changes to regulatory staff for incorporation into rate applications.
Considerations for Next Phase (Conversion Plan Activities)	• Conclude on appropriateness of reclassifying computer software from PP&E to Intangible Assets. • Consider plans for mapping the reclassed computer software to a separate line on the financial statements, and related processes for ongoing reconciliation between the sub-ledger and the general ledger. • Develop a process for annual review of the amortization period and method. • Configure reports or design new processes to address new disclosure requirements under IFRS.
Index of Additional Topics of Interest	• Refer to PP&E. • Refer to Impairments.

3. St. Thomas Energy Services Inc. – Miscellaneous Topics

Key GAAP Differences	There are other issues that arise due to differences in practice on the application of IFRS and CGAAP. Some of these are set out below. **Related Party Transactions** ● IFRS includes key management (including directors), their close family members, and post-employment benefit plans as related parties, whereas CGAAP does not address whether a post-employment benefit plan is a related party. ● Under CGAAP, there are special recognition and measurement requirements for related party transactions, whereas IFRS does not have specific requirements. **Leases** ● Under IFRS, a lease is classified as either a finance (capital) lease or an operating lease. The classification depends on whether substantially all of the risks and rewards incidental to ownership of a leased asset have been transferred from the lessor to the lessee. A number of indicators are used to assist classification. However, under CGAAP, in practice the quantitative thresholds included in the indicators generally are interpreted as "bright lines." **Employee Benefits** ● The rate used to discount post-employment benefit obligations is determined by reference to market yields on high quality corporate bonds. Services has discounted its employee future benefits using the long term yield on high quality bonds.
Impact on STESI's Current Accounting Policy / Application	**Related Party Transactions** ● There are a number of disclosure requirements for related parties of STESI. STESI's related parties would include: o Parent; o Key management personnel, including the board of directors, and their close family members; o OMERS; o Other related parties, including all parties controlled by their parent. ● The IASB issued an exposure draft that proposes amending IAS 24 to provide an exemption from requirements to disclose related party transactions in respect of related party relationships that arise through common control by the state, except if indicators of influence exist between the entities. This will need to be assessed. **Leases** ● Leases may be accounted for as financing leases under IFRS. Management will have to review the terms of the agreements to determine the appropriate accounting for these contracts. ● **Employee Benefits** ● The discount rate used to discount STESI's employee future benefits will have to reviewed and compared to the rate on high quality corporate bonds to determine if there is a significant difference in rates that would have a significant impact on the liability.
Additional IFRS Disclosures	**Related Party Transactions** ● IFRS requires specific disclosure of related party relationships between a parent and its subsidiaries, while CGAAP does not. ● Compensation of key management personnel must be disclosed and categorized as short-term employee benefits, post-employment benefits, other long-term benefits, and termination benefits. ● Comprehensive disclosures of related party transactions are required under both standards, however, IFRS requires the disclosure to be grouped into categories of related parties. ● IFRS requires disclosure of the details of any guarantees given or received for outstanding balances resulting from related party

	transactions. ● IFRS requires disclosure of the provisions for doubtful debts related to the amount of outstanding related party balances. ● Under IFRS, the expense recognized during the period in respect of bad or doubtful accounts due from related parties is disclosed. **Leases** ● There are different lease disclosure requirements that Services may be subject to pending materiality and classification as operating or finance, and lessee or lessor.
Impact on IT Systems and Processes	**New Processes** ● Related Party Transactions: Design processes to gather information necessary for the related party disclosure requirements. ● Leases: Change processes to classify leasing transactions in accordance with IFRS.
Other Impacts **(Business and People Impacts)**	**People Impact** ● Training for accounting and finance teams on new processes and requirements as described above. o Communication plan regarding disclosure of compensation of key management personnel.
Considerations for Next Phase **(Conversion Plan Activities)**	● Design new processes as set out above. ● Configure reports or design new processes to address new disclosure requirements under IFRS. **Related Party Transactions** ● Follow resolution of exposure draft to amend IAS 24. **Employee Benefits** ● Determine if the discount rate used to determine the employee future benefit liability is appropriate under IFRS. ● If the discount rate under IFRS differs from the current rate used, contact actuaries to determine the impact on the liability.

Tiltran Services Inc. - Summary of Key Findings

1. Tiltran Services Inc. – Revenue

Key GAAP Differences	**Revenue Recognition** ● Revenue from construction contracts is recognized using the percentage of completion method. ● Service contracts are accounted for similar to construction contracts. ● When a specific act in a service contract is more significant than any other acts, revenue is recognized only after the significant act is performed. ● In order for revenue to be recognized under the percentage of completion method; the outcome of the contract can be estimated reliably; and the stage of completion of the contract can be measured reliably. When the outcome of a construction project cannot be reliably estimated, no profit is recognized as an expense is incurred. ● There is specific guidance in IFRS of the costs that can be capitalized in relation to a contract. Costs that are not considered to be directly attributable to contract activity cannot be capitalized
Impact on Tiltran's Current Accounting Policy / Application	● Tiltran will have to review contracts to determine if they meet the criteria for recognition under IAS 11 Construction Contracts. ● Cost attributed to contracts will have to be reviewed to determine that no general administration costs, for which reimbursement is not specified are included and no selling cost have been attributed. ● An exposure draft has been released on revenue, that if passed will replace IAS 11 and IAS 18 and could impact percentage of completion revenue recognition.
Additional IFRS Disclosures	● Tiltran will have to disclose the amount of contract revenue recognized in the period, the methods used to determine the contract revenue recognized in the period and the methods used to determine the percentage of completion.
Impact on IT Systems and Processes	**New Processes** ● Tiltran will need to develop new processes to support revenue recognition in accordance with IFRS. **IT Systems** ● No system configuration impact is expected.
Other Impacts (Business and People Impacts)	**Financial Impact:** ● The introduction of IFRS may result in changes in the timing and recognition of certain revenues and expenses. **Other Business Impacts:** ● Changes to the amount and timing of revenue and expense recognition will affect the key performance measures reviewed by management, the audit committee and the board such as net income and cash flow. **Budget Impacts:** ● Consideration will have to be given to changes required in the budgeting process with respect to the amount and timing of revenue recognition. **Tax Impact:** ● Additional revenue sources will be included in accounting income. Tax impacts will have to be considered. **People Impact:** ● Accounting and finance staff will require training on the application of revenue recognition principles under IFRS.

Considerations for Next Phase (Conversion Plan Activities)	
	• Design new processes for the recognition of all customer billings as revenue while tracking revenue and associated costs and approved recoveries for rate setting purposes, if required. • Conclude on whether Tiltran is acting as agent or principal with respect to the billing, collection and payment of retailer billings and the debt retirement charge as well as other "pass through" activities. • May need to design new processes to capture debt retirement charges as revenue and record the related expense to the OEFC. • May need to redesign the budget process to reflect the changes to revenue recognition.Determine communication strategy with stakeholders regarding changes to amount and timing of revenue recognition. • Determine specific training requirements for finance staff. • Consider the need for documentation of technical conclusions through draft accounting policies. • Design financial reporting processes and procedures, and draft accounting policies.

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Tal Trees Inc. - Summary of Key Findings

1. Tal Trees Inc. – Impairments

Key GAAP Differences	• Similar to CGAAP, long lived assets other than goodwill or indefinite life intangible assets, are tested for impairment when there has been a triggering event. However, impairment testing under IFRS involves a one stage process where the carrying value of the asset (or group of assets) is compared to the recoverable amount, which is defined as the higher of the value-in-use (discounted cash flows) or fair value less cost to sell. In contrast, CGAAP first determines whether an impairment exists by comparing the carrying value to the undiscounted cash flows, and, if a write-down is necessary, the carrying value is compared to fair value of the asset. • Value-in-use is a new concept under IFRS; it represents the discounted future cash flows of an entity (entity specific). • Under IFRS, impairment testing is conducted for a Cash Generating Unit ("CGU"), the smallest group of assets that generates cash inflows from continuing use that largely are independent of the cash inflows of other assets or groups thereof. Generally, a CGU is at a lower level than an asset group used under CGAAP. • Impairment losses, other than from goodwill, are reversed if there has been a change in the estimate used to determine the assets' recoverable amount.
Impact on Tal Trees' Current Accounting Policy / Application	• Tal Trees has not recorded an impairment loss on its long lived assets or goodwill to date as no triggering events have occurred to warrant impairment testing. Management needs to review the impairment triggering events under IFRS to determine that this approach is still appropriate.

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Tal Trees Inc. – Impairments (continued)

Additional IFRS Disclosures	
	• If impairments of Long-lived Assets and Intangible Assets are recorded, then the following disclosures would be required for each class of asset: o the amount of impairment losses recognized or reversed in profit or loss during the period, and the line item it was recorded to; o the amount of impairment losses on revalued assets recognized (or reversed) in other comprehensive income during the period. • For each material impairment loss recognized or reversed during the period, disclose the following: o the events and circumstances that led to the recognition or reversal; o the amount; o the nature of any individual assets or a description of the CGU, where applicable; o any changes to the assets comprising a CGU; o whether the recoverable amount is the fair value less cost to sell or value–in-use, with discount rates used if the latter. • Disclose, in aggregate, the main classes of assets affected by, and the main events and circumstances that led to, an impairment loss or reversal.
Impact on IT Systems and Processes	**New Processes** • Tal Trees will need to develop processes in accordance with new IFRS accounting policies, such as: o Determining CGU's; o Gathering fair value and cost to sell information; o Gathering cash flow details and calculating other estimates (i.e. discount rate); o Allocating an impairment loss across the assets in a CGU; o Tracking assets that are impaired for potential future impairment reversals. **IT Systems** • As the fixed asset module within the Maestro application is not being utilized and fixed assets are tracked within Excel spreadsheets, impairments of fixed asset value can be recorded in the spreadsheet and manually recorded within the system. As histories of the previous values are no explicitly tracked within the fixed asset spreadsheet, changes will be required to do so, in the event the original carrying value needs to be recreated for an impairment reversal.

2. Tal Trees, Tiltran and Lizco (the companies) – Property, Plant and Equipment

Key GAAP Differences	
Key GAAP Differences	**<u>Capital vs. Expense</u>** ● Under both IFRS and CGAAP, costs of PP&E include all expenditures directly attributable to bringing the asset to the location and working condition for its intended use. **<u>Cost Model vs. Revaluation Model</u>** ● IFRS allows two models for measuring PP&E after recognition: the cost model and the revaluation model (based on fair value). **<u>Component Accounting</u>** ● Separate accounting for "significant" components of PP&E is more rigorously applied and broader under IFRS. CGAAP is less specific than IFRS about the level at which component accounting is required. ● Under IFRS, components include non-physical components such as a major inspection or overhaul, while CGAAP does not provide guidance on non-physical components. **<u>Depreciation</u>** ● IFRS requires that component depreciation be taken based on its cost less its residual value over its estimated useful life which is similar to CGAAP. However, IFRS also requires an annual review of the method of depreciation, residual value and useful life, where CGAAP requires review periodically or when events or changes in circumstances indicate that the current estimates may no longer be appropriate. ● IFRS requires idle assets to be depreciated. **<u>Classification and Presentation</u>** ● An asset which incorporates both intangible and tangible elements should be accounted for in accordance with the more significant element of the asset.
Impact on Tal Trees, Tiltran and Lizco Current Accounting Policy / Application	**<u>Cost Model vs. Revaluation Model</u>** ● The companies may elect to use the revaluation model to measure its PP&E or continue to use the cost model. If the revaluation method is adopted this may lead to higher future depreciation changes. <u>Component Accounting</u> ● IFRS requires different individual components of an asset that require different depreciation methods or rates to be accounted for separately. Although the companies identify individual components within its assets to some extent, management will need to analyze its current policy/method of identifying components to determine whether it is in compliance with IFRS requirements appropriate useful life for each component in the class. **<u>Depreciation</u>** ● The companies do not review their depreciation methods, useful lives or residual values on an annual basis. This needs to be done under IFRS.

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Additional IFRS Disclosures

Classification and Presentation

- The financial statements shall disclose, for each class of PP&E, a reconciliation of the cost and accumulated depreciation at the beginning and end of the period showing items including additions, disposals and depreciation.
- If the companies elect to use fair value in their opening IFRS statement of financial position as deemed cost for an item of PP&E, its first IFRS financial statements should disclose, for each line item in the opening statement of financial position (a) the aggregate of those fair values; and (b) the aggregate adjustment to the carrying amounts reported under previous CGAAP.
- If the companies choose the revaluation model for measurement of PP&E on an ongoing basis, significant differences in disclosure would result, and new disclosures would be necessary.
- The following additional disclosures are recommended but not required under IFRS:
  - Carrying amount of idle PP&E
  - Gross carrying amount of fully depreciated PP&E that is still in use
  - Carrying amount of PP&E retired from active use and not classified as "held for sale"
  - Where the cost model is used for measurement of PP&E, disclose the fair value of PP&E when it is materially different from the carrying amount.

Impact on IT Systems and Processes

IT Systems

Component Accounting

- The system impact of component accounting can be addressed by implementing the fixed asset module within the Maestro system (as Tiltran, Tal Trees and Lizco are not currently using a fixed asset module within the application) or modifying the existing fixed asset spreadsheets. Utilizing the fixed asset subledger within Maestro, each serialized item can be set up as a separate fixed asset record and multiple fixed asset records can be linked together (in a parent child relationship) within the system. From a business process perspective, the impact of this change is high, as each component must be set up in the Maestro fixed asset module with its own master record.

Cost Model vs. Revaluation Model

- As the fixed asset module within the Maestro system is not currently being utilizing, revaluations of fixed assets would need to be affected via a manual process of posting adjusting entries and a history of previous value maintained. Implementing the fixed asset module within Maestro, would enable revaluations of fixed assets to be recorded within the fixed asset subledger and amortization of these amounts performed.

Depreciation

- As Excel spreadsheets are currently used to calculate fixed asset depreciation, requirements for changes in depreciable amount, useful life and depreciation method can be addressed within the spreadsheet. Implementing the fixed asset module within Maestro, depreciation rules could be configured to address changes in useful life and depreciation method for each fixed asset class / record.
- Changes can be made to capture material fixed asset scrap / residual values within the fixed asset spreadsheet and adjust the depreciation amounts accordingly. Implementing the fixed asset module within the Maestro, residual values can be record and changed within the system and depreciation automatically calculated based on the established scrap / residual values.

De-recognition

- De-recognition of an asset can be achieved through the fixed asset spreadsheet and Maestro G/L via a manual adjustment process. The business process impact of this requirement will be high for assets that are currently pooled within the system (i.e. there is not an individual fixed asset record for each item in the system) as a specific asset within the pool cannot be identified for de-recognition.

Disclosure

- Existing reports and/or spreadsheets will need to be configured to create continuity schedules as required for disclosure under IFRS.

Other Impacts **(Business and People Impacts)**	**Financial Impact:** • Changes as a result of introducing IFRS will: o Affect the timing of expense recognition –administrative and other general overheads, interest expense, depreciation o Affect the timing of revenue recognition for customer contributions o Affect the net book value (“NBV”) of PP&E o Introduce volatility to the P&L **Other Business Impacts:** • Volatility in the P&L will affect key performance measures reviewed by management, the audit committee and the board such as return on net income, and cash flow. • Volatility in the P&L will affect key inputs to the debt covenant calculations for debt to capitalization such as net income and retained earnings. • Volatility in the P&L will affect overall results and thus consideration should be given to changes to how the bonus is determined. **Budget Impact:** • Changes in the P&L will affect the budget process to the extent that IFRS-based figures are used in establishing budget amounts (as most entities will establish a 2010 budget under old Canadian GAAP, comparison of budget to actual during 2010 should be clearly communicated as to which rules have been applied in displaying actuals on management reporting. • Changes in the P&L will affect peer comparisons used to assess reasonableness of the budget. **Tax Impact:** • The impact on taxable income will have to be assessed once Canada Revenue Agency’s guidelines are fully developed. **People Impact:** • Training for accounting and finance teams on new processes as described above.
Considerations for Next Phase **(Conversion Plan Activities)**	**Component Accounting** • Determine appropriateness of current level of PP&E componentization. • Conclude on whether significant non-physical components exist. • Once conclusions are reached regarding the appropriate level of componentization under IFRS: o quantify non-physical components if they exist; o calculate new carrying values for new components; o conclude on the need to retrospectively apply new component level based on materiality; o develop business processes to create new master file records as necessary for each new component. **De-recognition, Depreciation and Borrowing Costs** • Investigate appropriateness of current estimates of useful lives and residual values. Design process for updating the Maestro system and/or fixed asset spreadsheets for changes to useful lives (i.e. depreciable period) to ensure changes can be made on a prospective basis. • Consider appropriateness of current useful lives of significant components under IFRS. • Consider appropriateness of current depreciation method and residual values. • Design new process for annual review of useful lives, depreciation method and residual values. • Design new processes for de-recognition requirements when assets, components, or parts of assets are replaced. • Design new policies and processes for capitalizing borrowing costs with respect to the capitalization rates and qualifying assets.

IFRS 1

- Conclude on policy for assessing opening balance of PP&E at transition.
- Conclude on option for treatment of borrowing costs on transition.
- Conclude on option for treatment of past contributions of contributions from customers.
- If asset retirement obligations exist, conclude on option to depreciate changes to decommissioning liabilities on transition prospectively.

Transfers of assets

- Conclude on whether service associated with customer contributions is a connection to a network or involves the access to the supply of electricity on an ongoing basis at a price lower than would be charged without the customer contribution.

Classification and Presentation

- Conclude on the practical treatment for major spare parts, as either insurance or cyclical spares.
- Design new processes for any change in treatment of major spare parts.

Other

- Consider changes to incentive compensation programs such as the bonus plan.
- Determine communication strategy with stakeholders (shareholders, bondholders) regarding volatility in the P&L as a result of conversion to IFRS.
- Determine specific training requirements of various staff.
- Consider the need for documentation of technical conclusions through draft accounting policies.
- Design financial reporting processes and procedures, and draft accounting policies.

Attachment 2 of 2

Depreciation Study

St. Thomas Energy Inc

Useful Life of Assets

Kinectrics Report: K-418037-RA-001-R000

July 23, 2010

PRIVATE INFORMATION

Kinectrics Inc., 800 Kipling Avenue, Unit 2, Toronto, Ontario, Canada M8Z 6C4

DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the agreement between Kinectrics Inc. and St. Thomas Energy Inc.

St. Thomas Energy Inc, Useful Life of Assets

Kinectrics Report: K-418037-RA-001-R000

July 23, 2010

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Revision Number	Date	Comments	Approved
R000	July 23, 2010	Initial Draft	N/A
	March 10, 2011	*Final Report*	YT

EXECUTIVE SUMMARY

Ontario's Local Distribution Companies (LDCs) are switching to International Financial Reporting Standards (IFRS) methodology. One of the "tenants" of IFRS is the time period assets are amortized over should align with their actual useful life.

LDCs typically own and operate a large number of assets that are divided into different asset categories, each with its own degradation mechanism and useful life range. Furthermore, some assets are comprised of several components that may have differing useful lives than the assets themselves. To facilitate conversion to IFRS, LDCs need to ensure that a) they track all relevant asset categories and their components and b) that the amortization period for these are adequately aligned with actual LDC-specific useful lives.

This report reviews the useful lives of the assets, and their respective asset components that are applicable to St. Thomas Energy Inc (STEI). The useful life values are compiled from several different sources, namely, industrial statistics, research studies and reports (either by individuals or working groups such as CIGRE), and Kinectrics experience, all of which listed in *Section C* of this Report. These factors are described in detail in *Section A-3* of this report and are used to decide where the LDC-specific typical asset/components lives should be relative to the typical lives based on the industry data. It is also worth noting that the useful lives of assets do not generally follow standard distribution curves as they are derived from empirical statistics.

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A INTRODUCTION

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This report reviews the useful lives of the assets, and their respective asset components that are applicable to St. Thomas Energy Inc (STEI). The useful life values are compiled from several different sources, namely, industrial statistics, research studies and reports (either by individuals or working groups such as CIGRE), and Kinectrics experience, all of which listed in *Section C* of this Report. These factors are described in detail in *Section A-3* of this report and are used to decide where the LDC-specific typical asset/components lives should be relative to the typical lives based on the industry data. It is also worth noting that the useful lives of assets do not generally follow standard distribution curves as they are derived from empirical statistics.

A-1 Project Scope

This report provides an in-depth evaluation of the useful lives of the assets that are owned and operated by STEI. The typical system to which the asset belongs is provided and these systems are: *Overhead Lines* (OH), *Municipal Stations* (MS), *Underground Systems* (UG) and *Monitoring and Control System* (S). The long term degradation mechanism is described for each asset category and when applicable assets are sub-categorized into components. Components are included when their cost is material enough and, at the same time, could be replaced without a need to replace the whole asset. For each asset, the following information is presented:

1. Asset Description
2. Degradation Mechanism
3. Useful Life
4. Time Based Maintenance Intervals
5. Typical Replacement Costs
6. Sensitivity to Material Size

Section A-3 provides definitions for the above terms, as well as descriptions of typical distribution system assets and asset components.

A-2 Project Execution Process

The project execution process entailed a number of steps to ensure that the industry-based information compiled by Kinectrics not only includes all the relevant assets and components used by STEI, but also that it addresses the specific needs related to the IFRS review. The procedure is as follows:

1. The initial list of assets and components was produced by STEI to Kinectrics for review.
2. Upon review of the initial list, Kinectrics generated an intermediate asset list that had a somewhat different background, granularity, and componentization, based on industry practices and Kinectrics experience.
3. The intermediate list was reviewed jointly by Consortium and Kinectrics to derive a "final" list.
4. For each asset and component in the "final" list, Kinectrics then gathered the information described in *Section A-1* of this report. A Draft Report that summarized the findings and provided detail descriptions, including degradation mechanisms and applicable assumptions for each asset, was then produced.
5. This Draft Report was reviewed by STEI and their feedback was incorporated in the Final Report.

A-3 Definition of Terms

Typical Distribution System Asset

Typical distribution system assets include transformers, breakers, switches, underground cables, poles, vaults, cable chambers, etc. Some of the assets, such as power transformers, are rather complex systems and include a number of components.

Component

For the purposes of this study, component refers to the sub-category of an asset that meets both of the following criteria:

1. Its replacement value is significant enough, relative to the asset value
2. A need to replace the component does not necessarily warrant replacing the entire asset.

An *asset* may be comprised of more than one component, each with an independent failure mode and degradation mechanism that may result in a substantially different useful life than the overall asset. A component may also have an independent maintenance and replacement schedule.

Useful Life

Useful Life refers to an estimated range of years during which an electric utility asset or its component is expected to operate as designed, without experiencing major functional degradation that requires major refurbishment or replacement.

In this report, the useful life range, in years, is presented in terms of a minimum, maximum, and typical value. An overwhelming number of units within a population will perform their intended design functions for a period of time greater than or equal to the *minimum* life. Conversely, an overwhelming number of units will cease to perform as designed at or beyond the *maximum* life. A majority of the population will have useful lives of around the *typical* life. For example, consider an asset class with a useful life range of 20 to 40 years, and a typical life of 30 years. The majority of the units within this class will perform as required for at least 20 years and likewise the majority of the units will not operate beyond 40 years. Finally, a majority of the units within the population will operate for approximately 30 years. Note that an asset category can have a typical life that is equal to either the maximum or minimum life. This is simply an indication that the majority of the units within a population will be operational for either the minimum or maximum years; i.e. the statistical data is skewed towards either the maximum or minimum values. The range in useful lives reflects differences in various utilization factors including mechanical stress, electrical loading, and environmental conditions and operating practices.

Typical Life

Refers to the typical age at which the asset or component fails. This may vary depending on a utility's maintenance practices, environmental conditions, and operational stresses.

Typical Time-based Maintenance Intervals

For the purposes of this report, time-based maintenance refers to either *Routine Inspections* (RI) or *Routine Testing/Maintenance* (RTM). Other maintenance techniques such as Condition Based Maintenance, Reliability Centered Maintenance, and more intrusive periodic overhauls are very much dependent on individual utility's maintenance strategy and practices and, as such, could not be included in compiling industry-wide typical values.

Typical time-based maintenance intervals will be given only for assets that are proactively maintained, i.e. assets for which useful life is affected by regular planned maintenance. This excludes assets that are not routinely maintained.

Replacement Cost

Replacement Cost refers to industry typical "installed" cost that includes labour, material and equipment. These costs are derived from industry expertise. Variations from typical costs can be attributed to a number of factors, such as the purchasing power of larger utilities, different labor rates, higher construction costs in urban areas, or sophistication of construction practices.

Sensitivity of the Replacement Value to Typical Size

In addition to these factors, overall replacement cost of an asset depends on the ratio of its cost components, specifically labour versus material and equipment. Therefore, for assets and components for which the material represents a significant percentage of the cost the overall replacement cost is highly sensitive to the equipment's typical size. On the other hand, for assets that have low equipment costs relative to the labour costs, such as pole-mounted transformers, the equipment's typical size does not significantly impact the overall replacement cost.

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B RESULTS AND FINDINGS

Table B-1 summarizes useful and typical lives, time based maintenance schedules, and impact of stress for St. Thomas Energy Inc assets.

Table B-1 Summary of Componentized Assets

#	ASSET CATEGORY			System*	Typical Asset Size	Useful Life (years)			Maint. Type**	Time Based Maint Schedule (years)	Typical Replacement Cost***	Sensitivity to Material Size
	Asset	Sub-Category	Components			MIN	TYP	MAX				
1	Buildings			MS	Not Available	50	60	75	RI	1	Not Available	Not Available
2	Power Transformers		Overall	MS	5/6.7 MVA, 27.6/4 kV	30	45	55	RTM	2	$300,000	High
			Winding			30	45	55			$180,000	High
			Bushing			10	15	20			$2,000	Medium
			Tap Changer			20	30	30			$60,000	Low
3	Fully Dressed Wood Poles			OH	40 feet	40	45	50	RI	15	$10,000	Medium
4	Overhead Switches			OH	600 A, 28 kV	30	50	60	RTM	2	$13,000	Low
5	Overhead Conductors	Primary		OH	WIRE 556 ASC (DAHLIA)	50	60	75	N/A	N/A	$80 - $120/m (circuit)	Low
		Secondary		OH	TRIPLEX 2-266.8 AL XLPEI 1- 3/0	50	60	75	N/A	N/A	$75 - $90/m (circuit)	
6	Underground Conduit	Cross Linked Poly-Ethylene in Duct		UG	1/0 AL 28 kV TRXLPE ECNPEJ	40	40	60	N/A	N/A	$350 - $500/m (circuit) + $50/m (trench)	Medium
		Cross Linked Poly-Ethylene Direct Buried		UG	1/0 AL 28 kV TRXLPE ECNPEJ	20	25	25			$300 - $450/m (circuit) + $50/m (trench)	
		Paper Insulated Lead Covered		UG	500 KCMIL 3C CU 15 kV PILC	70	75	80			$800-$1500/m (circuit) + $50/m (trench)	
7	Pad Mounted Transformer			UG	1 PH, 100 kVA, 16 kV	30	40	40	N/A	N/A	$7000 (1 PH) $200,000 (3 PH)	Medium

* MS = Municipal Station OH = Overhead Lines System UG = Underground System S = Monitoring and Control System
** RI = Routine Inspection RTM = Routine Testing/Maintenance N/A = Not Applicable

#	ASSET CATEGORY			System *	Typical Asset Size	Useful Life (years)			Maint. Type**	Time Based Maint Schedule (years)	Typical Replacement Cost***	Sensitivity to Material Size
	Asset	Sub-Category	Components			MIN	TYP	MAX				
8	Pad Mounted Switchgear	Gas (SF6)/Vacuum Insulated		UG	VISTA or SF6 Canada power	30	30	50	RI	3	$100,000	Medium
		Air Insulated		UG	600 A, 28 kV	20	20	40			$40,000	
9	Pole Mounted Transformer			OH	1 PH, 100 kVA, 16 kV	30	40	40	N/A	N/A	$4500 (1 PH) $12000 (3 PH)	Low
10	Services	Underground Cable		UG	CABLE 500 KCMIL CU XLPE 600V	40	40	60	N/A	N/A	$75/m (circuit) + $50/m (trench)	Low
11	Energy Meters	Non Interval		S	Not Available	20	30	60	N/A	N/A	Not Available	Not Available
		Interval				10	15	15				
		Wholesale				15	30	30				
12	System Supervisory Equipment RTU			S	13.8 kV	15	20	30	N/A	N/A	$90,000	Medium

* MS = Municipal Station OH = Overhead Lines System UG = Underground System S = Monitoring and Control System
** RI = Routine Inspection RTM = Routine Testing/Maintenance N/A = Not Applicable

1 Buildings

1.1 Asset Description

Buildings at major transformer and municipal stations house the switchgear, relays and controls and serve as a base for administrative and service work.

1.1.1 Componentization

The Buildings asset category is not subject to componentization.

1.1.2 System Hierarchy

The Buildings asset category belongs to the Municipal Station asset grouping.

1.2 Typical Asset Size

The Buildings asset category's typical asset size is not available for the purposes of this report.

1.3 Degradation Mechanism

The following contribute to the degradation of this asset:

- Building age
- Structural condition of loading members
- Condition of floors, walls and ceilings
- Protection against weather elements
- Environmental concerns
- Functional requirements

Buildings are a very maintainable asset. The capital cost of replacement is high enough that the lowest long term cost is achieved even with quite high levels of annual maintenance. Age alone is a very poor indicator of end of life. Rather impacts such as environmental rain, wind and snow storms contribute highly to the degradation of buildings.

Also, since the foundation materials typically consist of reinforced concrete designed to consider environmental elements including soil conditions and climate. Landscaping is used to control soil erosion, maintain site cleanliness and facilitate an efficient and safe work environment.

Preventative maintenance helps ensure long-term integrity of buildings. This type of maintenance should be done on a regular basis. As well the occasional refurbishment of doors, windows and roofs helps with the viability of the building.

The building roof is the most susceptible to degradation due to environmental factors. The roof is typically level and composed of tar and an aggregate that is designed to keep the wind from wearing at the tar. Nevertheless, the roof is still susceptible to environmental degradation and if not sealed properly can become a source of flooding. The maintenance of the roof is generally the largest undertaking for buildings.

1.4 Useful Life

The useful life of the Buildings asset category can be in the range of 50 to 75 years, with a typical life of 60 years.

1.5 Time Based Maintenance Intervals

The typical routine inspection interval for Buildings asset category is every year.

1.6 Typical Replacement

The Buildings asset category's typical replacement costs are not available for the purposes of this report.

1.7 Sensitivity to Material Size

The Buildings asset category's sensitivity to material size is not available for the purposes of this report.

2 Power Transformers

2.1 Asset Description

While power transformers can be employed in either step-up or step-down mode, a majority of the applications in distribution stations involve step down of the transmission or sub-transmission voltage to distribution voltage levels. Power transformers vary in capacity and ratings over a broad range. There are two general classifications of power transformers: transmission station transformers and distribution station transformers. Substation power transformers at distribution stations typically step down voltage to distribution levels.

2.1.1 Componentization

The Power Transformers asset category has been componentized into the following:

1 Overall
2 Windings
3 Bushing
4 Tap Changer

2.1.2 System Hierarchy

The Power Transformers asset category belongs to the Municipal Station asset grouping.

2.2 Typical Asset Size

The Power Transformers asset category typical size is 5/6.7 MVA, 27.6/4 kV.

2.3 Degradation Mechanism

Transformers operate under many extreme conditions, and both normal and abnormal conditions affect their aging and breakdown. They are subject to thermal, electrical, and mechanical aging. Overloads cause above-normal temperatures, through-faults can cause displacement of coils and insulation, and lightning and switching surges can cause internal localized over-voltages.

For a majority of transformers, end of life is a result of the failure of insulation, more specifically, the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of the transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are the presence of oxygen, high temperature, and moisture. Particles and acids, as well as static electricity in oil cooled units, also affect the insulation.

Tap changers and bushing are major components of the power transformer. Tap changers are complex mechanical devices and are therefore prone to failure resulting from either mechanical or electrical degradation. Bushings are subject to aging from both electrical and thermal stresses.

2.4 Useful Life

The Power Transformers asset category also has major components that have different useful lives. Componentization is as follows:

1 Overall
2 Windings
3 Bushing
4 Tap Changer

2.4.1 Overall

The useful life of the overall transformer is 30 to 55 years; the typical life is 45 years.

2.4.2 Windings

The useful life of the overall transformer is 30 to 55 years; the typical life is 45 years.

2.4.3 Bushing

The useful life range of the bushing is 10 to 20 years; the typical life is 15 years.

2.4.4 Tap Changer

The useful life range of tap changers is 20 to 30 years; the typical life is 30 years.

2.5 Time Based Maintenance Intervals

The typical routine testing and maintenance interval for the Power Transformers asset category is every 2 years.

2.6 Typical Replacement Costs

The Power Transformers asset category also has major components that have different typical replacement costs. Componentization is as follows:

1 Overall
2 Windings
3 Bushing
4 Tap Changer

2.6.1 Overall

The typical replacement cost of the overall transformer is $300, 000.

2.6.2 Windings

The typical replacement cost of the transformer windings is $180,000.

2.6.3 Bushing

The typical replacement cost of the transformer bushing is $2,000.

2.6.4 Tap Changer

The typical replacement cost of the transformer tap changer is $60,000.

2.7 Sensitivity to Material Size

The Power Transformers asset category also has major components that have different sensitivity to material size. Componentization is as follows:

1 Overall
2 Windings
3 Bushing
4 Tap Changer

2.7.1 Overall

The sensitivity to material size of the overall transformer is high.

2.7.2 Windings

The sensitivity to material size of the transformer windings is high.

2.7.3 Bushing

The sensitivity to material size of the transformer bushing is medium.

2.7.4 Tap Changer

The sensitivity to material size of the transformer tap changer is low.

3 Fully Dressed Wood Poles

3.1 Asset Description

The asset referred to in this category is the fully dressed pole ranging in size from 30 to 75 feet. This includes the pole, cross arm, bracket, insulator, and anchor & guys. The most important component with respect to useful life is the pole itself.

3.1.1 Componentization

The Fully Dressed Wood Poles asset category is not subject to componentization.

3.1.2 System Hierarchy

The Fully Dressed Wood Poles asset category belongs to the Overhead Lines System asset grouping.

3.2 Typical Asset Size

The Fully Dressed Wood Poles asset category's typical asset size is 40 feet.

3.3 Degradation Mechanism

The most significant component of this asset is the wood pole itself. The degradation of poles is based on the pole type. Wood poles are typically the most common form of support for overhead distribution feeders and low voltage secondary lines. The wood species predominately used for distribution systems are Red Pine, Jack Pine, and Western Red Cedar (WRC), either butt treated or full length treated. Smaller numbers of Larch, Fir, White Pine and Southern Yellow Pine have also been used. Preservative treatments applied prior to 1980, range from none on some WRC poles, to butt treated and full length Creosote or Pentachlorophenol (PCP) in oil. The present day treatment, regardless of species, is CCA-Peg (Chromated Copper Arsenate, in a Polyethylene Glycol solution). Other treatments such as Copper Naphthenate and Ammoniacal Copper Arsenate have also been used, but these are relatively uncommon. As wood is a natural material the degradation processes are somewhat different from those which affect other physical assets on the electricity distribution systems. The critical processes are biological, involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Some fungi attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot. As a structural item the sole concern when assessing the condition for a wood pole is the reduction in mechanical strength due to degradation or damage.

3.4 Useful Life

The useful life of Fully Dressed Wood Poles is in the range of 40 to 50 years; the typical life is 45 years.

3.5 Time Based Maintenance Intervals

The typical routine inspection interval for Fully Dressed Wood Poles asset category is every 15 years.

3.6 Typical Replacement

The Fully Dressed Wood Poles asset category's typical replacement cost is $10,000.

3.7 Sensitivity to Material Size

The Fully Dressed Wood Poles asset category has a medium sensitivity to material size.

4 Overhead Switches

4.1 Asset Description

This asset class consists of overhead line switches. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. The operating control mechanism can be either a simple hook stick or manual gang.

4.1.1 Componentization

The Overhead Switches asset category is not subject to componentization.

4.1.2 System Hierarchy

The Overhead Switches asset category belongs to the Overhead Lines System asset grouping.

4.2 Typical Asset Size

The Overhead Switches asset category's typical asset size is 600 A, 28 kV.

4.3 Degradation Mechanism

The main degradation processes associated with manually operated line switches include the following, with rate and severity depending on operating duties and environment:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Insulators damage
- Missing ground connections

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions in which the equipment operates. Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. When lubrication dries out, the switch operating mechanism may seize making the disconnect switch inoperable. In addition, when blades fall out of alignment, excessive arcing may result. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road salt is used.

4.4 Useful Life

The useful life of Overhead Switches is in the range of 30 to 60 years; the typical life is 50 years.

4.5 Time Based Maintenance Intervals

The typical routine testing and maintenance interval for Overhead Switches asset category is every 2 years.

4.6 Typical Replacement

The Overhead Switches asset category's typical replacement cost is $13,000.

4.7 Sensitivity to Material Size

The Overhead Switches asset category has a low sensitivity to material size.

5 Overhead Conductors

5.1 Asset Description

Overhead conductors along with structures that support them constitute overhead lines or feeders that distribute electrical energy either directly to large customers or from Municipal Stations via distribution transformers to the end users. These conductors are sized to carry a specified maximum current and to meet other design criteria, i.e. mechanical loading.

The overhead conductors typically used by the Consortium are primary and secondary conductors. The types include aluminum conductor steel reinforced (ACSR), all aluminum conductor (AAC), copper, weather protected wire and insulated wire.

5.1.1 Componentization

The Overhead Conductors asset category is not subject to componentization.

5.1.2 System Hierarchy

The Overhead Conductors asset category belongs to the Overhead Lines System asset grouping.

5.2 Typical Asset Size

The Overhead Conductors asset category typical size is dependent on the conductor type. Overhead Conductors have been sub-categorized into the following:

1 Primary
2 Secondary

5.2.1 Primary

The Primary Overhead Conductors asset category typical size is wire 556 ASC (DAHLIA).

5.2.2 Secondary

The Secondary Overhead Conductors asset category typical size is triplex 2-266.8 AL XLPE 1-3/0.

5.3 Degradation Mechanism

To function properly, conductors must retain both their conductive properties and mechanical (i.e. tensile) strength. Aluminum conductors have three primary modes of degradation: corrosion, fatigue and creep. The rate of each degradation mode depends on several factors, including the size and construction of the conductor, as well as environmental and operating conditions. Most utilities find that corrosion and fatigue present the most critical forms of degradation.

Generally, corrosion represents the most critical life-limiting factor for aluminum-based conductors. Visual inspection cannot detect corrosion readily in conductors. Environmental conditions affect degradation rates from corrosion. Both aluminum and zinc-coated steel core conductors are particularly susceptible to corrosion from chlorine-based pollutants, even in low concentrations.

Fatigue degradation presents greater detection and assessment challenges than corrosion degradation. In extreme circumstances, under high tensions or inappropriate vibration or galloping control, fatigue can occur in very short timeframes. However, under normal operating conditions, with proper design and application of vibration control, fatigue degradation rates are relatively slow. Under normal circumstances, widespread fatigue degradation is not commonly seen in conductors less than 70 years of age. Also, in many cases detectable indications of fatigue may only exist during the last 10% of a conductor's life.

In designing transmission lines, engineers ensure that conductors receive no more than 60% of their rated tensile strength (RTS) during heaviest anticipated weather loads. The tensile strength of conductors gradually decreases over time. When conductors experience unexpectedly large mechanical loads and tensions beyond 50% of their RTS, they begin to undergo permanent stretching with noticeable increases in sagging.

Overloading lines beyond their thermal capacity causes elevated operating temperatures. When operating at elevated temperatures, aluminum conductors begin to anneal and lose tensile strength. Each elevated temperature event adds further damage to the conductor. After a loss of 10% of a conductor's RTS, significant sag occurs, requiring either resagging or replacement of the conductor.

Phase to phase power arcs can result from conductor galloping during severe storm events. This can cause localized burning and melting of a conductor's aluminum strands, reducing strength at those sites and potentially leading to conductor failures. Visual inspection readily detects arcing damage.

Other forms of conductor damage include:

- Broken strands (i.e., outer and inners)
- Strand abrasion
- Elongation (i.e., change in sags and tensions)
- Burn damage (i.e., power arc/clashing)
- Birdcaging

The degradation of copper wire is mostly due to corrosion. Oxidization gives copper a high resistance to corrosion. Derivatives of chlorine and sulfur contained in coastal atmospheres start the oxidation by forming a blackish or greenish film. The film is very dense, has low solubility, high electric resistance and high resistance to the chemical attack and to corrosion. Despite this, mechanical vibrations, abrasion, erosion and thermal variations may cause fissures and faults in this layer. When this happens, the metal is uncovered and corrosion may occur. Also electrolytes with low Cl contents could enter, causing a dislocation of the passivity. This may also be the result of a deficit of oxygen which would make the area anodic.

Please note that the weather protection and insulation on the Cables is for improving reliability of the distribution system as opposed to improving the useful life of this asset. The conductive properties of the wire are what degradation impacts, although Utilities may choose to replace weather protected cables for their own system reliability practices.

5.4 Useful Life

The typical life range of the Overhead Conductors asset category is 50 to 75 years; the typical life is 60 years.

5.5 Time Based Maintenance Intervals

The Overhead Conductors asset category is not subject to routine maintenance practices.

5.6 Typical Replacement Costs

The Overhead Conductors asset category also has major sub-categories that have different typical replacement costs. Types of Overhead Conductors are as follows:

1 Primary Conductors
2 Secondary Conductors

5.6.1 Primary Conductors

The typical replacement cost of the Primary Overhead Conductors asset category typical size $80 to $120 per circuit meter.

5.6.2 Secondary Conductors

The typical replacement cost of the Secondary Overhead Conductors asset category typical size is $75 to $90 per circuit meter.

5.7 Sensitivity to Material Size

The Overhead Conductors asset category also has a low sensitivity to material size.

6 Underground Conduit

6.1 Asset Description

Distribution underground cables are mainly used in urban areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental and safety reasons. The Report discusses two cable types: solid dielectric both in duct and direct buried and paper insulated lead covered (PILC). For the purposes of this report, solid dielectric cable refers to cross linked polyethylene (XLPE) cable.

6.1.1 Componentization

The Underground Conduit asset category is not subject to componentization.

6.1.2 System Hierarchy

The Underground Conduit asset category belongs to the Underground System asset grouping.

6.2 Typical Asset Size

The Underground Conduit asset category typical size is dependent on the conductor type. Underground Conduit has been sub-categorized into the following:

1 Cross Linked Polyethylene Conduit
2 Paper Insulated Lead Covered Conduit

6.2.1.1 Cross Linked Polyethylene Conduit

The Cross Linked Polyethylene Underground Conduit asset category typical size is 1/0 AL 28 kV TR XLPE ECNPEJ.

6.2.2 Paper Insulated Lead Covered Conduit

The Paper Insulated Lead Covered Underground Conduit asset category typical size is 500 KCMIL 3C CU 15 kV PILC.

6.3 Degradation Mechanism

For PILC cables, the two significant long-term degradation processes are corrosion of the lead sheath and dielectric degradation of the oil impregnated paper insulation. Isolated sites of corrosion resulting in moisture penetration or isolated sites of dielectric deterioration resulting in insulation breakdown can result in localized failures. However, if either of these conditions becomes widespread there will be frequent cable failures and the cable can be deemed to be at effective end-of-life.

Over the past 30 years XLPE insulated cables have all but replaced paper-insulated cables. These cables can be manufactured by a simple extrusion of the insulation over the conductor and therefore are much more economic to produce. In normal cable lifetime terms XLPE cables are still relatively young. Therefore, failures that have occurred can be classified as early life failures. Certainly in the early days of polymeric insulated cables their reliability was questionable. Many of the problems were associated with joints and accessories or defects introduced in the manufacturing process. Over the past 30 years many of these problems have been addressed and modern XLPE cables and accessories are generally very reliable.

Polymeric insulation is very sensitive to discharge activity. It is therefore very important that the cable, joints and accessories are discharge free when installed. Discharge testing is, therefore, an important factor for these cables. This type of testing is conducted during commissioning and is not typically used for detection of deterioration of the insulation. These commissioning tests are an area of some concern for polymeric cables because the tests themselves are suspected of causing permanent damage and reducing the life of polymeric cables.

6.4 Useful Life

The Underground Conduit asset category also has major sub-categories that have different useful lives. Types of Underground Conduit are as follows:

1. Cross Linked Polyethylene - In Duct
2. Cross Linked Polyethylene - Direct Buried
3. Paper Insulated Lead Covered

6.4.1 Cross Linked Polyethylene - In Duct

The useful life range of direct buried Cross Linked Polyethylene cable is 40 to 60 years; the typical life is 40 years.

6.4.2 Cross Linked Polyethylene - Direct Buried

The useful life range of in duct Cross Linked Polyethylene cable is 20 to 25 years; the typical life is 25 years.

6.4.3 Paper Insulated Lead Covered

The useful life range of Paper Insulated Lead Covered cable is 70 to 80 years; the typical life is 75 years.

6.5 Time Based Maintenance Intervals

The Underground Conduit asset category is not typically subject to routine maintenance practices.

6.6 Typical Replacement Costs

The Underground Conduit asset category also has major sub-categories that have different typical replacement costs. Types of Underground Conduit are as follows:

1. Cross Linked Polyethylene - In Duct
2. Cross Linked Polyethylene - Direct Buried
3. Paper Insulated Lead Covered

6.6.1 Cross Linked Polyethylene - In Duct

The typical replacement cost of direct buried Cross Linked Polyethylene cable is \$350-\$500 per circuit-meter plus \$50 per meter (trench).

6.6.2 Cross Linked Polyethylene - Direct Buried

The typical replacement cost of in duct Cross Linked Polyethylene cable is $350-$450 per circuit-meter plus $50 per meter (trench).

6.6.3 Cross Linked Polyethylene

The typical replacement cost of Cross Linked Polyethylene cable is $800-%1500 per circuit-meter plus $50 per meter (trench).

6.7 Sensitivity to Material Size

The Underground Conduit asset category also has a medium sensitivity to material size.

7 Pad Mounted Transformers

7.1 Asset Description

Pad-Mounted transformers typically employ sealed tank construction and are liquid filled, with mineral insulating oil being the predominant liquid. For the purposes of this report, the pad-mounted transformer has been componentized into the transformer itself and the enclosure.

7.1.1 Componentization

The Pad Mounted Transformers asset category is not subject to componentization.

7.1.2 System Hierarchy

The Pad Mounted Transformers asset category belongs to the Underground System asset grouping.

7.2 Typical Asset Size

The Pad Mounted Transformers asset category's typical asset size is 1 PH, 100 kVA, 16 kV.

7.3 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature rise and duration. Therefore, the transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage current surges also have strong effects. Therefore, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

In general, the following are considered when determining the health of the pad-mounted transformer:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs, etc.
- Transfer operating age and winding temperature profile

7.4 Useful Life

The useful life of Pad Mounted Transformers is in the range of 30 to 40 years; the typical life is 40 years.

7.5 Time Based Maintenance Intervals

The Pad Mounted Transformers asset category is not typically subject to routine maintenance practices.

7.6 Typical Replacement

The Pad Mounted Transformers asset category also has major sub-categories that have different typical replacement costs. Types of Pad Mounted Transformers are as follows:

1. Single Phase
2. Three Phase

7.6.1 Single Phase

The typical replacement cost of Single Phase Pad Mounted Transformers is $7000.

7.6.2 Three Phase

The typical replacement cost of Three Phase Pad Mounted Transformers is $200,000.

7.7 Sensitivity to Material Size

The Pad Mounted Transformers asset category has a medium sensitivity to material size.

8 Pad Mounted Switchgear

8.1 Asset Description

Pad Mounted Switchgear is used for protection and switching in the underground distribution system. The switching assemblies can be classified into gas (SF6)/vacuum insulated and air insulated.

8.1.1 Componentization

The Pad Mounted Switchgear asset category is not subject to componentization.

8.1.2 System Hierarchy

The Pad Mounted Switchgear asset category belongs to the Underground System asset grouping.

8.2 Typical Asset Size

The Pad Mounted Switchgear asset category typical size is dependent on the conductor type. Pad Mounted Switchgear has been sub-categorized into the following:

1. Gas (SF6)/Vacuum Insulated
2. Air Insulated

8.2.1.1 Gas (SF6)/Vacuum Insulated

The Gas (SF6)/Vacuum Insulated Pad Mounted Switchgear asset category typical size is not currently in our standards.

8.2.1.2 Air Insulated

The Air Insulated Pad Mounted Switchgear asset category typical size is 600 A, 28 kV.

8.3 Degradation Mechanism

The Pad Mounted Switchgear is very infrequently used for switching and often used to drop loads way below its rating. Therefore, switchgear aging and eventual end of life is often established by mechanical failures, e.g. rusting of the enclosures or ingress of moisture and dirt into the switchgear causing corrosion of operating mechanism and degradation of insulated barriers.

The first generation of pad mounted switchgear was first introduced in early 1970's and many of these units are still in good operating condition. The life expectancy of pad-mounted switchgear is impacted by a number of factors that include frequency of switching operations, load dropped, presence or absence of corrosive environmental and absence of existence of dampness at the installation site.

In the absence of specifically identified problems, the common industry practice for distribution switchgear is running it to end of life, just short of failure. To extend the life of these assets and to minimize in-service failures, a number of intervention strategies are employed on a regular basis: e.g. inspection with thermographic analysis and cleaning with CO2 for air insulated pad-mounted switchgear. If problems or defects are identified during inspection, often the affected component can be replaced or repaired without a total replacement of the switchgear.

Failures of switchgear are most often not directly related to the age of the equipment, but are associated instead with outside influences. Aging and end of life is established by mechanical failures, such as corrosion of operating mechanism from rusting of enclosure or moisture and dirt ingress. For example, pad-mounted switchgear is most likely to fail due to rodents, dirt/contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching. All of these causes are largely preventable with good design and maintenance practices. Failures caused by fuse malfunctions can result in a catastrophic switchgear failure.

8.4 Useful Life

The Pad Mounted Switchgear asset category also has major sub-categories that have different useful lives. Types of Pad Mounted Switchgear are as follows:

1. Gas (SF6)/Vacuum Insulated
2. Air Insulated

8.4.1 Gas (SF6)/Vacuum Insulated

The useful life range of this gas insulated switchgear is 30 to 50 years; the typical life is 30 years.

8.4.2 Air Insulated

The useful life range of this air insulated switchgear is 20 to 40 years; the typical life is 20 years.

8.5 Time Based Maintenance Intervals

The typical routine inspection interval for Pad Mounted Switchgear asset category is every 3 years.

8.6 Typical Replacement Costs

The Pad Mounted Switchgear asset category also has major sub-categories that have different typical replacement costs. Types of Pad Mounted Switchgear are as follows:

1. Gas (SF6)/Vacuum Insulated
2. Air Insulated

8.6.1 Gas (SF6)/Vacuum Insulated

The typical replacement cost of this gas (SF6)/vacuum insulated switchgear is 100,000.

8.6.2 Air Insulated

The typical replacement cost of this air insulated switchgear is $40,000.

8.7 Sensitivity to Material Size

The Pad Mounted Switchgear asset category also has a medium sensitivity to material size.

9 Pole Mounted Transformers

9.1 Asset Description

Distribution pole top transformers change sub-transmission or primary distribution voltages to 120/240 V or other common voltages for use in residential and commercial applications.

9.1.1 Componentization

The Pole Mounted Transformers asset category is not subject to componentization.

9.1.2 System Hierarchy

The Pole Mounted Transformers asset category belongs to the Overhead Lines System asset grouping.

9.2 Typical Asset Size

The Pole Mounted Transformers asset category's typical asset size is 1 PH, 100 kVA, 16 kV.

9.3 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of time in service. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI/IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

9.4 Useful Life

The useful life of Pole Mounted Transformers is in the range of 30 to 40 years, with a typical value of 40 years.

9.5 Time Based Maintenance Intervals

The Pole Mounted Transformers asset category is not typically subject to routine maintenance practices.

9.6 Typical Replacement

The Pole Mounted Transformers asset category also has major sub-categories that have different typical replacement costs. Types of Pole Mounted Transformers are as follows:

1 Single Phase
2 Three Phase

9.6.1 Single Phase

The typical replacement cost of Single Phase Pole Mounted Transformers is $4500.

9.6.2 Three Phase

The typical replacement cost of Three Phase Pole Mounted Transformers is $12,000.

9.7 Sensitivity to Material Size

The Pole Mounted Transformers asset category has a low sensitivity to material size.

10 Underground Cable

10.1 Asset Description

Distribution underground cables are mainly used in urban areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental and safety reasons. Secondary underground cables are used to supply customer premises.

10.1.1 Componentization

The Underground Cable asset category is not subject to componentization.

10.1.2 System Hierarchy

The Underground Cable asset category belongs to the Underground System asset grouping.

10.2 Typical Asset Size

The Underground Cable asset category typical size is 500 KCMIL CU XLPE 600 V.

10.3 Degradation Mechanism

For Underground Cable, the polymeric insulation is very sensitive to discharge activity. It is therefore very important that the cable, joints and accessories are discharge free when installed. Discharge testing is, therefore, an important factor for these cables. This type of testing is conducted during commissioning and is not typically used for detection of deterioration of the insulation. These commissioning tests are an area of some concern for polymeric cables because the tests themselves are suspected of causing permanent damage and reducing the life of polymeric cables.

10.4 Useful Life

The useful life range of the Underground Cable asset category is 40 to 60 years; the typical life is 40 years.

10.5 Time Based Maintenance Intervals

The Underground Cable asset category is not typically subject to routine maintenance practices.

10.6 Typical Replacement Costs

The typical replacement cost of the Underground Cable asset category is $75 per circuit-meter plus $50 per meter (trench).

10.7 Sensitivity to Material Size

The Underground Cable asset category also has a low sensitivity to material size.

11 Energy Meters

11.1 Asset Description

The metering is how electricity providers measure billable services by measuring various aspects of power usage. When used in electricity retailing, the utilities record the values measured by these meters to generate an invoice for the electricity. This report focuses on non interval, interval and wholesale meters.

11.1.1 Componentization

The Energy Meters asset category is not subject to componentization.

11.1.2 System Hierarchy

The Energy Meters asset category belongs to the Underground System asset grouping.

11.2 Typical Asset Size

The Energy Meters asset category's typical asset size is not available for the purposes of this report.

11.3 Degradation Mechanism

The major degradation mechanism of traditional meters is listed as follows:

- Electronic component aging due to long-term power quality impact, for solid-state meters
- Meter creep due to high temperature for induction type meters. This occurs when the meter disc rotates continuously with potential applied and the load terminals open circuited
- Magnetization alteration due to overload or short-circuited conditions
- Mechanical damage due to vibration of meter mounting
- Other adverse operating environment that might expedite the aging of components, such as humidity or dirt

The rate and severity of degradation in the equipment depend on its operational duties and environmental factors. Corrosion and moisture ingress, or combinations of these, represent the most critical degradation processes in microwave equipment of smart metering system.

Environmental conditions in relay and switch-rooms can affect microwave equipment's condition and reliability. Humidity, temperature, dust and pollution can cause component degradation. When plant temperatures fall below the dew point condensation can occur. When water enters equipment rooms through roof or other leaks, it can affect performance and aggravate corrosion.

11.4 Useful Life

The Energy Meters asset category also has major sub-categories that have different useful lives. Types of Energy Meters are as follows:

1. Non Interval Meters
2. Interval Meters
3. Wholesale Meters

11.4.1 Non Interval Meters

The useful life range of Non Interval Energy Meters is 20 to 60 years; the typical life is 30 years.

11.4.2 Interval Meters

The useful life range of Interval Energy Meters is 10 to 15 years; the typical life is 15 years.

11.4.3 Wholesale Meters

The useful life range of Wholesale Energy Meters is 15 to 30 years; the typical life is 30 years.

11.5 Time Based Maintenance Intervals

The Energy Meters asset category is not typically subject to routine maintenance practices.

11.6 Typical Replacement

The Energy Meters asset category's typical replacement costs are not available for the purposes of this report.

11.7 Sensitivity to Material Size

The Energy Meters asset category's sensitivity to material size is not available for the purposes of this report.

12 System Supervisory Equipment Remote Terminal Unit

12.1 Asset Description

Supervisory Control and Data Acquisition (SCADA) refers to the centralized monitoring and control system of a facility. SCADA remote terminal units (RTUs) allow the master SCADA system to communication, often wirelessly, with field equipment. In general, RTUs collect digital and analog data from equipment, exchange information to the master system, and perform control functions on field devices. They are typically comprised of the following: power supply, CPU, I/O Modules, housing and chassis, communications interface, and software.

12.1.1 Componentization

The System Supervisory Equipment Remote Terminal Unit asset category is not subject to componentization.

12.1.2 System Hierarchy

The System Supervisory Equipment Remote Terminal Unit asset category belongs to the Monitoring and Control System asset grouping.

12.2 Typical Asset Size

The System Supervisory Equipment Remote Terminal Unit asset category typical size is 13.8 kV.

12.3 Degradation Mechanism

There are many factors that contribute to the end-of-life of RTUs. Utilities may choose to upgrade or replace older units that are no longer supported by vendors or where spare parts are no longer available. Because RTUs are essentially computer devices, they are prone to obsolescence. For example, older units may lack the ability to interface with Intelligent Electronic Devices (IEDs), be unable to support newer or modern communications media and/or protocols, or not allow for the quantity, resolution, and accuracy of modern data acquisition. Legacy units may have limited ability of multiple master communication ports and protocols, or have an inability to segregate data into multiple RTU addresses based on priority.

12.4 Useful Life

The useful life range of the System Supervisory Equipment Remote Terminal Unit asset category is 15 to 30 years; the typical life is 20 years.

12.5 Time Based Maintenance Intervals

The System Supervisory Equipment Remote Terminal Unit asset category is not typically subject to routine maintenance practices.

12.6 Typical Replacement Costs

The typical replacement cost of the System Supervisory Equipment Remote Terminal Unit asset category is $90,000.

12.7 Sensitivity to Material Size

The System Supervisory Equipment Remote Terminal Unit asset category also has a medium sensitivity to material size.

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TAXES OR PAYMENTS IN LIEU OF TAXES (PILS)

STEI is subject to the payment of PILs under Section 93 of the Electricity Act, 1998, as amended. STEI Hydro does not pay Section 89 proxy taxes, and is exempt from the payment of income taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act.

STEI is forecasting a profit for tax purposes in the 2015TY. However, once the applicable tax credits, capital cost allowance and 1/5 of a 2014BY loss carry forward are incorporated, taxes payable is $54,162.

Therefore, STEI has included $54,162 amount for the recovery of PILs in this Application. This amount represents a significant reduction from the 2011 Board Approved amount of $377,416.

Some of the key causes for the reduction are:

- Increased capital cost allowance driven in part from the reorganization in 2012 where rolling stock was purchased at fair market value
- Lower financial performance in 2012
- Maximization of tax credits were available

The following Table 4-17 provides the 2011 Board Approved, 2011, 2012 and 2013 actual, 2014BY and 2015TY income tax estimates.

Table 4-17

SUMMARY OF INCOME TAXES

2011 Board Approved	2011 Actual	2012 Actual	2013 Actual	2014 BY	2015 TY
377,416	301,471	118,551	25,628	-	54,162

The estimates are based on the rates prescribed by the Board in the Board's Income Tax/PILs Workform (the "PILs Model") for 2015 Filers (Attachment 3). STEI doesn't anticipate any differences between the workform and the potential income tax returns for those years covered under this application. A copy of STEI's annual 2011 and 2012 tax returns been provided as Attachment 1.In accordance with the Filing Requirements, the Board's PILs model has also been completed and submitted and is consistent with the PILs included in the 2015 revenue requirement.

The historical income tax returns completed have included all of the potential income tax credits that STEI is eligible to earn. STEI engages KPMG as the outside consultant for all SRED claims for 2011, 2012 and 2013 (Attachment 2). It is anticipated, however, that with the completion of the GIS project (anticipated in 2014) that there will be no other opportunities to obtain SRED credits on future capital programs included in this application because of the potential nature of these projects.

In addition, it is not anticipated that additional apprentice credit would not be available as the current full time equivalent for staff does not anticipate additional accredited apprentices.

Based on the taxability for the 2015TY, it is anticipated that no further losses for income tax purposes should arise and, as such, the estimated loss for 2014 is carried into the test year at 1/5 the amount that would actually be included in the income tax return for 2015.

It is believed that the estimated income tax for the 2015TY is reasonable.

PROPERTY TAXES

STEI pays property taxes to the Town of STEI for its office premises and the municipal substations and municipal transformer station that it owns. The number of locations has not increased since the 2011 Cost of Service Application. In addition, STEI makes annual payments to the Ontario Electricity Financial Corporation for "Payments in Lieu of Property

Taxes". Property taxes for the historical, Bridge and Test years are provided in the following Table 4-18.

Table 4-18

SUMMARY OF PROPERTY TAXES

2011 Board Approved	2011 Actual	2012 Actual	2013 Actual	2014 BY	2015 TY
121,496	108,911	83,343	82,987	100,000	102,100

Attachment 1 of 3

Tax Returns

GRAHAM
SCOTT
ENNS LLP
CHARTERED ACCOUNTANTS

William A. Graham* Alan R. Enns*
John M. Scott* Michael S. Stover*
Robert B. Foster* William J. Luyks*
James G. Frederick* Betty A. Gropp
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PERSONAL AND CONFIDENTIAL

Glen Farrow
Chief Financial Officer
St. Thomas Energy Inc.
135 Edward Street
St. Thomas ON N5P 4A8

Mr. Farrow,

Corporate Tax Return Filing Instructions

T2 - CORPORATION INCOME TAX RETURN (FEDERAL)

The "T2 Bar codes format" has been adopted by the Canada Revenue Agency (CRA) for corporate income tax returns produced by tax preparation software. The traditional federal forms no longer have to be filed. Furthermore, the CRA requires that the General Index of Financial Information (GIFI) be used to report financial statement information.

The form containing the T2 bar codes includes information from your corporation's income tax return and all applicable schedules (traditional federal forms), including the GIFI.

Signature

✍ The form containing the T2 bar codes should be completed and signed.

Refund

A refund of $**282,029** is claimed and therefore no amount is payable for the 2012 taxation year.

Mailing

✉ A copy of the form containing the T2 bar codes (and of any required federal form, such as Form RC59) should be sent to the Taxation Centre, 66 Stapon Road, Winnipeg MB R3C 3M2 no later than June 30, 2013.

GRAHAM SCOTT ENNS LLP

Canada Revenue Agency / Agence du revenu du Canada

Code 1201

SCIENTIFIC RESEARCH AND EXPERIMENTAL DEVELOPMENT (SR&ED) EXPENDITURES CLAIM

Use this form:

- to provide technical information on your SR&ED projects;
- to calculate your SR&ED expenditures; and
- to calculate your qualified SR&ED expenditures for investment tax credits (ITC).

To claim an ITC, use either:

- Schedule T2SCH31, *Investment Tax Credit – Corporations*, or
- Form T2038(IND), *Investment Tax Credit (Individuals)*.

The information requested in this form and documents supporting your expenditures are prescribed information.

Your SR&ED claim must be filed within 12 months of the filing due date of your income tax return.

To help you fill out this form, use the T4088, *Guide to Form T661*, which is available on our Web site: **www.cra.gc.ca/sred**.

Part 1 – General information

010 Name of claimant: St. Thomas Energy Inc.	Enter one of the following: Business Number (BN): 89052 2014 RC0001
Tax year From: 2012-01-01 (Year Month Day) To: 2012-12-31 (Year Month Day)	Social Insurance Number (SIN):
050 Total number of projects you are claiming this tax year: 1	

100 Contact person for the financial information	**105** Telephone number/extension	**110** Fax number
Glen Farrow	(519) 631-5550	
115 Contact person for the technical information	**120** Telephone number/extension	**125** Fax number
Richard McDonald KPMG LLP	(519) 660-2136	(519) 672-5684

151 If this claim is filed for a partnership, was Form T5013 filed? . . . . 1 ☐ Yes 2 ☐ No

If you answered **no** to line 151, complete lines 153, 156 and 157.

153 Name of the partners	**156** %	**157** BN or SIN
1		
2		
3		
4		
5		

Part 2 - Project information

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A - Project identification

200 Project title (and identification code if applicable)

See schedule

Part 3 – Calculation of SR&ED expenditures

What did you spend on your SR&ED projects?

Section A – Select the method to calculate the SR&ED expenditures

I elect (choose) to use the following method to calculate my SR&ED expenditures and related investment tax credits (ITC) for this tax year.
I understand that my election is irrevocable (cannot be changed) for this tax year.

160 [X] I elect to use the proxy method
(Enter "0" on line 360. Complete Part 5 and you do not need to track any expenditure incurred for overhead)

162 [ ] I choose to use the traditional method
(Enter "0" on line 355. Complete line 360, and track any expenditure incurred for overhead)

Section B – Calculation of allowable SR&ED expenditures (to the nearest dollar)

• SR&ED portion of salary or wages of employees directly engaged in the SR&ED:			
a) Employees other than specified employees for work performed in Canada	300	+	26,135
b) Specified employees for work performed in Canada	305	+	
Subtotal (add lines 300 and 305)	306	=	26,135
c) Employees other than specified employees for work performed outside Canada (subject to limitations – see guide)	307	+	
d) Specified employees for work performed outside Canada (subject to limitations – see guide)	309	+	
• Salary or wages identified on line 315 in prior years that were paid in this tax year	310	+	
• Salary or wages incurred in the year but not paid within 180 days of the tax year end	315		
• Cost of materials consumed in performing SR&ED	320	+	
• Cost of materials transformed in performing SR&ED	325	+	
• Contract expenditures for SR&ED performed on your behalf:			
a) Arm's length contracts	340	+	69,312
b) Non-arm's length contracts	345	+	
• Lease costs of equipment used:			
a) All or substantially all (90% of the time or more) for SR&ED	350	+	
b) Primarily (more than 50% of the time but less than 90%) for SR&ED. (Enter 50% of lease costs if you use the proxy method or enter "0" if you use the traditional method)	355	+	
• Overhead and other expenditures (enter "0" if you use the proxy method)	360	+	
• Third-party payments (complete Form T1263*)	370	+	
Total current SR&ED expenditures (add lines 306 to 370; do not add line 315) (Corporations need to adjust line 118 of schedule T2SCH1)	380	=	95,447
• **Capital Expenditures** (see guide for what qualifies for SR&ED) (Do not include these capital expenditures on schedule T2SCH8)	390	+	
Total allowable SR&ED expenditures (add lines 380 and 390)	400	=	95,447

Section C – Calculation of pool of deductible SR&ED expenditures (to the nearest dollar)

Amount from line 400	420		95,447
Deduct			
• provincial government assistance for expenditures included on line 400	429	–	4,295
• other government assistance for expenditures included on line 400	431	–	
• non-government assistance for expenditures included on line 400	432	–	
• SR&ED ITCs applied and/or refunded in the prior year (see guide)	435	–	
• sale of SR&ED capital assets and other deductions	440	–	
Subtotal (line 420 minus lines 429 to 440)	442	=	91,152
Add			
• repayments of government and non-government assistance that previously reduced the SR&ED expenditure pool	445	+	
• prior year's pool balance of deductible SR&ED expenditures (from line 470 of prior year T661)	450	+	
• SR&ED expenditure pool transfer from amalgamation or wind-up	452	+	
• amount of SR&ED ITC recaptured in the prior year	453	+	
Amount available for deduction (add lines 442 to 453) (enter positive amount only, include negative amount in income)	455	=	91,152
• Deduction claimed in the year (Corporations should enter this amount on line 411 of schedule T2SCH1)	460	–	91,152
Pool balance of deductible SR&ED expenditures to be carried forward to future years (line 455 minus 460)	470	=	

* Form T1263, *Third-Party Payments for Scientific Research and Experimental Development (SR&ED)*

Part 4 – Calculation of qualified SR&ED expenditures for investment tax credit (ITC) purposes

The resulting amount is used to calculate your refundable and/or non refundable ITC.

Enter the breakdown between current and capital expenditures (to the nearest dollar)

	Line	Current Expenditures	Line	Capital Expenditures
Total expenditures for SR&ED (from line 380 and 390)	492	95,447	496	
Add				
• payment of prior years' unpaid amounts (other than salary or wages)	500 +			
• prescribed proxy amount (complete Part 5) (Enter "0" if you use the traditional method)	502 +	16,879		
• expenditures on shared-use equipment (see guide)			504 +	
• qualified expenditures transferred to you (complete Form T1146**)	508 +		510 +	
Subtotal (add lines 492 to 508, and add lines 496 to 510)	511 =	112,326	512 =	
Deduct				
• provincial government assistance	513 –	5,055	514 –	
• other government assistance	515 –		516 –	
• non-government assistance and contract payments	517 –		518 –	
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	520 –			
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	528 –			
• 20% of expenditures included on lines 340 and 370 that were incurred after December 31, 2012	529 –			
• prescribed expenditures not allowed by regulations (see guide)	530 –		532 –	
• other deductions (see guide)	533 –		535 –	
• non-arm's length transactions				
– assistance allocated to you (complete Form T1145*)	538 –		540 –	
– expenditures for non-arm's length SR&ED contracts (from line 345)	541 –			
– adjustments to purchases (limited to costs) of goods and services from non-arm's length suppliers (see guide)	542 –		543 –	
– qualified expenditures you transferred (complete Form T1146**)	544 –		546 –	
Subtotal (line 511 minus lines 513 to 544 and line 512 minus lines 514 to 546)	557 =	107,271	558 =	
Qualified SR&ED expenditures (add lines 557 and 558)			559 =	107,271
Add				
• repayments of assistance and contract payments made in the year			560 +	
Total qualified SR&ED expenditures for ITC purposes (add lines 559 and 560)			570 =	107,271

* Form T1145, *Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*

** Form T1146, *Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*

Part 5 – Calculation of prescribed proxy amount (PPA)

A notional amount representing your overhead and other expenditures.

This part calculates the PPA to enter on line 502 in Part 4. Do not complete this part if you have chosen to use the traditional method in Part 3 (line 162).
You can only claim a PPA if you elected to use the proxy method for the year in Part 3 (line 160).

Special rules apply for specified employees. Calculate your salary base in Section A and the PPA in section B.

Section A – Salary base

Salary or wages of employees other than specified employees (from line 300 and 307)	**810**	+	26,135
Deduct			
Bonuses, remuneration based on profits, and taxable benefits that were included on line 810	**812**	–	167
Subtotal (line 810 minus 812)	**814**	=	25,968

Salary or wages of specified employees

850	852	854	856	858	860
Column 1	**Column 2**	**Column 3**	**Column 4**	**Column 5**	**Column 6**
Name of specified employee	Total salary or wages for the year (SR&ED and non-SR&ED) excluding bonuses, remuneration based on profits, and taxable benefits (to the nearest dollar)	% of time spent on SR&ED (maximum 75%)	Amount in column 2 multiplied by percentage in column 3	2,5 x A x B/365 A = Year's maximum pensionable earnings B = Number of days employed in tax year	Amount in column 4 or 5, whichever amount is less

(Enter total of column 6 on line 816)	**816**	+	
Salary base (total of lines 814 and 816)	**818**	=	25,968

Section B – Prescribed proxy amount (PPA)

Enter 65% of the salary base (line 818) less 5% of the salary base for the number of 2013 calendar days in the tax year (use formula in the guide – line 820)	**820**	=	16,879

Enter the amount from line 820 on line 502 in Part 4 unless the overall cap on PPA applies to you.

(See the guide for explanation and example of the overall cap on PPA)

Part 6 – Project costs

Information requested in this part must be provided for **all** SR&ED projects claimed in the year.
Expenditures should be recorded and allocated on a project basis.

750	752	754	756
Project title or identification code	Salary or wages in the tax year (Total of lines 306 to 309)	Cost of materials in the tax year (Total of lines 320 and 325)	Contract expenditures for SR&ED performed on your behalf in the tax year (Total of lines 340 and 345)
1. STE2010-01-03 Development of a Scalable Metering Networ	26,135		69,312
Total	26,135		69,312

Part 7 – Additional information

Expenditures for SR&ED performed by you in Canada (line 400 minus lines 307, 309, 340, 345, and 370) **605** 26,135

From the total you entered on line 605, estimate the percentage of distribution of the sources of funds for SR&ED performed within your organization.

	Line	Canadian (%)	Line	Foreign (%)
Internal	600	100.000		
Parent companies, subsidiaries, and affiliated companies	602		604	
Federal grants (do not include funds or tax credits from SR&ED tax incentives)	606			
Federal contracts	608			
Provincial funding	610			
SR&ED contract work performed for other companies on their behalf	612		614	
Other funding (e.g., universities, foreign governments)	616		618	

Enter the number of SR&ED personnel in full-time equivalents (FTE):

	Line	FTE
Scientists and engineers	632	
Technologists and technicians	634	
Managers and administrators	636	
Other technical supporting staff	638	

Part 8 – Claim checklist

To ensure your claim is complete, make sure you have:

1. used the current version of this form X
2. entered the method you have chosen for reporting your SR&ED expenditures in Section A of Part 3 X
3. completed Part 2 for each project . . . . . . ☐
4. filed a completed Schedule T2SCH31 or Form T2038(IND) to claim ITCs on your qualified SR&ED expenditures X
5. filed a completed Form T1145*, T1146**, T1174*** and/or T1263**** including any required attachments, if applicable X

To expedite the processing of your claim, make sure you have:

1. completed Form T2, *Corporation Income Tax Return* or Form T1, *Income Tax and Benefit Return* X
2. filed the appropriate provincial and/or territorial tax credit forms, if applicable X
3. retained documents to support the SR&ED expenditures you claimed X
4. checked boxes 231 and 232 on page 2 of your T2 return to indicate attachment of Form T661 and Schedule T2SCH31 X

* Form T1145, *Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*

** Form T1146, *Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*

*** Form T1174, *Agreement Between Associated Corporations to Allocate Salary or Wages of Specified Employees for Scientific Research and Experimental Development (SR&ED)*

**** Form T1263, *Third·Party Payments for Scientific Research and Experimental Development (SR&ED)*

Part 9 – Certification

I certify that I have examined the information provided on this form and on the attachments and it is true, correct, and complete.

165 Glen Farrow
Name of authorized signing officer of the corporation, or individual

Signature

170
Date

175 KPMG LLP
Name of person/firm who completed this form

Part 2 - Project information (continued)

Project number **1**

CRA internal form identifier 060
Code 1201

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

STE2010-01-03 Development of a Scalable Metering Network

202 Project start date: 2010-04 (Year Month)

204 Completion or expected completion date: 2013-03 (Year Month)

206 Field of science or technology code (See guide for list of codes): 2.02.01 | Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project

210 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

	220 Names of the businesses	**221** BN
1		

The work was carried out (Check any that apply)

223 1 [ ] In a laboratory

226 1 [X] In a commercial plant or facility

224 1 [ ] In a dedicated research facility

228 1 [ ] Others, specify **229** ______

Purpose of the work

230 1 [X] To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. (**Go to Section B** – Experimental development)

232 1 [ ] For the advancement of scientific knowledge (**Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 [X]	**236** 1 [X]
The improvement of existing	**237** 1 [ ]	**238** 1 [ ]

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

1. St. Thomas Energy Inc. (the Company or St. Thomas Energy) is a local
2. electricity distribution company which delivers power to over 16,500
3. businesses and residents of the St. Thomas in Ontario. The Company seeks to
4. develop intelligent capabilities (smart metering, automated field data
5. collection, etc.) within their power distribution framework. However,
6. attaining the targeted capabilities could not be achieved by applying current
7. engineering concepts due to technological challenges, such the requirement for
8. high data integrity and security, and data transmission over environments
9. prone to noise and other interferences.
10.
11. This project represents a technological advancement in the fields of
12. Electrical Engineering and Telecommunications. If this project is successful,
13. St. Thomas Energy would have:
14.
15. - developed a generic geographical information management architecture that
16. can flexibly integrate and interact with disparate legacy and newer electrical
17. and software sub-systems, while providing reliable geo-referenced monitoring
18. in real-time. The architecture will enable advanced technologies such as
19. FIT/microFlT analytic tools and load monitoring systems to be integrated
20. within the distribution network for spatially-driven monitoring, connection
21. impact analysis, etc.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

In FY2012, St. Thomas Energy addressed the following uncertainties.

- The Company sought to develop a generic geographical data management architecture that can flexibly integrate with existing and future applications and hardware (such as outage management system, smart-metering system, CIS, SCADA, etc.) However, there were uncertainties regarding specific design concepts that could provide a generic architecture capable of integrating with legacy (e.g., centralized monitoring systems) and newer devices (e.g., smart switches) and software frameworks. In addition, the sheer size of data (e.g., graphical entities) and complex inter-relationships required to represent physical objects (e.g., feeders, transformers, etc.) imposed reliability constraints that prompted the need for experimental development. Furthermore, there was the need to integrate data from legacy sources that use different underlying data structures. This introduced uncertainties in how to maintain critical referential integrity of the various sub-systems. In addition, within the spatial-physical entity relationships, St. Thomas Energy was not certain about how to ensure that thousands of end-devices are properly connected spatially (e.g., phasing properly shown throughout the model), and traces done on various feeders pick up the actual routing of these feeders in the field.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

In FY2012, St. Thomas Energy sought to develop a generic and extensible architecture that would allow flexible integration with various disparate sub-systems such as the GIS, CIS, load analysis system, etc. In order to develop a reliable platform, various alternatives were investigated. In particular, due to inherent proprietary limitations, it was found to be technologically infeasible to extend the legacy system for improved field device representations and interactivity in software. St. Thomas Energy then hypothesized that a hybrid solution that combines 3D mapping (i.e., Autodesk 3DAutoCAD Map 3D) with Topobase data management as the GIS platform would lead to a reliable and flexible solution. After determining the GIS platform, techniques were developed to transition legacy engineering data related to electrical connectivity and secondary feeder maps to the GIS/AM (geographic information system/Asset Management) platform. This was achieved through modeling and establishing relationships between physical entities (e.g., conductors/feeders, relays, transformers, etc.) and virtual representations (i.e., graphical nodes and polygons), while mitigating the risks of connectivity failures. The virtual representations and their associated properties were modeled within entity-relationship data structures and persisted in a backend database. The associated relationship models were designed such that sub-system categories automatically inherited the proper characteristics in an accurate and timely manner in the event of physical changes from upstream services such as handheld devices. St. Thomas Energy also sought to improve the responsiveness of the smart grid system by leveraging the GIS framework for dynamic sub-system/asset management, outage management, etc. In particular, a connectivity model was developed for primary data encompassing field sub-systems (i.e., transformers and feeders), and this was integrated with the GIS framework. To this end, the GIS framework was integrated with field devices such as networked thermostats, independent energy systems (i.e., MicroFIT) as well as transformer and feeder loading models. Systematic testing was done to ensure that when the status of a circuit changes in the field (energized/non-energized), virtual controls/monitors would react consistently and in real-time in order to reflect actual field conditions. This involved several spatial connections associated with switches, feeders, etc., each with a network of slave field-devices. In the upcoming FY, St. Thomas Energy plans to continue pursuing

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

36. geocoding techniques for reliable coordination between spatial entities. By
37. the end of the FY, the geo-referencing aspect of the architecture was
38. successfully completed. In the upcoming FY, St. Thomas Energy will focus on
39. techniques to integrate the GIS platform with the smart metering network.
40.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

1.
2.
3.
4.

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

1.
2.
3.
4.

Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 [X] Employee directly involved in the project	**254** Name: Filice, Shawn
255 1 [ ] Other employee of the company	**256** Name:
257 1 [X] External consultant	**258** Name: KPMG LLP — **259** Firm: KPMG LLP

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	**261** Qualifications/experience and position title
1	Van Patter, Judy	Operations Coordinator, 25 years of experience with STEI
2	Tosolini, Danny	Engineering Manager, P.Eng. with over 20 years of experience
3	Karl, Ryan	Engineering Technologist,C. Tech with 5 years of experience

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 [X] Yes 2 [ ] No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	**269** BN
1	Automated Solutions International Inc.	89163 1095 RC0001
2		

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	1	X	Project planning documents	276	1	X	Progress reports, minutes of project meetings
271	1	X	Records of resources allocated to the project, time sheets	277	1		Test protocols, test data, analysis of test results, conclusions
272	1		Design of experiments	278	1		Photographs and videos
273	1	X	Project records, laboratory notebooks	279	1		Samples, prototypes, scrap or other artefacts
274	1		Design, system architecture and source code	280	1	X	Contracts
275	1	X	Records of trial runs	281	1		Others, specify 282

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

055 **Do not use this area**

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business number (BN) **001** 89052 2014 RC0001

Corporation's name
002 St. Thomas Energy Inc.

Address of head office
Has this address changed since the last time we were notified? . . . . **010** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 135 Edward Street
012
City: **015** St. Thomas
Province, territory, or state: **016** ON
Country (other than Canada): **017**
Postal code/Zip code: **018** N5P 4A8

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? . . . . **020** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028.)
021 c/o
022
023
City: **025**
Province, territory, or state: **026**
Country (other than Canada): **027**
Postal code/Zip code: **028**

Location of books and records
Has the location of books and records changed since the last time we were notified? . . . . **030** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
031 135 Edward Street
032
City: **035** St. Thomas
Province, territory, or state: **036** ON
Country (other than Canada): **037**
Postal code/Zip code: **038** N5P 4A8

040 **Type of corporation at the end of the tax year**
1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. **043** ____ YYYY MM DD

To which tax year does this return apply?
Tax year start **060** 2012-01-01 (YYYY MM DD)
Tax year-end **061** 2012-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . **063** 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . **065** ____ YYYY MM DD

Is the date on line 061 a deemed tax year-end according to:
subparagraph 88(2)(a)(iv)? . . . . **064** 1 Yes [ ] 2 No [X]
subsection 249(3.1)? . . . . **066** 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . **067** 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? . . . . **070** 1 Yes [ ] 2 No [X]
Amalgamation? . . . . **071** 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . **072** 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . **076** 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . **078** 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used . . . . **079** ____

Is the corporation a resident of Canada?
080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081 ____

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . **082** 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area
095 **096**

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210		10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265		55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

		1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? 913910 Other Local, Municipal and Regional Public Administration CAN

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Energy	285	100.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		
If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible	294	YYYY MM DD	
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295		

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		-390,284	A
Deduct: Charitable donations from Schedule 2	311			
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal			►	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360			
Income exempt under paragraph 149(1)(t)	370			
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				Z

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8. Use 3.2 for tax years ending before 2012.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . . **400** ______ A

Taxable income from line 360 on page 3, **minus** 100/28* 3.57143 of the amount on line 632** on page 7, **minus** 1/(0.38 - X***) 4 times the amount on line 636**** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . . **405** ______ B

Business limit (see notes 1 and 2 below) . . . . . **410** ______ C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C ______ x **415** ***** 89,553 D / 11,250 = ... ______ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . **425** ______ F

Small business deduction

Amount A, B, C, or F, whichever is the least ______ x 17 % = ... **430** ______ G

Enter amount G on line 1 on page 7.

* 10/3 for tax years ending before November 1, 2011. The result of the multiplication by line 632 has to be pro-rated based on the number of days in the tax year that are in each period: before November 1, 2011, and after October 31, 2011.

** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

*** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

**** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3*				A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		B		
Amount QQ from Part 13 of Schedule 27		C		
Personal service business income**	432	D		
Amount used to calculate the credit union deduction from Schedule 17		E		
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least		F		
Aggregate investment income from line 440 on page 6***		G		
Total of amounts B to G			▶	H
Amount A **minus** amount H (if negative, enter "0")				I

Amount I		x	Number of days in the tax year before January 1, 2011 / Number of days in the tax year	/ 366	x 10 %	=	J
Amount I		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 366	x 11.5 %	=	K
Amount I		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	366 / 366	x 13 %	=	L

General tax reduction for Canadian-controlled private corporations – Total of amounts J to L .... M
Enter amount M on line 638 on page 7.

* For tax years ending after October 31, 2011, line 360 or amount Z, whichever applies.

** For tax years beginning after October 31, 2011.

*** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)				N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		O		
Amount QQ from Part 13 of Schedule 27		P		
Personal service business income*	434	Q		
Amount used to calculate the credit union deduction from Schedule 17		R		
Total of amounts O to R			▶	S
Amount N **minus** amount S (if negative, enter "0")				T

Amount T		x	Number of days in the tax year before January 1, 2011 / Number of days in the tax year	/ 366	x 10 %	=	U
Amount T		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 366	x 11.5 %	=	V
Amount T		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	366 / 366	x 13 %	=	W

General tax reduction – Total of amounts U to W X
Enter amount X on line 639 on page 7.

* For tax years beginning after October 31, 2011.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440** ________ x 26 2/3 % = ... ________ A

Foreign non-business income tax credit from line 632 on page 7 . . . . ________

Deduct:
Foreign investment income from Schedule 7 . . . . **445** ________ x 9 1/3 % = ________
(if negative, enter "0") ________ ▶ ________ B

Amount A **minus** amount B (if negative, enter "0") . . . . ________ C

Taxable income from line 360 on page 3 . . . . ________

Deduct:
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . ________

Foreign non-business income tax credit from line 632 on page 7 . . . ________ x $\frac{100}{35}$ (25/9*) = ________

Foreign business income tax credit from line 636 on page 7 . . . . ________ x $\frac{1}{(0.38 - X^{**})}$ 4 = ________

________ ▶ ________

________ x 26 2/3 % = ________ D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . ________ E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least . . . . **450** ________ F

* 100/35 for tax years beginning after October 31, 2011.
** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . **460** ________
Deduct: Dividend refund for the previous tax year . . . . **465** ________
________ ▶ ________ G

Add the total of:
Refundable portion of Part I tax from line 450 above . . . . ________
Total Part IV tax payable from Schedule 3 . . . . ________
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . **480** ________
________ ▶ ________ H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H . . . . **485** ________

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . ________ x 1 / 3 ________ I

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . ________ J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 on page 8) . . . . ________

Part I tax

Base amount of Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 % **550** ______ A

Recapture of investment tax credit from Schedule 31 . . . . . **602** ______ B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6 . . . . . ______ i

Taxable income from line 360 on page 3 . . . . . ______

Deduct:

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . . ______

Net amount . . . . . ______ ► ______ ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . . . **604** ______ C

Subtotal (**add** lines A to C) ______ D

Deduct:

Small business deduction from line 430 on page 4		______	1
Federal tax abatement	**608**	______	
Manufacturing and processing profits deduction from Schedule 27	**616**	______	
Investment corporation deduction	**620**	______	
Taxed capital gains **624** ______			
Additional deduction – credit unions from Schedule 17	**628**	______	
Federal foreign non-business income tax credit from Schedule 21	**632**	______	
Federal foreign business income tax credit from Schedule 21	**636**	______	
General tax reduction for CCPCs from amount M on page 5	**638**	______	
General tax reduction from amount X on page 5	**639**	______	
Federal logging tax credit from Schedule 21	**640**	______	
Federal qualifying environmental trust tax credit	**648**	______	
Investment tax credit from Schedule 31	**652**	______	
	Subtotal	______ ►	______ E

Part I tax payable – Line D **minus** line E . . . . . ______ F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	
Provincial tax on large corporations (Nova Scotia Schedule 342)	765	
(The Nova Scotia tax on large corporations is eliminated effective July 2012.)		

Total tax payable 770 ______ A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund from page 6	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	18,675
Tax instalments paid	840	263,354
Total credits	890	282,029

Total credits ▶ 282,029 B

Refund code 894 1 Overpayment 282,029

Balance (line A **minus** line B) -282,029

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid ______

Enclosed payment 898 ______

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 ______ Branch number

914 ______ Institution number 918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

Certification

I, 950 Farrow (Last name (print)) 951 Glen (First name (print)) 954 Chief Financial Officer (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 ______ Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (519) 631-5550 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes ☐ 2 No ☒

958 Glen Farrow (Name (print)) 959 (519) 631-5550 (Telephone number)

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Privacy Act, Personal Information Bank number CRA PPU 047

Schedule of Instalment Remittances

Name of corporation contact

Telephone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Instalments	263,354

Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	263,354	**A**
Total instalments credited to the taxation year per T9	263,354	**B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2012-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

	Line	Amount	Total	
Amount calculated on line 9999 from Schedule 125			173,814	A
Add:				
Provision for income taxes – current	101	118,551		
Amortization of tangible assets	104	1,422,683		
Scientific research expenditures deducted per financial statements	118	95,447		
Reserves from financial statements – balance at the end of the year	126	1,234,948		
Subtotal of additions		2,871,629	2,871,629	
Other additions:				
Resource amounts deducted	232			
Miscellaneous other additions:				
600 Prior year capital tax	290	7,500		
601 Ontario ATTC & CETC	291	18,675		
604				
Total	294			
Subtotal of other additions	199	26,175	26,175	
Total additions	500	2,897,804	2,897,804	B
Amount A **plus** amount B			3,071,618	
Deduct:				
Gain on disposal of assets per financial statements	401	1,270		
Capital cost allowance from Schedule 8	403	2,110,919		
SR&ED expenditures claimed in the year from Form T661 (line 460)	411	91,152		
Reserves from financial statements – balance at the beginning of the year	414	1,213,561		
Subtotal of deductions		3,416,902	3,416,902	
Other deductions:				
Miscellaneous other deductions:				
704 20 (1)(e) deduction on $225,000 finance fees — 45,000				
Total 45,000	394	45,000		
Subtotal of other deductions	499	45,000	45,000	
Total deductions	510	3,461,902	3,461,902	
Net income (loss) for income tax purposes – enter on line 300 of the T2 return			-390,284	

T2 SCH 1 E (12)

Canada

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 4

CORPORATION LOSS CONTINUITY AND APPLICATION

Name of corporation	Business number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2012-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending (TYE) before that time is deductible in computing taxable income in a TYE after that time. Also, no amount of capital loss incurred in a TYE after that time is deductible in computing taxable income of a TYE before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide.*
- File one completed copy of this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- Parts, sections, subsections, paragraphs, and subparagraphs mentioned in this schedule refer to the Act.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes				-390,284	A
Deduct: (increase a loss)					
Net capital losses deducted in the year (enter as a positive amount)			a		
Taxable dividends deductible under sections 112, 113(1), or subsection 138(6)			b		
Amount of Part VI.1 tax deductible			c		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)			d		
Subtotal (total of amounts a to d)			▶		B
Subtotal (amount A **minus** amount B; if positive, enter "0")				-390,284	C
Deduct: (increase a loss)					
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions					D
Subtotal (amount C **minus** amount D)				-390,284	E
Add: (decrease a loss)					
Current-year farm loss (whichever is less: the net loss from farming or fishing included in the income, or the non-capital loss before deducting the farm loss. Enter amount F on line 310)					F
Current-year non-capital loss (amount E **plus** amount F; if positive, enter "0"; if negative, enter amount G on line 110 as a positive)				-390,284	G

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year			e		
Deduct: Non-capital loss expired*	100		f		
Non-capital losses at the beginning of the tax year (amount e **minus** amount f)	102		▶		H
Add:					
Non-capital losses transferred on an amalgamation or the wind-up of a subsidiary corporation	105		g		
Current-year non-capital loss (amount G above)	110	390,284	h		
Subtotal (amount g **plus** amount h)		390,284	▶	390,284	I
Subtotal (amount H **plus** amount I)				390,284	J

* A non-capital loss expires as follows:
- after **7** tax years if it arose in a tax year ending before March 23, 2004;
- after **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss as follows:
- after **7** tax years if it arose in a tax year ending before March 23, 2004; and
- after **10** tax years if it arose in a tax year ending after March 22, 2004.

Part 1 – Non-capital losses (continued)

Amount J from page 1			390,284	
Deduct:				
Other adjustments (includes adjustments for an acquisition of control)	150			i
Section 80 – Adjustments for forgiven amounts	140			j
Subsection 111(10) – Adjustments for fuel tax rebate				j.1
Non-capital losses of previous tax years applied in the current tax year (enter on line 331 of the T2 Return)	130			k
Current and previous year non-capital losses applied against current-year taxable dividends subject to Part IV tax (enter on lines 330 and 335 of Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*, respectively)	135			l
Subtotal (total of amounts i to l)				K
Non-capital losses before any request for a carryback (amount J **minus** amount K)			390,284	L
Deduct – **Request to carry back non-capital loss to:**				
First previous tax year to reduce taxable income	901			m
Second previous tax year to reduce taxable income	902			n
Third previous tax year to reduce taxable income	903			o
First previous tax year to reduce taxable dividends subject to Part IV tax	911			p
Second previous tax year to reduce taxable dividends subject to Part IV tax	912			q
Third previous tax year to reduce taxable dividends subject to Part IV tax	913			r
Total of requests to carry back non-capital losses to previous tax years (total of amounts m to r)				M
Closing balance of non-capital losses to be carried forward to future tax years (amount L **minus** amount M)	180		390,284	N

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200			a
Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	205			b
Subtotal (amount a **plus** amount b)				A
Deduct:				
Other adjustments (includes adjustments for an acquisition of control)	250			c
Section 80 – Adjustments for forgiven amounts	240			d
Subtotal (amount c **plus** amount d)				B
Subtotal (amount A **minus** amount B)				C
Add: Current-year capital loss (from the calculation on Schedule 6)	210			D
Unused non-capital losses that expired in the tax year*				e
Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year**				f
Enter amount e or f, whichever is less	215			
ABILs expired as non-capital loss: line 215 **divided** by 0.500000	220			E
Subtotal (total of amounts C to E)				F

Note

If there has been an amalgamation or a windup of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary. Add all these amounts and enter the total on line 220 above.

* If the losses were incurred in a tax year ending before March 23, 2004, enter the losses from the 8th previous tax year. If the losses were incurred in a tax year ending after March 22, 2004, and before 2006, enter the losses from the 11th previous tax year. Enter the losses from the 21st previous tax year if the losses were incurred in a tax year ending after 2005. Enter the part that was not used in previous years and the current year on line e.

** If the losses were incurred in a tax year ending before March 23, 2004, enter the losses from the 8th previous tax year. If the losses were incurred in a tax year ending after March 22, 2004, enter the losses from the 11th previous tax year. Enter the full amount on line f.

Part 2 – Capital losses (continued)

Amount F from page 2			
Deduct: Capital losses from previous tax years applied against the current-year net capital gain (see Note 1)	225		G
Capital losses before any request for a carryback (amount F **minus** amount G)			H

Deduct – **Request to carry back capital loss to** (see Note 2):

	Capital gain (100%)		Amount carried back (100%)			
First previous tax year		951		g		
Second previous tax year		952		h		
Third previous tax year		953		i		
Subtotal (total of amounts g to i)				▶		I
Closing balance of capital losses to be carried forward to future tax years (amount H **minus** amount I)					280	J

Note 1

To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the purpose of current-year tax, enter the amount from line 225 **multiplied** by 50% on line 332 of the T2 return.

Note 2

On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, **multiply** this amount by the 50% inclusion rate.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year			a		
Deduct: Farm loss expired*	300		b		
Farm losses at the beginning of the tax year (amount a **minus** amount b)	302		▶		A
Add:					
Farm losses transferred on the amalgamation or the windup of a subsidiary corporation	305		c		
Current-year farm loss	310		d		
Subtotal (amount c **plus** amount d)			▶		B
Subtotal (amount A **plus** amount B)					C
Deduct:					
Other adjustments (includes adjustments for an acquisition of control)	350		e		
Section 80 – Adjustments for forgiven amounts	340		f		
Farm losses of previous tax years applied in the current tax year (enter on line 334 of the T2 Return)	330		g		
Current and previous year farm losses applied against current-year taxable dividends subject to Part IV tax (enter on lines 340 and 345 of Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*, respectively)	335		h		
Subtotal (total of amounts e to h)			▶		D
Farm losses before any request for a carryback (amount C **minus** amount D)					E
Deduct – **Request to carry back farm loss to:**					
First previous tax year to reduce taxable income	921		i		
Second previous tax year to reduce taxable income	922		j		
Third previous tax year to reduce taxable income	923		k		
First previous tax year to reduce taxable dividends subject to Part IV tax	931		l		
Second previous tax year to reduce taxable dividends subject to Part IV tax	932		m		
Third previous tax year to reduce taxable dividends subject to Part IV tax	933		n		
Subtotal (total of amounts i to n)			▶		F
Closing balance of farm losses to be carried forward to future tax years (amount E **minus** amount F)			380		G

* A farm loss expires as follows:

- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business			485		A
Minus the deductible farm loss:					
(amount A above ______ – $2,500) **divided** by 2 =	a				
Amount a or $ 6,250 , whichever is less			b		
		2,500	c		
Subtotal (amount b **plus** amount c)		2,500		2,500	B
Current-year restricted farm loss (amount A **minus** amount B; enter amount C on line 410)					C

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			d		
Deduct: Restricted farm loss expired*	400		e		
Restricted farm losses at the beginning of the tax year (amount d **minus** amount e)	402				D
Add:					
Restricted farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation	405		f		
Current-year restricted farm loss (enter on line 233 of Schedule 1)	410		g		
Subtotal (amount f **plus** amount g)					E
Subtotal (amount D **plus** amount E)					F
Deduct:					
Restricted farm losses from previous tax years applied against current farming income (enter on line 333 of the T2 Return)	430		h		
Section 80 – Adjustments for forgiven amounts	440		i		
Other adjustments	450		j		
Subtotal (total of amounts h to j)					G
Restricted farm losses before any request for a carryback (amount F **minus** amount G)					H
Deduct – **Request to carry back restricted farm loss to:**					
First previous tax year to reduce farming income	941		k		
Second previous tax year to reduce farming income	942		l		
Third previous tax year to reduce farming income	943		m		
Subtotal (total of amounts k to m)					I
Closing balance of restricted farm losses to be carried forward to future tax years (amount H **minus** amount I)	480				J

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

* A restricted farm loss expires as follows:

- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year			a		
Deduct: Listed personal property loss expired after seven tax years	500		b		
Listed personal property losses at the beginning of the tax year (amount a **minus** amount b)	502		▶		A
Add: Current-year listed personal property loss (from Schedule 6)				510	B
Subtotal (amount A **plus** amount B)					C
Deduct:					
Previous year personal property losses applied in the current tax year against listed personal property gains (enter on line 655 of Schedule 6)	530		c		
Other adjustments	550		d		
Subtotal (amount c **plus** amount d)			▶		D
Listed personal property losses remaining before any request for a carryback (amount C **minus** amount D)					E
Deduct – **Request to carry back listed personal property loss to:**					
First previous tax year to reduce listed personal property gains	961		e		
Second previous tax year to reduce listed personal property gains	962		f		
Third previous tax year to reduce listed personal property gains	963		g		
Subtotal (total of amounts e to g)			▶		F
Closing balance of listed personal property losses to be carried forward to future tax years (amount E **minus** amount F)				580	G

Part 7 – Limited partnership losses

Current-year limited partnership losses

1	2	3	4	5	6	7
Partnership identifier	Tax year ending YYYY/MM/DD	Corporation's share of limited partnership loss	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Current-year limited partnership losses (column 3 **minus** 6)
600	602	604	606	608		620

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from previous tax years that may be applied in the current year

1	2	3	4	5	6	7
Partnership identifier	Tax year ending YYYY/MM/DD	Limited partnership losses at the end of the previous tax year	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6)
630	632	634	636	638		650

Continuity of limited partnership losses that can be carried forward to future tax years

1	2	3	4	5	6
Partnership identifier	Limited partnership losses at the end of the previous tax year	Limited partnership losses transferred on an amalgamation or the windup of a subsidiary	Current-year limited partnership losses (from column 620)	Limited partnership losses applied in the current year (cannot be more than column 650)	Current year limited partnership losses closing balance to be carried forward to future years (662 + 664 + 670 – 675)
660	662	664	670	675	680

Total (enter this amount on line 335 of the T2 return)

Note

If you have any current–or previous–year losses, enter your partnership identifier on line 600, 630, or 660.

Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . 190 Yes

Further to a winding-up of a subsidiary, the portion of a non-capital loss, restricted farm loss, farm loss, or limited partnership loss from a wholly-owned subsidiary is deemed to be the loss of a parent from its tax year starting after the commencement of the winding-up.

Note

This election is only applicable for wind-ups under 88(1) that are reported on Schedule 24, *First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent*, and the deemed provision is only for the tax years that start after the commencement of the wind-up.

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses – losses that can be carried forward over 20 years

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce Taxable income	Applied to reduce Part IV tax	Balance at end of year
Current	N/A	390,284			N/A		390,284
1st preceding taxation year 2011-12-31		N/A		N/A			
2nd preceding taxation year 2010-12-31		N/A		N/A			
3rd preceding taxation year 2009-12-31		N/A		N/A			
4th preceding taxation year 2008-12-31		N/A		N/A			
5th preceding taxation year 2007-12-31		N/A		N/A			
6th preceding taxation year 2006-12-31		N/A		N/A			
7th preceding taxation year 2005-12-31		N/A		N/A			
8th preceding taxation year 2004-12-31		N/A		N/A			
9th preceding taxation year 2003-12-31		N/A		N/A			
10th preceding taxation year 2002-12-31		N/A		N/A			
11th preceding taxation year 2001-12-31		N/A		N/A			
12th preceding taxation year 2000-12-31		N/A		N/A			
13th preceding taxation year 1999-12-31		N/A		N/A			
14th preceding taxation year 1998-12-31		N/A		N/A			
15th preceding taxation year 1997-12-31		N/A		N/A			
16th preceding taxation year 1996-12-31		N/A		N/A			
17th preceding taxation year 1995-12-31		N/A		N/A			
18th preceding taxation year 1994-12-31		N/A		N/A			
19th preceding taxation year 1993-12-31		N/A		N/A			
20th preceding taxation year 1992-12-31		N/A		N/A			*
Total		390,284					390,284

* **This balance expires this year and will not be available next year.**

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Schedule 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2012-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ____________ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes	103		143		
Newfoundland and Labrador offshore	004 1 Yes	104		144		
Prince Edward Island	005 1 Yes	105		145		
Nova Scotia	007 1 Yes	107		147		
Nova Scotia offshore	008 1 Yes	108		148		
New Brunswick	009 1 Yes	109		149		
Quebec	011 1 Yes	111		151		
Ontario	013 1 Yes	113		153		
Manitoba	015 1 Yes	115		155		
Saskatchewan	017 1 Yes	117		157		
Alberta	019 1 Yes	119		159		
British Columbia	021 1 Yes	121		161		
Yukon	023 1 Yes	123		163		
Northwest Territories	025 1 Yes	125		165		
Nunavut	026 1 Yes	126		166		
Outside Canada	027 1 Yes	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** If the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits

Description	Line	Amount		Amount	Ref
Ontario basic income tax (from Schedule 500)	270				
Deduct: Ontario small business deduction (from Schedule 500)	402				
Subtotal			►		A6
Add:					
Surtax re Ontario small business deduction (from Schedule 500)	272				
Ontario additional tax re Crown royalties (from Schedule 504)	274				
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal			►		B6
Subtotal (amount A6 **plus** amount B6)					C6
Deduct:					
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario transitional tax credits (from Schedule 506)	414				
Ontario political contributions tax credit (from Schedule 525)	415				
Subtotal			►		D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")					E6
Deduct: Ontario research and development tax credit (from Schedule 508)			416		
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")					F6
Deduct: Ontario corporate minimum tax credit (from Schedule 510)			418		
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")					G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278				
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies)	282				
Subtotal			►		H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)					I6
Deduct:					
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452	8,675			
Ontario apprenticeship training tax credit (from Schedule 552)	454	10,000			
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario sound recording tax credit (from Schedule 562)	464				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Other Ontario tax credits					
Subtotal		18,675	►	18,675	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.			290	-18,675	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits	255	-18,675

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2012-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1	Electrical distribut	17,539,683			0		17,539,683	4	0	0	701,587	16,838,096
2.	1	Building	1,514,316			0		1,514,316	4	0	0	60,573	1,453,743
3.	8	System Supervisory	4,723	14,409		0	7,205	11,927	20	0	0	2,385	16,747
4.	47	Electrical Distribution	4,728,234	4,887,099		0	2,443,550	7,171,783	8	0	0	573,743	9,041,590
5.	8	Office Furniture & Equipment		99,896		0	49,948	49,948	20	0	0	9,990	89,906
6.	12	Computer Software		122,966		0		122,966	100	0	0	122,966	
7.	12	Cayenta Software		353,134		0		353,134	100	0	0	353,134	
8.	50	Computer Equipment		136,794		0	68,397	68,397	55	0	0	37,618	99,176
9.	50	GIS		397,908		0	198,954	198,954	55	0	0	109,425	288,483
10.	10	Rolling Stock		679,340		0	339,670	339,670	30	0	0	101,901	577,439
11.	8	Tools and Equipment		377,239		1,270	187,985	187,984	20	0	0	37,597	338,372
		Totals	23,786,956	7,068,785		1,270	3,295,709	27,558,762				2,110,919	28,743,552

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2012-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	Ascent Group Inc.		86367 7191 RC0001	1					
2.	Ascent Energy Services Inc.		86367 7399 RC0001	3					
3.	Ascent Solutions Inc.		10082 7476 RC0003	3					
4.	2154310 Ontario Inc.		83387 9356 RC0001	3					
5.	Ascent Renewables Inc.		83145 8260 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	Employee Retirement benefit		1,213,561	21,387		1,234,948
2						
	Reserves from Part 2 of Schedule 13					
	Totals		1,213,561	21,387		1,234,948

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . . . **050** Year 2012

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . . **075** 1 Yes [ ] 2 No [X]

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 Asso-ciation code **300**	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**
1	St. Thomas Energy Inc.	89052 2014 RC0001	1	500,000		
2	Ascent Group Inc.	86367 7191 RC0001	1	500,000		
3	Ascent Energy Services Inc.	86367 7399 RC0001	1	500,000	100.0000	500,000
4	Ascent Solutions Inc.	10082 7476 RC0003	1	500,000		
5	2154310 Ontario Inc.	83387 9356 RC0001	1	500,000		
6	Ascent Renewables Inc.	83145 8260 RC0001	1	500,000		
				Total	100.0000	500,000 A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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SCHEDULE 31

INVESTMENT TAX CREDIT – CORPORATIONS

General information

1. For use by a corporation that during a tax year:
   - earned an investment tax credit (ITC);
   - is claiming a deduction against its Part I tax payable;
   - is claiming a refund of credit earned during the current tax year;
   - is claiming a carryforward of credit from previous tax years;
   - is transferring a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act;*
   - is requesting a credit carryback; or
   - is subject to a recapture of ITC.
2. References to parts, sections, and subsections on this schedule are from the federal *Income Tax Act* and the federal *Income Tax Regulations*. References to interpretation bulletins and information circulars are to the latest versions.
3. The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
4. Investments or expenditures, as defined in subsection 127(9) and Part XLVI of the federal *Income Tax Regulations*, that earn the ITC are:
   - qualified property (Parts 4 to 7);
   - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). Complete and file Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
   - pre-production mining expenditures (Parts 18 to 20);
   - apprenticeship job creation expenditures (Parts 21 to 23); and
   - child care spaces expenditures (Parts 24 to 28).
5. Attach a completed copy of this schedule with the *T2 Corporation Income Tax Return.*
6. For more information on ITCs, see the section called "Investment Tax Credit" in the *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates,* and its related Special Release. Also, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures.*
7. For information on SR&ED, see Interpretation Bulletin IT-151 (**consolidated**), *Scientific Research and Experimental Development Expenditures*; Information Circular 86-4, *Scientific Research and Experimental Development*; Brochure RC4472, *Overview of the Scientific Research and Experimental Development Program (SR&ED) Tax Incentive Program*; Brochure RC4467, *Support for your R&D in Canada* and T4088, *Guide to Form T661 Scientific Research and Experimental Development (SR&ED) Expenditures Claim*.

Detailed information

1. For the purpose of this schedule, **"investment"** means:
   The capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
2. An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
3. Property acquired has to be "available for use" before a claim for an ITC can be made.
4. Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which the expenditures or capital costs were incurred.
5. Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITC's is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 of the Act is not applicable for the agreement to share any income or loss. Special rules apply to specified and limited partners. For more information, see Guide T4068-1, 2010 Supplement to the 2006 T4068, Guide for the T5013 Partnership Information Return.
6. For SR&ED expenditures, the expression "in Canada" includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.

Name of corporation	Business Number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2012-12-31

Part 1 – Investments, expenditures and percentages

	Specified percentage
Investments	
Qualified property acquired primarily for use in Newfoundland and Labrador, Prince Edward Island, Nova Scotia, New Brunswick, the Gaspé Peninsula, or a prescribed offshore region . . .	10 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10) . . .	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate.	
If you are a corporation that is not a CCPC that incurred qualified expenditures for SR&ED in any area in Canada . . .	20 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures	
Before January 1, 2013 . . .	10 %
In 2013 . . .	5 %
After December 31, 2013 . . .	0 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment . . .	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children . . .	25 %

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . **101** 1 Yes [ ] 2 No [X]

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and the taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . **102** 1 Yes [ ] 2 No [X]

Contributions to agricultural organizations for SR&ED . . . **103** ______

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see the *Guide to the General Index of Financial Information (GIFI) for Corporations.* Enter contributions on line 350 of Part 8.

QUALIFIED PROPERTY

Part 4 – Eligible investments for qualified property from the current tax year

	CCA* class number 105	Description of investment 110	Date available for use 115	Location used (province or territory) 120	Amount of investment 125
1.					

* CCA: capital cost allowance

Total investment – enter in formula on line 240 in Part 5

Part 5 – Calculation of current-year credit and account balances – ITC from investments in qualified property

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations 210

Credit expired 215

Subtotal ▶

ITC at the beginning of the tax year 220

Add:

Credit transferred on amalgamation or wind-up of subsidiary 230

ITC from repayment of assistance 235

Total current-year credit: total of column 125 x 10 % = 240

Credit allocated from a partnership 250

Subtotal ▶

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B1 in Part 30) 260

Credit carried back to the previous year(s) (from Part 6) A

Credit transferred to offset Part VII tax liability 280

Subtotal ▶

Credit balance before refund B

Deduct:

Refund of credit claimed on investments from qualified property (from Part 7) 310

ITC closing balance of investments from qualified property 320

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day		
1st previous tax year				Credit to be applied 901	
2nd previous tax year				Credit to be applied 902	
3rd previous tax year				Credit to be applied 903	

Total (enter on line A in Part 5)

Part 7 – Calculation of refund for qualifying corporations on investments from qualified property

Current-year ITCs (total of lines 240 and 250 in Part 5) C

Credit balance before refund (amount B from Part 5) D

Refund (40 % of amount C or D, whichever is less) E

Enter amount E or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures

Current expenditures (from line 557 on Form T661)	107,271		
Add:			
Contributions to agricultural organizations for SR&ED*			
Current expenditures (including contributions to agricultural organizations for SR&ED at line 103 in Part 3)* (from line 557 on Form T661)	107,271 ▶	350	107,271
Capital expenditures (from line 558 on Form T661)		360	
Repayments made in the year (from line 560 on Form T661)		370	
Total (this must equal the amount from line 570 on Form T661)*		380	107,271

* Do not file form T661 if you are only claiming contributions made to agricultural organizations for SR&ED.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC.

Note: A CCPC that calculates SR&ED expenditure limit, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? . . . . **385** 1 Yes [X] 2 No [ ]

Complete lines 390 and 398, if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied). . . . . **390** ______

Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million. . . . . **398** ______

* If either of the tax years referred to at line 390 is less than 51 weeks, multiply the taxable income by the following result: 365 divided by the number of days in these tax years.

Part 10 – Calculation of SR&ED expenditure limit for a CCPC

For stand-alone corporations:

Calculation 1A: Tax year ends before January 1, 2010.

[($7,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . ____________

Calculation 1: Tax year starts after December 31, 2009.

[($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . ____________

Calculation 2: Tax year straddles January 1, 2010.

EE + [(FF **minus** EE) x (GG **divided by** HH)] where, ... ____________

EE = [($7,000,000 **minus** (10**A**)) x (($40,000,000 **minus B**) **divided by** $40,000,000)];

FF = [($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)];

GG = number of days in the tax year after December 31, 2009;

HH = number of days in the tax year.

Amount A **408** ____________ Amount B **409** ____________

A = the greater of:

- $400,000; and
- your taxable income for the last tax year* ending in the previous calendar year (tax years ending in 2008) (prior to any loss carry-backs applied).

B = the taxable capital employed in Canada for the last tax year ending in the previous calendar year (tax years ending in 2008) minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million.

* If any of the tax years referred to in **A** above are less than 51 weeks, gross up the taxable incomes for those tax years by the ratio that 365 is of the number of days in those tax years. Use these grossed up amounts when calculating the expenditure limit.

Enter the amount from Calculation 1A, 1 or 2, whichever is applicable ____________ G*

For associated corporations:

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 . . . . **400** ____________ H*

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Line G or H ____________ x Number of days in the tax year 366 / 365 = ... ____________ I

Your SR&ED expenditure limit for the year (enter the amount from line G, H, or I, whichever applies) . . . . **410** ____________

* Amount G or H cannot be more than $3,000,000.

Part 11 – Calculation of investment tax credits on SR&ED expenditures

Enter whichever is less: current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10)*	420		x	35 %	=		J
Line 350 minus line 410 (if negative, enter "0")	430	107,271	x	20 %	=	21,454	K
Line 410 minus line 350 (if negative, enter "0")			L				
Enter whichever is less: capital expenditures (line 360 from Part 8) or line L above*	440		x	35 %	=		M
Line 360 minus line L (if negative, enter "0")	450		x	20 %	=		N

Repayments (amount from line 370 in Part 8) . . . .

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.								
	460		x	35 %	=			
	480		x	20 %	=			
				Total			►	O

Current-year SR&ED ITC (total of lines J, K, M, N, and O; enter on line 540 in Part 12) 21,454

* For corporations that are not CCPCs, enter "0" on lines J and M.

Part 12 – Calculation of current-year credit and account balances – ITC from SR&ED expenditures

	Line	Amount	Line	Amount	
ITC at the end of the previous tax year					
Deduct:					
Credit deemed as a remittance of co-op corporations	510				
Credit expired	515				
Subtotal			►		
ITC at the beginning of the tax year			520		
Add:					
Credit transferred on amalgamation or wind-up of subsidiary	530				
Total current-year credit	540	21,454			
Credit allocated from a partnership	550				
Subtotal		21,454	►	21,454	
Total credit available				21,454	
Deduct:					
Credit deducted from Part I tax (enter on line B2 in Part 30)	560				
Credit carried back to the previous year(s) (from Part 13)			P		
Credit transferred to offset Part VII tax liability	580				
Subtotal			►		
Credit balance before refund				21,454	Q
Deduct:					
Refund of credit claimed on expenditures of SR&ED (from Part 14 or 15, whichever applies)			610		
ITC closing balance on SR&ED			620	21,454	

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day		Line	Amount
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	
				Total (enter on line P in Part 12)		

Part 14 – Calculation of refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . 650 1 Yes [ ] 2 No [X]

Credit balance before refund (amount Q from Part 12)		R		
Current-year ITC (lines 540 plus 550 from Part 12 **minus** line O from Part 11)		S		
Refundable credits (amount R or S, whichever is less)*				T
Amount J from Part 11		U		
Subtract: Amount T or U, whichever is less				V
Net amount (if negative, enter "0")				W
Amount W	x 40 %			X
Add: Amount V				Y
Refund of ITC (amounts X **plus** Y – enter this, or a lesser amount, on line 610 in Part 12)				Z

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC on line Z.

Part 15 – Calculation of refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined in Part 2.

Credit balance before refund (amount Q from Part 12)			21,454	AA
Amount J from Part 11		BB		
Subtract: Amount AA or BB, whichever is less				CC
Net amount (if negative, enter "0")			21,454	DD
Amount M from Part 11				EE
Amount DD or EE, whichever is less	x 40 %			FF
Add : Amount CC above				GG
Refund of ITC (amounts FF **plus** GG)				HH

Enter HH, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

RECAPTURE – SR&ED

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

	Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter this amount on line LL in Part 17) ______ II

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at line JJ in Part 16.

	A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**
1.			

Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line JJ below.

	D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred **750**	F Amount from column D or E, whichever is less
1.			

Subtotal (enter this amount on line MM in Part 17) ______ JJ

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line KK below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line NN in Part 17) **760** ______ KK

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from line II in Part 16		LL
Recaptured ITC for calculation 2 from line JJ in Part 16 above		MM
Recaptured ITC for calculation 3 from line KK in Part 16 above		NN
Total recapture of SR&ED investment tax credit – Add lines LL, MM and NN		OO

Enter amount OO at line A1 in Part 29.

PRE-PRODUCTION MINING

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

	List of minerals 800
1.	

For each of the minerals reported in column 800 above, identify each project, mineral title, and mining division where title is registered. If there is no mineral title, identify the project and mining division only.

	Project name 805	Mineral title 806	Mining division 807
1.			

Pre-production mining expenditures *

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810		PP
Geological, geophysical, or geochemical surveys	811		QQ
Drilling by rotary, diamond, percussion, or other methods	812		RR
Trenching, digging test pits, and preliminary sampling	813		SS

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820		TT
Sinking a mine shaft, constructing an adit, or other underground entry	821		UU

Other pre-production mining expenditures incurred in the tax year:

	Description 825	Amount 826
1.		

Add amounts at column 826	▶		VV
Total pre-production mining expenditures (add amounts PP to VV)	830		
Deduct: Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above	832		
Excess (line 830 minus line 832) (if negative, enter "0")			WW
Add: Repayments of government and non-government assistance	835		XX
Pre-production mining expenditures (amount WW plus amount XX)			YY

* A pre-production mining expenditure is defined under subsection 127(9).

Part 19 – Calculation of current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year . . . .

Deduct:

Credit deemed as a remittance of co-op corporations **841**

Credit expired **845**

Subtotal ▶

ITC at the beginning of the tax year **850**

Add:

Credit transferred on amalgamation or wind-up of subsidiary **860**

Expenditures from line YY in Part 18:

Expenditures incurred before January 1, 2013 . .		x	10 %	=	**1**
Expenditures incurred in 2013		x	5 %	=	**2**
Expenditures incurred after December 31, 2013 .		x	0 %	=	**3**
Add lines 1, 2 and 3 **870**					▶ **880**

Total credit available . . . .

Deduct:

Credit deducted from Part I tax (enter on line B3 in Part 30) **885**

Credit carried back to the previous year(s) (from Part 20) CCC

Subtotal ▶

ITC closing balance from pre-production mining expenditures **890**

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day			
1st previous tax year				. . . . Credit to be applied	**921**	
2nd previous tax year				. . . . Credit to be applied	**922**	
3rd previous tax year				. . . . Credit to be applied	**923**	

Total (enter on line CCC in Part 19)

APPRENTICESHIP JOB CREATION

Part 21 – Calculation of total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) . . . . **611** 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice. Attach additional schedules if more space is needed.

	A Contract number (SIN or name of apprentice) **601**	B Name of eligible trade **602**	C Eligible salary and wages* **603**	D Column C x 10 % **604**	E Lesser of column D or $ 2,000 **605**
1.					

Total current-year credit (enter at line 640)

* Net of any other government or non-government assistance received or to be received.

Part 22 – Calculation of current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year			
Deduct:			
Credit deemed as a remittance of co-op corporations	612		
Credit expired after 20 tax years	615		
	Subtotal		▶
ITC at the beginning of the tax year		625	
Add:			
Credit transferred on amalgamation or wind-up of subsidiary	630		
ITC from repayment of assistance	635		
Total current-year credit (total of column 605)	640		
Credit allocated from a partnership	655		
	Subtotal		▶
Total credit available			
Deduct:			
Credit deducted from Part I tax (enter on line B4 in Part 30)	660		
Credit carried back to the previous year(s) (from Part 23)		DDD	
	Subtotal		▶
ITC closing balance from apprenticeship job creation expenditures		690	

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	931	
2nd previous tax year				Credit to be applied	932	
3rd previous tax year				Credit to be applied	933	
				Total (enter on line DDD in Part 22)		

CHILD CARE SPACES

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	CCA* class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year	715		EEE
Add: Specified child care start-up expenditures from the current tax year	705		FFF
Total gross eligible expenditures for child care spaces (line 715 **plus** line 705)			GGG
Deduct: Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line GGG)	725		HHH
Excess (amount GGG **minus** amount HHH) (if negative, enter "0")			III
Add: Repayments of government and non-government assistance	735		JJJ
Total eligible expenditures for child care spaces (amount III **plus** amount JJJ)	745		

* CCA: capital cost allowance

Part 25 – Calculation of current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (line 745)			x 25 % =		KKK
Number of child care spaces	755		x $ 10,000 =		LLL
ITC from child care spaces expenditures (amount KKK or LLL, whichever is less)					MMM

Part 26 – Calculation of current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year			
Deduct:			
Credit deemed as a remittance of co-op corporations	765		
Credit expired after 20 tax years	770		
Subtotal			▶
ITC at the beginning of the tax year		775	
Add:			
Credit transferred on amalgamation or wind-up of subsidiary	777		
Total current-year credit (amount MMM above)	780		
Credit allocated from a partnership	782		
Subtotal			▶
Total credit available			
Deduct:			
Credit deducted from Part I tax (enter on line B5 in Part 30)	785		
Credit carried back to the previous year(s) (from Part 27)		NNN	
Subtotal			▶
ITC closing balance from child care spaces expenditures		790	

Part 27 – Request for carryback of credit from child care space expenditures

	Year Month Day			
1st previous tax year	2011-12-31	Credit to be applied	941	
2nd previous tax year	2010-12-31	Credit to be applied	942	
3rd previous tax year	2009-12-31	Credit to be applied	943	
		Total (enter on line NNN in Part 26)		

RECAPTURE – CHILD CARE SPACES

Part 28 – Calculating the recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . . **792** ______ ZZZ

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . . . **795** ______

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property . . . . **797** ______

Amount from line 795 or line 797, whichever is less . . . . ______ OOO

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line PPP below.

Corporate partner's share of the excess of ITC **799** ______ PPP

Total recapture of child care spaces investment tax credit – Add lines ZZZ, OOO, and PPP
Enter amount QQQ on line A2 in Part 29. . . . . ______ QQQ

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC from line OO in Part 17 . . . . ______ A1

Recaptured child care spaces ITC from line QQQ in Part 28 above . . . . ______ A2

Total recapture of investment tax credit – Add lines A1 and A2 . . . . ______ A3
Enter amount A3 on line 602 of the T2 return.

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5) . . . . ______ B1

ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12) . . . . ______ B2

ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19) . . . . ______ B3

ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22) . . . . ______ B4

ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26) . . . . ______ B5

Total ITC deducted from Part I tax (add lines B1, B2, B3, B4, and B5) . . . . ______ B6
Enter amount B6 at line 652 of the T2 return.

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Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 99 Cur. or cap. R&D for ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
21,454				21,454

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2011-12-31				
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				*
2001-12-31				
2000-12-31				
1999-12-31				
1998-12-31				
1997-12-31				
1996-12-31				
1995-12-31				
1994-12-31				
1993-12-31				
1992-12-31				*
Total				

B+C+D+G **Total ITC utilized**

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit will only expire at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 of the subsequent fiscal year.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2012-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Provide only one number per shareholder: Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	St. Thomas Holding Inc.	86367 7191 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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SCHEDULE 508

ONTARIO RESEARCH AND DEVELOPMENT TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2012-12-31

- Use this schedule to:
  - calculate an Ontario research and development tax credit (ORDTC);
  - claim an ORDTC earned in the tax year or carried forward from any of the 20 previous tax years that are a tax year ending after December 31, 2008, to reduce Ontario corporate income tax payable in the current tax year;
  - carry back an ORDTC to reduce Ontario corporate income tax payable in any of the three previous tax years, but not to a tax year that ends before January 1, 2009;
  - add an ORDTC that was allocated to the corporation by a partnership of which it was a member;
  - transfer an ORDTC after an amalgamation or windup; or
  - calculate a recapture of the ORDTC.
- The ORDTC is a 4.5% non-refundable tax credit on eligible expenditures incurred by a corporation in a tax year that ends after December 31, 2008.
- An eligible expenditure is an expenditure for a permanent establishment in Ontario of a corporation, that is a qualified expenditure for the purposes of section 127 of the federal *Income Tax Act* for scientific research and experimental development (SR&ED) carried on in Ontario.
- Only corporations that are not exempt from Ontario corporate income tax and none of whose income is exempt income can claim the ORDTC.
- Attach a completed copy of this schedule to the *T2 Corporation Income Tax Return.*

Part 1 – Ontario SR&ED expenditure pool

	Line				
Total eligible expenditures incurred by the corporation in Ontario in the tax year	100	112,326	A		
Deduct: Government assistance, non-government assistance, or a contract payment for eligible expenditures	105		B		
Net eligible expenditures for the tax year (amount A **minus** amount B) (if negative, enter "0")		112,326	C		
Add: Eligible expenditures transferred to the corporation by another corporation	110		D		
Subtotal (amount C **plus** amount D)		112,326	►	112,326	E
Deduct: Eligible expenditures the corporation transferred to another corporation	115				F
Ontario SR&ED expenditure pool (amount E **minus** amount F) (if negative, enter "0")	120			112,326	G

Part 2 – Calculation of the current part of the ORDTC

Ontario SR&ED expenditure pool (amount G in Part 1)			112,326	x 4.50 % =	200	5,055	H
ORDTC allocated to a corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *					205		I
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure other than for first term or second term shared-use equipment	210			x 4.50 % =	215		J
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure for first term or second term shared-use equipment	220	x 1 / 4 =		x 4.50 % =	225		K
Current part of the ORDTC (total of amounts H to K)					230	5,055	L

* If there is a disposal or change of use of eligible property, see Part 6

Part 3 – Calculation of ORDTC available for deduction and ORDTC balance

ORDTC balance at the end of the previous tax year . . . . M

Deduct: ORDTC expired after 20 tax years . . . . **300** N

ORDTC at the beginning of the tax year (amount M **minus** amount N) . . . . **305** O

Add:

ORDTC transferred on amalgamation or windup . . . . **310** P

Current part of ORDTC (amount L in Part 2) . . . . 5,055 Q

Are you waiving all or part of the current part of the ORDTC? . . . . . . **315** Yes 1 [ ] No 2 [X]

If you answered **yes** at line 315, enter the amount of the tax credit waived on line 320.

If you answered **no** at line 315, enter "0" on line 320.

Deduct: Waiver of the current part of the ORDTC . . . . **320** R

Subtotal (amount Q **minus** amount R) 5,055 ► 5,055 S

ORDTC available for deduction (total of amounts O, P and S) . . . . 5,055 ► 5,055 T

Deduct:

ORDTC claimed * (Enter amount U on line 416 of Schedule 5, *Tax Calculation Supplementary – Corporations*) . . . . U

ORDTC carried back to a previous tax year (from Part 4) V

Subtotal (amount U **plus** amount V) ► W

ORDTC balance at the end of the tax year (amount T **minus** amount W) . . . . **325** 5,055 X

* This amount cannot be more than the lesser of the following amounts:
- ORDTC available for deduction (amount T); or
- Ontario corporate income tax payable before the ORDTC and the Ontario corporate minimum tax credit (amount from line E6 of Schedule 5).

Part 4 – Request for carryback of tax credit

	Year Month Day			
1st previous tax year	2011-12-31	Credit to be applied	**901**	
2nd previous tax year	2010-12-31	Credit to be applied	**902**	
3rd previous tax year	2009-12-31	Credit to be applied	**903**	

Total (enter amount on line V in Part 3)

Part 5 – Analysis of tax credit available for carryforward by tax year of origin

You can complete this part to show all the credits from preceding tax years available for carryforward, by year of origin. This will help you determine the amount of credit that could expire in following years.

Tax year of origin (earliest tax year first) Year Month Day	Credit available
1992-12-31	
1993-12-31	
1994-12-31	
1995-12-31	
1996-12-31	
1997-12-31	
1998-12-31	
1999-12-31	
2000-12-31	
2001-12-31	

	Tax year of origin (earliest tax year first) Year Month Day	Credit available
	2002-12-31	
	2003-12-31	
	2004-12-31	
	2005-12-31	
	2006-12-31	
	2007-12-31	
	2008-12-31	
	2009-12-31	
	2010-12-31	
	2011-12-31	
Current tax year	2012-12-31	5,055

Total (equals line 325 in Part 3) 5,055

The amount available from the 20th preceding tax year will expire after this year. When you file your return for the next year, you will enter the expired amount on line 300 of Schedule 508 for that year.

Part 6 – Calculation of a recapture of ORDTC

You will have a recapture of ORDTC in a tax year when you meet **all** of the following conditions:

- you acquired a particular property in the current year or in any of the 20 previous tax years if the ORDTC was earned in a tax year ending after 2008;
- you claimed the cost of the property as an eligible expenditure for the ORDTC;
- the cost of the property was included in computing your ORDTC or was subject to an agreement made under subsection 127(13) of the federal Act to transfer qualified expenditures and section 42 of the *Taxation Act, 2007* (Ontario) applied; and
- you disposed of the property or converted it to commercial use in a tax year ending after December 31, 2008. You also meet this condition if you disposed of or converted to commercial use a property which incorporates the particular property previously referred to.

  Note: The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED in Ontario. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical federal investment tax credit (ITC) rate * of the original user in Calculation 1 below.

You have to report the recapture on Schedule 5 for the year in which you disposed of the property or converted it to commercial use. If the corporation is a member of a partnership, report its share of the recapture.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

* Federal ITC in calculations 1 and 2 should be determined without reference to paragraph (e) of the definition **investment tax credit** in subsection 127(9) of the federal Act.

Calculation 1 – If you meet all of the above conditions

	Y Amount of federal ITC you originally calculated for the property you acquired, or the original user's federal ITC where you acquired the property from a non-arm's length party, as described in the note above 700	Z Amount calculated using the federal ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	AA Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter amount BB, on line KK in Part 7) BB

Calculation 2 – If the corporation is deemed by subsection 42(1) of the *Taxation Act, 2007* (Ontario) to have transferred all or part of the eligible expenditure to another corporation as a consequence of an agreement described in subsection 127(13) of the federal Act complete Calculation 2. Otherwise, enter nil on line II.

	CC The rate percentage that the transferee used to determine its federal ITC for a qualified expenditure that was transferred under an agreement under subsection 127(13) of the federal Act **720**	DD The proceeds of disposition of the property if you dispose of it to a person at arm's length; or, in any other case, the fair market value of the property at conversion or disposition **730**	EE The amount, if any, already provided for in Calculation 1 (this allows for the situation where only part of the cost of a property is transferred for an agreement under subsection 127(13) of the federal Act) **740**
1.			

	FF Amount determined by the formula (CC x DD) – EE (using the columns above)	GG The federal ITC earned by the transferee for the qualified expenditure that was transferred **750**	HH Amount from column FF or GG, whichever is less
1.			

Subtotal (enter amount II on line LL below) ______ II

Calculation 3

As a member of a partnership, you will report your share of the ORDTC of the partnership after the ORDTC has been reduced by the amount of the recapture. If this is a positive amount, you will report it on line 205 in Part 2. However, if the partnership does not have enough ORDTC otherwise available to offset the recapture, then the amount by which reductions to the ORDTC exceeds additions (the excess) will be determined and reported on line JJ.

Corporate partner's share of the excess of ORDTC (enter amount JJ at line NN below) . . . . **760** ______ JJ

Part 7 – Total recapture of ORDTC

Recaptured federal ITC for Calculation 1 (amount from line BB) . . . . ______ KK

Recaptured federal ITC for Calculation 2 (amount from line II above) . . . . ______ LL

Amount KK **plus** amount LL . . . . ______ x 23.56 % = ______ MM

Add: Corporate partner's share of the excess of ORDTC for Calculation 3 (amount from line JJ above) . . . . ______ NN

Recapture of ORDTC (amount MM **plus** amount NN) (enter amount OO on line 277 of Schedule 5) . . . . ______ OO

Schedule A - Worksheet for eligible expenditures incurred by the corporation in Ontario for the current taxation year

This worksheet allows you to report the amount of eligible expenditures entered on Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim* which represents eligible expenditures as defined in section 127 of the *Income Tax Act* (ITA) with regard to scientific research and experimental development (SR&ED) **carried on in Ontario and attributable to a permanent establishment in Ontario of a corporation**.

Data on the worksheet is calculated based on the amounts on Form T661, but will have to be adjusted according to the rules of Ontario, if applicable, in particular when the corporation has had a permanent establishment in more than one jurisdiction. This data will be used when calculating Schedule 508 and Schedule 566.

Enter the breakdown between current and capital expenditures

		Current Expenditures			Capital Expenditures	
Total expenditures for SR&ED		95,447				
Add						
• payment of prior years' unpaid expenses (other than salary or wages)	+					
• prescribed proxy amount (Enter "0" if you use the traditional method)	+	16,879				
• expenditures on shared-use equipment				+		
• other additions	+			+		
Subtotal	=	112,326		=		
Less						
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	–					
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	–					
• prescribed expenditures not allowed by regulations	–			–		
• other deductions	–			–		
• non-arm's length transactions						
– expenditures for non-arm's length SR&ED contracts	–					
– purchases (limited to costs) of goods and services from non-arm's length suppliers	–			–		
Subtotal	=	112,326	I	=		II
Total eligible expenditures incurred by the corporation in Ontario in the tax year (add amount I and II)				=	112,326	III

Enter amount III on line 100 of Schedule 508.

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SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2012-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
St. Thomas Energy Inc.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	110 Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	120 Ontario Corporation No.
Ontario	2000-11-03	1448635

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	220 Street name/Rural route/Lot and Concession number	230 Suite number
135	Edward Street	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	260 Province/state	270 Country	280 Postal/zip code
St Thomas	ON	CA	N5P 4A9

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 1 If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 Farrow (Last name) **451** Glen (First name)

454 ______________________, (Middle name(s))

460 2 Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number

530 Street name/Rural route/Lot and Concession number

540 Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town)

570 Province/state

580 Country

590 Postal/zip code

Part 6 – Language of preference

600 Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

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SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2012-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information	120 Telephone number including area code
Glen Farrow	(519) 631-5550

Is the claim filed for a CETC earned through a partnership?* . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ______

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * 300

For eligible expenditures incurred before March 27, 2009:

– If line 300 is $400,000 or less, enter 15% on line 310.
– If line 300 is $600,000 or more, enter 10% on line 310.
– If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \;\; \textbf{minus} \;\; \$\;400{,}000}{\$\;200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . 310 15.000 %

For eligible expenditures incurred after March 26, 2009:

– If line 300 is $400,000 or less, enter 30% on line 312.
– If line 300 is $600,000 or more, enter 25% on line 312.
– If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \;\; \textbf{minus} \;\; \$\;400{,}000}{\$\;200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . 312 30.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution **400**	**B** Name of qualifying co-operative education program **405**
1.	Fanshawe College, London, ON	Electrical Engineering Technology Program
2.	Fanshawe College, London, ON	Electrical Engineering Technology Program
3.	Conestoga College, Ingersoll Campus	Powerline Technician (Co-op)
4.		

	C Name of student **410**	**D** Start date of WP (see note 1 below) **430**	**E** End date of WP (see note 2 below) **435**
1.	RIESS R ENGELS	2012-01-01	2012-04-30
2.	RIESS R ENGELS	2012-05-01	2012-08-10
3.	MASCHMANN, MATT	2012-05-07	2012-08-31
4.			

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		15.000 %	10,592	30.000 %		17
2.		15.000 %	8,915	30.000 %		14
3.		15.000 %	12,850	30.000 %		17
4.		15.000 %		30.000 %		

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	3,178	3,000	3,000		3,000
2.	2,675	3,000	2,675		2,675
3.	3,855	3,000	3,000		3,000
4.					

Ontario co-operative education tax credit (total of amounts in column K) 500 ... 8,675 L

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ________ x percentage on line 170 in Part 1 ________ % = ... M

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received.
Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

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SCHEDULE 552

ONTARIO APPRENTICESHIP TRAINING TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2012-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. Before March 27, 2009, the maximum credit for each apprentice is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship. After March 26, 2009, the maximum credit for each apprentice is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. The maximum credit amount is prorated for an employment period of an apprentice that straddles March 26, 2009.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if incurred before March 27, 2009; and
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if incurred after March 26, 2009.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario); and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009 or* the *Apprenticeship and Certification Act, 1998* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Make sure you keep a copy of the training agreement or contract of apprenticeship to support your claim. Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information (please print)

110 Name of person to contact for more information	120 Telephone number including area code
Glen Farrow	(519) 631-5550

Is the claim filed for an ATTC earned through a partnership? * . . . . **150** 1 Yes [ ] 2 No [X]

If **yes** to the question at line 150, what is the name of the partnership? . . . . **160** ____________

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * **300** 1

For eligible expenditures incurred before March 27, 2009:
- If line 300 is $400,000 or less, enter 30% on line 310.
- If line 300 is $600,000 or more, enter 25% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Specified percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \;\; \textbf{minus} \;\; 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . **310** 30.000 %

For eligible expenditures incurred after March 26, 2009:
- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\,\% - \left[10\,\% \times \left(\frac{\text{amount on line 300} \;\; \textbf{minus} \;\; 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . **312** 45.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice that is in a qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code **400**	B Apprenticeship program/ trade name **405**	C Name of apprentice **410**
1.	434a	Powerline Technician	Shawn Gaudon
2.			

	D Original contract or training agreement number **420**	E Original registration date of apprenticeship contract or training agreement (see note 1 below) **425**	F Start date of employment as an apprentice in the tax year (see note 2 below) **430**	G End date of employment as an apprentice in the tax year (see note 3 below) **435**
1.	AL9844	2010-10-19	2012-01-01	2012-12-31
2.				

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

Part 4 – Calculation of the Ontario apprenticeship training tax credit (continued)

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
1.		366	366	10,000
2.				

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
1.		57,587	57,587	25,914
2.				

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
1.	10,000		10,000
2.			

Ontario apprenticeship training tax credit (total of amounts in column N) **500** 10,000 **O**

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ________ x percentage on line 170 in Part 1 ________ % = ... ________ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, add the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.

For H1: The days employed as an apprentice must be within 36 months of the registration date provided in column E.

For H2: The days employed as an apprentice must be within 48 months of the registration date provided in column E.

Note 2: Maximum credit = ($5,000 x H1/365*) + ($10,000 x H2/365*)
* 366 days, if the tax year includes February 29

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

For J1: Eligible expenditures before March 27, 2009, must be for services provided by the apprentice during the first 36 months of the apprenticeship program.

For J2: Eligible expenditures after March 26, 2009, must be for services provided by the apprentice during the first 48 months of the apprenticeship program.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 x line 310) + (J2 x line 312)

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year.
Complete a **separate entry** for each repayment of government assistance.

June 28, 2012

PERSONAL AND CONFIDENTIAL

Glen Farrow
Chief Financial Officer
St. Thomas Energy Inc.
135 Edward Street
St. Thomas ON N5P 4A8

Mr. Farrow,

Corporate Tax Return Filing Instructions

Instalments

An attached chart indicates the instalments to be made for the taxation year ending on December 31, 2012.

GRAHAM SCOTT ENNS LLP

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2012-12-31

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Revenue Canada. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. A cheque or money order should be made payable to the Receiver General. Payment may be made by cheque or money order payable to the Receiver General either to an authorized financial institution or filed with **the appropriate remittance voucher to the following address**:

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Instalments paid	Cumulative difference	Instalments payable
2012-01-31	24,158			24,158
2012-02-29	24,158			24,158
2012-03-31	24,158			24,158
2012-04-30	24,158			24,158
2012-05-31	24,158			24,158
2012-06-30	24,158			24,158
2012-07-31	24,158			24,158
2012-08-31	24,158			24,158
2012-09-30	24,158			24,158
2012-10-31	24,158			24,158
2012-11-30	24,158			24,158
2012-12-31	24,149			24,149
Total	289,887			289,887

Quarterly instalment workchart

Date	Quarterly tax instalments	Instalments paid	Cumulative difference	Instalments payable
2012-03-31				
2012-06-30				
2012-09-30				
2012-12-31				
Total				

Instalment method

Indicate instalment method chosen [1-3] 1

1st Instalment base method

If payment of instalments other than quarterly instalments is delayed, indicate the MONTH in which you want them to begin (1=January, 2=February, etc.). 1

Select this box if you want the instalments to be calculated without taking the applicable threshold into account ☐

Quarterly instalments calculation

The corporation must meet requirements 1 to 5 to be eligible for quarterly instalments for a tax year.

1 – Is the corporation a Canadian-controlled private corporation (CCPC)?	X Yes	No
2 – Did the corporation claim any deduction under the section 125, during either the current or previous year?	Yes	X No
3 – Is the corporation's, or any of its associated corporations', taxable income for the current or previous year less than or equal to $500,000?*	Yes	No
4 – Is the corporation and any associated corporations' taxable capital employed in Canada for the current or previous year less than or equal to $10,000,000?	Yes	No
5 – Does the corporation have a perfect compliance history in the last 12 months?	Yes	No
If you do not want to use the quarterly instalments option, select this box to go back to monthly instalments.		

*Consult the Help (F1) for information on the changes relating to years subsequent to 2008.

1 – 1st Instalment base method

1st Instalment base amount (amount N below)	289,887	÷ 12	=	24,158	
Monthly instalments required				24,158	
Quarterly tax instalments required	289,887	÷ 4	=		

2 – Combined 1st and 2nd instalment base method

Select this box if you want the first 2 payments* to be calculated without taking the applicable threshold into account?

2nd Monthly instalment base amount

Indicate: Part I tax		250,140				
Part VI, VI.1 and XIII.1 tax	+					
Federal adjustment for amalgamation, winding up or transfer	+					
Provincial tax, other than Alberta, Québec and Ontario	+					
Ontario tax**	+	170,425				
Provincial adjustment for amalgamation, winding up or transfer	+					
Total	=	420,565	÷ 12	=	35,048	A
1/12 of estimated current year credits (M below /12)				–		
Each of the first two instalment payments				=	35,048	B
Total tax from N below		289,887				
Amount B above x 2	–	70,096				
	=	219,791	÷ 10	=	21,980	
Each of the remaining ten instalment payments				=	21,980	

2nd Quarterly instalment base amount

Indicate: Part I tax		250,140				
Part VI, VI.1 and XIII.1 tax	+					
Federal adjustment for amalgamation, winding up or transfer	+					
Provincial tax, other than Alberta, Québec and Ontario	+					
Ontario tax**	+	170,425				
Provincial adjustment for amalgamation, winding up or transfer	+					
Total	=	420,565	÷ 4	=	105,142	A
1/4 of estimated current year credits (M below /4)				–		
The first instalment payment				=		B
Total tax from N below		289,887				
Amount B above	–					
	=	289,887	÷ 3	=	96,629	
Each of the remaining three instalment payments				=		

* It is the first payment if the quarterly instalments are applicable.
** Use this line only to calculate instalments payable with regard to taxation years ending in 2009 and after.

3 – Estimated tax method

Instalment base amount (amount N below)		÷ 12	=	
Monthly instalments required				
Quarterly tax instalments required		÷ 4	=	

Instalment base calculation

Federal tax

		1st instalment base method		Estimated tax method	
Taxable income		1,154,515			
Calculation of tax payable					
Federal part I tax		438,716			
Recapture of investment tax credit	+		+		
Refundable tax on a CCPC's investment income	+		+		
Subtotal	=	438,716	=		**A**
Deduction					
Small business deduction					
Investment corporation deduction	+		+		
Federal tax abatement	+	115,452	+		
Manufacturing and processing profits deduction	+		+		
Non-business foreign tax credit	+		+		
Business foreign tax credit	+		+		
Tax reduction, general and accelerated	+	132,769	+		
Logging tax credit	+		+		
Investment tax credit per Schedule 31	+		+		
Qualifying environmental trust tax credit	+		+		
Subtotal	=	248,221	=		**B**
Federal tax summary					
Total part I tax payable (A minus B)		190,495			**C**
Part VI tax	+		+		**D**
Part VI.1 tax	+		+		**E1**
Part XIII.1 tax	+		+		**E2**
Parts I, VI, VI.1 and XIII.1 **Total**	=	190,495	=		**F**
Federal adjustments					
Adjustment for short taxation years multiplied by 365 and divided by the number of days in the year if less than 365	x	365 / 365	x	365 / 365	
Subtotal	=	190,495	=		
Federal adjustment for amalgamation, winding up or transfer	+		+	N/A	
Total federal tax after adjustments	=	190,495	=		**G**

Provincial tax

		1st instalment base method		Estimated tax method	
Provincial/territorial tax, other than Alberta, Québec and Ontario	+		+		**H**

Ontario tax

Use this section only to calculate instalments payable with regard to taxation years ending in 2009 and after (for other tax years, see the *Ontario Tax Instalments* schedule (Jump Code: **ION**)):

Income tax		99,392					
Capital tax	+						
Corporate minimum tax paid (credited)	+						
Special additional tax on life insurance corporations	+						
Total Ontario tax*	=	99,392	▶ +	99,392	+		**I**
Harmonized provincial tax (H + I) **Total harmonized provincial tax**			=	99,392	=		**J**

		1st instalment base method		Estimated tax method	
Provincial adjustments					
Adjustment for short taxation years multiplied by 365 and divided by the number of days in the year if less than 365	x	365 / 365	x	365 / 365	
Subtotal	=	99,392	=		
Provincial adjustment for amalgamation, winding up or transfer	+		+	N/A	
Total provincial tax after adjustments	=	99,392	=		**K**
Total of tax before refundable credits** (G + K)	=	289,887	=		**L**

Instalment base calculation (continued)

Estimated current year credits

Investment tax credit refund					
Dividend refund	+		+		
Federal capital gains refund	+		+		
Provincial and territorial capital gains refund	+		+		
NRO allowable refund per Schedule 26	+		+		
Tax withheld at source	+		+		
Other estimated credits	+		+		
Total estimated current year credits	=		=		**M**
Instalment base amount (L – M)		289,887			**N**

* Ontario tax corresponds to the amount before the application of specified Ontario tax credits.

** For instalments payable the amount on line G is not added to line L unless it exceeds $3,000. The same rule applies to line K.

Canada Revenue Agency / Agence du revenu du Canada

INFORMATION RETURN FOR CORPORATIONS FILING ELECTRONICALLY

- You have to complete this return to allow your transmitter to electronically file your corporation income tax return to us at the Canada Revenue Agency. You have to complete this return for each tax year.
- By completing part B and signing part C, you acknowledge that, under the *Income Tax Act*, you have to keep all records used to prepare your corporation income tax return, and provide this information to us on request.
- Part D must be completed by either you or the electronic transmitter of your corporation income tax return.
- Give the signed original of this return to the transmitter and keep a copy for yourself. Under the Act, you have to keep your copy for six years.
- We are responsible for ensuring the confidentiality of your electronically filed tax information only after we have accepted it.

This return is for your records. Do not send it to us unless we ask for it.

Part A – Identification

Name of corporation: St. Thomas Energy Inc.

Business Number	Tax year	From (Y M D)	To (Y M D)
89052 2014 RC0001		2011-01-01	2011-12-31

Part B – Declaration

Enter the following amounts, if applicable, from your corporation income tax return for the tax year noted above:

Net income or (loss) for income tax purposes from Schedule 1, financial statements or GIFI (line 300)	1,154,515
Part I tax payable (line 700)	190,495
Part II surtax payable (line 708)	
Part III.1 tax payable (line 710)	
Part IV tax payable (line 712)	
Part IV.1 tax payable (line 716)	
Part VI tax payable (line 720)	
Part VI.1 tax payable (line 724)	
Part XIV tax payable (line 728)	
Net provincial and territorial tax payable (line 760)	99,392
Provincial tax on large corporations (line 765)	

Part C – Certification and authorization

I, Farrow (Last name in block letters) Glen (First name in block letters) Chief Financial Officer (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined the corporation T2 income tax return, including accompanying schedules and statements, and that the information given on the T2 return and this T183 Corp information return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

I authorize the transmitter identified in Part D to electronically file the corporation income tax return identified in Part A. The transmitter can also modify the information originally filed in response to any errors Canada Revenue Agency identifies. This authorization expires when the Minister of National Revenue accepts the electronic return as filed.

2012-06-28		(519) 631-5550
Date (yyyy/mm/dd)	Signature of an authorized signing officer of the corporation	Telephone number

Part D – Transmitter identification

The following transmitter has electronically filed the tax return of the corporation identified in Part A.

Name of person or firm: GRAHAM SCOTT ENNS LLP   Electronic filer number: A4980

Privacy Act, Personal Information Bank number CRA PPU 047

Canada

Canada Revenue Agency / Agence du revenu du Canada

200

T2 CORPORATION INCOME TAX RETURN

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, paragraphs, and subparagraphs mentioned on this return refer to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) **001** 89052 2014 RC0001

Corporation's name

002 St. Thomas Energy Inc.

Address of head office

Has this address changed since the last time we were notified? . . . . **010** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 011 to 018.)

011 135 Edward Street

012

City	Province, territory, or state
015 St. Thomas	**016** ON
Country (other than Canada)	Postal code/Zip code
017	**018** N5P 4A8

Mailing address (if different from head office address)

Has this address changed since the last time we were notified? . . . . **020** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 021 to 028.)

021 c/o

022

023

City	Province, territory, or state
025	**026**
Country (other than Canada)	Postal code/Zip code
027	**028**

Location of books and records

Has the location of books and records changed since the last time we were notified . . . . **030** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 031 to 038.)

031 135 Edward Street

032

City	Province,territory, or state
035 St. Thomas	**036** ON
Country (other than Canada)	Postal code/Zip code
037	**038** N5P 4A8

040 **Type of corporation at the end of the tax year**

1 [X] Canadian-controlled private corporation (CCPC)

2 [ ] Other private corporation

3 [ ] Public corporation

4 [ ] Corporation controlled by a public corporation

5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. **043** ________ YYYY MM DD

To which tax year does this return apply?

Tax year start **060** 2011-01-01 (YYYY MM DD)

Tax year-end **061** 2011-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . **063** 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . **065** ________ YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with:

subparagraph 88(2)(a)(iv)? . . . . **064** 1 Yes [ ] 2 No [X]

subsection 249(3.1)? . . . . **066** 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . **067** 1 Yes [ ] 2 No [X]

Is this the first year of filing after:

Incorporation? . . . . **070** 1 Yes [ ] 2 No [X]

Amalgamation? . . . . **071** 1 Yes [ ] 2 No [X]

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . **072** 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . **076** 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . **078** 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used . . . . **079** ________

Is the corporation a resident of Canada?

080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

081 ________

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . **082** 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085

1 [ ] Exempt under paragraph 149(1)(e) or (l)

2 [ ] Exempt under paragraph 149(1)(j)

3 [ ] Exempt under paragraph 149(1)(t)

4 [ ] Exempt under other paragraphs of section 149

Do not use this area

095 **096**

Canada

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.

Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Was the resident corporation the beneficiary of a non-resident discretionary trust or did it make a contribution to a non-resident discretionary trust at any time during the tax year?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210		10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265		55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

		1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? 913910 Other Local, Municipal and Regional Public Administration CAN

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Energy	285	100.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ______ YYYY MM DD

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes ☐ 2 No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		1,154,515	A
Deduct: Charitable donations from Schedule 2	311			
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal				B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			1,154,515	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		1,154,515	
Income exempt under paragraph 149(1)(t)	370			
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			1,154,515	Z

* This amount is equal to 3.2 times the Part VI.1 tax payable at line 724 on page 8.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	1,154,515	A
Taxable income from line 360 on page 3, **minus** 10/3 of the amount on line 632* on page 7, **minus** 1/(0.38 - X**) 3.77358 times the amount on line 636*** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax	405	1,154,515	B
Business limit (see notes 1 and 2 below)	410	500,000	C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x **415** **** 70,183 D / 11,250 = 3,119,244 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") **425** ______ F

Small business deduction

Amount A, B, C, or F, whichever is the least ______ x 17 % = **430** ______ G

Enter amount G on line 1 on page 7.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** General rate reduction percentage for the tax year. It has to be pro-rated.

*** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

**** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3			1,154,515	A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		B		
Amount QQ from Part 13 of Schedule 27		C		
Amount used to calculate the credit union deduction from Schedule 17		D		
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least		E		
Aggregate investment income from line 440 on page 6*		F		
Total of amounts B to F		▶		G
Amount A **minus** amount G (if negative, enter "0")			1,154,515	H

Amount H	1,154,515	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 365	x 9 %	=	I
Amount H	1,154,515	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	/ 365	x 10 %	=	J
Amount H	1,154,515	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	365 / 365	x 11.5 %	= 132,769	K
Amount H	1,154,515	x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	/ 365	x 13 %	=	L

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L . . . . . 132,769 M

Enter amount M on line 638 on page 7.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)				N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		O		
Amount QQ from Part 13 of Schedule 27		P		
Amount used to calculate the credit union deduction from Schedule 17		Q		
Total of amounts O to Q		▶		R
Amount N **minus** amount R (if negative, enter "0")				S

Amount S		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 365	x 9 %	=	T
Amount S		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	/ 365	x 10 %	=	U
Amount S		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	365 / 365	x 11.5 %	=	V
Amount S		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	/ 365	x 13 %	=	W

General tax reduction – Total of amounts T to W X

Enter amount X on line 639 on page 7.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440**		x 26 2 / 3 % = ...		A
Foreign non-business income tax credit from line 632 on page 7				
Deduct:				
Foreign investment income from Schedule 7 . . . . **445**		x 9 1 / 3 % =		
		(if negative, enter "0")	▶	B
Amount A **minus** amount B (if negative, enter "0")				C
Taxable income from line 360 on page 3		1,154,515		
Deduct:				
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least				
Foreign non-business income tax credit from line 632 on page 7 . . .	x 25 / 9 =			
Foreign business income tax credit from line 636 on page 7	x 1(0.38 - X*) / 3.77358 =			
	▶			
		1,154,515		
		x 26 2 / 3 % =	307,871	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8)			190,495	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least **450**				F

* General rate reduction percentage for the tax year. It has to be pro-rated.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year **460**				
Deduct: Dividend refund for the previous tax year **465**		▶		G
Add the total of:				
Refundable portion of Part I tax from line 450 above				
Total Part IV tax payable from Schedule 3				
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation **480**				
		▶		H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H **485**				

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3		x 1 / 3	I
Refundable dividend tax on hand at the end of the tax year from line 485 above			J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 on page 8)			

Part I tax

Base amount of Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by	38 %	550	438,716	A
Recapture of investment tax credit from Schedule 31		602		B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			i
Taxable income from line 360 on page 3	1,154,515		
Deduct:			
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			
Net amount	1,154,515 ▶	1,154,515	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii	604		C
Subtotal (**add** lines A to C)		438,716	D

Deduct:

Small business deduction from line 430 on page 4			1		
Federal tax abatement	608	115,452			
Manufacturing and processing profits deduction from Schedule 27	616				
Investment corporation deduction	620				
Taxed capital gains 624					
Additional deduction – credit unions from Schedule 17	628				
Federal foreign non-business income tax credit from Schedule 21	632				
Federal foreign business income tax credit from Schedule 21	636				
General tax reduction for CCPCs from amount M on page 5	638	132,769			
General tax reduction from amount X on page 5	639				
Federal logging tax credit from Schedule 21	640				
Federal qualifying environmental trust tax credit	648				
Investment tax credit from Schedule 31	652				
Subtotal		248,221	▶	248,221	E

Part I tax payable – Line D **minus** line E	190,495	F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	190,495
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		190,495

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . **750** ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	99,392	
Provincial tax on large corporations (Nova Scotia Schedule 342)	765		
		99,392 ▶	99,392
Total tax payable	770		289,887 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from page 6	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	334,425	
Total credits	890	334,425 ▶	334,425 B

Refund code **894** 1 Overpayment 44,538

Balance (line A minus line B) -44,538

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . .

Enclosed payment **898**

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information **910** ______ Branch number

914 ______ Institution number **918** ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . **896** 1 Yes ☐ 2 No ☒

Certification

I, **950** Farrow (Last name in block letters) **951** Glen (First name in block letters) **954** Chief Financial Officer (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2012-06-28 — Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation **956** (519) 631-5550 — Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . . **957** 1 Yes ☐ 2 No ☒

958 Glen Farrow — Name in block letters **959** (519) 631-5550 — Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. **990** 1

Schedule of Instalment Remittances

Name of corporation contact
Telephone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Instalments	334,425

Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	334,425	**A**
Total instalments credited to the taxation year per T9	334,425	**B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2011-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				647,127 A
Add:				
Provision for income taxes – current		101	301,471	
Amortization of tangible assets		104	1,386,336	
Subtotal of additions			1,687,807 ▶	1,687,807
Other additions:				
Miscellaneous other additions:				
600 Prior year capital tax		290	15,000	
604				
Total		294		
Subtotal of other additions		199	15,000 ▶	15,000
Total additions		500	1,702,807 ▶	1,702,807
Deduct:				
Capital cost allowance from Schedule 8		403	1,136,254	
Subtotal of deductions			1,136,254 ▶	1,136,254
Other deductions:				
Miscellaneous other deductions:				
700 Ontario Capital tax current year accrual		390	7,500	
701 Prior year actual capital tax		391	6,665	
704 20 (1)(e) deduction on $225,000 finance fees	45,000			
Total	45,000	394	45,000	
Subtotal of other deductions		499	59,165 ▶	59,165
Total deductions		510	1,195,419 ▶	1,195,419
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				1,154,515

Canada

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SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2011-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ____________ Enter the regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes	103		143		
Newfoundland and Labrador offshore	004 1 Yes	104		144		
Prince Edward Island	005 1 Yes	105		145		
Nova Scotia	007 1 Yes	107		147		
Nova Scotia offshore	008 1 Yes	108		148		
New Brunswick	009 1 Yes	109		149		
Quebec	011 1 Yes	111		151		
Ontario	013 1 Yes	113		153		
Manitoba	015 1 Yes	115		155		
Saskatchewan	017 1 Yes	117		157		
Alberta	019 1 Yes	119		159		
British Columbia	021 1 Yes	121		161		
Yukon	023 1 Yes	123		163		
Northwest Territories	025 1 Yes	125		165		
Nunavut	026 1 Yes	126		166		
Outside Canada	027 1 Yes	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Canada

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
1,154,515		1,154,515	99,392

Ontario basic income tax (from Schedule 500)	270	135,632		
Deduct: Ontario small business deduction (from schedule 500)	402	36,240		
Subtotal		99,392	99,392	A6
Add:				
Surtax re Ontario small business deduction (from Schedule 500)	272			
Ontario additional tax re Crown royalties (from Schedule 504)	274			
Ontario transitional tax debits (from Schedule 506)	276			
Recapture of Ontario research and development tax credit (from Schedule 508)	277			
Subtotal				B6
Subtotal (amount A6 **plus** amount B6)			99,392	C6
Deduct:				
Ontario resource tax credit (from Schedule 504)	404			
Ontario tax credit for manufacturing and processing (from Schedule 502)	406			
Ontario foreign tax credit (from Schedule 21)	408			
Ontario credit union tax reduction (from Schedule 500)	410			
Ontario transitional tax credits (from Schedule 506)	414			
Ontario political contributions tax credit (from Schedule 525)	415			
Subtotal				D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")			99,392	E6
Deduct: Ontario research and development tax credit (from Schedule 508)	416			
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")			99,392	F6
Deduct: Ontario corporate minimum tax credit (from schedule 510)	418			
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")			99,392	G6
Add:				
Ontario corporate minimum tax (from Schedule 510)	278			
Ontario special additional tax on life insurance corporations (from Schedule 512)	280			
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies)	282			
Subtotal				H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)			99,392	I6
Deduct:				
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452			
Ontario apprenticeship training tax credit (from Schedule 552)	454			
Ontario computer animation and special effects tax credit (from Schedule 554)	456			
Ontario film and television tax credit (from Schedule 556)	458			
Ontario production services tax credit (from Schedule 558)	460			
Ontario interactive digital media tax credit (from Schedule 560)	462			
Ontario sound recording tax credit (from Schedule 562)	464			
Ontario book publishing tax credit (from Schedule 564)	466			
Ontario innovation tax credit (from Schedule 566)	468			
Ontario business-research institute tax credit (from Schedule 568)	470			
Other Ontario tax credits				
Subtotal				J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.	290		99,392	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits	255	99,392

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2011-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒ X

	1 Class number (See Note) **200**	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) **201**	3 Cost of acquisitions during the year (new property must be available for use)* **203**	4 Net adjustments** **205**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) **207**	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** **211**	7 Reduced undepreciated capital cost	8 CCA rate % **** **212**	9 Recapture of capital cost allowance (line 107 of Schedule 1) **213**	10 Terminal loss (line 404 of Schedule 1) **215**	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** **217**	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) **220**
1.	1	Electrical distribut	18,270,503			0		18,270,503	4	0	0	730,820	17,539,683
2.	1	Building	1,577,413			0		1,577,413	4	0	0	63,097	1,514,316
3.	8	System Supervisory	5,904			0		5,904	20	0	0	1,181	4,723
4.	47	Electrical Distribution	3,459,501	1,609,889		0	804,945	4,264,445	8	0	0	341,156	4,728,234
		Totals	23,313,321	1,609,889			804,945	24,118,265				1,136,254	23,786,956

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2011-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	St. Thomas Holding Inc.		86367 7191 RC0001	1					
2.	St. Thomas Energy Services Inc.		86367 7399 RC0001	3					
3.	Tiltran Services Inc.		10082 7476 RC0002	3					
4.	Lizco Sales Inc.		10659 2421 RC0002	3					
5.	2154310 Ontario Inc.		83387 9356 RC0001	3					
6.	TAL TREES INC.		11823 7486 RC0002	3					
7.	ECM Controls Inc.		10156 0084 RC0002	3					
8.	Terra Vox Group Inc.		83145 8260 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . . **050** Year 2011

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . **075** 1 Yes [ ] 2 No [X]

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 Association code **300**	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**
1	St. Thomas Energy Inc.	89052 2014 RC0001	1	500,000	100.0000	500,000
2	St. Thomas Holding Inc.	86367 7191 RC0001	1	500,000		
3	St. Thomas Energy Services Inc.	86367 7399 RC0001	1	500,000		
4	Tiltran Services Inc.	10082 7476 RC0002	1	500,000		
5	Lizco Sales Inc.	10659 2421 RC0002	1	500,000		
6	2154310 Ontario Inc.	83387 9356 RC0001	1	500,000		
7	TAL TREES INC.	11823 7486 RC0002	1	500,000		
8	ECM Controls Inc.	10156 0084 RC0002	1	500,000		
9	Terra Vox Group Inc.	83145 8260 RC0001	1	500,000		
				Total	100.0000	500,000 A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2011-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)	Business Number (If a corporation is not registered, enter "NR")	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
		Provide only one number per shareholder				
	100	200	300	350	400	500
1	St. Thomas Holding Inc.	86367 7191 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2011-12-31

On: 2011-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the I*ncome Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . ☒ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . . ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC . . . . . ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation . . . . . ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary . . . . . ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Canada

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year			100	6,701,066 A
Taxable income for the year (DICs enter "0") *	110	1,154,515 B		
Income for the credit union deduction * (amount E in Part 3 of Schedule 17) 120				
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less * 130				
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income * 140				
Subtotal (**add** lines 120, 130, and 140) ►		C		
Income taxable at the general corporate rate (line B **minus** line C) (if negative enter "0")	150	1,154,515		
After-tax income (line 150 x general rate factor for the tax year ** 0.7)			190	808,161 D
Eligible dividends received in the tax year	200			
Dividends deductible under section 113 received in the tax year	210			
Subtotal (**add** lines 200 and 210)		►		E
GRIP addition:				
Becoming a CCPC (line PP from Part 4)	220			
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230			
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240			
Subtotal (**add** lines 220, 230, and 240)		►	290	F
Subtotal (**add** lines A, D, E, and F)				7,509,227 G
Eligible dividends paid in the previous tax year	300			
Excessive eligible dividend designations made in the previous tax year	310			

Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.

Subtotal (line 300 **minus** line 310) ►			H
GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative)	490	7,509,227	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)	560		
GRIP at the end of the tax year (line 490 **minus** line 560)	590	7,509,227	

Enter this amount on line 160 of Schedule 55.

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2010-12-31

Taxable income before specified future tax consequences from the current tax year		1,389,662 J1	
Enter the following amounts before specified future tax consequences from the current tax year:			
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	L1		
Aggregate investment income (line 440 of the T2 return)	M1		
Subtotal (**add** lines K1, L1, and M1)	►	N1	
Subtotal (line J1 **minus** line N1) (if negative, enter "0")		1,389,662 ►	1,389,662 O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year					
Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R1

Aggregate investment income (line 440 of the T2 return) . . . . ______ S1

Subtotal (**add** lines Q1, R1, and S1) ______ ▶ ______ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ______ ▶ ______ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") ______ V1

GRIP adjustment for specified future tax consequences to the first previous tax year

(line V1 **multiplied by** the general rate factor for the tax year 0.69) . . . . **500** ______

Second previous tax year 2009-12-31

Taxable income before specified future tax consequences from the current tax year 1,531,489 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L2

Aggregate investment income (line 440 of the T2 return) . . . . ______ M2

Subtotal (**add** lines K2, L2, and M2) ______ ▶ ______ N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") 1,531,489 ▶ 1,531,489 O2

Future tax consequences that occur for the current year					
Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R2

Aggregate investment income (line 440 of the T2 return) . . . . ______ S2

Subtotal (**add** lines Q2, R2, and S2) ______ ▶ ______ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ______ ▶ ______ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") ______ V2

GRIP adjustment for specified future tax consequences to the second previous tax year

(line V2 **multiplied by** the general rate factor for the tax year 0.68) . . . . **520** ______

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2008-12-31

Taxable income before specified future tax consequences from the current tax year 1,927,618 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L3

Aggregate investment income (line 440 of the T2 return) . . . . . ______ M3

Subtotal (**add** lines K3, L3, and M3) ______ ► ______ N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") 1,927,618 ► 1,927,618 O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R3

Aggregate investment income (line 440 of the T2 return) . . . . . ______ S3

Subtotal (**add** lines Q3, R3, and S3) ______ ► ______ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") ______ ► ______ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") ______ V3

GRIP adjustment for specified future tax consequences to the third previous tax year
(line V3 **multiplied by** the general rate factor for the tax year 0.68) . . . . . **540** ______

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . . ______ W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . . ______ AA

Eligible dividends paid by the corporation in its last tax year . . . . . ______ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . . . ______ CC

Subtotal (line BB **minus** line CC) ______ ► ______ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)
(line AA **minus** line DD) . . . . . ______ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . ☐ Post wind-up . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year			FF
The corporation's money on hand immediately before the end of its previous/last tax year			GG
Unused and unexpired losses at the end of the corporation's previous/last tax year:			
Non-capital losses			
Net capital losses			
Farm losses			
Restricted farm losses			
Limited partnership losses			
Subtotal		►	HH
Subtotal (**add** lines FF, GG, and HH)			II
All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year		JJ	
Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year		KK	
All the corporation's reserves deducted in its previous/last tax year		LL	
The corporation's capital dividend account immediately before the end of its previous/last tax year		MM	
The corporation's low rate income pool immediately before the end of its previous/last tax year		NN	
Subtotal (**add** lines JJ, KK, LL, MM, and NN)		►	OO
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0")			PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 5 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year.

0.68	x	number of days in the tax year before January 1, 2010 / number of days in the tax year	/ 365	. . . . =		QQ
0.69	x	number of days in the tax year in 2010 / number of days in the tax year	/ 365	. . . . =		RR
0.7	x	number of days in the tax year in 2011 / number of days in the tax year	365 / 365	. . . . =	0.70000	SS
0.72	x	number of days in the tax year after December 31, 2011 / number of days in the tax year	/ 365	. . . . =		TT

General rate factor for the tax year (total of lines QQ to TT) . . . . 0.70000 UU

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SCHEDULE 500

ONTARIO CORPORATION TAX CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2011-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references on this schedule are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only and does not have to be filed with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic rate of tax for the year

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	/ 365	x	14.00 %	=	%	A1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	181 / 365	x	12.00 %	=	5.95068 %	A2
Number of days in the tax year after June 30, 2011, and before July 1, 2012 / Number of days in the tax year	184 / 365	x	11.50 %	=	5.79726 %	A3
Number of days in the tax year after June 30, 2012, and before July 1, 2013 / Number of days in the tax year	/ 365	x	11.00 %	=	%	A4
Number of days in the tax year after June 30, 2013 / Number of days in the tax year	/ 365	x	10.00 %	=	%	A5

Ontario basic rate of tax for the year (total of rates A1 to A5) 11.74794 ▶ 11.74794 % A6

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . 1,154,515 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A6 from Part 1) . . . . . . 135,632 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit, in addition to Ontario basic income tax, or has Ontario corporate minimum tax, Ontario special additional tax on life insurance corporations or Ontario capital tax payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Canada

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)						1,154,515	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)						1,154,515	2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return)	500,000	x	500,000 / 500,000 (line 4 on page 4 of the T2 return *)	=		500,000	3
Enter the least of amounts 1, 2, and 3						500,000	D
Ontario domestic factor:	Ontario taxable income ** / taxable income earned in all provinces and territories ***		1,154,515.00 / 1,154,515	=		1.00000	E

Amount D x amount E	500,000	a
Ontario taxable income (amount B from Part 2)	1,154,515	b

Ontario small business income (lesser of amount a and amount b) . . . . . 500,000 F

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	/ 365	x	8.50 %	=	%	G1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	181 / 365	x	7.50 %	=	3.71918 %	G2
Number of days in the tax year after June 30, 2011, and before July 1, 2012 / Number of days in the tax year	184 / 365	x	7.00 %	=	3.52877 %	G3
Number of days in the tax year after June 30, 2012, and before July 1, 2013 / Number of days in the tax year	/ 365	x	6.50 %	=	%	G4
Number of days in the tax year after June 30, 2013 / Number of days in the tax year	/ 365	x	5.50 %	=	%	G5

OSBD rate for the year (total of rates G1 to G5) . . . . . 7.24795 % G6

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G6) . . . . . 36,240 H

Enter amount H on line 402 of Schedule 5.

* For 2011 and later tax years, enter the amount from line 410 of the T2 return on line 3 of this schedule.

** Enter amount B from Part 2.

*** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Calculation of surtax re Ontario small business deduction

Complete this part if the corporation is claiming the OSBD and its adjusted taxable income, **plus** the adjusted taxable income of each corporation with which the corporation was associated during its tax year, is greater than $500,000. If the corporation is a member of an associated group, complete Schedule 501, *Ontario Adjusted Taxable Income of Associated Corporations to Determine Surtax re Ontario Small Business Deduction*.

Note: For days in the tax year after June 30, 2010, the small business surtax rate is 0%. You do not have to complete this part if the corporation's tax year begins after June 30, 2010.

Adjusted taxable income *		I		
Adjusted taxable income of all associated corporations (amount from line 500 of Schedule 501)		J		
Aggregate adjusted taxable income (amount I **plus** amount J)		▶		K
Deduct:				
Ontario business limit			500,000	
Subtotal (amount K **minus** Ontario business limit) (if negative, enter "0" on this line and on line P)				L

Small business surtax rate for the year:

Number of days in the tax year before July 1, 2010 / Number of days in the tax year: ____ / 365 x 4.25 % = ____ % M

Amount L x % on line M = ____ N

Amount N ____ x Ontario small business income (amount F from Part 3) ____ / 500,000 = ____ O
500,000

Surtax re Ontario small business deduction: lesser of amount O and OSBD (amount H from Part 3) ____ P

Enter amount P on line 272 of Schedule 5.

* Adjusted taxable income is equal to the corporation's taxable income or taxable income earned in Canada for the year **plus** the amount of the corporation's adjusted Crown royalties for the year **minus** the amount of the corporation's notional resource allowance for the year (from Schedule 504, *Ontario Resource Tax Credit and Ontario Additional Tax re Crown Royalties*).

If the tax year of the corporation is less than 51 weeks, **multiply** the adjusted taxable income of the corporation for the year by 365 and **divide** by the number of days in the tax year.

Part 5 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Lesser of amount D and amount b from Part 3 .... 500,000 Q

Surtax payable (amount P from Part 4) / Ontario domestic factor (amount E from Part 3) x OSBD rate (rate G6 from Part 3) 7.24795 % = ____ / 0.07248 = ____ R

Note: Enter "0" on line R for tax years beginning after June 30, 2010.

Ontario adjusted small business income (amount Q **minus** amount R) (if negative, enter "0") .... 500,000 S

Enter amount S on line U in Part 6 or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 6 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17 . . . . T

Deduct:

Ontario adjusted small business income (amount S from Part 5) . . . . U

Subtotal (amount T **minus** amount U) (if negative, enter "0") V

OSBD rate for the year (rate G6 from Part 3) . . . . 7.24795 %

Amount V **multiplied** by the OSBD rate for the year . . . . W

Ontario domestic factor (amount E from Part 3) . . . . 1.00000 X

Ontario credit union tax reduction (amount W **multiplied** by amount X) . . . . Y

Enter amount Y on line 410 of Schedule 5.

Canada Revenue Agency   Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2011-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
St. Thomas Energy Inc.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent	Year Month Day	**120** Ontario Corporation No.
Ontario		2000-11-03	1448635

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
135	Edward Street	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
St Thomas	ON	CA	N5P 4A9

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 1
If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 Farrow
Last name

451 Glen
First name

454 ,
Middle name(s)

460 2
Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Canada

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number	**530** Street name/Rural route/Lot and Concession number	**540** Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town)	**570** Province/state	**580** Country	**590** Postal/zip code

Part 6 – Language of preference

600 Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

File Number:EB-2014-0113

Exhibit: 4
Tab: 1
Schedule: 12

Date Filed: April 25, 2014

Attachment 2 of 3

2012 SRED Filing

Canada Revenue Agency   Agence du revenu du Canada

Code 1301

SCIENTIFIC RESEARCH AND EXPERIMENTAL DEVELOPMENT (SR&ED) EXPENDITURES CLAIM

Use this form:

- to provide technical information on your SR&ED projects;
- to calculate your SR&ED expenditures; and
- to calculate your qualified SR&ED expenditures for investment tax credits (ITC).

To claim an ITC, use either:

- Schedule T2SCH31, *Investment Tax Credit – Corporations*, or
- Form T2038(IND), *Investment Tax Credit (Individuals)*.

The information requested in this form and documents supporting your expenditures are prescribed information.

Your SR&ED claim must be filed within 12 months of the filing due date of your income tax return.

To help you fill out this form, use the T4088, *Guide to Form T661*, which is available on our Web site: **www.cra.gc.ca/sred**.

Part 1 – General information

010 Name of claimant: St. Thomas Energy Inc.

Enter one of the following:

Business number (BN): 89052 2014 RC0001

Social insurance number (SIN):

Tax year
From: 2012-01-01 (Year Month Day)
To: 2012-12-31 (Year Month Day)

050 Total number of projects you are claiming this tax year: 1

100 Contact person for the financial information	**105** Telephone number/extension	**110** Fax number
Glen Farrow	(519) 631-5550	
115 Contact person for the technical information	**120** Telephone number/extension	**125** Fax number
Richard McDonald KPMG LLP	(519) 660-2136	(519) 672-5684

151 If this claim is filed for a partnership, was Form T5013 filed? . . . . 1 ☐ Yes 2 ☐ No

If you answered **no** to line 151, complete lines 153, 156 and 157.

153 Names of the partners	**156** %	**157** BN or SIN
1		
2		
3		
4		
5		

Part 2 - Project information

CRA internal form identifier 060
Code 1301

Complete a separate Part 2 for each project claimed this year.

Section A - Project identification

200 Project title (and identification code if applicable)

See schedule

T661 E (13)

Canada

Part 3 – Calculation of SR&ED expenditures

What did you spend on your SR&ED projects?

Section A – Select the method to calculate the SR&ED expenditures

I elect (choose) to use the following method to calculate my SR&ED expenditures and related investment tax credits (ITC) for this tax year.
I understand that my election is irrevocable (cannot be changed) for this tax year.

160 [X] I elect to use the proxy method
(Enter "0" on line 360. Complete Part 5 and you do not need to track any expenditure incurred for overhead)

162 [ ] I choose to use the traditional method
(Enter "0" on line 355. Complete line 360, and track any expenditure incurred for overhead)

Section B – Calculation of allowable SR&ED expenditures (to the nearest dollar)

	Line		Amount
• SR&ED portion of salary or wages of employees directly engaged in the SR&ED:			
a) Employees other than specified employees for work performed in Canada	300	+	26,135
b) Specified employees for work performed in Canada	305	+	
Subtotal (add lines 300 and 305)	306	=	26,135
c) Employees other than specified employees for work performed outside Canada (subject to limitations – see guide)	307	+	
d) Specified employees for work performed outside Canada (subject to limitations – see guide)	309	+	
• Salary or wages identified on line 315 in prior years that were paid in this tax year	310	+	
• Salary or wages incurred in the year but not paid within 180 days of the tax year end	315		
• Cost of materials consumed in performing SR&ED	320	+	
• Cost of materials transformed in performing SR&ED	325	+	
• Contract expenditures for SR&ED performed on your behalf:			
a) Arm's length contracts (see note 1)	340	+	69,312
b) Non-arm's length contracts (see note 1)	345	+	
• Lease costs of equipment used before 2014:			
a) All or substantially all (90% of the time or more) for SR&ED	350	+	
b) Primarily (more than 50% of the time but less than 90%) for SR&ED. (Enter 50% of lease costs if you use the proxy method or enter "0" if you use the traditional method)	355	+	
• Overhead and other expenditures (enter "0" if you use the proxy method)	360	+	
• Third-party payments (see note 2) (complete Form T1263*)	370	+	
Total current SR&ED expenditures (add lines 306 to 370; do not add line 315) (Corporations need to adjust line 118 of schedule T2SCH1)	380	=	95,447
• Capital expenditures for depreciable property available for use before 2014 (Do not include these capital expenditures on schedule T2SCH8)	390	+	
Total allowable SR&ED expenditures (add lines 380 and 390)	400	=	95,447

Section C – Calculation of pool of deductible SR&ED expenditures (to the nearest dollar)

	Line		Amount
Amount from line 400	420		95,447
Deduct			
• provincial government assistance for expenditures included on line 400	429	–	4,295
• other government assistance for expenditures included on line 400	431	–	
• non-government assistance for expenditures included on line 400	432	–	
• SR&ED ITCs applied and/or refunded in the prior year (see guide)	435	–	
• sale of SR&ED capital assets and other deductions	440	–	
Subtotal (line 420 minus lines 429 to 440)	442	=	91,152
Add			
• repayments of government and non-government assistance that previously reduced the SR&ED expenditure pool	445	+	
• prior year's pool balance of deductible SR&ED expenditures (from line 470 of prior year T661)	450	+	
• SR&ED expenditure pool transfer from amalgamation or wind-up	452	+	
• amount of SR&ED ITC recaptured in the prior year	453	+	
Amount available for deduction (add lines 442 to 453) (enter positive amount only, include negative amount in income)	455	=	91,152
• Deduction claimed in the year (Corporations should enter this amount on line 411 of schedule T2SCH1)	460	–	91,152
Pool balance of deductible SR&ED expenditures to be carried forward to future years (line 455 minus 460)	470	=	

* Form T1263, *Third-Party Payments for Scientific Research and Experimental Development (SR&ED)*

Note 1 – For contract expenditures made after 2013, no amounts for purchasing or leasing capital property can be included.

Note 2 – For third-party payments made after 2013, no amounts for purchasing or leasing capital property can be included.

Part 4 – Calculation of qualified SR&ED expenditures for investment tax credit (ITC) purposes

The resulting amount is used to calculate your refundable and/or non refundable ITC.

Enter the breakdown between current and capital expenditures (to the nearest dollar)

	Line	Current Expenditures	Line	Capital Expenditures
Total expenditures for SR&ED (from lines 380 and 390)	492	95,447	496	
Add				
• payment of prior years' unpaid amounts (other than salary or wages)	500 +			
• prescribed proxy amount (complete Part 5) (Enter "0" if you use the traditional method)	502 +	16,879		
• expenditures on shared-use equipment for property acquired before 2014			504 +	
• qualified expenditures transferred to you (see note 3) (complete Form T1146**)	508 +		510 +	
Subtotal (add lines 492 to 508, and add lines 496 to 510)	511 =	112,326	512 =	
Deduct (see note 4)				
• provincial government assistance	513 –	5,055	514 –	
• other government assistance	515 –		516 –	
• non-government assistance and contract payments	517 –		518 –	
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	520 –			
• amounts paid in respect of an SR&ED contract to a person or partnership that is not a taxable supplier	528 –			
• 20% of expenditures included on lines 340 and 370 that were incurred after December 31, 2012	529 –			
• prescribed expenditures not allowed by regulations (see guide)	530 –		532 –	
• other deductions (see guide)	533 –		535 –	
• non-arm's length transactions				
– assistance allocated to you (complete Form T1145*)	538 –		540 –	
– expenditures for non-arm's length SR&ED contracts (from line 345)	541 –			
– adjustments to purchases (limited to costs) of goods and services from non-arm's length suppliers (see guide)	542 –		543 –	
– qualified expenditures you transferred (complete Form T1146**)	544 –		546 –	
Subtotal (line 511 minus lines 513 to 544 and line 512 minus lines 514 to 546)	557 =	107,271	558 =	
Qualified SR&ED expenditures (add lines 557 and 558)			559 =	107,271
Add				
• repayments of assistance and contract payments made in the year			560 +	
Total qualified SR&ED expenditures for ITC purposes (add lines 559 and 560)			570 =	107,271

* Form T1145, *Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*

** Form T1146, *Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*

Note 3 – On line 510 (capital) – Only include expenditures made before 2014 by the transferor (performer). Complete the latest version of Form T1146.

Note 4 – On lines 514, 516, 518, 532, 535, 540, 543 and 546 – Only include amounts related to expenditures of a capital nature made before 2014.

Part 5 – Calculation of prescribed proxy amount (PPA)

A notional amount representing your overhead and other expenditures.

This part calculates the PPA to enter on line 502 in Part 4. Do not complete this part if you have chosen to use the traditional method in Part 3 (line 162).
You can only claim a PPA if you elected to use the proxy method for the year in Part 3 (line 160).

Special rules apply for specified employees. Calculate your salary base in Section A and the PPA in Section B.

Section A – Salary base

Salary or wages of employees other than specified employees (from lines 300 and 307)	810	+	26,135
Deduct			
Bonuses, remuneration based on profits, and taxable benefits that were included on line 810	812	–	167
Subtotal (line 810 minus 812)	814	=	25,968

Salary or wages of specified employees

850	852	854	856	858	860
Column 1	**Column 2**	**Column 3**	**Column 4**	**Column 5**	**Column 6**
Name of specified employee	Total salary or wages for the year (SR&ED and non-SR&ED) excluding bonuses, remuneration based on profits, and taxable benefits (to the nearest dollar)	% of time spent on SR&ED (maximum 75%)	Amount in column 2 multiplied by percentage in column 3	2,5 x A x B/365 A = Year's maximum pensionable earnings B = Number of days employed in tax year	Amount in column 4 or 5, whichever amount is less

(Enter total of column 6 on line 816) 816 +

Salary base (total of lines 814 and 816) 818 = 25,968

Section B – Prescribed proxy amount (PPA)

Enter 65% of the salary base (line 818) less 5% of the salary base for the number of 2013 calendar days in the tax year, and less 10% of the salary base for number of days after 2013 in the tax year (use the formula in the guide-line 820) 820 = 16,879

Enter the amount from line 820 on line 502 in Part 4 unless the overall cap on PPA applies to you.

(See the guide for explanation and example of the overall cap on PPA)

Part 6 – Project costs

Information requested in this part must be provided for **all** SR&ED projects claimed in the year.
Expenditures should be recorded and allocated on a project basis.

750	752	754	756
Project title or identification code	Salary or wages in the tax year (Total of lines 306 to 309)	Cost of materials in the tax year (Total of lines 320 and 325)	Contract expenditures for SR&ED performed on your behalf in the tax year (Total of lines 340 and 345)
1. STE2010-01-03 Development of a Scalable Metering Networ	26,135		69,312
Total	26,135		69,312

Part 7 – Additional information

Expenditures for SR&ED performed by you in Canada (line 400 minus lines 307, 309, 340, 345, and 370) **605** 26,135

From the total you entered on line 605, estimate the percentage of distribution of the sources of funds for SR&ED performed within your organization.

		Canadian (%)		Foreign (%)
Internal	600	100.000		
Parent companies, subsidiaries, and affiliated companies	602		604	
Federal grants (do not include funds or tax credits from SR&ED tax incentives)	606			
Federal contracts	608			
Provincial funding	610			
SR&ED contract work performed for other companies on their behalf	612		614	
Other funding (e.g., universities, foreign governments)	616		618	

For statistical purposes indicate whether the work you performed falls within the realm of Basic or Applied research (to advance scientific knowledge) or Experimental development (to achieve a technological advancement):

620 [ ] Basic or Applied research **622** [X] Experimental development

Enter the number of SR&ED personnel in full-time equivalents (FTE):

Scientists and engineers	632	
Technologists and technicians	634	
Managers and administrators	636	
Other technical supporting staff	638	

Part 8 – Claim checklist

To ensure your claim is complete, make sure you have:

1. used the current version of this form X
2. entered the method you have chosen for reporting your SR&ED expenditures in Section A of Part 3 X
3. completed Part 2 for each project X
4. filed a completed Schedule T2SCH31 or Form T2038(IND) to claim ITCs on your qualified SR&ED expenditures X
5. filed a completed Form T1145*, T1146**, T1174*** and/or T1263**** including any required attachments, if applicable X

To expedite the processing of your claim, make sure you have:

1. completed Form T2, *Corporation Income Tax Return* or Form T1, *Income Tax and Benefit Return* X
2. filed the appropriate provincial and/or territorial tax credit forms, if applicable X
3. retained documents to support the SR&ED work performed and SR&ED expenditures you claimed X
4. checked boxes 231 and 232 on page 2 of your T2 return to indicate attachment of Form T661 and Schedule T2SCH31 X

* Form T1145, *Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*

** Form T1146, *Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*

*** Form T1174, *Agreement Between Associated Corporations to Allocate Salary or Wages of Specified Employees for Scientific Research and Experimental Development (SR&ED)*

**** Form T1263, *Third-Party Payments for Scientific Research and Experimental Development (SR&ED)*

Part 9 – Claim preparer information

Information requested in this part must be provided for each claim preparer that has accepted consideration to prepare or assist in the preparation of this SR&ED claim. Certification is required on lines 935, 970, and 975.

A $1000 penalty may be assessed if the information requested below about the claim preparer(s) and billing arrangement(s), is missing, incomplete, or inaccurate. Where a claim preparer has prepared or assisted in the preparation of this SR&ED form, the claimant and the claim preparer will be jointly and severally, or solidarily, liable for the penalty.

935 **Was a claim preparer engaged in any aspect of the preparation of this SR&ED claim?**

1. ☐ Yes (complete the claim preparer information table and lines 970 and 975 below)

2. ☐ No (complete lines 970 and 975)

Claim preparer information table

940	945	950	955	960	965
Name of claim preparer (company or individual)	Business number	Billing arrangement code (see codes*)	Billing rate (percentage, hourly/daily rate or flat fee)	Other billing arrangement(s) (Maximum 10 words)	Total fee paid, payable, or expected to pay
1.					
				Total	

*** Billing arrangement codes**

Code	Type of billing arrangement
1	Contingency fee arrangement – where the fee is based on a percentage of the investment tax credit earned
2	Hourly rate
3	Daily rate
4	Flat fee arrangement (lump sum)
5	Other arrangements – describe the arrangement in box 960 in 10 words or less

970 I, Glen Farrow , certify that the information provided in this part is complete
Name of authorized signing officer of the corporation , or individual (print)
and accurate.

Signature

975 2014-04-11
Year Month Day

Part 10 – Certification

I certify that I have examined the information provided on this form and on the attachments and it is true, correct, and complete.

165 Glen Farrow
Name of authorized signing officer of the corporation, or individual

Signature

170
Date

175 KPMG LLP
Name of person/firm who completed this form

Part 2 - Project information (continued)

Project number **1**

CRA internal form identifier 060
Code 1301

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

STE2010-01-03 Development of a Scalable Metering Network

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2010-04 (Year Month)	2013-03 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

Section B – Project descriptions

242 What scientific or technological uncertainties did you attempt to overcome – uncertainties that could not be removed using standard practice? (*Maximum 50 lines*)

1. In FY2012, St. Thomas Energy addressed the following uncertainties.
2.
3. - The Company sought to develop a generic geographical data management
4. architecture that can flexibly integrate with existing and future applications
5. and hardware (such as outage management system, smart-metering system, CIS,
6. SCADA, etc.) However, there were uncertainties regarding specific design
7. concepts that could provide a generic architecture capable of integrating with
8. legacy (e.g., centralized monitoring systems) and newer devices (e.g., smart
9. switches) and software frameworks. In addition, the sheer size of data (e.g.,
10. graphical entities) and complex inter-relationships required to represent
11. physical objects (e.g., feeders, transformers, etc.) imposed reliability
12. constraints that prompted the need for experimental development. Furthermore,
13. there was the need to integrate data from legacy sources that use different
14. underlying data structures. This introduced uncertainties in how to maintain
15. critical referential integrity of the various sub-systems. In addition, within
16. the spatial-physical entity relationships, St. Thomas Energy was not certain
17. about how to ensure that thousands of end-devices are properly connected
18. spatially (e.g., phasing properly shown throughout the model), and traces done
19. on various feeders pick up the actual routing of these feeders in the field.

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in Line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

1. In FY2012, St. Thomas Energy sought to develop a generic and extensible
2. architecture that would allow flexible integration with various disparate sub-
3. systems such as the GIS, CIS, load analysis system, etc. In order to develop a
4. reliable platform, various alternatives were investigated. In particular, due
5. to inherent proprietary limitations, it was found to be technologically
6. infeasible to extend the legacy system for improved field device
7. representations and interactivity in software. St. Thomas Energy then
8. hypothesized that a hybrid solution that combines 3D mapping (i.e., Autodesk
9. 3DAutoCAD Map 3D) with Topobase data management as the GIS platform would lead
10. to a reliable and flexible solution. After determining the GIS platform,
11. techniques were developed to transition legacy engineering data related to
12. electrical connectivity and secondary feeder maps to the GIS/AM (geographic
13. information system/Asset Management) platform. This was achieved through
14. modeling and establishing relationships between physical entities (e.g.,
15. conductors/feeders, relays, transformers, etc.) and virtual representations

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in Line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

16. (i.e., graphical nodes and polygons), while mitigating the risks of
17. connectivity failures. The virtual representations and their associated
18. properties were modeled within entity-relationship data structures and
19. persisted in a backend database. The associated relationship models were
20. designed such that sub-system categories automatically inherited the proper
21. characteristics in an accurate and timely manner in the event of physical
22. changes from upstream services such as handheld devices. St. Thomas Energy
23. also sought to improve the responsiveness of the smart grid system by
24. leveraging the GIS framework for dynamic sub-system/asset management, outage
25. management, etc. In particular, a connectivity model was developed for primary
26. data encompassing field sub-systems (i.e., transformers and feeders), and this
27. was integrated with the GIS framework. To this end, the GIS framework was
28. integrated with field devices such as networked thermostats, independent
29. energy systems (i.e., MicroFIT) as well as transformer and feeder loading
30. models. Systematic testing was done to ensure that when the status of a
31. circuit changes in the field (energized/non-energized), virtual
32. controls/monitors would react consistently and in real-time in order to
33. reflect actual field conditions. This involved several spatial connections
34. associated with switches, feeders, etc., each with a network of slave field-
35. devices. In the upcoming FY, St. Thomas Energy plans to continue pursuing
36. geocoding techniques for reliable coordination between spatial entities. By
37. the end of the FY, the geo-referencing aspect of the architecture was
38. successfully completed. In the upcoming FY, St. Thomas Energy will focus on
39. techniques to integrate the GIS platform with the smart metering network.
40.

246 What scientific or technological advancements did you achieve as a result of the work described in Line 244? (*Maximum 50 lines*)

1. St. Thomas Energy Inc. (the Company or St. Thomas Energy) is a local
2. electricity distribution company which delivers power to over 16,500
3. businesses and residents of the St. Thomas in Ontario. The Company seeks to
4. develop intelligent capabilities (smart metering, automated field data
5. collection, etc.) within their power distribution framework. However,
6. attaining the targeted capabilities could not be achieved by applying current
7. engineering concepts due to technological challenges, such the requirement for
8. high data integrity and security, and data transmission over environments
9. prone to noise and other interferences.
10.
11. This project represents a technological advancement in the fields of
12. Electrical Engineering and Telecommunications. If this project is successful,
13. St. Thomas Energy would have:
14.
15. - developed a generic geographical information management architecture that
16. can flexibly integrate and interact with disparate legacy and newer electrical
17. and software sub-systems, while providing reliable geo-referenced monitoring
18. in real-time. The architecture will enable advanced technologies such as
19. FIT/microFlT analytic tools and load monitoring systems to be integrated
20. within the distribution network for spatially-driven monitoring, connection
21. impact analysis, etc.

Section C – Additional project information

Who prepared the responses for Section B?

253	1 [X] Employee directly involved in the project	254 Name	Filice, Shawn
255	1 [ ] Other employee of the company	256 Name	
257	1 [X] External consultant	258 Name: KPMG LLP	259 Firm: KPMG LLP

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	261 Qualifications/experience and position title
1	Van Patter, Judy	Operations Coordinator, 25 years of experience with STEI
2	Tosolini, Danny	Engineering Manager, P.Eng. with over 20 years of experience
3	Karl, Ryan	Engineering Technologist,C. Tech with 5 years of experience

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 [X] Yes 2 [ ] No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	269 BN
1	Automated Solutions International Inc.	89163 1095 RC0001
2		

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	1 [X] Project planning documents	276	1 [X] Progress reports, minutes of project meetings
271	1 [X] Records of resources allocated to the project, time sheets	277	1 [ ] Test protocols, test data, analysis of test results, conclusions
272	1 [ ] Design of experiments	278	1 [ ] Photographs and videos
273	1 [X] Project records, laboratory notebooks	279	1 [ ] Samples, prototypes, scrap or other artefacts
274	1 [ ] Design, system architecture and source code	280	1 [X] Contracts
275	1 [X] Records of trial runs	281	1 [ ] Others, specify 282

Attachment 3 of 3

OEB-PILS Model

In
Workf

Utility Name	St. Thomas Energy Inc.
Assigned EB Number	EB-2014-0113
Name and Title	Robert Kent, Director Finance and Regulat
Phone Number	519-631-5550 x 5258
Email Address	rkent@sttenergy.com
Date	25-Apr-14
Last COS Re-based Year	**2011**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

come Tax/PILs
orm for 2015 Filers

Version **2.0**

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engineering or other use or dissemination of this model without the
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applications, the onus remains on the applicant to ensure the accuracy of

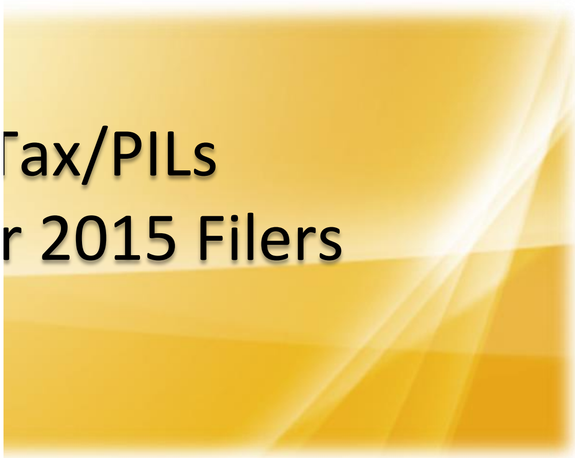
Algoma Power Inc.
Atikokan Hydro Inc.
Attawapiskat Power Corp.
Bluewater Power Distribution Corporation
Brant County Power Inc.
Brantford Power Inc.
Burlington Hydro Inc.
Cambridge and North Dumfries Hydro Inc.
Canadian Niagara Power Inc. - Eastern Ontario Power
Canadian Niagara Power Inc. - Fort Erie

Canadian Niagara Power Inc. - Port Colborne Hydro Inc.
Centre Wellington Hydro Ltd.

Clinton Power Corporation
COLLUS Power Corporation
Cooperative Hydro Embrun Inc.
E.L.K. Energy Inc.
Enersource Hydro Mississauga Inc.
Entegrus Powerlines Inc. - Chatham-Kent
Entegrus Powerlines Inc. - Dutton
Entegrus Powerlines Inc. - Newbury
Entegrus Powerlines Inc. - Strathroy, Mounth Brydges & Parkhill
ENWIN Utilities Ltd.
Erie Thames Powerlines Corporation
Espanola Regional Hydro Distribution Corporation
Essex Powerlines Corporation
Festival Hydro Inc.
Festival Hydro Inc. - Hensall
Fort Albany Power Corporation
Fort Frances Power Corporation
Greater Sudbury Hydro Inc.
Grimsby Power Inc.
Guelph Hydro Electric Systems Inc.
Haldimand County Hydro Inc.
Halton Hills Hydro Inc.
Hearst Power Distribution Company Limited
Horizon Utilities Corporation
Hydro 2000 Inc.
Hydro Hawkesbury Inc.
Hydro One Brampton Networks Inc.
Hydro One Networks Inc.
Hydro Ottawa Limited

Innisfil Hydro Distribution Systems Limited
Kashechewan Power Corporation
Kenora Hydro Electric Corporation Ltd.
Kingston Hydro Corporation
Kitchener-Wilmot Hydro Inc.
Lakefront Utilities Inc.
Lakeland Power Distribution Ltd.
London Hydro Inc.
Midland Power Utility Corporation
Milton Hydro Distribution inc.
Newmarket - Tay Power Distribution Ltd. - Newmarket
Newmarket - Tay Power Distribution Ltd. - Tay
Niagara Peninsula Energy Inc. - Niagara Falls
Niagara Peninsula Energy Inc. - Peninsula West
Niagara-on-the-Lake Hydro Inc.
Norfolk Power Distribution Inc.
North Bay Hydro Distribution Limited
Northern Ontario Wires Inc.
Oakville Hydro Electricity Distribution Inc.
Orangeville Hydro Limited
Orillia Power Distribution Corporation
Oshawa PUC Networks Inc.
Ottawa River Power Corporation
Parry Sound Power Corporation
Peterborough Distribution Incorporated
PowerStream Inc. - Barrie
PowerStream Inc. - South
PUC Distribution Inc.
Renfrew Hydro Inc.
Rideau St. Lawrence Distribution Inc.
Sioux Lookout Hydro Inc.
St. Thomas Energy Inc.
Thunder Bay Hydro Electricity Distribution Inc.
Tillsonburg Hydro Inc.
Toronto Hydro-Electric System Limited
Veridian Connections Inc.
Veridian Connections Inc. - Gravenhurst
Wasaga Distribution Inc.
Waterloo North Hydro Inc.
Welland Hydro-Electric System Corp.
Wellington North Power Inc.
West Coast Huron Energy Inc.
West Perth Power Inc.
Westario Power Inc.
Whitby Hydro Electric Corporation
Woodstock Hydro Services Inc.


Income T
Workform fo


Tax/PILs
r 2015 Filers

Income Tax/PILs Workform for 2015 Filers

Rate Base			$	**31,409,045**	*estimated*
Return on Ratebase					
Deemed ShortTerm Debt %	4.00%	T	$	1,256,362	*W = S * T*
Deemed Long Term Debt %	56.00%	U	$	17,589,065	*X = S * U*
Deemed Equity %	40.00%	V	$	12,563,618	*Y = S * V*
Short Term Interest Rate	2.11%	Z	$	26,509	*AC = W * Z*
Long Term Interest	4.88%	AA	$	858,346	*AD = X * AA*
Return on Equity (Regulatory Income)	9.36%	AB	$	**1,175,955**	*AE = Y * AB*
Return on Rate Base			$	**2,060,810**	*AF = AC + AD + AE*

Questions that must be answered

	Historic	Bridge	Test Year
1. Does the applicant have any Investment Tax Credits (ITC)?	No	No	No
2. Does the applicant have any SRED Expenditures?	Yes	Yes	No
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No	No	No
4. Does the applicant have any Capital Leases?	No	No	No
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No	No	No
6. Since 1999, has the applicant acquired another regulated applicant's assets?	No	No	No
7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.*	No	No	No
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No

Income Tax/PILs Workform for 2015 Filers

Tax Rates Federal & Provincial As of June 20, 2012	Effective January-01-12	Effective January-01-13	Effective January-01-14	Effective January-01-15
Federal income tax				
General corporate rate	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%
Rate reduction	-11.50%	-13.00%	-13.00%	-13.00%
	16.50%	15.00%	15.00%	15.00%
Ontario income tax	11.75%	11.50%	11.50%	11.50%
Combined federal and Ontario	28.25%	26.50%	26.50%	26.50%
Federal & Ontario Small Business				
Federal small business threshold	500,000	500,000	500,000	500,000
Ontario Small Business Threshold	500,000	500,000	500,000	500,000
Federal small business rate	11.00%	11.00%	11.00%	11.00%
Ontario small business rate	4.50%	4.50%	4.50%	4.50%

Income Tax/PILs Workform for 2015 Filers

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historic per tax returns	Less: Non-Distribution Portion	UCC Regulated Historic Year
1	Distribution System - post 1987	17,571,242		17,571,242
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election			0
2	Distribution System - pre 1988			0
8	General Office/Stores Equip	382,624		382,624
10	Computer Hardware/ Vehicles	588,388		588,388
10.1	Certain Automobiles			0
12	Computer Software			0
13_1	Lease # 1			0
13_2	Lease #2			0
13_3	Lease # 3			0
13_4	Lease # 4			0
14	Franchise			0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs			0
42	Fibre Optic Cable			0
43.1	Certain Energy-Efficient Electrical Generating Equipment			0
43.2	Certain Clean Energy Generation Equipment			0
45	Computers & Systems Software acq'd post Mar 22/04			0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			0
47	Distribution System - post February 2005	9,300,231		9,300,231
50	Data Network Infrastructure Equipment - post Mar 2007	345,227		345,227
52	Computer Hardware and system software			0
95	CWIP			0
				0
				0
				0
				0
				0
				0
				0
				0
				0
				0
	SUB-TOTAL - UCC	**28,187,712**	**0**	**28,187,712**

Income Tax/PILs
Workform for 2015 Filers

Schedule 10 CEC - Historical Year

Cumulative Eligible Capital				**0**
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**0**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**0**
Current Year Deduction		**0**	**x 7% =**	**0**
Cumulative Eligible Capital - Closing Balance				**0**

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital Gains Reserves ss.40(1)			0
Tax Reserves Not Deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)			0
Reserve for goods and services not delivered ss. 20(1)(m)			0
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & Share Issue Expenses ss. 20(1)(e)			0
Other tax reserves			0
			0
			0
			0
			0
			0
Total	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)			
General Reserve for Inventory Obsolescence (non-specific)			0
General reserve for bad debts			0
Accrued Employee Future Benefits:			0
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost			0
- Other Post-Employment Benefits	1,081,373		1,081,373
Provision for Environmental Costs			0
Restructuring Costs			0
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other			0
			0
			0
Total	**1,081,373**	**0**	**1,081,373**

Schedule 7-1 Loss Carry Forward - Historic

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic			0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic			0

Adjusted Taxable Income - Historic Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	A	1,676,338		1,676,338
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104	1,081,077		1,081,077
Amortization of intangible assets	106			0
Recapture of capital cost allowance from Schedule 8	107			0
Gain on sale of eligible capital property from Schedule 10	108			0
Income or loss for tax purposes- joint ventures or partnerships	109			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111			0
Charitable donations	112			0
Taxable Capital Gains	113			0
Political Donations	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118			0
Capitalized interest	119			0
Non-deductible club dues and fees	120			0
Non-deductible meals and entertainment expense	121			0
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements- balance at end of year	126	1,081,373		1,081,373
Soft costs on construction and renovation of buildings	127			0
Book loss on joint ventures or partnerships	205			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other Additions				
Interest Expensed on Capital Leases	290			0
Realized Income from Deferred Credit Accounts	291			0
Pensions	292			0
Non-deductible penalties	293			0
	294			0
	295			0
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))				0
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received				0
				0

				0
				0
				0
				0
				0
				0
				0
				0
				0
Total Additions		**2,162,450**	**0**	**2,162,450**
Deductions:				
Gain on disposal of assets per financial statements	401			0
Dividends not taxable under section 83	402			0
Capital cost allowance from Schedule 8	403	2,086,961		2,086,961
Terminal loss from Schedule 8	404			0
Cumulative eligible capital deduction from Schedule 10	405			0
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411			0
Tax reserves claimed in current year	413			0
Reserves from financial statements - balance at beginning of year	414	1,234,948		1,234,948
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390			0
Capital Lease Payments	391			0
Non-taxable imputed interest income on deferral and variance accounts	392			0
	393			0
	394			0
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received				0
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)		45,000		45,000
				0
				0
				0
				0
				0
				0
				0
Total Deductions		**3,366,909**	**0**	**3,366,909**
Net Income for Tax Purposes		**471,879**	**0**	**471,879**
Charitable donations from Schedule 2	311			0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320			0
Non-capital losses of preceding taxation years from Schedule 4	331	390,284		390,284
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332			0
Limited partnership losses of preceding taxation years from Schedule 4	335			0
TAXABLE INCOME		**81,595**	**0**	**81,595**

PILs Tax Provision - Historic Year

Note: Input the actual information from the tax returns for the historic year.

						Wires Only	
Regulatory Taxable Income						$ 81,595	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$ 9,383	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ -	**D**				
	Rate reduction (negative)		**E**		**F = D * E**		
Ontario Income tax						$ 9,383	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			11.50%	**K = J / A**		
	Federal tax rate			15.00%	**L**		
	Combined tax rate					26.50%	**M = K + L**
Total Income Taxes						**$ 21,622**	**N = A * M**
Investment Tax Credits						$ 12,239	**O**
Miscellaneous Tax Credits						$ 15,055	**P**
Total Tax Credits						**$ 27,294**	**Q = O + P**
Corporate PILs/Income Tax Provision for Historic Year						**$ -**	**R = N - Q**

Income Tax/PILs
Workform for 2015 Filers

Schedule 8 CCA - Bridge Year

Class	Class Description	UCC Regulated Historic Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}
1	Distribution System - post 1987	$ 17,571,242			$ 17,571,242	$ -
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election				$ -	$ -
2	Distribution System - pre 1988				$ -	$ -
8	General Office/Stores Equip	$ 382,624	$ 70,000		$ 452,624	$ 35,000
10	Computer Hardware/ Vehicles	$ 588,388	$ 400,292		$ 988,680	$ 200,146
10.1	Certain Automobiles				$ -	$ -
12	Computer Software		$ 96,500		$ 96,500	$ 48,250
13 1	Lease # 1				$ -	$ -
13 2	Lease #2				$ -	$ -
13 3	Lease # 3				$ -	$ -
13 4	Lease # 4				$ -	$ -
14	Franchise				$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				$ -	$ -
42	Fibre Optic Cable				$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment				$ -	$ -
43.2	Certain Clean Energy Generation Equipment				$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04				$ -	$ -
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				$ -	$ -
47	Distribution System - post February 2005	$ 9,300,231	$ 1,950,000		$ 11,250,231	$ 975,000
50	Data Network Infrastructure Equipment - post Mar 2007	$ 345,227			$ 345,227	$ -
52	Computer Hardware and system software				$ -	$ -
95	CWIP				$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
	TOTAL	$ 28,187,712	$ 2,516,792	$ -	$ 30,704,504	$ 1,258,396

Reduced UCC	Rate %	Bridge Year CCA	UCC End of Bridge Year
$ 17,571,242	4%	$ 702,850	$ 16,868,392
$ -	6%	$ -	$ -
$ -	6%	$ -	$ -
$ 417,624	20%	$ 83,525	$ 369,099
$ 788,534	30%	$ 236,560	$ 752,120
$ -	30%	$ -	$ -
$ 48,250	100%	$ 48,250	$ 48,250
$ -		$ -	$ -
$ -		$ -	$ -
$ -		$ -	$ -
$ -		$ -	$ -
$ -		$ -	$ -
$ -	8%	$ -	$ -
$ -	12%	$ -	$ -
$ -	30%	$ -	$ -
$ -	50%	$ -	$ -
$ -	45%	$ -	$ -
$ -	30%	$ -	$ -
$ 10,275,231	8%	$ 822,018	$ 10,428,213
$ 345,227	55%	$ 189,875	$ 155,352
$ -	100%	$ -	$ -
$ -		$ -	$ -
$ -		$ -	$ -
$ -		$ -	$ -
$ -		$ -	$ -
$ -		$ -	$ -
$ -		$ -	$ -
$ -		$ -	$ -
$ -		$ -	$ -
$ -		$ -	$ -
$ -		$ -	$ -
$ -		$ -	$ -
$ 29,446,108		**$ 2,083,078**	**$ 28,621,426**

Schedule 10 CEC - Bridge Year

Cumulative Eligible Capital				**0**
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**0**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**0**
Current Year Deduction		**0**	**x 7% =**	**0**
Cumulative Eligible Capital - Closing Balance				**0**

Income Tax/PILs Workform for 2015 Filers

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

				Bridge Year Adjustments				
Description	**Historic Utility Only**	**Eliminate Amounts Not Relevant for Bridge Year**	**Adjusted Utility Balance**	**Additions**	**Disposals**	**Balance for Bridge Year**	**Change During the Year**	**Disallowed Expenses**
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	1,081,373		1,081,373	10,000		1,091,373	10,000	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**1,081,373**	**0**	**1,081,373**	**10,000**	**0**	**1,091,373**	**10,000**	**0**

Income Tax/PILs Workform for 2015 Filers

Corporation Loss Continuity and Application

Schedule 7-1 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction	**Total**
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Net Capital Loss Carry Forward Deduction	**Total**
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Income Tax/PILs Workform for 2015 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Total for Regulated Utility
Income before PILs/Taxes	**A**	606,729
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets	104	1,255,000
Amortization of intangible assets	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves deducted in prior year	125	0
Reserves from financial statements- balance at end of year	126	1,091,373
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	

Income Tax/PILs Workform for 2015 Filers

Adjusted Taxable Income - Bridge Year

Other Additions		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		
Total Additions		**2,346,373**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	2,083,078
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10	405	0
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves claimed in current year	413	0
Reserves from financial statements - balance at beginning of year	414	1,081,373
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		

Adjusted Taxable Income - Bridge Year

Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Total Deductions		**3,164,451**
Net Income for Tax Purposes		**-211,349**
Charitable donations from Schedule 2	311	
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	
Non-capital losses of preceding taxation years from Schedule 4	331	
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
TAXABLE INCOME		**-211,349**

Income Tax/PILs Workform for 2015 Filers

PILS Tax Provision - Bridge Year

						Wires Only	
Regulatory Taxable Income						-$ 211,349	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	4.50%	**B**	$ -	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ -	**D**				
	Rate reduction	-7.00%	**E**	$ -	**F = D * E**		
Ontario Income tax						$ -	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			0.00%	**K = J / A**		
	Federal tax rate			0.00%	**L**		
	Combined tax rate					0.00%	**M = K + L**
Total Income Taxes						**$ -**	**N = A * M**
Investment Tax Credits							**O**
Miscellaneous Tax Credits							**P**
Total Tax Credits						**$ -**	**Q = O + P**
Corporate PILs/Income Tax Provision for Bridge Year						**$ -**	**R = N - Q**

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.

Income Tax/PILs Workform for 2015 Filers

Schedule 8 CCA - Test Year

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}
1	Distribution System - post 1987	$ 16,868,392			$ 16,868,392	$ -
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -
2	Distribution System - pre 1988	$ -			$ -	$ -
8	General Office/Stores Equip	$ 369,099	215,000		$ 584,099	$ 107,500
10	Computer Hardware/ Vehicles	$ 752,120	85,000		$ 837,120	$ 42,500
10.1	Certain Automobiles	$ -			$ -	$ -
12	Computer Software	$ 48,250	13,000		$ 61,250	$ 6,500
13 1	Lease # 1	$ -			$ -	$ -
13 2	Lease #2	$ -			$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -
14	Franchise	$ -			$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than B	$ -			$ -	$ -
42	Fibre Optic Cable	$ -			$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ -			$ -	$ -
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -			$ -	$ -
47	Distribution System - post February 2005	$ 10,428,213	1,850,000		$ 12,278,213	$ 925,000
50	Data Network Infrastructure Equipment - post Mar 2007	$ 155,352			$ 155,352	$ -
52	Computer Hardware and system software	$ -			$ -	$ -
95	CWIP	$ -			$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
	TOTAL	$ 28,621,426	$ 2,163,000	$ -	$ 30,784,426	$ 1,081,500

Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
$ 16,868,392	4%	$ 674,736	$ 16,193,657
$ -	6%	$ -	$ -
$ -	6%	$ -	$ -
$ 476,599	20%	$ 95,320	$ 488,779
$ 794,620	30%	$ 238,386	$ 598,734
$ -	30%	$ -	$ -
$ 54,750	100%	$ 54,750	$ 6,500
$ -		$ -	$ -
$ -		$ -	$ -
$ -		$ -	$ -
$ -		$ -	$ -
$ -		$ -	$ -
$ -	8%	$ -	$ -
$ -	12%	$ -	$ -
$ -	30%	$ -	$ -
$ -	50%	$ -	$ -
$ -	45%	$ -	$ -
$ -	30%	$ -	$ -
$ 11,353,213	8%	$ 908,257	$ 11,369,956
$ 155,352	55%	$ 85,444	$ 69,908
$ -	100%	$ -	$ -
$ -	0%	$ -	$ -
$ -	0%	$ -	$ -
$ -	0%	$ -	$ -
$ -	0%	$ -	$ -
$ -	0%	$ -	$ -
$ -	0%	$ -	$ -
$ -	0%	$ -	$ -
$ -	0%	$ -	$ -
$ -	0%	$ -	$ -
$ -	0%	$ -	$ -
$ -	0%	$ -	$ -
$ 29,702,926		**$ 2,056,892**	**$ 28,727,534**

Income Tax/PILs Workform for 2015 Filers

Schedule 10 CEC - Test Year

Cumulative Eligible Capital				**0**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**0**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**0**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")		**0**	**x 7% =**	**0**
Cumulative Eligible Capital - Closing Balance				**0**

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

				Test Year Adjustments				
Description	**Bridge Year**	**Eliminate Amounts Not Relevant for Bridge Year**	**Adjusted Utility Balance**	**Additions**	**Disposals**	**Balance for Test Year**	**Change During the Year**	**Disallowed Expenses**
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	1,091,373		1,091,373	10,000		1,101,373	10,000	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**1,091,373**	**0**	**1,091,373**	**10,000**	**0**	**1,101,373**	**10,000**	**0**

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year	42,270		42,270
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	42,270	0	42,270
Amount to be used in Test Year			0
Balance available for use post Test Year	42,270	0	42,270

Net Capital Loss Carry Forward Deduction	**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Income Tax/PILs Workform for 2015 Filers

Taxable Income - Test Year

		Test Year Taxable Income
Net Income Before Taxes		1,175,955

	T2 S1 line #	
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	1,208,480
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	0
Reserves from financial statements- balance at end of year	126	1,101,373
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	

Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
	296	
	297	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		
Total Additions		**2,309,853**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	2,056,892
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	0
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	0
Reserves from financial statements - balance at beginning of year	414	1,091,373
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	

Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
	395	
	396	
	397	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Total Deductions		**3,148,265**
NET INCOME FOR TAX PURPOSES		**337,542**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	42,270
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**295,273**

Income Tax/PILs Workform for 2015 Filers

PILs Tax Provision - Test Year

							Wires Only	
Regulatory Taxable Income							$ 295,273	**A**
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	4.50%	**B**	$	13,287	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ -	**D**					
	Rate reduction	-7.00%	**E**	$	-	**F = D * E**		
Ontario Income tax							$ 13,287	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate				4.50%	**K = J / A**		
	Federal tax rate				11.00%	**L**		
	Combined tax rate						15.50%	**M = K + L**
Total Income Taxes							**$ 45,767**	**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							**$ 45,767**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up [1]					84.50%	**S = 1 - M**	**$ 8,395**	**T = R / S - R**
Income Tax (grossed-up)							**$ 54,162**	**U = R + T**

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

NON-RECOVERABLE AND DISALLOWED EXPENSES

St. Thomas Energy Inc. does not have any expenses that are non-recoverable or disallowed for tax purposes.

INTEGRITY CHECKS

St. Thomas Energy Inc. confirms that it has reviewed the filing requirements section 2.7.5.2 integrity checks and these have been achieved in this application. St. Thomas Energy Inc. has considered the following:

- The depreciation and amortization added back in the application's PILs model agree with the numbers disclosed in the rate base section of the application;
- The capital additions and deductions in the UCC/ CCA Schedule 8 agree with the rate base section for historic, bridge and test years;
- Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31st historic year UCC that agrees with the opening bridge year UCC at January 1st;
- The CCA deductions in the application's PILs tax model for historic, bridge and test years agree with the numbers in the UCC schedules for the same years filed in the application;
- Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application;
- CCA is maximized even if there are tax loss carry-forwards;
- A statement is included in the application as to when the losses, if any, will be fully utilized;
- Accounting OPEB and pension amounts added back on Schedule 1 reconciliation of accounting income to net income for tax purposes agree with the OM&A analysis for compensation; and
- The income tax rate used to calculate the tax expense must be consistent with the utility's actual tax facts and evidence filed in the proceeding.

CONSERVATION AND DEMAND MANAGEMENT COSTS

St. Thomas Energy Inc. intends to only offer the OPA – contracted province wide CDM programs. Only a minimal amount of staff time has been allocated to other CDM related activities. The management of the St. Thomas Energy Inc.'s CDM program has been outsourced to Burman Energy. The costs related to the CDM program are recovered from the Ontario Power Authority.

LOST REVENUE ADJUSTMENT MECHANISM

On March 31, 2010, the Minister of Energy and Infrastructure issued a directive (the "Directive") to the Board regarding electricity CDM targets to be met by licensed electricity distributors. The Directive required that the Board amend the licenses of distributors to add, as a condition of licence, the requirement for distributors to achieve reductions in electricity demand through the delivery of CDM programs over a four-year period beginning January 1, 2011. Section 12 of the Directive required that the Board have regard to the objective that lost revenues that result from CDM Programs should not act as a disincentive to a distributor. On April 26, 2012, the Board issued Guidelines for Electricity Distributor Conservation and Demand Management ("CDM Guidelines"). In keeping with the Directive, the Board adopted a mechanism to capture the difference between the results of actual, verified impacts of authorized CDM activities undertaken by distributors between 2011 and 2014 and the level of activities embedded into rates through the distributors load forecast in an LRAM variance account.

On April 26, 2012, the Board issued Guidelines for Electricity Distributor Conservation and Demand Management ("CDM Guidelines"). In keeping with the Directive, the Board adopted a mechanism to capture the difference between the results of actual, verified impacts of authorized CDM activities undertaken by distributors between 2011 and 2014 and the level of activities embedded into rates through the distributors load forecast in an LRAM variance account.

LRAMVA

In accordance with the Board's Guidelines for Electricity Distributor Conservation and Demand Management, EB-2012-0003, distributors must apply for disposition of the LRAMVA balance at the time of their Cost of Service rate applications. Distributors may also apply for the disposition of the balance in the LRAMVA on an annual basis, as part of the Incentive Regulation Mechanism rate applications. All requests for disposition must be made together with carrying charges, after the completion of the annual independent third party evaluation.

Elenchus performed an independent review on behalf of STEI based upon the most recent input assumptions available. Elenchus has calculated a 2011 LRAMVA of $2,295, a 2012 LRAMVA of $28,665 and carrying charges of $867. The LRAMVA amounts have been adjusted for the 2011 COS CDM load forecast. STEI did not apply for LRAMVA disposition in its 2013 or 2014 IRM applications.

STEI is not requesting disposition of the total LRAMVA balance of $31,827 at this time as the amount is not deemed to be material. STEI will continue calculating carrying charges at the Board approved rates.

Attachment 1 of 1

STEI 2011 and 2012 LRAMVA

Elenchus

St. Thomas Energy 2011 and 2012 LRAMVA

Date Prepared: September 24, 2013

Elenchus

34 King Street East

Suite 600

Toronto, ON

M5C 2X8

elenchus

Input Table One
2011 Programs in 2011
(Net kWh)

Amount	2011
RES	
2011	
Consumer Program	
Appliance Exchange	2,671
Appliance Retirement	73,726
Bi-Annual Retailer Event	86,380
Conservation Instant Coupon Booklet	56,382
HVAC Incentives	242,763
Consumer Program Total	461,922
2011 CDM Load Forecast Adjustment	
2011 CDM Load Forecast Adjustment	-419,793
2011 CDM Load Forecast Adjustment Total	-419,793
2011 Total	**42,129**
RES Total	**42,129**
GSLT50	
2011	
Business Program	
Demand Response 3*	1,421
Direct Install Lighting	161,971
Retrofit	593,844
Business Program Total	757,236
2011 CDM Load Forecast Adjustment	
2011 CDM Load Forecast Adjustment	-632,603
2011 CDM Load Forecast Adjustment Total	-632,603
2011 Total	**124,633**
GSLT50 Total	**124,633**

Input Table Two
2011 Persistence in 2012 and 2012 Programs
(Net kWh)

Amount	2012
RES	
2011	
2011 CDM Load Forecast Adjustment	
2011 CDM Load Forecast Adjustment	-419,793
2011 CDM Load Forecast Adjustment Total	-419,793
Consumer Program	
Appliance Exchange	2,671
Appliance Retirement	73,726
Bi-Annual Retailer Event	86,380
Bi-Annual Retailer Event - previous year adjustment	6,418
Conservation Instant Coupon Booklet	56,382
Conservation Instant Coupon Booklet - previous year adjustment	810
HVAC Incentives	242,763
HVAC Incentives - previous year adjustment	-24,326
Consumer Program Total	444,824
2011 Total	**25,031**
2012	
Consumer Program	
Appliance Exchange	22,042
Appliance Retirement	48,303
Bi-Annual Retailer Event	78,720
Conservation Instant Coupon Booklet	4,110
HVAC Incentives	127,224
Consumer Program Total	280,399
2012 Total	**280,399**
RES Total	**305,430**
GSLT50	
2011	
Business Program	
Direct Install Lighting	161,971
Retrofit	593,844
Retrofit - previous year adjustment	24,232
Business Program Total	780,047
2011 CDM Load Forecast Adjustment	
2011 CDM Load Forecast Adjustment	-632,603
2011 CDM Load Forecast Adjustment Total	-632,603
2011 Total	**147,444**
2012	
Business Program	
Demand Response 3*	531

Direct Install Lighting	461,385
Retrofit	1,013,698
Business Program Total	1,475,614
2012 Total	**1,475,614**
GSLT50 Total	**1,623,058**

Input Table Three
2011 Programs in 2011
(Net kW)

	2011 Report Amount	Months	Annual Amount
GSGT50			
2011			
Industrial Program			
Retrofit	4	12	48
Industrial Program Total	4		48
2011 CDM Load Forecast Adjustment			
2011 CDM Load Forecast Adjustment	-115	1	-115
2011 CDM Load Forecast Adjustment Total	-115		-115
2011 Total	**-111**		**-67**
GSGT50 Total	**-111**		**-67**

Input Table Four
2011 Persistence in 2012 and 2012 Programs
(Net kW)

	2012 Report Amount	Months	Annual Amount
GSGT50			
2011			
Industrial Program			
Retrofit	4	12	48
Industrial Program Total	4		48
2011 CDM Load Forecast Adjustment			
2011 CDM Load Forecast Adjustment	-115	1	-115
2011 CDM Load Forecast Adjustment Total	-115		-115
2011 Total	**-111**		**-67**
GSGT50 Total	**-111**		**-67**

Output Table One

2011 and 2012 LRAMVA

2011 Programs in 2011

	Net kWh	2011 Rate	Amount		RES	GSLT 50	GSGT50
RES	42,129	0.0160	$ 674		$ 674		
GSLT 50	124,633	0.0147	$ 1,832			$ 1,832	
			$ 2,506				
	Net kW	**2011 Rate**	**Amount**				
GSGT50	- 67	3.149	-$ 210.98				-$ 211
			2012 LRAMVA	**$ 2,295**	$ 674	$ 1,832	-$ 211

2011 Persistence in 2012 and 2012 Programs

	Net kWh	2012 Rate	Amount		RES	GSLT 50	GSGT50
RES	305,430	0.0159	$ 4,856		$ 4,856		
GSLT 50	1,623,058	0.0148	$ 24,021			$ 24,021	
			$ 28,878				
	Net kW	**2012 Rate**	**Amount**				
GSGT50	- 67	3.1767	-$ 212.84				-$ 213
			2012 LRAMVA	**$ 28,665**	$ 4,856	$ 24,021	-$ 213
			Total	**$ 30,960**	**$ 5,530**	**$ 25,853**	**-$ 424**

Output Table Two
Calculated Carrying Costs to April 30, 2014

				LRAM LRAMVA			Allocated Carrying Costs		
Month	OEB Prescribed Annual Rate	Days in Month	Monthly Interest Rate	Residential	GS LT 50	GS GT 50	Residential	GS LT 50	GS GT 50
Jan-2011	1.47%	31	0.12%	$ 56	$ 153	-$ 18	$ 0.07	$ 0.19	-$ 0.02
Feb-2011	1.47%	28	0.11%	$ 112	$ 305	-$ 35	$ 0.13	$ 0.34	-$ 0.04
Mar-2011	1.47%	31	0.12%	$ 169	$ 458	-$ 53	$ 0.21	$ 0.57	-$ 0.07
Apr-2011	1.47%	30	0.12%	$ 225	$ 611	-$ 70	$ 0.27	$ 0.74	-$ 0.08
May-2011	1.47%	31	0.12%	$ 281	$ 763	-$ 88	$ 0.35	$ 0.95	-$ 0.11
Jun-2011	1.47%	30	0.12%	$ 337	$ 916	-$ 105	$ 0.41	$ 1.11	-$ 0.13
Jul-2011	1.47%	31	0.12%	$ 393	$ 1,069	-$ 123	$ 0.49	$ 1.33	-$ 0.15
Aug-2011	1.47%	31	0.12%	$ 449	$ 1,221	-$ 141	$ 0.56	$ 1.52	-$ 0.18
Sep-2011	1.47%	30	0.12%	$ 506	$ 1,374	-$ 158	$ 0.61	$ 1.66	-$ 0.19
Oct-2011	1.47%	31	0.12%	$ 562	$ 1,527	-$ 176	$ 0.70	$ 1.91	-$ 0.22
Nov-2011	1.47%	30	0.12%	$ 618	$ 1,679	-$ 193	$ 0.75	$ 2.03	-$ 0.23
Dec-2011	1.47%	31	0.12%	$ 674	$ 1,832	-$ 211	$ 0.84	$ 2.29	-$ 0.26
Jan-2012	1.47%	31	0.12%	$ 1,079	$ 3,834	-$ 229	$ 1.35	$ 4.79	-$ 0.29
Feb-2012	1.47%	29	0.12%	$ 1,483	$ 5,836	-$ 246	$ 1.73	$ 6.82	-$ 0.29
Mar-2012	1.47%	31	0.12%	$ 1,888	$ 7,837	-$ 264	$ 2.36	$ 9.78	-$ 0.33
Apr-2012	1.47%	30	0.12%	$ 2,293	$ 9,839	-$ 282	$ 2.77	$ 11.89	-$ 0.34
May-2012	1.47%	31	0.12%	$ 2,698	$ 11,841	-$ 300	$ 3.37	$ 14.78	-$ 0.37
Jun-2012	1.47%	30	0.12%	$ 3,102	$ 13,843	-$ 317	$ 3.75	$ 16.73	-$ 0.38
Jul-2012	1.47%	31	0.12%	$ 3,507	$ 15,845	-$ 335	$ 4.38	$ 19.78	-$ 0.42
Aug-2012	1.47%	31	0.12%	$ 3,912	$ 17,846	-$ 353	$ 4.88	$ 22.28	-$ 0.44
Sep-2012	1.47%	30	0.12%	$ 4,316	$ 19,848	-$ 371	$ 5.22	$ 23.98	-$ 0.45
Oct-2012	1.47%	31	0.12%	$ 4,721	$ 21,850	-$ 388	$ 5.89	$ 27.28	-$ 0.48
Nov-2012	1.47%	30	0.12%	$ 5,126	$ 23,852	-$ 406	$ 6.19	$ 28.82	-$ 0.49
Dec-2012	1.47%	31	0.12%	$ 5,530	$ 25,853	-$ 424	$ 6.90	$ 32.28	-$ 0.53
Jan-2013	1.47%	31	0.12%	$ 5,530	$ 25,853	-$ 424	$ 6.89	$ 32.19	-$ 0.53
Feb-2013	1.47%	28	0.11%	$ 5,530	$ 25,853	-$ 424	$ 6.22	$ 29.07	-$ 0.48
Mar-2013	1.47%	31	0.12%	$ 5,530	$ 25,853	-$ 424	$ 6.89	$ 32.19	-$ 0.53
Apr-2013	1.47%	30	0.12%	$ 5,530	$ 25,853	-$ 424	$ 6.66	$ 31.15	-$ 0.51
May-2013	1.47%	31	0.12%	$ 5,530	$ 25,853	-$ 424	$ 6.89	$ 32.19	-$ 0.53
Jun-2013	1.47%	30	0.12%	$ 5,530	$ 25,853	-$ 424	$ 6.66	$ 31.15	-$ 0.51
Jul-2013	1.47%	31	0.12%	$ 5,530	$ 25,853	-$ 424	$ 6.89	$ 32.19	-$ 0.53
Aug-2013	1.47%	31	0.12%	$ 5,530	$ 25,853	-$ 424	$ 6.89	$ 32.19	-$ 0.53
Sep-2013	1.47%	30	0.12%	$ 5,530	$ 25,853	-$ 424	$ 6.66	$ 31.15	-$ 0.51
Oct-2013	1.47%	31	0.12%	$ 5,530	$ 25,853	-$ 424	$ 6.89	$ 32.19	-$ 0.53
Nov-2013	1.47%	30	0.12%	$ 5,530	$ 25,853	-$ 424	$ 6.66	$ 31.15	-$ 0.51
Dec-2013	1.47%	31	0.12%	$ 5,530	$ 25,853	-$ 424	$ 6.89	$ 32.19	-$ 0.53
Jan-2014	1.47%	31	0.12%	$ 5,530	$ 25,853	-$ 424	$ 6.90	$ 32.28	-$ 0.53
Feb-2014	1.47%	28	0.11%	$ 5,530	$ 25,853	-$ 424	$ 6.24	$ 29.15	-$ 0.48
Mar-2014	1.47%	31	0.12%	$ 5,530	$ 25,853	-$ 424	$ 6.90	$ 32.28	-$ 0.53
Apr-2014	1.47%	30	0.12%	$ 5,530	$ 25,853	-$ 424	$ 6.68	$ 31.24	-$ 0.51
							$ 156.59	$ 723.15	-$ 13.07

Output Table Three
2011 and 2012 LRAMVA

Customer Class	Amount	Interest *	Total
Residential	$ 5,530	$ 157	$ 5,687
General Service Less Than 50 kW	$ 25,853	$ 723	$ 26,577
General Service Greater Than 50 kW	-$ 424	-$ 13	-$ 437
Total	**$ 30,960**	**$ 867**	**$ 31,827**

* Carrying Costs to April 30, 2014

Appendix 1 of 4

Appendix 1 - OPA Final Verified 2012 Annual CDM Report

saveONenergy

Message from the Vice President:

The OPA is pleased to provide you with the enclosed Final 2012 Results Report. We have seen a 39% increase in energy savings for our new province-wide 2011-2014 suite of saveONenergy initiatives. Overall progress to targets is moving up with 29% of demand and 65% of energy savings achieved. Many LDCs, both large and small, continue to stay on track to meet or exceed their OEB targets. Conservation programs continue to be a valuable and cost effective resource for customers across the province, over the past two years the program cost to consumers remains within 3 cents per kWh.

Further to programmatic savings, capability building efforts launched in 2011 are yielding healthy enabled savings through Embedded Energy Managers and Audit initiative projects. The strong momentum continues in 2013.

We remain committed to ensuring LDCs are successful in meeting their objectives and our collective efforts to date have improved the current program suite by offering more local program opportunities, implementing a new expedited change management process, and enhancing incentives to make it easier for customers to participate in programs. We invite you to continue to provide your feedback to us and to celebrate our successes as we move forward.

The format of this report was developed in collaboration with the OPA-LDC Reporting and Evaluation Working Group and is designed to help populate LDC annual report templates that will be submitted to the OEB in late September. All results are now considered final for 2012. Any additional 2012 program activity not captured will be reported in the Final 2013 Results Report.

Please continue to monitor saveONenergy E-blasts for any further updates and should you have any other questions or comments please contact LDC.Support@powerauthority.on.ca.

We appreciate your ongoing collaboration and cooperation throughout the reporting and evaluation process. We look forward to another successful year.

Sincerely,

Andrew Pride

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OPA-Contracted Province-Wide CDM Programs FINAL 2012 Results

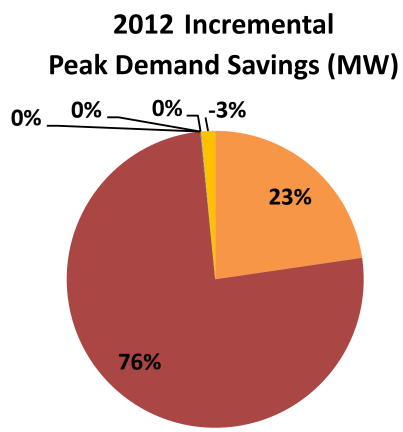
LDC: St. Thomas Energy Inc.

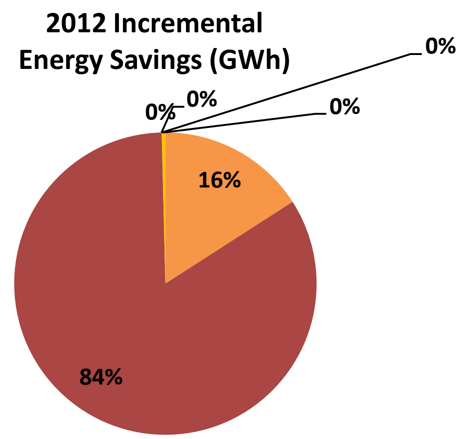
FINAL 2012 Progress to Targets	2012 Incremental	Program-to-Date Progress to Target (Scenario 1)	Scenario 1: % of Target Achieved	Scenario 2: % of Target Achieved
Net Annual Peak Demand Savings (MW)	0.4	0.7	**16.5%**	**17.4%**
Net Energy Savings (GWh)	1.8	10.2	**68.1%**	**68.1%**

Scenario 1 = Assumes that demand resource resources have a persistence of 1 year

Scenario 2 = Assumes that demand response resources remain in your territory until 2014

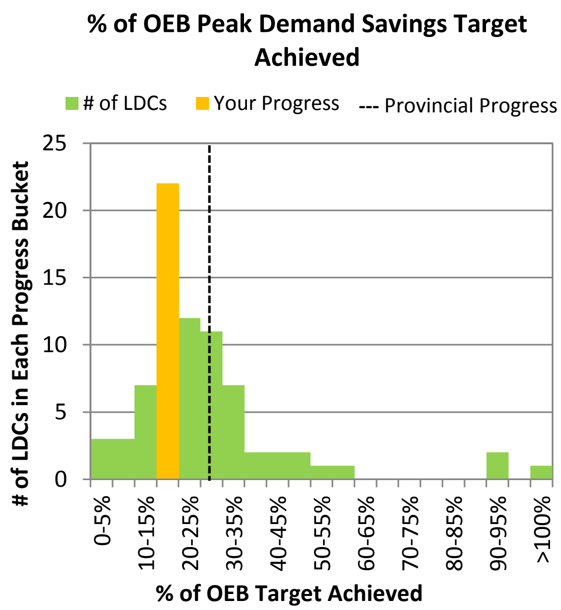
Achievement by Sector





Comparison: Your Achievement vs. LDC Community Achievement (Progress to Target)

The following graphs assume that demand response resources remain in your territory until 2014 (aligns with Scenario 2)



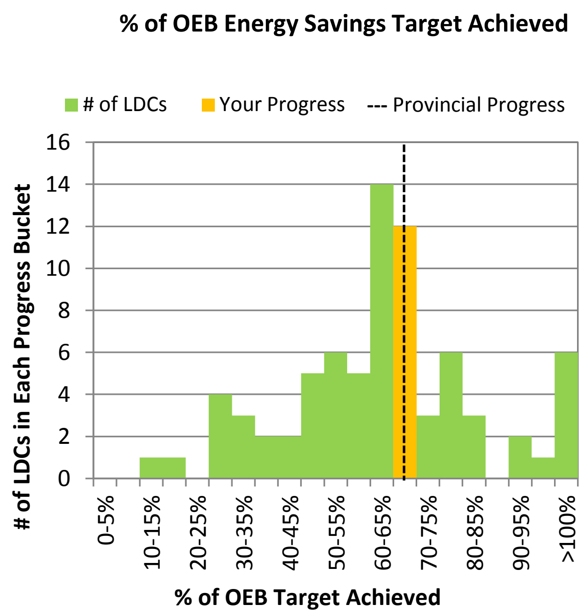


Table 1: St. Thomas Energy Inc. Initiative and Program Level Savings by Year (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR) 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR) 2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	175	119			11	7			73,726	48,303			17	439,307
Appliance Exchange	Appliances	24	86			2	13			2,671	22,042			13	75,366
HVAC Incentives	Equipment	458	345			131	75			242,763	127,224			206	1,352,724
Conservation Instant Coupon Booklet	Items	1,482	91			3	1			56,382	4,110			4	237,857
Bi-Annual Retailer Event	Items	2,558	3,118			5	4			86,380	78,720			9	581,680
Retailer Co-op	Items	0	0			0	0			0	0			0	0
Residential Demand Response (switch/pstat)	Devices	56	0			31	0			0	0			0	0
Residential Demand Response (IHD)	Devices	0	0			0				0					
Residential New Construction	Homes	0	0			0	0			0	0			0	0
Consumer Program Total						**185**	**99**			**461,921**	**280,399**			**250**	**2,686,934**
Business Program															
Retrofit	Projects	5	21			83	180			593,844	1,013,698			256	5,386,388
Direct Install Lighting	Projects	47	115			61	114			161,971	461,385			147	1,952,103
Building Commissioning	Buildings	0	0			0	0			0	0			0	0
New Construction	Buildings	0	0			0	0			0	0			0	0
Energy Audit	Audits	0	0			0	0			0	0			0	0
Small Commercial Demand Response	Devices	6	0			4	0			0	0			0	0
Small Commercial Demand Response (IHD)	Devices	0	0			0				0				0	0
Demand Response 3	Facilities	1	1			36	37			1,421	531			0	1,952
Business Program Total						**184**	**330**			**757,237**	**1,475,613**			**402**	**7,340,443**
Industrial Program															
Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
Energy Manager	Projects	0	0			0	0			0	0			0	0
Retrofit	Projects	2				4				26,362				4	105,446
Demand Response 3	Facilities	0	0			0	0			0	0			0	0
Industrial Program Total						**4**	**0**			**26,362**	**0**			**4**	**105,446**
Home Assistance Program															
Home Assistance Program	Homes	0	0			0	0			0	0			0	0
Home Assistance Program Total						**0**	**0**			**0**	**0**			**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	0	0			0	0			0	0			0	0
High Performance New Construction	Projects	0	0			0	0			841	322			0	4,328
Toronto Comprehensive	Projects	0	0			0	0			0	0			0	0
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0			0	0			0	0
LDC Custom Programs	Projects	0	0			0	0			0	0			0	0
Pre-2011 Programs completed in 2011 Total						**0**	**0**			**841**	**322**			**0**	**4,328**
Other															
Program Enabled Savings	Projects	0	0			0	0			0	0			0	0
Time-of-Use Savings	Homes														
Other Total							**0**				**0**			**0**	**0**
Adjustments to Previous Year's Verified Results							**-7**				**7,134**			**-7**	**28,535**
Energy Efficiency Total						**301**	**393**			**1,244,939**	**1,755,803**			**657**	**10,135,199**
Demand Response Total (Scenario 1)						**72**	**37**			**1,421**	**531**			**0**	**1,952**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**373**	**423**			**1,246,360**	**1,763,468**			**650**	**10,165,686**
													Full OEB Target:	**3,940**	**14,920,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**16.5%**	**68.1%**

Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item on the 2012 annual report will be left blank. Once a full year of data is available (2013 evaluation), and the savings are quantified, 2012 results will be updated to reflect the quantified savings.

Table 2: Adjustments to **St. Thomas Energy Inc.** Verified Results due to Errors or Omissions (Scenario 1)

Initiative	Unit	**Incremental Activity** (new program activity occurring within the specified reporting period)				**Net Incremental Peak Demand Savings (kW)** (new peak demand savings from activity within the specified reporting period)				**Net Incremental Energy Savings (kWh)** (new energy savings from activity within the specified reporting period)				**Program-to-Date Verified Progress to Target** (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	**2011-2014 Net Cumulative Energy Savings (kWh)**
		2011	**2012**	**2013**	**2014**	**2011**	**2012**	**2013**	**2014**	**2011**	**2012**	**2013**	**2014**	**2014**	**2014**
Consumer Program															
Appliance Retirement	Appliances	0				0				0				0	0
Appliance Exchange	Appliances	0				0				0				0	0
HVAC Incentives	Equipment	-44				-13				-24,326				-13	-97,306
Conservation Instant Coupon Booklet	Items	24				0				810				0	3,241
Bi-Annual Retailer Event	Items	240				0				6,418				0	25,671
Retailer Co-op	Items	0				0				0				0	0
Residential Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Residential Demand Response (IHD)	Devices	0				0				0				0	0
Residential New Construction	Homes	0				0				0				0	0
Consumer Program Total						**-13**				**-17,099**				**-13**	**-68,394**
Business Program															
Retrofit	Projects	2				6				24,232				6	96,929
Direct Install Lighting	Projects	0				0				0				0	0
Building Commissioning	Buildings	0				0				0				0	0
New Construction	Buildings	0				0				0				0	0
Energy Audit	Audits	0				0				0				0	0
Small Commercial Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Small Commercial Demand Response (IHD)	Devices	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Business Program Total						**6**				**24,232**				**6**	**96,929**
Industrial Program															
Process & System Upgrades	Projects	0				0				0				0	0
Monitoring & Targeting	Projects	0				0				0				0	0
Energy Manager	Projects	0				0				0				0	0
Retrofit	Projects	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Industrial Program Total						**0**				**0**				**0**	**0**
Home Assistance Program															
Home Assistance Program	Homes	0				0				0				0	0
Home Assistance Program Total						**0**				**0**				**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	0				0				0				0	0
High Performance New Construction	Projects	0				0				0				0	0
Toronto Comprehensive	Projects	0				0				0				0	0
Multifamily Energy Efficiency Rebates	Projects	0				0				0				0	0
LDC Custom Programs	Projects	0				0				0				0	0
Pre-2011 Programs completed in 2011 Total						**0**				**0**				**0**	**0**
Other															
Program Enabled Savings	Projects	0				0				0				0	0
Time-of-Use Savings	Homes														
Other Total						**0**				**0**				**0**	**0**
Adjustments to Previous Year's Verified Results						**-7**				**7,134**				**-7**	**28,535**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Table 3: St. Thomas Energy Inc. Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement		1.00				0.47				1.00				0.47		
Appliance Exchange		1.00				0.52				1.00				0.52		
HVAC Incentives		1.00				0.50				1.00				0.49		
Conservation Instant Coupon Booklet		1.00				1.00				1.00				1.05		
Bi-Annual Retailer Event		1.00				0.91				1.00				0.92		
Retailer Co-op		n/a				n/a				n/a				n/a		
Residential Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Residential Demand Response (IHD)		n/a				n/a				n/a				n/a		
Residential New Construction		n/a				n/a				n/a				n/a		
Business Program																
Retrofit		0.94				0.75				1.11				0.74		
Direct Install Lighting		0.68				0.94				0.85				0.94		
Building Commissioning		n/a				n/a				n/a				n/a		
New Construction		n/a				n/a				n/a				n/a		
Energy Audit		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (IHD)		n/a				n/a				n/a				n/a		
Demand Response 3*		n/a				n/a				n/a				n/a		
Industrial Program																
Process & System Upgrades		n/a				n/a				n/a				n/a		
Monitoring & Targeting		n/a				n/a				n/a				n/a		
Energy Manager		n/a				n/a				n/a				n/a		
Retrofit																
Demand Response 3*		n/a				n/a				n/a				n/a		
Home Assistance Program																
Home Assistance Program		n/a				n/a				n/a				n/a		
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program		n/a				n/a				n/a				n/a		
High Performance New Construction		1.00				0.50				1.00				0.50		
Toronto Comprehensive		n/a				n/a				n/a				n/a		
Multifamily Energy Efficiency Rebates		n/a				n/a				n/a				n/a		
LDC Custom Programs		n/a				n/a				n/a				n/a		
Other																
Program Enabled Savings		n/a				n/a				n/a				n/a		
Time-of-Use Savings		n/a				n/a				n/a				n/a		

Progress Towards CDM Targets

Results are attributed to target using current OPA reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year. Please see methodology tab for more detailed information.

Table 4: Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	0.4	0.3	0.3	0.3
2012 - Verified		0.4	0.4	0.4
2013				
2014				
Verified Net Annual Peak Demand Savings Persisting in 2014:				0.7
St. Thomas Energy Inc. 2014 Annual CDM Capacity Target				3.9
Verified Portion of Peak Demand Savings Target Achieved in 2014(%):				16.5%

Table 5: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	1.2	1.2	1.2	1.2	4.9
2012 - Verified		1.8	1.8	1.7	5.3
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					10.2
St. Thomas Energy Inc. 2011-2014 Annual CDM Energy Target					14.9
Verified Portion of Cumulative Energy Target Achieved (%):					68.1%

*2011 energy adjustments included in cumulative energy savings.

Table 6: Province-Wide Initiatives and Program Level Savings by Year

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR): 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR): 2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	56,110	34,146			3,299	2,011			23,005,812	13,424,518			5,171	132,176,857
Appliance Exchange	Appliances	3,688	3,836			371	556			450,187	974,621			689	4,512,525
HVAC Incentives	Equipment	111,587	85,221			32,037	19,060			59,437,670	32,841,283			51,097	336,274,530
Conservation Instant Coupon Booklet	Items	559,462	30,891			1,344	230			21,211,537	1,398,202			1,575	89,040,754
Bi-Annual Retailer Event	Items	870,332	1,060,901			1,681	1,480			29,387,468	26,781,674			3,161	197,894,897
Retailer Co-op	Items	152	0			0	0			2,652	0			0	10,607
Residential Demand Response (switch/pstat)*	Devices	19,550	98,388			10,947	49,038			24,870	359,408			0	384,279
Residential Demand Response (IHD)	Devices	0	49,689			0				0					
Residential New Construction	Homes	7	19			0	2			743	17,152			2	54,430
Consumer Program Total						**49,681**	**72,377**			**133,520,941**	**75,796,859**			**61,696**	**760,348,879**
Business Program															
Retrofit	Projects	2,516	5,605			24,467	61,147			136,002,258	314,922,468			84,018	1,480,647,459
Direct Install Lighting	Projects	20,297	18,494			23,724	15,284			61,076,701	57,345,798			31,181	391,072,869
Building Commissioning	Buildings	0	0			0	0			0	0			0	0
New Construction	Buildings	10	69			123	764			411,717	1,814,721			888	7,091,031
Energy Audit	Audits	103	280			0	1,450			0	7,049,351			1,450	21,148,054
Small Commercial Demand Response	Devices	132	294			84	187			157	1,068			0	1,224
Small Commercial Demand Response (IHD)	Devices	0	0			0				0				0	0
Demand Response 3*	Facilities	145	151			16,218	19,389			633,421	281,823			0	915,244
Business Program Total						**64,617**	**98,221**			**198,124,253**	**381,415,230**			**117,535**	**1,900,875,881**
Industrial Program															
Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
Energy Manager	Projects	0	39			0	1,086			0	7,372,108			1,086	22,116,324
Retrofit	Projects	433				4,615				28,866,840				4,613	115,462,282
Demand Response 3*	Facilities	124	185			52,484	74,056			3,080,737	1,784,712			0	4,865,449
Industrial Program Total						**57,098**	**75,141**			**31,947,577**	**9,156,820**			**5,699**	**142,444,054**
Home Assistance Program															
Home Assistance Program	Homes	46	5,033			2	566			39,283	5,442,232			569	16,483,831
Home Assistance Program Total						**2**	**566**			**39,283**	**5,442,232**			**569**	**16,483,831**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	2,016	0			21,662	0			121,138,219	0			21,662	484,552,876
High Performance New Construction	Projects	145	69			5,098	3,251			26,185,591	11,901,944			8,349	140,448,197
Toronto Comprehensive	Projects	577	0			15,805	0			86,964,886	0			15,805	347,859,545
Multifamily Energy Efficiency Rebates	Projects	110	0			1,981	0			7,595,683	0			1,981	30,382,733
LDC Custom Programs	Projects	8	0			399	0			1,367,170	0			399	5,468,679
Pre-2011 Programs completed in 2011 Total						**44,945**	**3,251**			**243,251,550**	**11,901,944**			**48,195**	**1,008,712,030**
Other															
Program Enabled Savings	Projects	0	16			0	2,304			0	1,188,362			2,304	3,565,086
Time-of-Use Savings	Homes														
Other Total							**2,304**				**1,188,362**			**2,304**	**3,565,086**
Adjustments to Previous Year's Verified Results							**1,406**				**18,689,081**			**1,156**	**73,918,598**
Energy Efficiency Total						**136,610**	**109,191**			**603,144,419**	**482,474,435**			**235,998**	**3,826,263,564**
Demand Response Total (Scenario 1)						**79,733**	**142,670**			**3,739,185**	**2,427,011**			**0**	**6,166,196**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**216,343**	**253,267**			**606,883,604**	**503,590,526**			**237,154**	**3,906,348,358**
Full OEB Target:														**1,330,000**	**6,000,000,000**
% of Full OEB Target Achieved to Date (Scenario 1):														**17.8%**	**65.1%**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item on the 2012 annual report will be left blank. Once a full year of data is available (2013 evaluation), and the savings are quantified, 2012 results will be updated to reflect the quantified savings.

Table 7: Adjustments to **Province-Wide** Verified Results due to Errors & Omissions (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	0				0				0				0	0
Appliance Exchange	Appliances	0				0				0				0	0
HVAC Incentives	Equipment	-18,866				-5,278				-9,721,817				-5,278	-38,887,267
Conservation Instant Coupon Booklet	Items	8,216				16				275,655				16	1,102,621
Bi-Annual Retailer Event	Items	81,817				108				2,183,391				108	8,733,563
Retailer Co-op	Items	0				0				0				0	0
Residential Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Residential Demand Response (IHD)	Devices	0				0				0				0	0
Residential New Construction	Homes	19				1				13,767				1	55,069
Consumer Program Total						**-5,153**				**-7,249,004**				**-5,153**	**-28,996,015**
Business Program															
Retrofit	Projects	303				3,204				16,216,165				3,083	64,398,674
Direct Install Lighting	Projects	444				501				1,250,388				372	4,624,945
Building Commissioning	Buildings	0				0				0				0	0
New Construction	Buildings	12				828				3,520,620				828	14,082,482
Energy Audit	Audits	93				481				2,341,392				481	9,365,567
Small Commercial Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Small Commercial Demand Response (IHD)	Devices	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Business Program Total						**5,014**				**23,328,565**				**4,764**	**92,471,668**
Industrial Program															
Process & System Upgrades	Projects	0				0				0				0	0
Monitoring & Targeting	Projects	0				0				0				0	0
Energy Manager	Projects	0				0				0				0	0
Retrofit	Projects	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Industrial Program Total						**0**				**0**				**0**	**0**
Home Assistance Program															
Home Assistance Program	Homes	0				0				0				0	0
Home Assistance Program Total						**0**				**0**				**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	12				138				545,536				138	2,182,145
High Performance New Construction	Projects	34				1,407				2,065,200				1,407	8,260,800
Toronto Comprehensive	Projects	0				0				0				0	0
Multifamily Energy Efficiency Rebates	Projects	0				0				0				0	0
LDC Custom Programs	Projects	0				0				0				0	0
Pre-2011 Programs completed in 2011 Total						**1,545**				**2,610,736**				**1,545**	**10,442,945**
Other															
Program Enabled Savings	Projects	0				0				0				0	0
Time-of-Use Savings	Homes														
Other Total						**0**				**0**				**0**	**0**
Adjustments to Previous Year's Verified Results						**1,406**				**18,690,297**				**1,156**	**73,918,598**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Table 8: Province-Wide Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement		1.00				0.46				1.00				0.47		
Appliance Exchange		1.00				0.52				1.00				0.52		
HVAC Incentives		1.00				0.50				1.00				0.49		
Conservation Instant Coupon Booklet		1.00				1.00				1.00				1.05		
Bi-Annual Retailer Event		1.00				0.91				1.00				0.92		
Retailer Co-op		n/a				n/a				n/a				n/a		
Residential Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Residential Demand Response (IHD)		n/a				n/a				n/a				n/a		
Residential New Construction		3.65				0.49				7.17				0.49		
Business Program																
Retrofit		0.93				0.75				1.05				0.76		
Direct Install Lighting		0.69				0.94				0.85				0.94		
Building Commissioning		n/a				n/a				n/a				n/a		
New Construction		0.98				0.49				0.99				0.49		
Energy Audit		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (IHD)		n/a				n/a				n/a				n/a		
Demand Response 3*		n/a				n/a				n/a				n/a		
Industrial Program																
Process & System Upgrades		n/a				n/a				n/a				n/a		
Monitoring & Targeting		n/a				n/a				n/a				n/a		
Energy Manager		1.16				0.90				1.16				0.90		
Retrofit																
Demand Response 3*		n/a				n/a				n/a				n/a		
Home Assistance Program																
Home Assistance Program		0.32				1.00				0.99				1.00		
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program		n/a				n/a				n/a				n/a		
High Performance New Construction		1.00				0.50				1.00				0.50		
Toronto Comprehensive		n/a				n/a				n/a				n/a		
Multifamily Energy Efficiency Rebates		n/a				n/a				n/a				n/a		
LDC Custom Programs		n/a				n/a				n/a				n/a		
Other																
Program Enabled Savings		1.06				1.00				2.26				1.00		
Time-of-Use Savings		n/a				n/a				n/a				n/a		

Summary - Provincial Progress

Table 9: Province-Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011	216.3	136.6	135.8	129.0
2012		253.3	109.8	108.2
2013				
2014				
Verified Net Annual Peak Demand Savings in 2014:				**237.2**
2014 Annual CDM Capacity Target				**1,330**
Verified Peak Demand Savings Target Achieved - 2011 (%):				**17.8%**

Table 10: Province-Wide Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011	606.9	603.0	601.0	582.3	2,393
2012		503.6	498.4	492.6	1,513
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					**3,906**
2011-2014 Cumulative CDM Energy Target:					**6,000**
Verified Portion of Energy Target Achieved - 2011 (%):					**65.1%**

*2011 energy adjustments included in cumulative energy savings.

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS	
Prescriptive Measures and Projects	**Gross Savings** = Activity * Per Unit Assumption **Net Savings** = Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
Engineered and Custom Projects	**Gross Savings** = Reported Savings * Realization Rate **Net Savings** = Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
Demand Response	**Peak Demand: Gross Savings = Net Savings =** contracted MW at contributor level * Provincial contracted to ex ante ratio **Energy: Gross Savings = Net Savings =** provincial ex post energy savings * LDC proportion of total provincial contracted MW All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)
Adjustments to Previous Year's Verified Results	All errors and omissions from the prior years Final Annual Results report will be adjusted within this report. Any errors and ommissions with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the cumulative effect of energy savings.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program			
Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection	Savings are considered to begin in the year the appliance is picked up.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year that the exchange event occurred	
HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year that the installation occurred	

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the coupon was redeemed.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the event occurs.	
Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any “snapback” in energy consumption experienced after the event. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program			
Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
	Additional Note: project counts were derived by filtering out "Application Status" = "Post-Project Submission - Payment denied by LDC" and only including projects with an "Actual Project Completion Date" in 2012 and pulling both the "Application Name" field followed by the "Building Address 1" field from the Post Stage Retrofit Report and finally performing a count of the Building Addresses.		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the actual project completion date.	
Energy Audit	Projects are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year of the audit date.	**Peak demand and energy savings** are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program			
Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
Energy Manager	Results are directly attributed to LDC based on LDC identified in the application; No completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Home Assistance Program			

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	**Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Pre-2011 Programs completed in 2011			
Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	
Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation		
EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation		

ERII Sector (C&I vs. Industrial Mapping)

Building Type	Sector
Agribusiness - Cattle Farm	C&I
Agribusiness - Dairy Farm	C&I
Agribusiness - Greenhouse	C&I
Agribusiness - Other	C&I
Agribusiness - Other,Mixed-Use - Office/Retail	C&I
Agribusiness - Other,Office,Retail,Warehouse	C&I
Agribusiness - Other,Office,Warehouse	C&I
Agribusiness - Poultry	C&I
Agribusiness - Poultry,Hospitality - Motel	C&I
Agribusiness - Swine	C&I
Convenience Store	C&I
Education - College / Trade School	C&I
Education - College / Trade School,Multi-Residential - Condominium	C&I
Education - College / Trade School,Multi-Residential - Rental Apartment	C&I
Education - College / Trade School,Retail	C&I
Education - Primary School	C&I
Education - Primary School,Education - Secondary School	C&I
Education - Primary School,Multi-Residential - Rental Apartment	C&I
Education - Primary School,Not-for-Profit	C&I
Education - Secondary School	C&I
Education - University	C&I
Education - University,Office	C&I
Hospital/Healthcare - Clinic	C&I
Hospital/Healthcare - Clinic,Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Clinic,Industrial	C&I
Hospital/Healthcare - Clinic,Retail	C&I
Hospital/Healthcare - Long-term Care	C&I
Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail,Office	C&I
Hospitality - Hotel	C&I
Hospitality - Hotel,Restaurant - Dining	C&I
Hospitality - Motel	C&I
Industrial	Industrial
Mixed-Use - Office/Retail	C&I
Mixed-Use - Office/Retail,Industrial	Industrial
Mixed-Use - Office/Retail,Mixed-Use - Other	C&I
Mixed-Use - Office/Retail,Mixed-Use - Other,Not-for-Profit,Warehouse	C&I
Mixed-Use - Office/Retail,Mixed-Use - Residential/Retail	C&I
Mixed-Use - Office/Retail,Office,Restaurant - Dining,Restaurant - Quick Serve,Retail,Warehouse	C&I

Mixed-Use - Office/Retail,Office,Warehouse	C&I
Mixed-Use - Office/Retail,Retail	C&I
Mixed-Use - Office/Retail,Warehouse	C&I
Mixed-Use - Office/Retail,Warehouse,Industrial	Industrial
Mixed-Use - Other	C&I
Mixed-Use - Other,Industrial	Industrial
Mixed-Use - Other,Not-for-Profit,Office	C&I
Mixed-Use - Other,Office	C&I
Mixed-Use - Other,Other: Please specify	C&I
Mixed-Use - Other,Retail,Warehouse	C&I
Mixed-Use - Other,Warehouse	C&I
Mixed-Use - Residential/Retail	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Condominium	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Rental Apartment	C&I
Mixed-Use - Residential/Retail,Retail	C&I
Multi-Residential - Condominium	C&I
Multi-Residential - Condominium,Multi-Residential - Rental Apartment	C&I
Multi-Residential - Condominium,Other: Please specify	C&I
Multi-Residential - Rental Apartment	C&I
Multi-Residential - Rental Apartment,Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Warehouse	C&I
Multi-Residential - Social Housing Provider	C&I
Multi-Residential - Social Housing Provider,Industrial	C&I
Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Not-for-Profit	C&I
Not-for-Profit,Office	C&I
Not-for-Profit,Other: Please specify	C&I
Not-for-Profit,Warehouse	C&I
Office	C&I
Office,Industrial	Industrial
Office,Other: Please specify	C&I
Office,Other: Please specify,Warehouse	C&I
Office,Restaurant - Dining	C&I
Office,Restaurant - Dining,Industrial	Industrial
Office,Retail	C&I
Office,Retail,Industrial	C&I
Office,Retail,Warehouse	C&I
Office,Warehouse	C&I
Office,Warehouse,Industrial	Industrial
Other: Please specify	C&I
Other: Please specify,Industrial	Industrial
Other: Please specify,Retail	C&I
Other: Please specify,Warehouse	C&I
Restaurant - Dining	C&I
Restaurant - Dining,Retail	C&I

Restaurant - Quick Serve	C&I
Restaurant - Quick Serve,Retail	C&I
Retail	C&I
Retail,Industrial	Industrial
Retail,Warehouse	C&I
Warehouse	C&I
Warehouse,Industrial	Industrial

Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Local Distribution Company	Allocation
Algoma Power Inc.	0.2%
Atikokan Hydro Inc.	0.0%
Attawapiskat Power Corporation	0.0%
Bluewater Power Distribution Corporation	0.6%
Brant County Power Inc.	0.2%
Brantford Power Inc.	0.7%
Burlington Hydro Inc.	1.4%
Cambridge and North Dumfries Hydro Inc.	1.0%
Canadian Niagara Power Inc.	0.5%
Centre Wellington Hydro Ltd.	0.1%
Chapleau Public Utilities Corporation	0.0%
COLLUS Power Corporation	0.3%
Cooperative Hydro Embrun Inc.	0.0%
E.L.K. Energy Inc.	0.2%
Enersource Hydro Mississauga Inc.	3.9%
ENTEGRUS	0.6%
ENWIN Utilities Ltd.	1.6%
Erie Thames Powerlines Corporation	0.4%
Espanola Regional Hydro Distribution Corporation	0.1%
Essex Powerlines Corporation	0.7%
Festival Hydro Inc.	0.3%
Fort Albany Power Corporation	0.0%
Fort Frances Power Corporation	0.1%
Greater Sudbury Hydro Inc.	1.0%
Grimsby Power Inc.	0.2%
Guelph Hydro Electric Systems Inc.	0.9%
Haldimand County Hydro Inc.	0.4%
Halton Hills Hydro Inc.	0.5%
Hearst Power Distribution Company Limited	0.1%
Horizon Utilities Corporation	4.0%
Hydro 2000 Inc.	0.0%
Hydro Hawkesbury Inc.	0.1%
Hydro One Brampton Networks Inc.	2.8%
Hydro One Networks Inc.	30.0%

Hydro Ottawa Limited	5.6%
Innisfil Hydro Distribution Systems Limited	0.4%
Kashechewan Power Corporation	0.0%
Kenora Hydro Electric Corporation Ltd.	0.1%
Kingston Hydro Corporation	0.5%
Kitchener-Wilmot Hydro Inc.	1.6%
Lakefront Utilities Inc.	0.2%
Lakeland Power Distribution Ltd.	0.2%
London Hydro Inc.	2.7%
Middlesex Power Distribution Corporation	0.1%
Midland Power Utility Corporation	0.1%
Milton Hydro Distribution Inc.	0.6%
Newmarket - Tay Power Distribution Ltd.	0.7%
Niagara Peninsula Energy Inc.	1.0%
Niagara-on-the-Lake Hydro Inc.	0.2%
Norfolk Power Distribution Inc.	0.3%
North Bay Hydro Distribution Limited	0.5%
Northern Ontario Wires Inc.	0.1%
Oakville Hydro Electricity Distribution Inc.	1.5%
Orangeville Hydro Limited	0.2%
Orillia Power Distribution Corporation	0.3%
Oshawa PUC Networks Inc.	1.2%
Ottawa River Power Corporation	0.2%
Parry Sound Power Corporation	0.1%
Peterborough Distribution Incorporated	0.7%
PowerStream Inc.	6.6%
PUC Distribution Inc.	0.9%
Renfrew Hydro Inc.	0.1%
Rideau St. Lawrence Distribution Inc.	0.1%
Sioux Lookout Hydro Inc.	0.1%
St. Thomas Energy Inc.	0.3%
Thunder Bay Hydro Electricity Distribution Inc.	0.9%
Tillsonburg Hydro Inc.	0.1%
Toronto Hydro-Electric System Limited	12.8%
Veridian Connections Inc.	2.4%
Wasaga Distribution Inc.	0.2%
Waterloo North Hydro Inc.	1.0%
Welland Hydro-Electric System Corp.	0.4%
Wellington North Power Inc.	0.1%
West Coast Huron Energy Inc.	0.1%
Westario Power Inc.	0.5%
Whitby Hydro Electric Corporation	0.9%
Woodstock Hydro Services Inc.	0.3%

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years).

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

Free-ridership: the percentage of participants who would have implemented the program measure or practice in the absence of the program.

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start' (please see table 5).

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net-to-Gross Ratio: The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

Program: a group of initiatives that target a particular market sector (i.e. Consumer, Industrial).

Realization Rate: A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.

Settlement Account: the grouping of demand response facilities (contributors) into one contractual agreement

Spillover: Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

Appendix 2 of 4

Appendix 2 - 2011 Schedule of Rates and Charges

St. Thomas Energy Inc.
TARIFF OF RATES AND CHARGES
Effective Date July 1, 2011
Implementation Date August 1, 2011

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

EB-2010-0141

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	11.50
Smart Meter Funding Adder - effective until April 30, 2012	$	2.50
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.28
Rate Rider for Foregone Revenue Recovery – effective until April 30, 2012	$	0.10
Distribution Volumetric Rate	$/kWh	0.0160
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	0.0003
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	(0.0008)
Rate Rider for Global Adjustment Sub-Account Disposition (2011) – effective until April 30, 2012		
Applicable only for Non-RPP Customers	$/kWh	0.0033
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kWh	0.0001
Rate Rider for Lost Revenue Adjustment Mechanism/Shared Savings Mechanism Recovery		
– 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

MONTHLY RATES AND CHARGES – Regulatory Component

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

St. Thomas Energy Inc.
TARIFF OF RATES AND CHARGES
Effective Date July 1, 2011
Implementation Date August 1, 2011

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EB-2010-0141

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	17.00
Smart Meter Funding Adder – effective until April 30, 2012	$	2.50
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.45
Rate Rider for Foregone Revenue Recovery – effective until April 30, 2012	$	0.29
Distribution Volumetric Rate	$/kWh	0.0147
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0003
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	(0.0008)
Rate Rider for Global Adjustment Sub-Account Disposition (2011) – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kWh	0.0033
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kWh	(0.0000)
Rate Rider for Lost Revenue Adjustment Mechanism/Shared Savings Mechanism Recovery – 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

MONTHLY RATES AND CHARGES – Regulatory Component

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

St. Thomas Energy Inc.
TARIFF OF RATES AND CHARGES
Effective Date July 1, 2011
Implementation Date August 1, 2011

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EB-2010-0141

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	70.35
Smart Meter Funding Adder – effective until April 30, 2012	$	2.50
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	5.79
Rate Rider for Foregone Revenue Recovery – effective until April 30, 2012	$	3.22
Distribution Volumetric Rate	$/kW	3.1490
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	0.1102
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.3156)
Rate Rider for Global Adjustment Sub-Account Disposition (2011) – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kW	1.2689
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kW	(0.0421)
Rate Rider for Lost Revenue Adjustment Mechanism/Shared Savings Mechanism Recovery – effective until April 30, 2014	$/kW	0.1925
Retail Transmission Rate – Network Service Rate	$/kW	2.3569
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9727

MONTHLY RATES AND CHARGES – Regulatory Component

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

St. Thomas Energy Inc.
TARIFF OF RATES AND CHARGES
Effective Date July 1, 2011
Implementation Date August 1, 2011

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EB-2010-0141

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for individual lighting on private property controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	3.75
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.03
Rate Rider for Foregone Revenue Recovery – effective until April 30, 2012	$	0.25
Distribution Volumetric Rate	$/kW	4.5344
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	0.1176
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.2510)
Rate Rider for Global Adjustment Sub-Account Disposition (2011) – effective until April 30, 2012		
Applicable only for Non-RPP Customers	$/kW	1.2024
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kW	0.0181
Retail Transmission Rate – Network Service Rate	$/kW	1.4816
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2392

MONTHLY RATES AND CHARGES – Regulatory Component

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

St. Thomas Energy Inc.
TARIFF OF RATES AND CHARGES
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EB-2010-0141

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	1.67
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.00
Rate Rider for Foregone Revenue Recovery – effective until April 30, 2012	$	0.18
Distribution Volumetric Rate	$/kW	0.0163
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	0.0988
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.2823)
Rate Rider for Global Adjustment Sub-Account Disposition (2011) – effective until April 30, 2012		
Applicable only for Non-RPP Customers	$/kW	1.2040
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kW	(0.0601)
Retail Transmission Rate – Network Service Rate	$/kW	1.8175
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5210

MONTHLY RATES AND CHARGES – Regulatory Component

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

St. Thomas Energy Inc.
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EB-2010-0141

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

St. Thomas Energy Inc.
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EB-2010-0141

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)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

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
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
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 – per pole/year	$	22.35
Disconnect/Reconnect Charge at customer's request – at meter during regular hours	$	65.00

St. Thomas Energy Inc.
TARIFF OF RATES AND CHARGES
Effective Date July 1, 2011
Implementation Date August 1, 2011

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EB-2010-0141

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

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

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

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0350
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0247
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Appendix 3 of 4

Appendix 2 - 2012 Schedule of Rates and Charges

St. Thomas Energy Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0196

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	11.46
Distribution Volumetric Rate	$/kWh	0.0159
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0003
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0051
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	(0.0008)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0069)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism Recovery (2011) – effective until April 30, 2014	$/kWh	0.0004
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – effective until April 30, 2013	$/kWh	0.0003
Rate Rider for Tax Change - effective until April 30, 2013	$/kWh	(0.0001)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0070
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0055

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

St. Thomas Energy Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0196

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	17.15
Distribution Volumetric Rate	$/kWh	0.0148
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0003
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0051
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	(0.0008)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0065)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism Recovery (2011) – effective until April 30, 2014	$/kWh	0.0003
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – effective until April 30, 2013	$/kWh	0.0004
Rate Rider for Tax Change - effective until April 30, 2013	$/kWh	(0.0001)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0069
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0051

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

St. Thomas Energy Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0196

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	70.97
Distribution Volumetric Rate	$/kW	3.1767
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	0.1102
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kW	1.9365
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.3156)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(2.2190)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism Recovery (2011) – effective until April 30, 2014	$/kW	0.1925
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – effective until April 30, 2013	$/kW	0.0270
Rate Rider for Tax Change - effective until April 30, 2013	$/kW	(0.0101)
Retail Transmission Rate – Network Service Rate	$/kW	2.7425
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0684

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

St. Thomas Energy Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0196

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for individual lighting on private property controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	4.72
Distribution Volumetric Rate	$/kW	5.7103
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	0.1176
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kW	1.8351
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.2510)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(2.8121)
Rate Rider for Tax Change - effective until April 30, 2013	$/kW	(0.0526)
Retail Transmission Rate – Network Service Rate	$/kW	1.7240
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2993

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

St. Thomas Energy Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0196

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.51
Distribution Volumetric Rate	$/kW	0.0245
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	0.0988
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kW	1.8376
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.2823)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(2.4720)
Rate Rider for Tax Change - effective until April 30, 2013	$/kW	(0.0314)
Retail Transmission Rate – Network Service Rate	$/kW	2.1149
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5948

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

St. Thomas Energy Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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EB-2011-0196

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

St. Thomas Energy Inc.
TARIFF OF RATES AND CHARGES
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EB-2011-0196

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)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

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
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
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 – per pole/year	$	22.35
Disconnect/Reconnect Charge at customer's request - at meter during regular hours	$	65.00

St. Thomas Energy Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0196

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

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

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0350
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0247
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Appendix 4 of 4

Appendix 3 - 2011 COS Load Forecast per Settlement

Supplemental Information Regarding Settlement Agreement Section 3 (a) Operating Revenue (Is the Customer and Load Forecast appropriate?)

	Residential kWh	GS <50 kWh	GS >50 kWh	Street Light kWh	Sentinel Light kWh	Total kWh	GS >50 kW	Street Light kW	Sentinel Light kW	Total kW
Original Application Submission										
2011 Normalized Load Forecast	123,211,245	40,961,251	129,249,343	3,109,206	56,665	296,587,710	348,643	8,603	157	357,403
OEB/OPA Direct CDM Target 25 %	-1,049,902	-1,581,380	-1,098,718	0	0	-3,730,000	-286	0	0	-286
2011 Net Normalized Load Forecast	**122,161,343**	**39,379,871**	**128,150,625**	**3,109,206**	**56,665**	**292,857,710**	**348,357**	**8,603**	**157**	**357,117**
Settlement Agreement										
2011 Normalized Load Forecast	123,211,245	40,961,251	133,183,012	3,109,206	56,665	300,521,379	348,643	8,603	157	357,403
OEB/OPA Direct CDM Target 10%	-419,793	-632,603	-439,604	0	0	-1,492,000	-115	0	0	-115
2011 Net Normalized Load Forecast	**122,791,452**	**40,328,648**	**132,743,408**	**3,109,206**	**56,665**	**299,029,379**	**348,528**	**8,603**	**157**	**357,288**
Customer Count	**14,562**	**1,676**	**192**	**4,834**	**50**	**21,314**				

Revision of GS > 50 kW Class Load

Customer Class	**GS > 50 kWh A**	**GS > 50 Customer Count B**	**GS > 50 kWh per Customer A / B**
2009 Load Forecast Actual	127,173,724	189	672,877
2010 Load Forecast Estimated	136,459,223	191	714,446
Average of 2009 & 2010			693,662
2011 Load Forecast	**133,183,012**	**192**	**693,662**

LRAM FOR PRE-2011 CDM ACTIVITIES

STEI confirms that no LRAM claims have been included in the 2015TY Cost of Service rate application relating to LRAM claims prior to 2010.