1.0 ABBREVIATIONS

Accounting Procedures Handbook (“APH”)

Advanced Metering Communications Device (“AMCD”)

Advanced Metering Infrastructure (“AMI”)

Affiliate Relationships Code for Electricity Transmitters and Distributors (“ARC”)

Arrears Management Plan (“AMP”)

Canadian Generally Accepted Accounting Principles (“CGAPP”)

Canadian Institute of Chartered Accountants (“CICA”)

Capital Cost Allowance (“CCA”)

Conservation and Demand Management (“CDM”)]

Construction-Work-in-Progress (“CIP”)

Consumer Price Index (“CPI”)

Cooling Degree Days (“CDD”)

Cost Allocation for Electricity Distributors: Application dated November 28, 2007 – Report of the Board (the “Cost Allocation Report”)

Cumulative Eligible Capital (“CEC”)

Customer Care & Billing (“CC&B”)

Customer Information System (“CIS”)

Debt Retirement Charge (“DRC”)

Electricity Distribution Rate (“EDR”)

Electricity Distributor’s Deferral and Variance Account Review Initiative – Report of the Board (“EDDVAR Report”)

Electronic Business Transactions (“EBT”)

Eligible Capital Expenditure (“ECE”)

Fair Market Value (“FMV”)

Fault Circuit Indicator (“FCI”)

Full time equivalent (“FTE”)

Geographic Information System (“GIS”)

Global Adjustment (“GA”)

Goods and Service Tax (“GST”)

Green Energy and Green Economy Act (“GEA”)

Greenhouse Gas (“GHG”)

Gross Domestic Product (“GDP”)

Harmonized Sales Tax (“HST”)
Health and Safety (“H&S”)
Heating Degree Days (“HDD”)
Human Resources (“HR”)
Hydro One Networks Inc. (“Hydro One”)
Incentive Regulation Mechanism (“IRM”)
Independent Electricity System Operator (the “IESO”)
Information Management and Information Technology (“IM/IT”)
Information Technology (“IT”)
Input Tax Credit (“ITC”)
International Financial Reporting Standards (“IFRS”)
Kilowatt (“kW”)
Kilowatt hours (“kWhs”)
Large Corporation Tax (“LCT”)
Local Distribution Company (“LDC”)
Long Canada Bond Forecast (“LCBF”)
Long Term Load Transfer (“LTLT”)
Lost Revenue Adjustment Mechanism (“LRAM”)
Low Voltage (“LV”)
Meter Data Management/Repository (“MDM/R”)
Modified International Financial Reporting Standards (“MIFRS”)
Monthly Service Charge (“MSC”)
Municipal Electric Association Reciprocal Insurance Exchange (“MEARIE”)
Net Book Value (“NBV”)
Net Present Value (“NPV”)
Non Regulated Price Plan (“non RPP”)
Ontario Power Authority (“OPA”)
Ontario Price Credit (“OPC”)
Operations and Maintenance (“O&M”)
Operations, Maintenance and Administration (“OM&A”)
Outage Management System (“OMS”)
Paid-up Capital (“PUC”)
Payments in Lieu of Taxes (“PILs”)

Personal Computer (“PC”)
Polychlorinated Biphenyls (“PCBs”)
Power line Maintainer (“PLM”)
Property, plant and equipment (“PP&E”)
Public Service Works on Highways Act (“PSWHA”)
Regulated Price Plan (“RPP”)
Retail Cost Variance Account (“RCVA”)
Retail Settlement Variance Account (“RSVA”)
Return on Equity (“ROE”)
Service transaction requests (“STRs”)
Shard Savings Mechanism (“SSM”)
Smart Meters (“SM”)
Smart Meter Initiative (“SMI”)
Special Purpose Charge (“SPC”)
Supervisory Control and Data Acquisition (“SCADA”)
Systems of Accounts (“SOA”)
Time of Use (“TOU”)
Transformer Ownership Credit (“TOC”)
Undepreciated Capital Cost (“UCC”)
Uniform System of Accounts (“USofA”)
Unmetered Scattered Load (“USL”)
Update to Chapter 2 of the Filing Requirements for Transmission and Distribution Application, June 26, 2011 (“Board Filing Requirements”)
Working Capital Allowance (“WCA”)
Work-order Supply Chain Process (“WSCP”)

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ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Erie Thames Powerlines Corporation an Interim Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity commencing May 1, 2012.

AND IN THE MATTER OF an Application by Erie Thames Powerlines Corporation an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity effective as at May 1, 2012 and to be implemented September 1, 2012.

APPLICATION

(1) The Applicant is Erie Thames Powerlines Corporation ("**Erie Thames**"). Erie Thames is an Ontario corporation with its office in the Town of Ingersoll, Ontario. It carries on the business of distributing electricity pursuant to a license, License Number ED-2002-0516 issued by the Ontario Energy Board ("**OEB**").

(2) Erie Thames distributes electricity within the town/villages of Belmont, Port Stanley, Aylmer, Ingersoll, Beachville, Norwich, Otterville, Burgessville, Embro, Thamesford, Clinton, Mitchell and Dublin and the Townships of South-West Oxford and East Zorra-Tavistock. The various towns, villages and municipalities are separated by Hydro One service territory. The service territory spans a distance of approximately 130km from north to south. Maps of the licensed service territory may be found at Exhibit 1, Tab 1, Schedule 11.

(3) This is the first cost of service rate application for Erie Thames since the amalgamation with Clinton Power Corporation ("**CPC**") and West Perth Power Inc. ("**WPPI**") and includes plans for harmonization of rates. Note, the recovery of certain LRAM/SSM and Deferral/Variance accounts will be differentiated between customers based upon the historic service provider. In addition, Erie

Thames proposes to change the thresholds for certain General Service customers. Erie Thames retained an independent consultant to perform a cost allocation study to support the rate harmonization and rate classification.

(4) Erie Thames hereby applies to the OEB pursuant to section 78 of the *Ontario Energy Board Act, 1998* for approval of its proposed distribution rates and other charges, effective May 1, 2012 from a service revenue requirement of $10,107,049. This service revenue requirement is based on CGAAP.

(5) As Erie Thames is late in filing this Application, it would request the OEB issue an interim order that would continue the existing rates and charges until a final decision and order is rendered in this proceeding.

(6) At this point in time, Erie Thames has a revenue deficiency of $609,251 and therefore, it would request that any under-collection resulting from the interim rates be retained by the ratepayers.

(7) Except where specifically identified in the Application, Erie Thames followed Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 22nd, 2011 (the "**Filing Requirements**") in order to prepare this Application.

(8) Excluding variance accounts related to Smart Meters, Erie Thames has accumulated balances in its Board-approved deferral and variance accounts since such accounts were approved by the OEB. Erie Thames proposes to clear the balances accumulated in all of these accounts to December 31, 2010.

(9) Erie Thames has installed Smart Meters to replace existing meters and it retains in rate base the cost of the meters that have been replaced.

(10) Erie Thames pays low voltage ("**LV**") charges to Hydro One Networks Inc. ("**Hydro One**") for its use of shared distribution stations, shared distribution lines, and specific distribution lines. Records of these charges, net of its own charges to customers for low voltage services, in Account 1550 – LV Variance

Account. As per Board direction, LV charges and revenues are recorded in Accounts 4750 and 4075 respectively, and are therefore not part of distribution costs and revenue. In 2008, the Board approved separate LV charges for Erie Thames. Erie Thames is now seeking approval to increase these charges to reflect the LV charges from Hydro One in 2012.

(11) In accordance with the Board's Retail Settlement Code, Erie Thames has calculated a revised Total Loss Factor to apply to end-use metered kilowatt-hour loads for the purposes of determining charges for the electricity commodity, retail transmission rates, LV rates and wholesale market charges (including rural or remote electricity rate protection and special purpose charges). Erie Thames is seeking approval for new Total Loss Factors based on a five year average of losses from 2007 to 2011 to be applied across the entire geographic service territory.

(12) This Application is supported by the written evidence that is filed with the Application (as enumerated in Exhibit of the evidence). Erie Thames may amend or supplement this written evidence prior to or during the course of the Board's hearing of the Application.

(13) The names of Erie Thames' authorized representative and its counsel, with their contact information, are set out in the evidence that is filed with the Application (at Exhibit1, Tab 1, Schedule 5). Erie Thames requests that all documents issued or filed in connection with this proceeding are served on its authorized representative and its counsel.

(14) As part of this Application, the Schedule of Rates and Charges proposed in this Application is identified in Exhibit 8; Tab 1; Schedule 5.

(15) Erie Thames submits the proposed distribution rates contained in this Application are just and reasonable on the following grounds:

(a) the proposed rates for the distribution of electricity have been prepared in accordance with the Filing Requirements;

(b) the proposed adjusted rates are necessary to meet Return on Equity set by the OEB and PILs requirements;
(c) are necessary to ensure the safe, reliable and efficient distribution of electricity;
(d) there are no impacts to any of the customer classes or consumption level subgroups that are so significant as to warrant the deferral of any adjustments being requested by Erie Thames; and
(e) other grounds as may be set out in the material accompanying this Application Summary.

(16) Erie Thames applies for an Order or Orders:

(a) Approving, on an interim basis, commencing May 1, 2012 continuing the existing rates now in effect until the Board issues a final decision and order in the proceeding establishing new rates;
(b) Approving final new rates and charges until April 30, 2013.
(c) Deferring the amortization of the cost of meters included in rate base that have been replaced with Smart Meters until the next IRM filing;
(d) approving clearance of the balances recorded in certain deferral and variance accounts by means of rate riders;
(e) approval of LRAM/SSM recovery over a 2 year period commencing the implementation date of the final rates set herein;
(f) approving the separate charges for Low Voltage Services effective the implementation date;
(g) approving new Total Loss Factors;
(h) approving Erie Thames' Green Energy Act Basic Plan filed with the Board pursuant to the deemed licence condition provided for in paragraph 2 of section 70(2.1) of the OEB Act;
(i) such further or other final or interim Orders as may be necessary or appropriate to give effect to this Application.

(17) The address for service of Erie Thames is:

Erie Thames Powerlines Corporation
143 Bell Street
Ingersoll ON N5C 2N9

DATED at Ingersoll, Ontario, this 13th, day of April, 2012.

ERIE THAMES POWERLINES CORPORATION

____
Chris White, President

<u>Electricity Distribution License</u>

Attachment A is Erie Thames' Electricity Distribution Licence ED-2002-0516 issued on December 18, 2003 and last amended November 15, 2011 (valid until December 17, 2023).

Erie Thames has three exemptions provided in Schedule 3 of its distribution license and does not have any special conditions or restrictions in its licence.

Electricity Distribution Licence

ED-2002-0516

Erie Thames Powerlines Corporation

Valid Until

December 17, 2023

Original signed by

Theodore Antonopoulos
Manager, Electricity Rates
Ontario Energy Board

Date of Issuance: December 18, 2003
Date of Last Amendment: November 15, 2011

Ontario Energy Board	Commission de l'énergie de l'Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
27th Floor	27e étage
Toronto, ON M4P 1E4	Toronto ON M4P 1E4

LIST OF AMENDMENTS

Board File No.	Date of Amendment
EB-2002-0462	July 9, 2004
EB-2005-0304	September 9, 2005
EB-2007-0659	September 5, 2007
EB-2007-0774	November 29, 2007
EB-2009-0375	January 8, 2009
EB-2010-0215	November 12, 2010
EB-2010-0338	January 31, 2011
EB-2011-0010	March 17, 2011
EB-2011-0122	June 14, 2011
EB-2010-0386	June 30, 2011
EB-2011-0085	November 15, 2011

Erie Thames Powerlines Corporation
Electricity Distribution Licence ED-2002-0516

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1 Definitions

In this Licence:

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

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

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

"Conservation and Demand Management" and "CDM" means distribution activities and programs to reduce electricity consumption and peak provincial electricity demand;

"Conservation and Demand Management Code for Electricity Distributors" means the code approved by the Board which, among other things, establishes the rules and obligations surrounding Board approved programs to help distributors meet their CDM Targets;

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

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

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

"Licensee" means Erie Thames Powerlines Corporation

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

"Net Annual Peak Demand Energy Savings Target" means the reduction in a distributor's peak electricity demand persisting at the end of the four-year period (i.e. December 31, 2014) that coincides with the provincial peak electricity demand that is associated with the implementation of CDM Programs;

"Net Cumulative Energy Savings Target" means the total amount of reduction in electricity consumption associated with the implementation of CDM Programs between 2011-2014;

"OPA" means the Ontario Power Authority;

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

"Provincial Brand" means any mark or logo that the Province has used or is using, created or to be created by or on behalf of the Province, and which will be identified to the Board by the Ministry as a provincial mark or logo for its conservation programs;

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

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

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

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

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

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

2 Interpretation

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

3 Authorization

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

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

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

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

4 Obligation to Comply with Legislation, Regulations and Market Rules

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

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

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

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

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

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

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

6 Obligation to Provide Non-discriminatory Access

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

7 Obligation to Connect

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

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

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

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

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

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

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

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

8 Obligation to Sell Electricity

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

9 Obligation to Maintain System Integrity

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

10 Market Power Mitigation Rebates

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

11 Distribution Rates

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

12 Separation of Business Activities

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

13 Expansion of Distribution System

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

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

14 Provision of Information to the Board

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

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

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

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

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

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

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

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

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

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

15 Restrictions on Provision of Information

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

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

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

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

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

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

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

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

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

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

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

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

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

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

17 Term of Licence

17.1 This Licence shall take effect on December 18, 2003 and expire on December 17, 2023. The term of this Licence may be extended by the Board.

18 Fees and Assessments

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

19 Communication

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

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

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

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

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

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

20 Copies of the Licence

20.1 The Licensee shall:

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

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

21 Conservation and Demand Management

21.1 The Licensee shall achieve reductions in electricity consumption and reductions in peak provincial electricity demand through the delivery of CDM programs. The Licensee shall meet its 2014 Net Annual Peak Demand Savings Target of 5.220 MW, and its 2011-2014 Net Cumulative Energy Savings Target of 22.970 GWh (collectively the "CDM Targets"), over a four-year period beginning January 1, 2011.

21.2 The Licensee shall meet its CDM Targets through:

a) the delivery of Board approved CDM Programs delivered in the Licensee's service area ("Board-Approved CDM Programs");

b) the delivery of CDM Programs that are made available by the OPA to distributors in the Licensee's service area under contract with the OPA ("OPA-Contracted Province-Wide CDM Programs"); or

c) a combination of a) and b).

21.3 The Licensee shall make its best efforts to deliver a mix of CDM Programs to all consumer types in the Licensee's service area.

21.4 The Licensee shall comply with the rules mandated by the Board's Conservation and Demand Management Code for Electricity Distributors.

21.5 The Licensee shall utilize the common Provincial brand, once available, with all Board-Approved CDM Programs, OPA-Contracted Province-Wide Programs, and in conjunction with or co-branded with the Licensee's own brand or marks.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

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

1. The former Villages of Belmont and Port Stanley as of December 31, 1997, now in the Municipality of Central Elgin

2. The Town of Aylmer as of January 1, 1998, also outlined on a map filed on August 6, 2003 as part of the application.

3. The Town of Ingersoll as of December 31, 2000.

4. The former Village of Beachville as of December 31, 1974, now in the Township of South-West Oxford.

5. The former Town of Tavistock as of December 31, 1974, now in the Township of East Zorra-Tavistock.

6. Lands in the Township of East Zorra-Tavistock described as:

   - Plan of Subdivision 32T-89005; or PIN 00246-0129: Part of Lot 125, Southeast of Woodstock Street and South of Hope Street, Plan 307 and part of Lot 35, Concession 12; Designated as Parts 1, 2, 3, 4, 5, 6, 7 and 8, 41R7562

7. The former Villages of Norwich, Otterville & Burgessville as of December 31, 1974, now in the Township of Norwich.

8. The Villages of Embro & Thamesford as of December 31, 1974, now in the Township of Zorra.

9. Ottercreek Golf and Country Club; Legal Description for PIN 00052-0502, Part of Lot 13, Concession 9, Designated as Part 1, 41R-5735, Lots 1, 2, 3, 4, 5, 6, 7, 8, 9 and 10, East of James Street, Plan 129, Lot 137 and Part of Lots 139 and 144, Plan 388 and Part of Lot 12, Concession 9, Subject of easement in favour of Ontario Hydro over Part 3, 41R-5736 as in Plan 1743 subject to easement in favour of the Corporation of the Township of Norwich over Part of Lot 144, Plan 388, Designated as Part 3, 41R-6035, Township of Norwich, County of Oxford, formerly the Village of Otterville.

10. Part Lot 17 and 18, Concession 1 (West Oxford), Township of Ingersoll.

11. Part Lots 34 and 35, Concession 13 (East Zorra), in the Township of East-Zorra Tavistock.

12. Part Lot 7, Concession 4 (North Norwich), in the Village of Norwich.

13. The boundary of the former Town of Clinton as of December 31, 2000, now part of the Municipality of Central Huron.

14. The customer located at 80212 Baseline Road in the former Township of Hullett now in the Municipality of Central Huron.

15. The Town of Mitchell as of December 31, 1997.

16. The Police Village of Dublin as of December 31, 1997.

17. West Perth Packers Ltd., Part of Lot 23, Concession 2, Fularton Ward as Part 9 of Reference Plan 44-R-3945.

18. Ball Park, Part of Lot 24, Concession 2, Fularton Ward as Part 6 of Reference Plan 44-R-3945.

19. Sewage Treatment Plant, Part of Lot 23 and 24, Concession 2, Fularton Ward as Part 7 of Reference Plan 44-R-3945.

20. Vacant Land (In Front of Sewage Treatment Plant), Part of Lot 23 and 24, Concession 2, Fularton Ward as Part 8 on Reference Plan 44-R-3945.

21. Part Lot 19, Concession 1 (West Oxford), Town of Ingersoll.

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

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

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

SCHEDULE 3 LIST OF CODE EXEMPTIONS

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

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

2. Erie Thames Powerlines Corporation's Electricity Distribution Licence (ED-2002-0516), specifically Schedule 3 of the licence, is amended to reflect the exemption from the requirements of section 6.5.4 of the Distribution System Code as per Erie Thames Powerlines Corporation's request set out in the application.

3. The Licensee is exempt from the requirement for meter enrollment testing as of the mandatory date for time-of-use pricing for RPP consumers with eligible time-of-use meters as required under the Standard Supply Service Code for Electricity Distributors. This exemption expires February 28, 2011.

APPENDIX A

MARKET POWER MITIGATION REBATES

1. Definitions and Interpretations

In this Licence

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

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

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

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

2. Information Given to IESO

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

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

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

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

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

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

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

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

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

3. Pass Through of Rebate

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

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

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act*, 1998 and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

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

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

"ONTARIO POWER GENERATION INC. rebate"

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

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

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

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

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

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

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i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

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

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

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act*, *1998*.

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b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act*, *1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

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

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

CONTACT INFORMATION

Applicant:

Graig Pettit Manager Finance & Regulatory Affairs	Address:	143 Bell Street Ingersoll ON N5C 2N9
	Phone:	(519) 485-1820 ext. 254
	Fax:	(519) 485-5838
	E-mail:	gpettit@eriethamespowerlines.com

Applicant Counsel:

Scott Stoll Aird & Berlis LLP	Address:	Suite 1800, Box 754 181 Bay Street Toronto, ON M5J 2T9
	Phone:	(416) 865-4703
	Fax:	(416) 863-1515
	E-mail:	sstoll@airdberlis.com

SPECIFIC APPROVALS REQUESTED

Erie Thames hereby requests the following specific approvals:

1) Approval to charge rates effective May 1, 2012 to reflect a revenue deficiency of $609,251 (Exhibit 6) with an Implementation Date to be determined, but Erie Thames Power is suggesting September 1, 2012 or one month following the timing of the OEB's Decision.

2) Approval of Erie Thames proposed capital structure with a deemed common equity component of 40.00% and a long term debt component of 56% and a short-term debt component of 4%;

3) Approval for rate riders for clearance of deferral and variance accounts;

4) Approval to continue the existing deferral/variance accounts;

5) Approval to charge rate riders for LRAM and SSM;

6) Approval of the proposed total loss factor of 4.83 Exhibit 4, Tab 2, Schedule 7.

Erie Thames is not proposing to recover any under-collection of distribution revenues from May 1, 2012 through the implementation date.

DRAFT ISSUES LIST

Based upon Erie Thames experience, it would expect the Application raises the following issues:

i) Rate Base:

(1) Is the proposed rate base for 2012 appropriate?
(2) Is the proposed capital expenditure program for the 2012 Test Year appropriate?
(3) Is the proposed calculation of Working Capital Allowance of 15% of the cost of power and expenses appropriate?
(4) Is the proposed cost of power appropriate?

ii) Operating Revenue:

(1) Is the proposed throughput for the 2012 Test Year appropriate?
(2) Is the customer and load forecast (kW and kWh) appropriate?
(3) Is the proposed forecast of Test Year 2012 revenues from other regulated rates and charges appropriate?

iii) Operating Costs:

(1) Is the proposed Operations and Maintenance program for the 2012 Test Year appropriate?
(2) Is the proposed level of the Depreciation/Amortization expense for the 2012 Test Year appropriate?
(3) Is the proposed PILs requirement for the 2012 Test Year appropriate?

iv) Deferral and Variance Accounts:

(1) Is the proposed clearance of deferral and variance account balances appropriate?
(2) Are the proposed new deferral and variance accounts for the test year appropriate?

v) Capital Structure and Cost of Capital:

(1) Is the proposed capital structure of 40% equity, 56% long-term debt and 4% short-term debt appropriate?
(2) Is the proposed return on equity, short-term debt rate and long-term debt rate appropriate?

vi) Cost Allocation:

(1) Are the revenue to cost ratios in the cost allocation for Test Year 2012 appropriate?

vii) Rate Design:

(1) Is the full schedule of rates as proposed, including the changes to the rate classifications and the harmonization of rates, appropriate?
(2) Is the derivation of the proposed base distribution rates appropriate?
(3) Is the derivation of the proposed rate riders appropriate?
(4) Are the proposed changes to LV rates appropriate?
(5) Are the proposed Loss Factors appropriate?

viii) **Smart Meters:**

(1) Is the proposed elimination of the Smart Meter Rate Adder and the inclusion of the Smart Meter capital in the 2012 rate base appropriate?

ix) **Modified International financial Reporting System**

(1) Is the proposed service revenue requirement calculated using modified IFRS appropriate?

x) **CDM, Green Energy Plan:**

(1) Is the proposed Basic Green Energy Plan appropriate?
(2) Are the proposed CDM measures appropriate?

PROCEDURAL ORDERS/MOTIONS/NOTICES

To be included when received

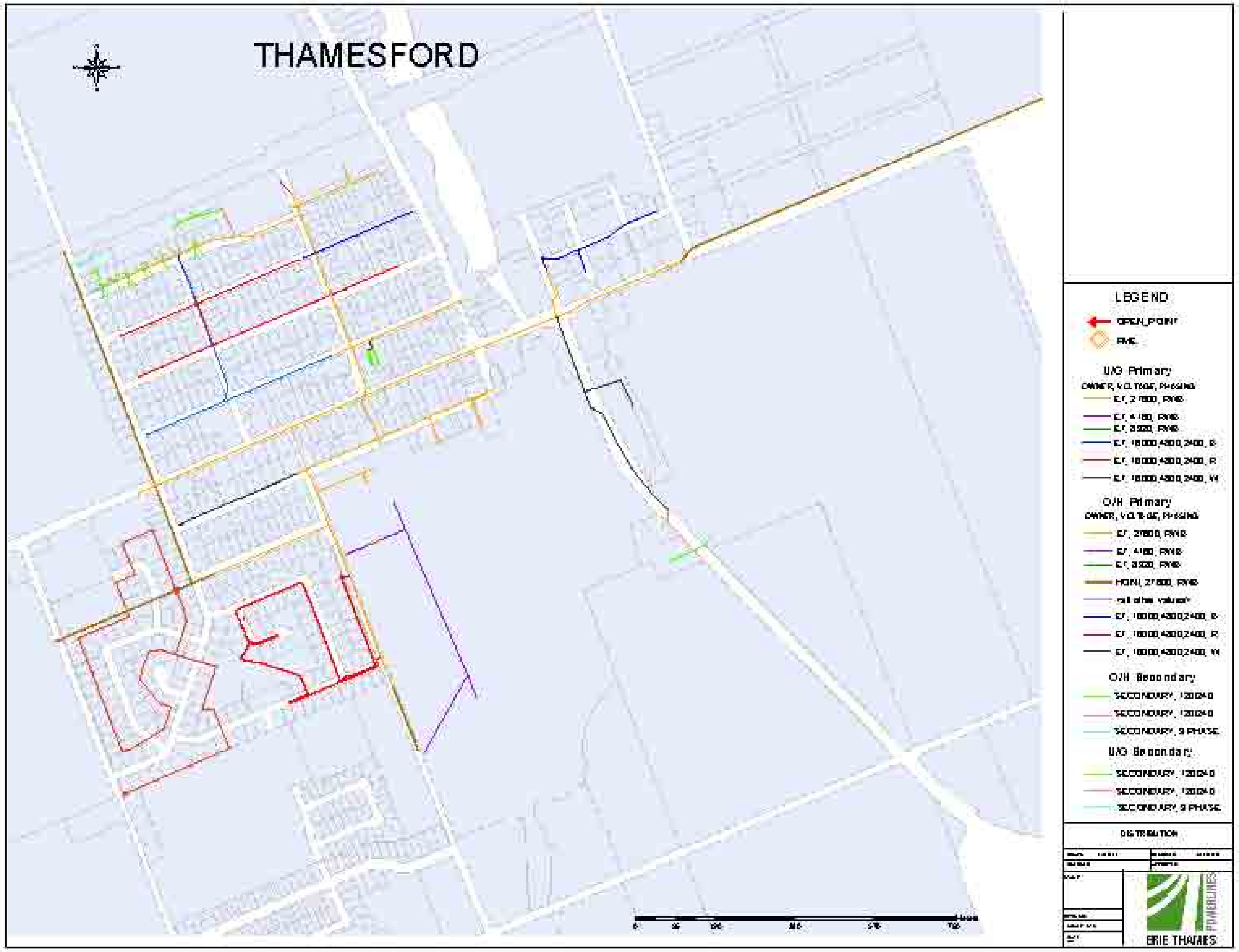
ACCOUNTING ORDERS REQUESTED

NON-COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS

Erie Thames follows the main categories and accounting guidelines as stated in the Uniform System of Accounts.

MAP OF DISTRIBUTION SYSTEM

Note to Draft insert maps



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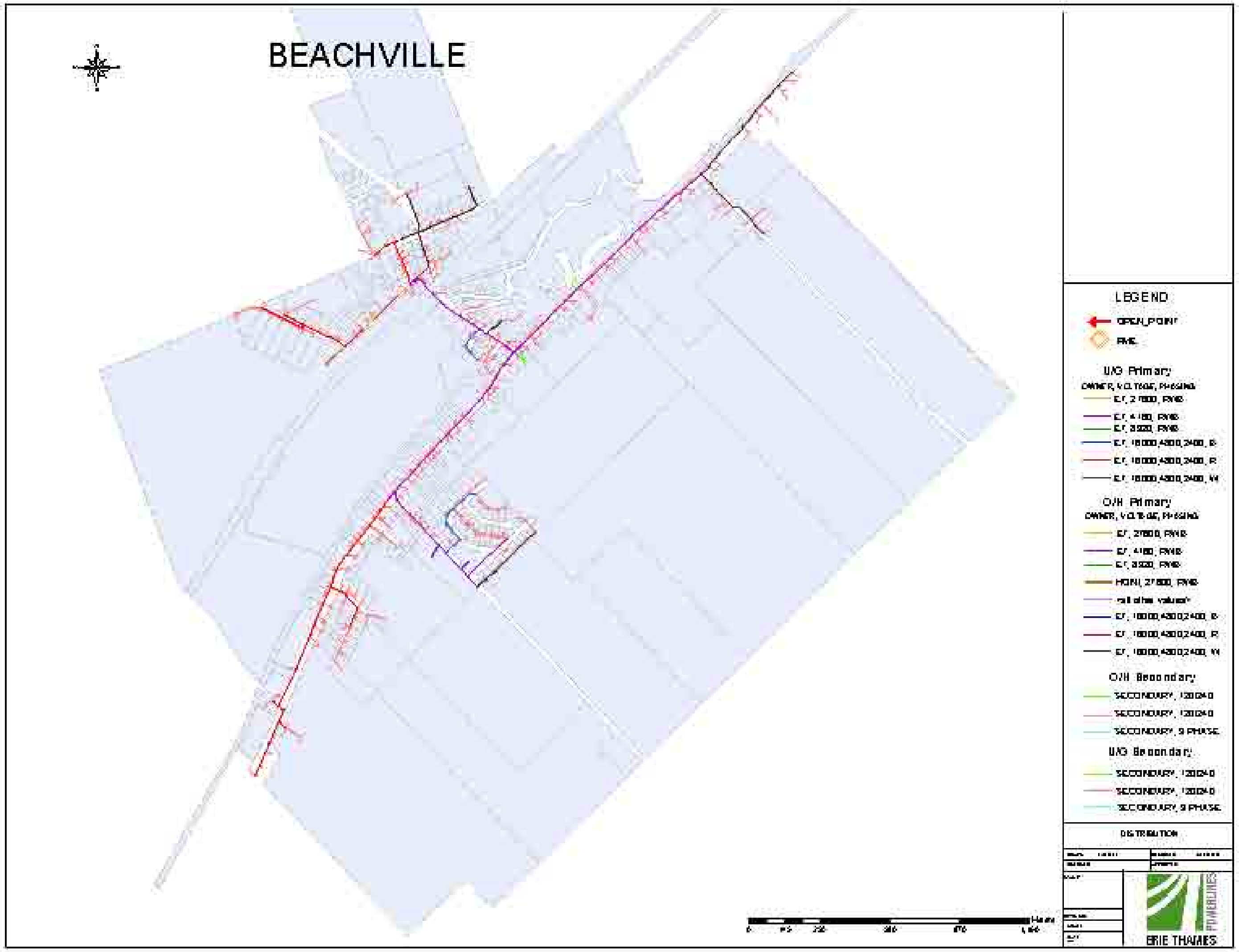

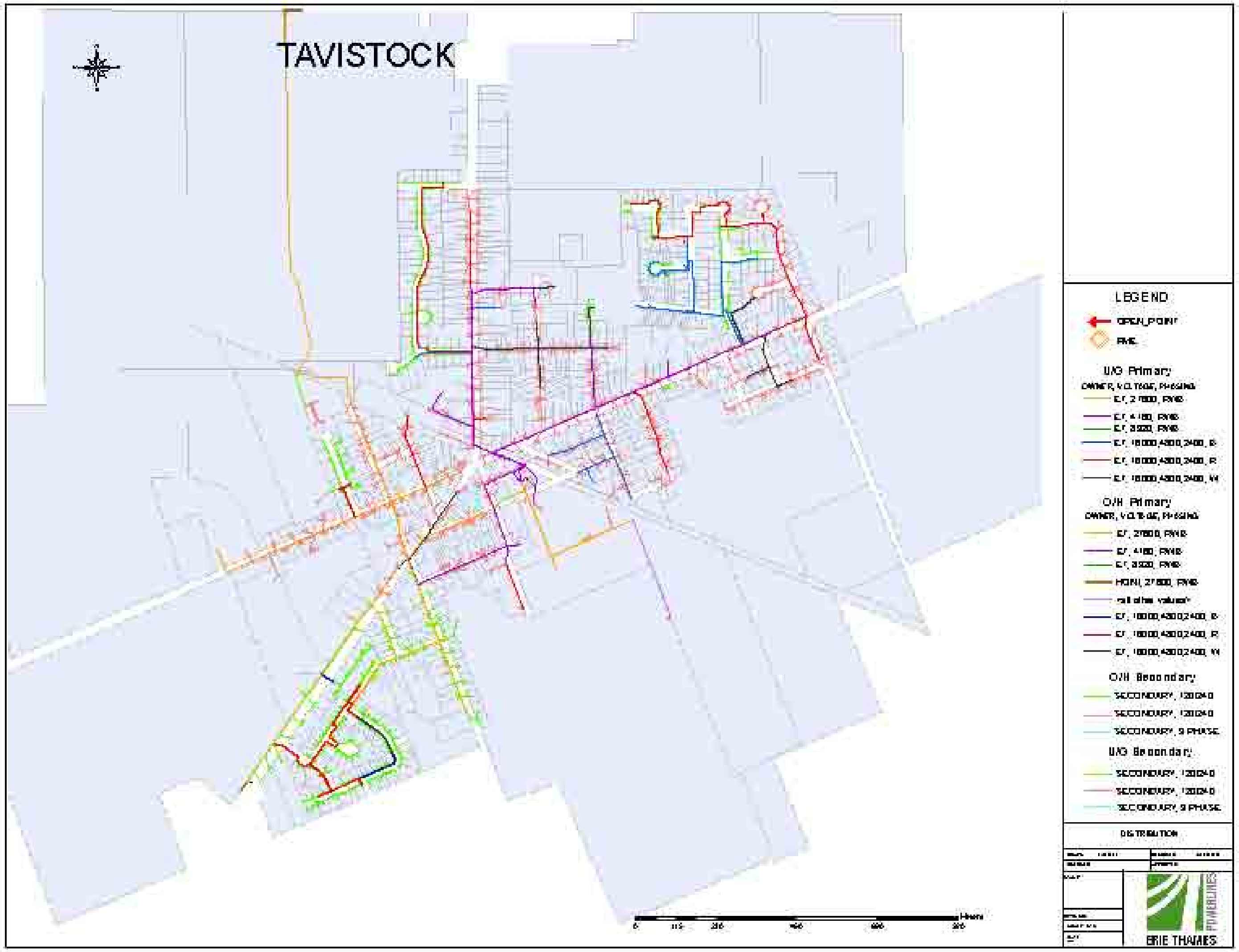
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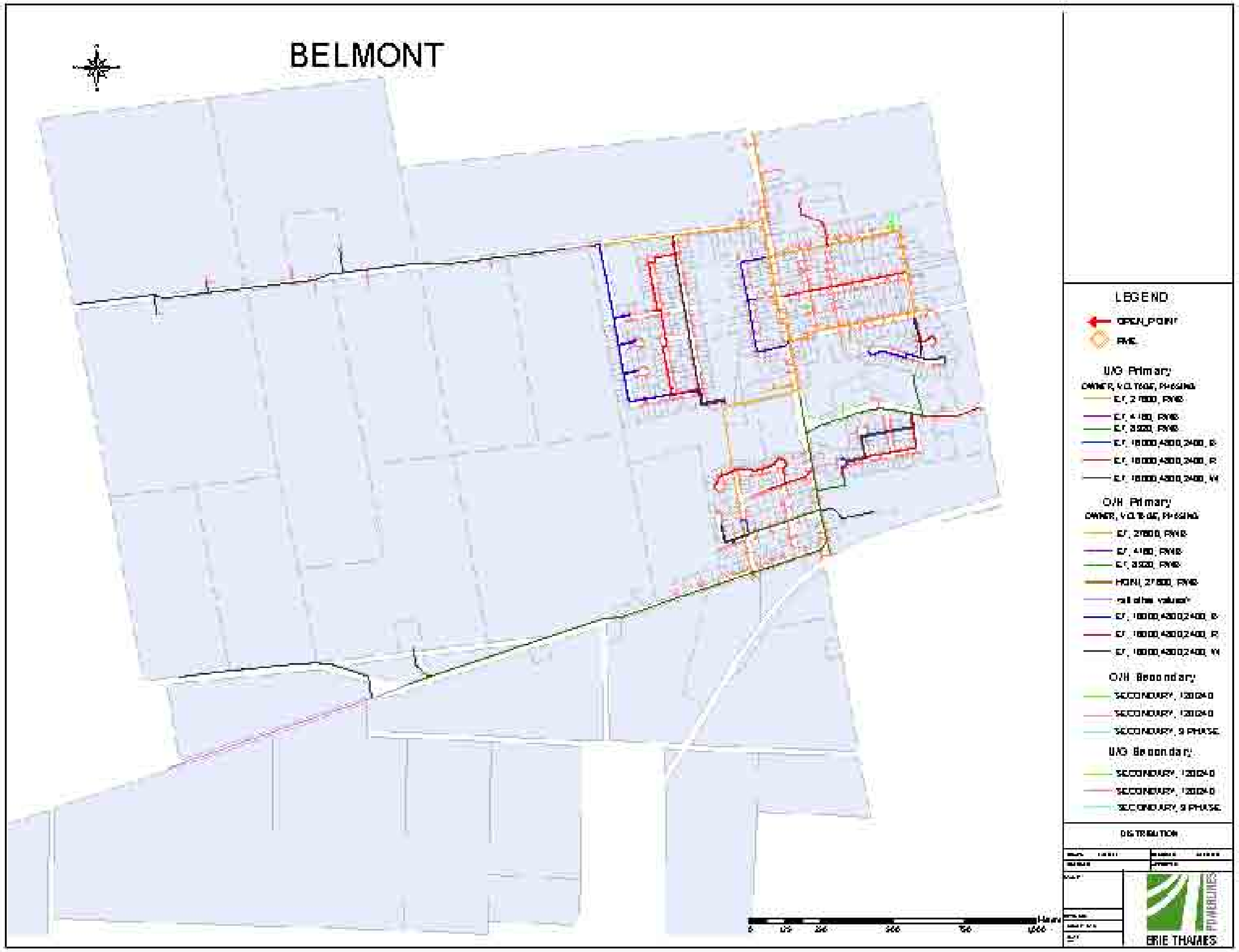
POWERLINES
ERIE THAMES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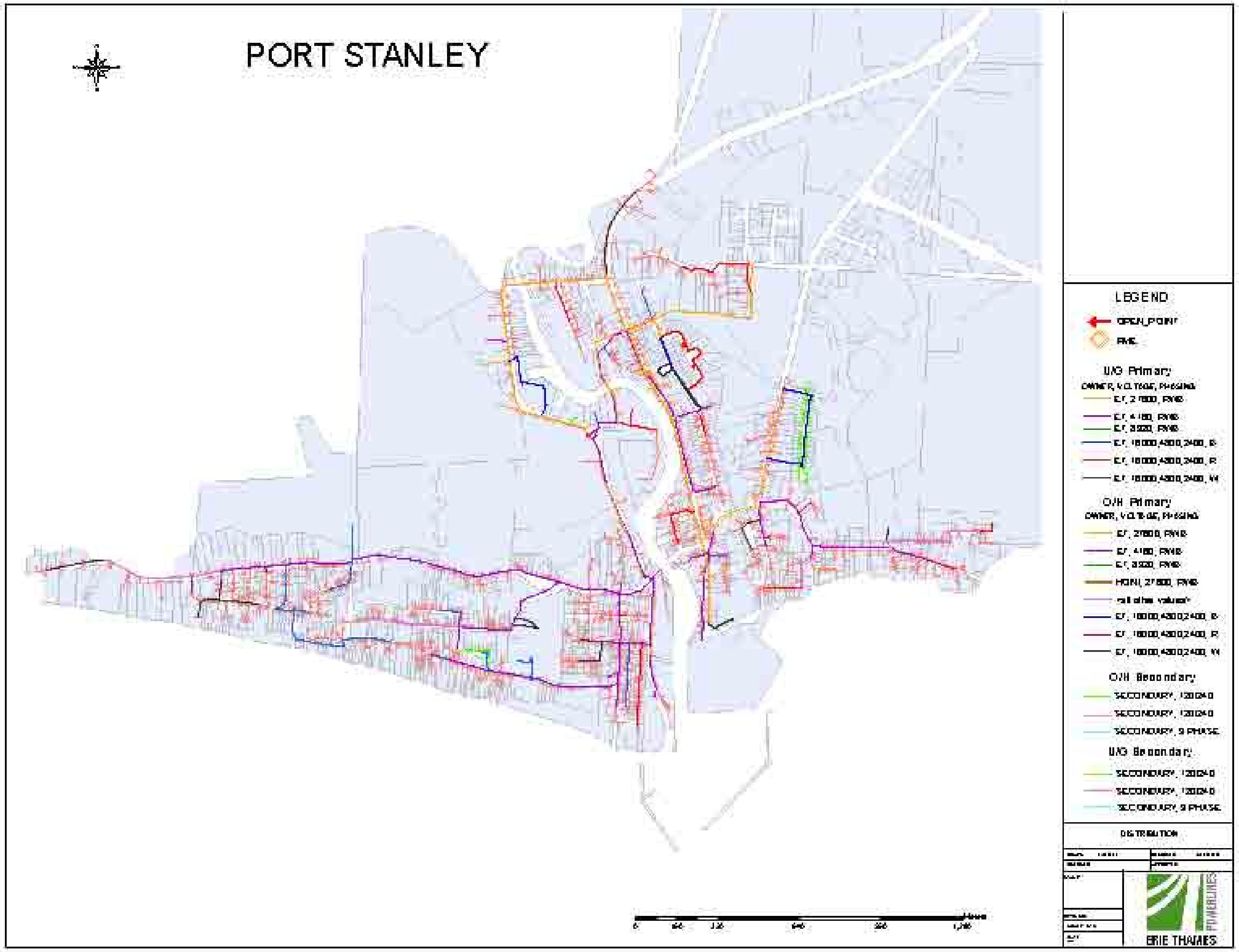
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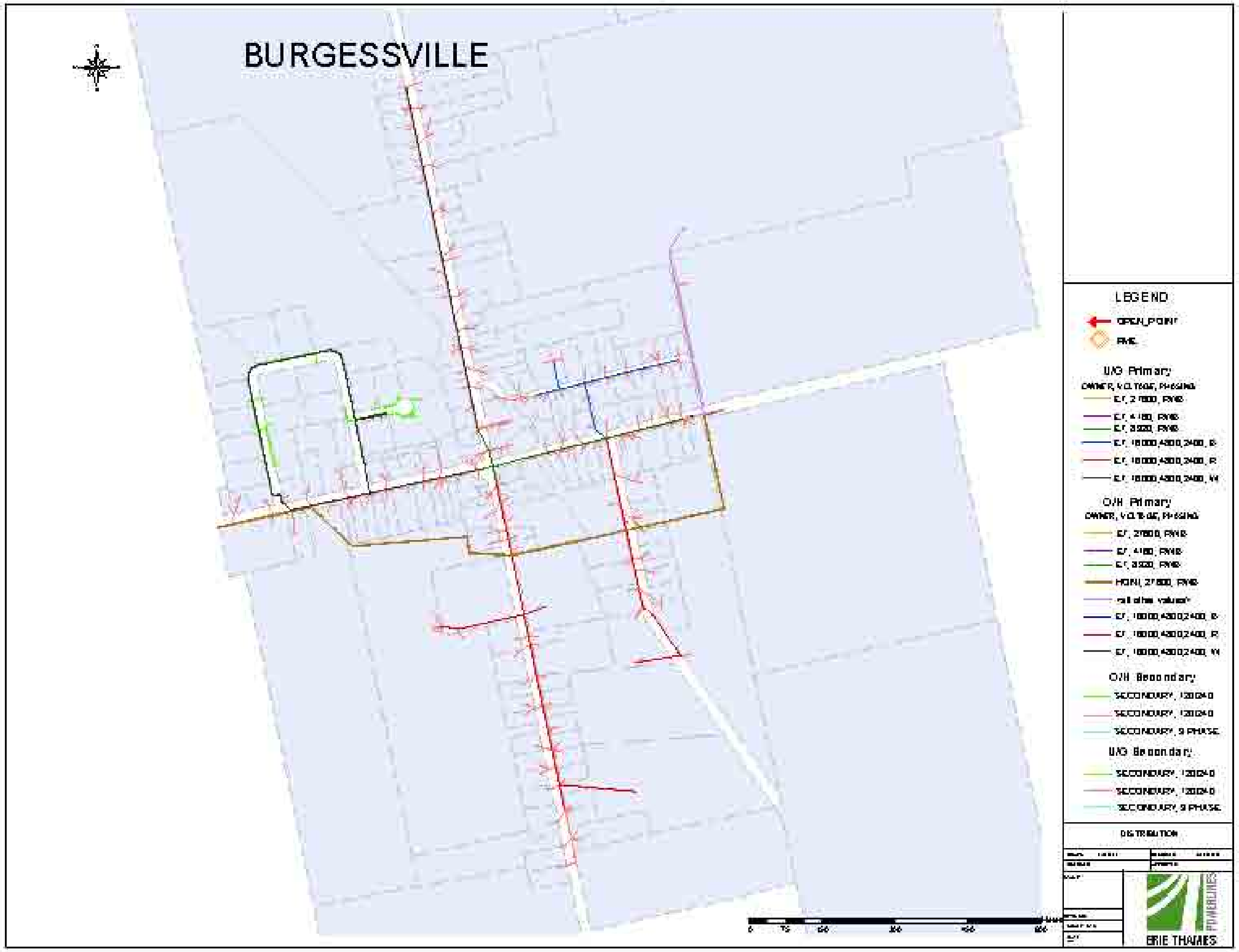
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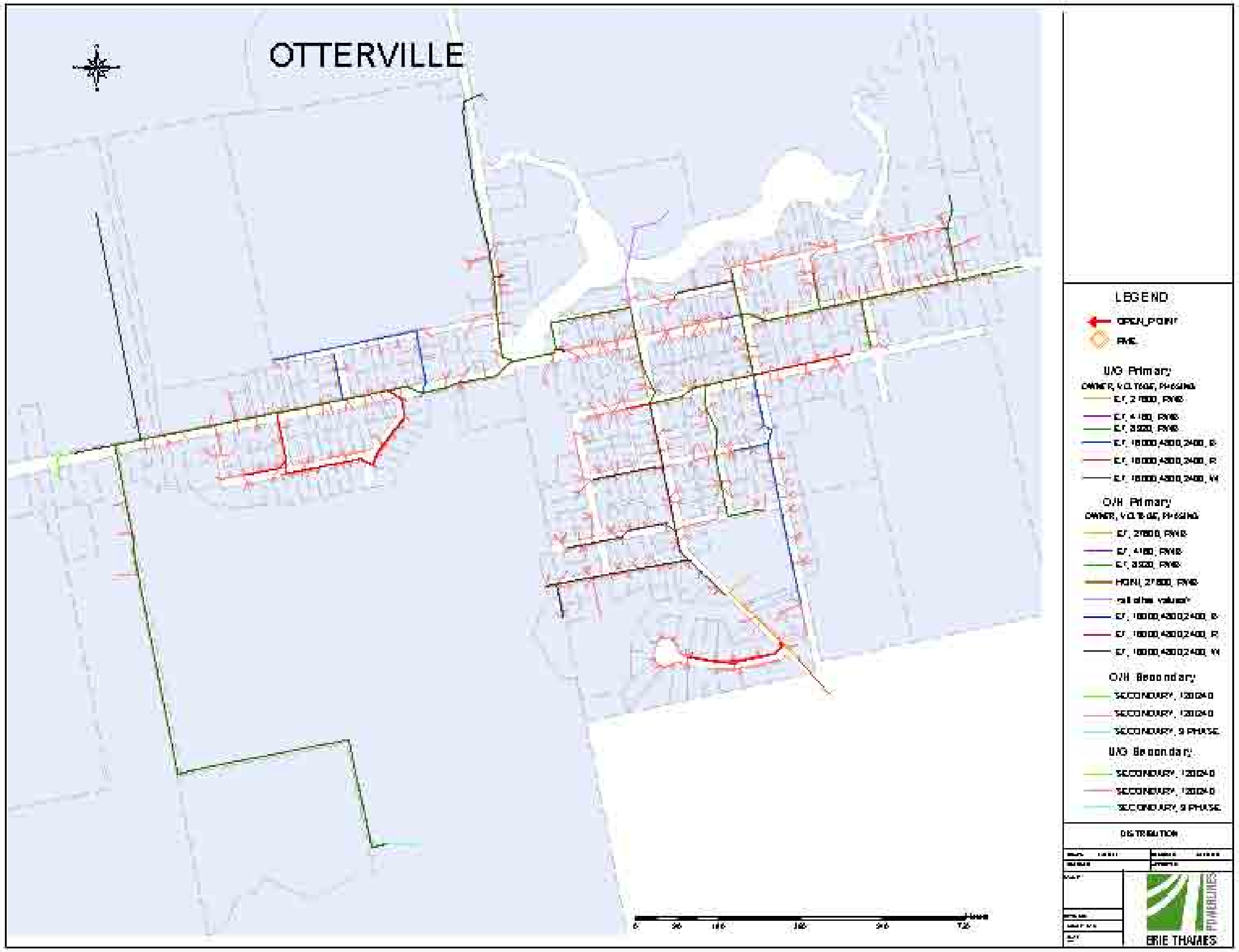
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DISTRIBUTION
ERIE THAMES
POWERLINES

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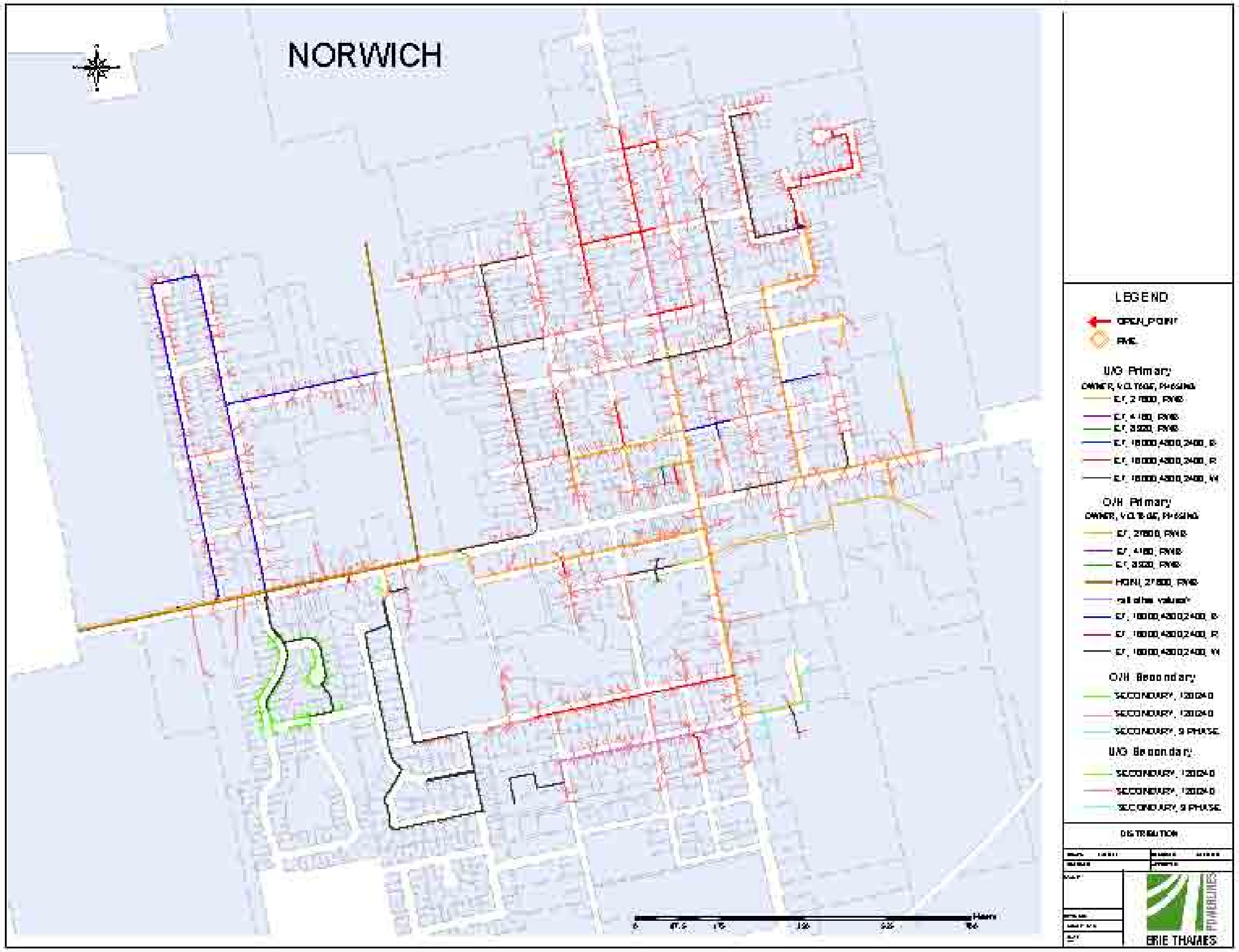

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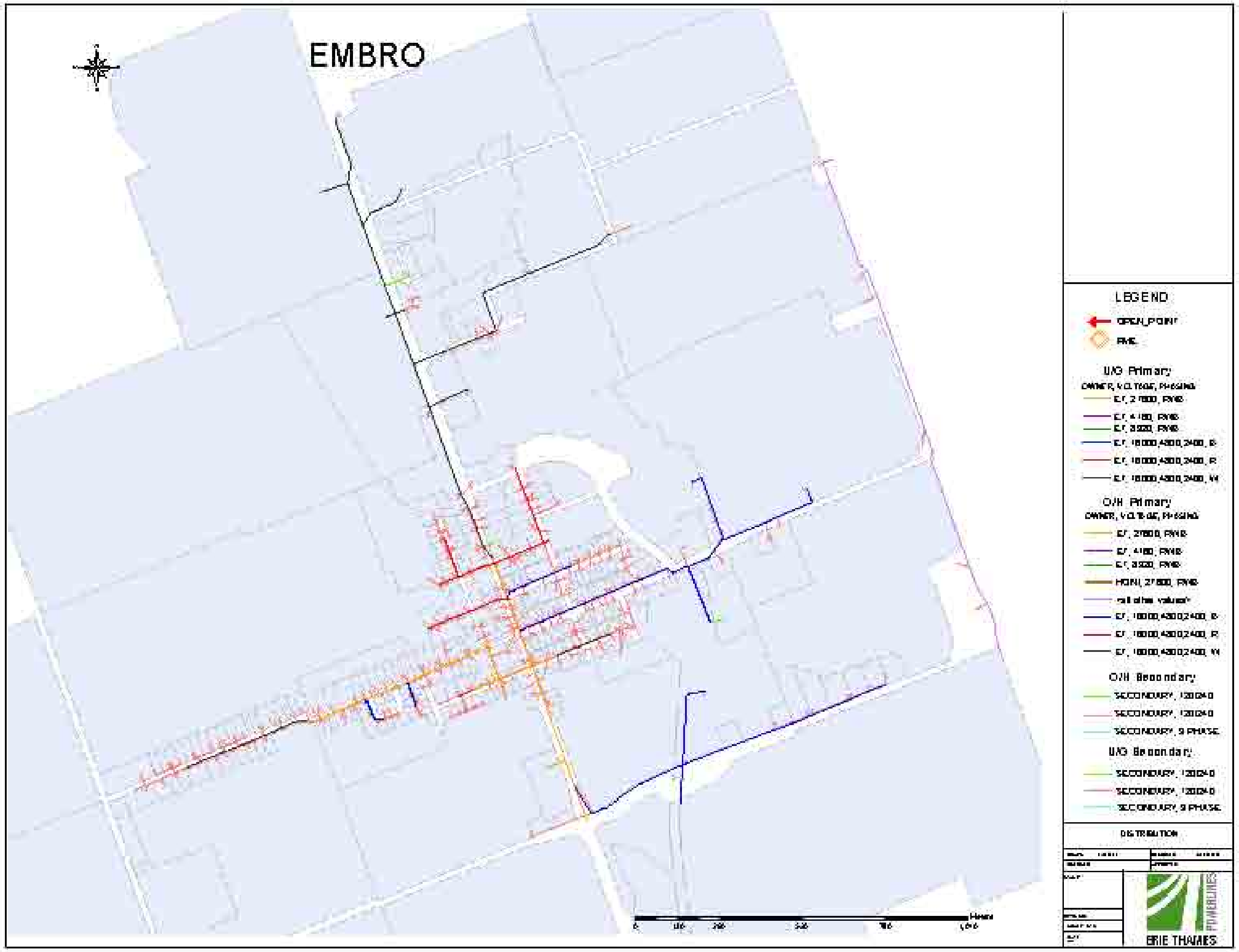

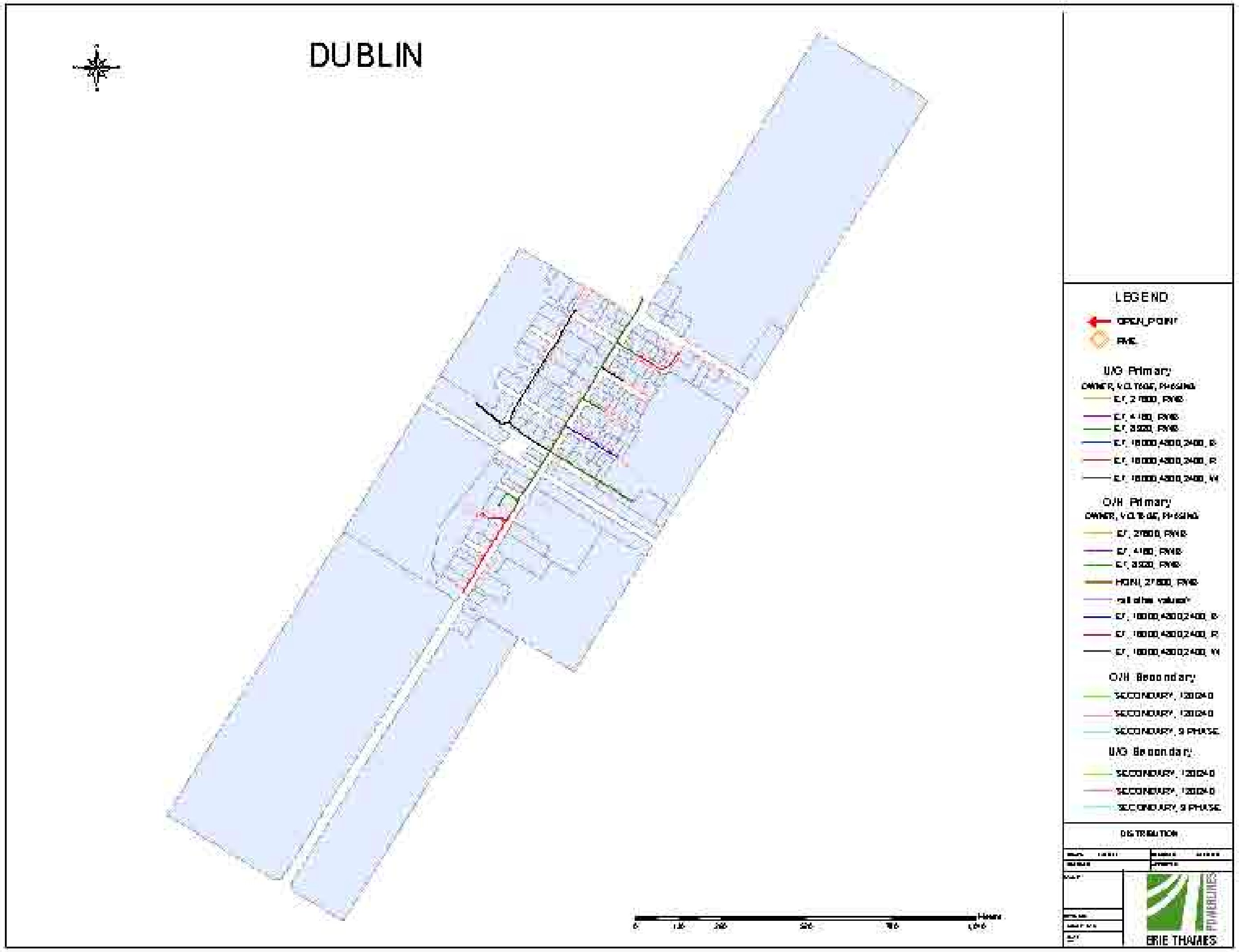
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POWERLINES
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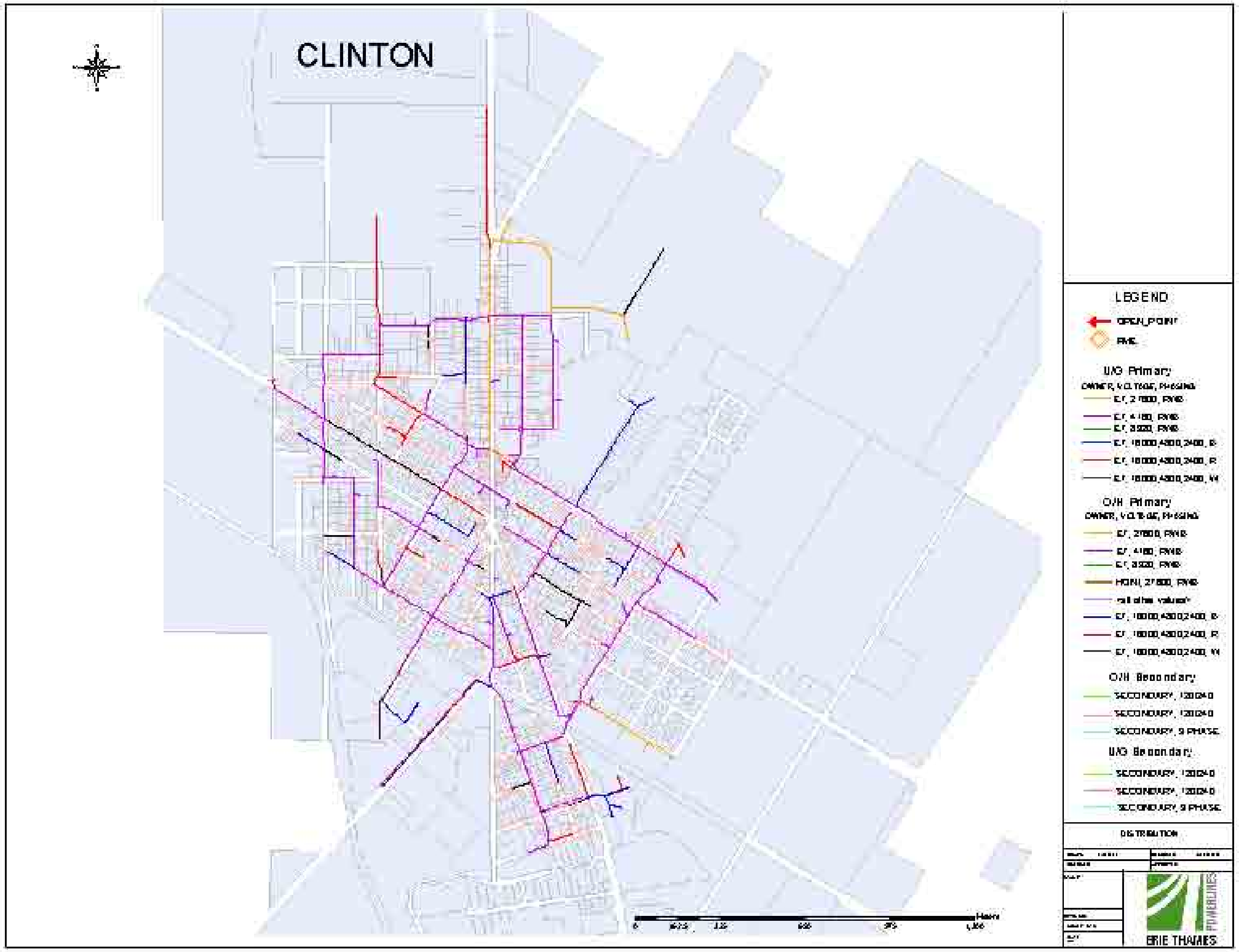
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ERIE THAMES
POWERLINES

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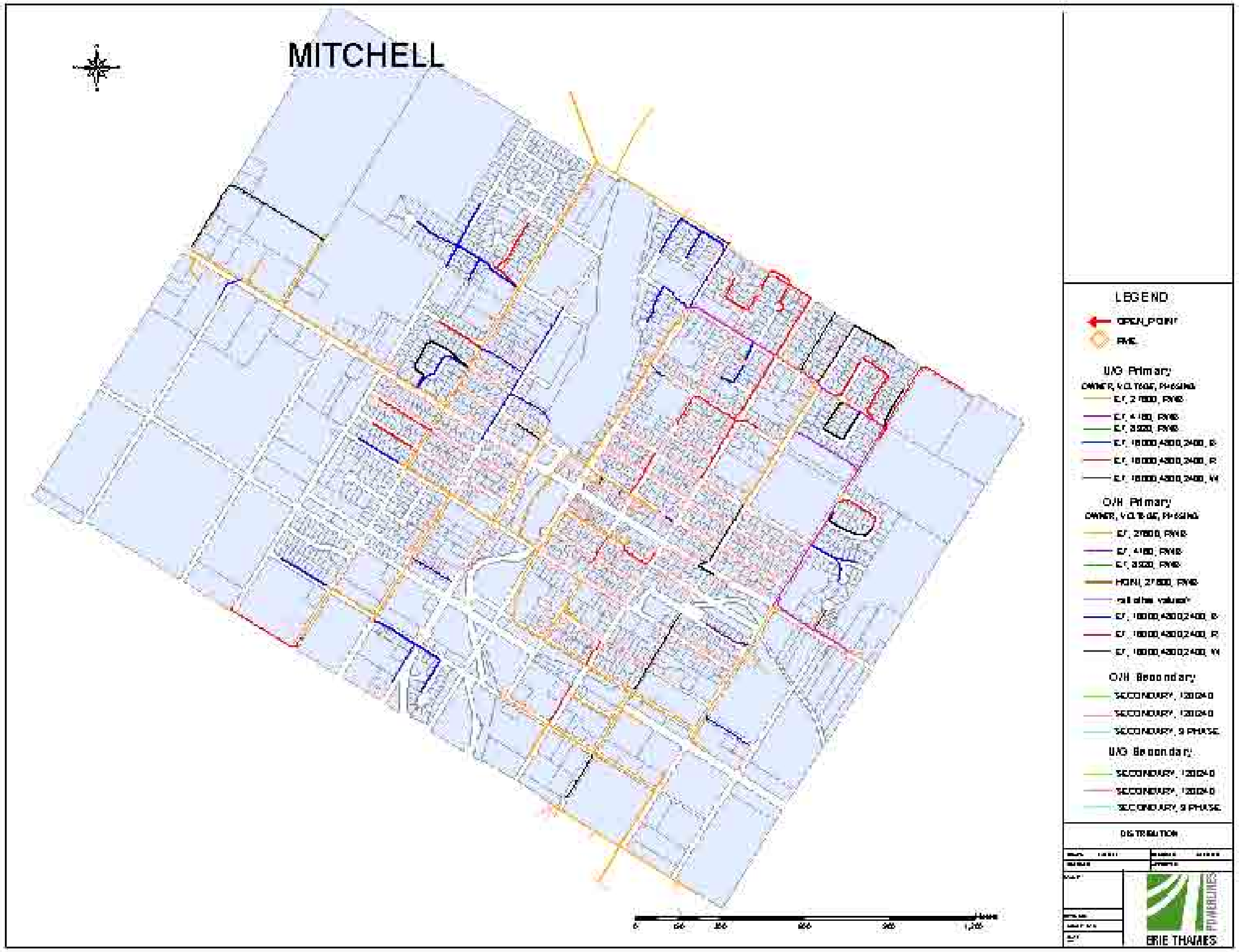

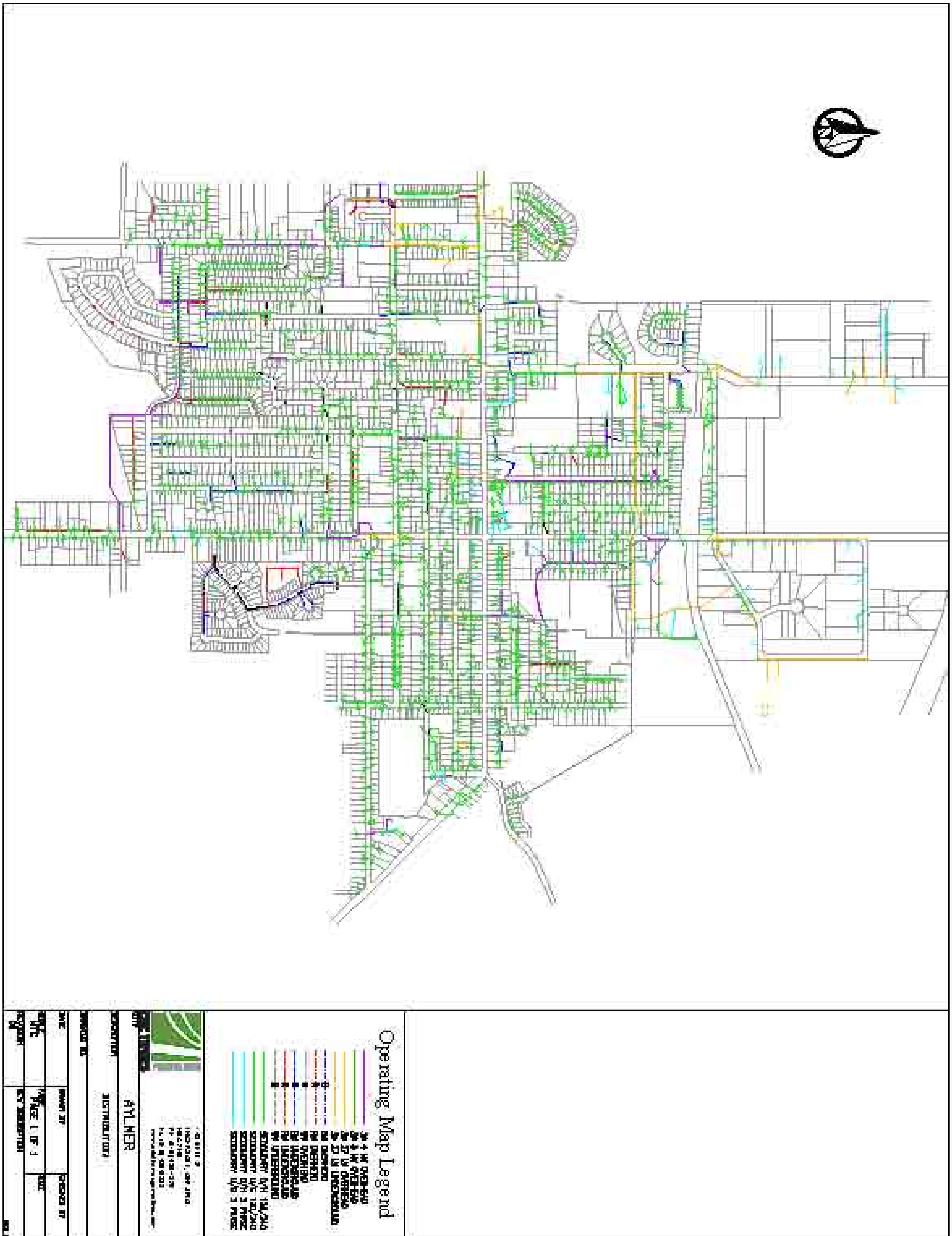
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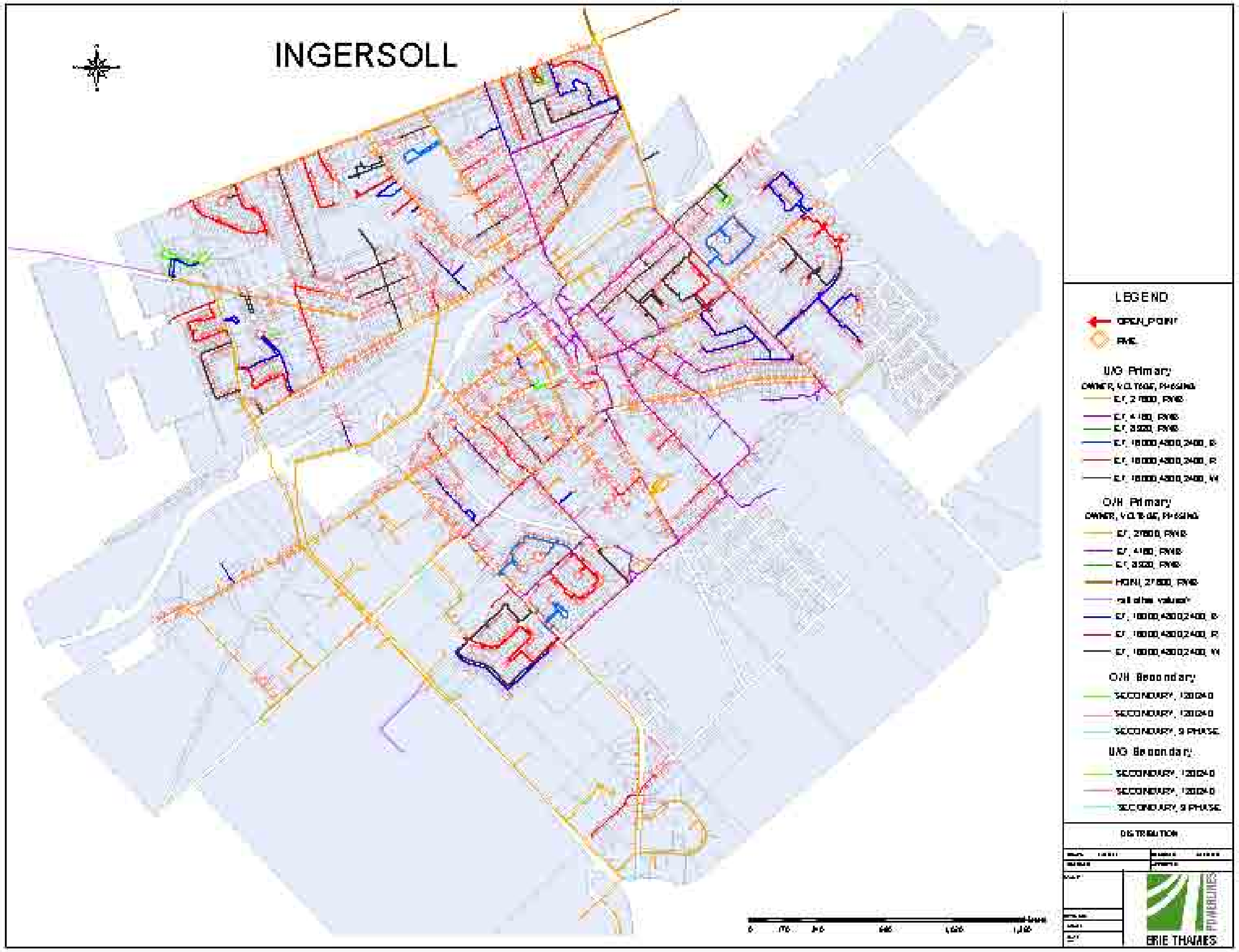
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U/G Secondary
SECONDARY, 120/240
SECONDARY, 120/240
SECONDARY, 3 PHASE
DISTRIBUTION
POWERLINES
ERIE THAMES

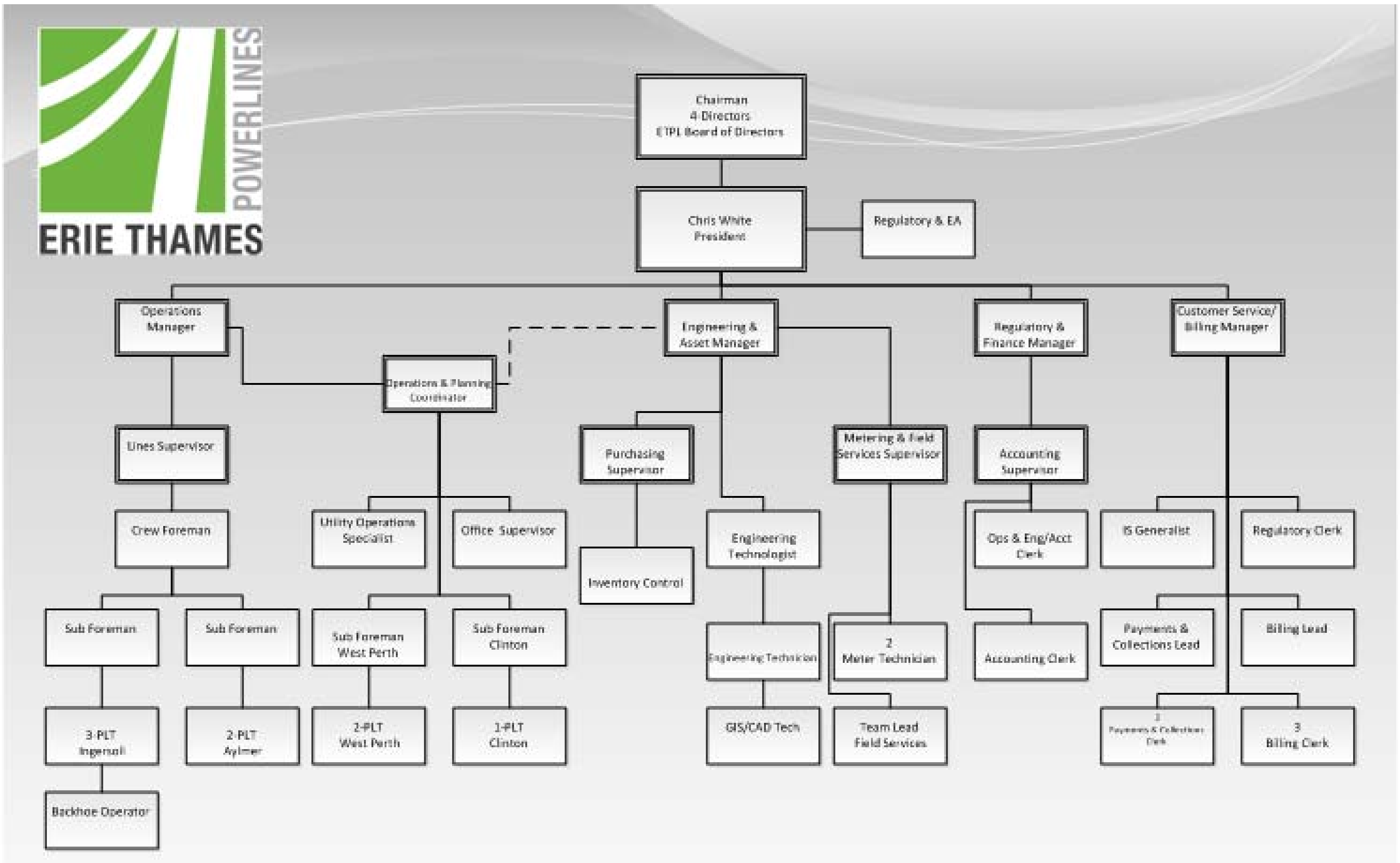
LIST OF NEIGHBORING UTILITIES

Hydro One Networks Inc.	Direct line:	416-345-5000
483 Bay St.		
Toronto, ON M5G 2P5	Website:	www.HydroOne.com

EXPLANATION OF HOST AND EMBEDDED UTILITIES

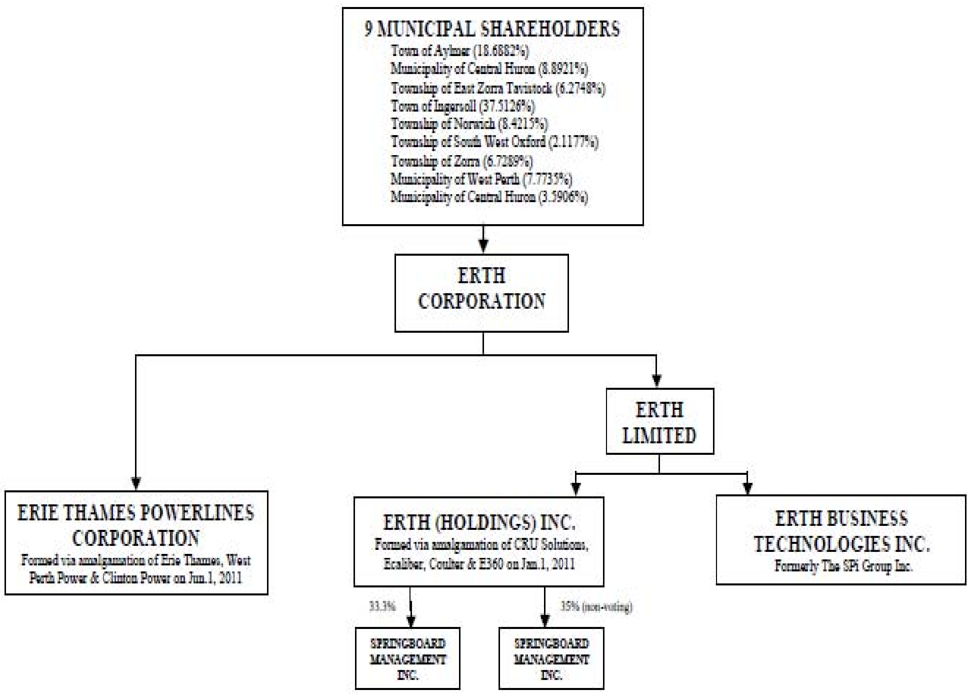
Erie Thames has Hydro One as an Embedded Distributor within its service area at three locations. Hydro One deregistered several of its wholesale meter points with the IESO. Consequently, Erie Thames is charged for electricity that flows through its system, but is not consumed by its customers. Erie Thames therefore needs an embedded distributor rate to charge Hydro One for the use of its system.

UTILITY ORGANIZATIONAL CHART



Current to: January 12, 2012

ERTH Corporation
Corporate Chart



Notes:

All ownership is100% unless indicated otherwise.

PLANNED CHANGES IN CORPORATE AND OPERATIONAL STRUCTURE

Erie Thames is not proposing any further changes to its corporate and operational structure.

STATUS REPORT ON BOARD DIRECTIVES

Erie Thames Power has no Board Directives at this time.

CONDITIONS OF SERVICE

ERIE THAMES POWERLINES

CONDITIONS OF SERVICE

January 2012
Version 6.2

(CONDITIONS OF SERVICE

TABLE OF CONTENTS

(SECTION 1 INTRODUCTION

1.1 Identification of Distributor and Territory

Erie Thames is a corporation, incorporated under the laws of the Province of Ontario to distribute electricity.

Erie Thames is licensed by the Ontario Energy Board "OEB" to distribute electricity to Customers in the service area described in Erie Thames Distribution License, ED-2002-0516 (the "Licence").

Additionally there are requirements imposed on Erie Thames by the various codes referred to in the License and by the *Electricity Act* and the *Ontario Energy Board Act*.

1.1.1 General

Nothing contained in this document or in any contract for the supply of electricity by Erie Thames shall prejudice or affect any rights, privileges, or powers vested in Erie Thames by law under any Act of the Legislature of Ontario or the Parliament of Canada, or any regulations thereunder.

Erie Thames will normally provide one electrical service to each customer location at a nominal service voltage.

Modifications to an existing service must comply with the requirements of the standards in effect at the time of the modifications.

The customer or their authorized representative must make application for new or upgraded electric services and temporary power services.

The customer or their representative shall consult with Erie Thames concerning the availability of supply, the voltage of supply, service location, metering and any other details. These requirements are separate from and in addition to those of the Electrical Inspection Authority. Erie Thames will confirm, in writing, the Characteristics of Electric Supply available at a specific site.

The customer is required to provide Erie Thames sufficient lead-time in order to ensure:

(a) *the timely provision of supply to new and upgraded premises or*
(b) *the availability of adequate capacity for additional loads to be connected in existing premises.*

If special equipment is required or equipment delivery problems occur then longer lead times may be necessary. The customer will be notified of any extended lead times.

Customers will be required to pay the cost of repair or replacement of Erie Thames equipment that has been damaged through the customers' action or neglect.

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

(The Customer shall not build, plant or maintain or cause to be built, planted or maintained any structure, tree, shrub or landscaping that would or could obstruct the running of distribution lines, endanger the equipment of Erie Thames, interfere with the proper and safe operation of Erie Thames's facilities or adversely affect compliance with any applicable legislation in the sole opinion of Erie Thames.

Prior to commencing any service work, the customer must consult with Erie Thames to ensure compliance with current requirements.

Customers may be required to pay Capital Contributions for the addition of new electrical services based on the requirements of the Distribution System Code.

1.2 Related Codes and Governing Laws

Erie Thames and the Customer shall comply with all Applicable Laws, including the provisions of the latest editions of the following documents:

1. *Electricity Act, 1998*
2. *Ontario Energy Board Act, 1998*
3. *Distribution Licence* ED-2002-0526
4. *Affiliate Relationships Code*
5. *Distribution System Code*
6. *Retail Settlements Code*
7. *Standard Service Supply Code*
8. *Transmission System Code*

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

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

1.3 Interpretations

In these Conditions, unless the context otherwise requires:

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

1.4 Amendments and Changes

The provisions of these Conditions of Service and any amendments made from time to time form part of any Contract made between Erie Thames and any connected Customer, Generator or their agents.

In the event of changes to this Conditions of Service, a Public notice shall be made in the form of a (customer bill note and/or a notice on Erie Thames Website.

The Customer is responsible for contacting Erie Thames to ensure that the Customer has, or to obtain the current version of the Conditions of Service.

1.5 Contact Information

For general inquiries, Erie Thames Powerlines can be contacted during normal business hours: Monday to Friday between 8:30 am to 4:30 pm at 519-485-1820 or toll free 1-877-850-3128, by email at info@eriethamepower.com or by writing to:

Erie Thames Powerlines Corporation
P.O. Box 157, 143 Bell Street
Ingersoll ON N5C 3K5

For emergency purposes during or after normal business hours, Customers can call Erie Thames at 1-877-850-3128.

1.6 Customer Rights

In those instances where the Customer will own their secondary or primary service, the Customer has the right to hire a Contractor to supply and install the service.

The customer has the right to demand identification from any person purporting to be an authorized agent or employee of Erie Thames.

A customer, who believes that he has suffered damages to his property or equipment as a result of negligence on the part of Erie Thames, may submit a written claim for damages to Erie Thames. Erie Thames will investigate the claim and respond in writing within 10 business days of the receipt of the claim.

1.7 Distributor Rights

In those instances where the Customer has the authority to hire a Contractor to construct plant which will become part of Erie Thames' system, Erie Thames shall have the right to require the Contractor to submit proof of previous experience and satisfactory performance, and, Erie Thames shall have the right to investigate such proof and approve the Contractor prior to the Owner awarding a contract for the work to the Contractor.

Erie Thames shall have access to Customer property in accordance with section 40 of the *Electricity Act, 1998.*

1.8 Disputes

If, following good faith negotiations between a customer or other market participant and Erie Thames, a resolution cannot be reached, the dispute may be submitted to a dispute resolution process.

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

(**Mediation**

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

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

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

Referral to Dispute Resolution

Any dispute that is not resolved through mediation as described above shall be referred to the Ontario Energy Board dispute resolution agency according to the following procedure:

- Upon the written demand of either of the parties, the dispute shall be referred to the disputes resolution agency that has been appointed by the Ontario Energy Board.

SECTION 2 DISTRIBUTION ACTIVITIES (GENERAL)

2.1 Connections

This section includes information that is applicable to all customer classes of Erie Thames. Items that are applicable to only a specific customer class are covered in Section 3.

2.1.1 Building that Lies Along

As provided in Section 28 of the *Electricity Act 1998* Erie Thames has the Obligation to connect any Building that 'lies along" its distribution system. A building 'lies along" a distribution line if it can be connected to Erie Thames's distribution system, and meets the conditions listed in the Conditions of Service of Erie Thames who owns or operates the distribution line.

A Building that 'lies along" a distribution line may be refused connection to that line should the connection have an adverse effect on the reliability or safety of the distribution system.

2.1.2 Expansions / Offer to Connect

Under the terms of the Distribution System Code Section 3.1, a Distributor has the Obligation to make an Offer to Connect any Building that 'lies along" its distribution system. Erie Thames may refuse to connect a customer for the reason described in subsection 2.1.3 of Erie Thames Conditions of Service. The Offer to Connect must be fair and reasonable and be based on Erie Thames design standard. The Offer to Connect must also be made within a reasonable time from the request for connection.

Erie Thames may require a customer to pay all or a part of the costs of electrical plant installed to supply only that customer. Such capital contributions will be calculated using the guidelines set out by the OEB in the Distribution System Code.

2.1.3 Connection Denial

The Distribution System Code in section 3.1 sets outs the conditions for a Distributor to deny connections. A Distributor is not obligated to connect a building within its service territory if the connection would result in any of the following:

- Contravention of existing Canadian Laws, and those of the Province of Ontario.
- Violations of conditions in a Distributors' Licence.
- Materially adverse effect on the reliability or safety of the distribution system.
- Imposition of an unsafe worker situation beyond normal risks inherent in the operation of the distribution system.
- A material decrease in the efficiency of Erie Thames's distribution system.
- A materially adverse effect on the quality of distribution services received by an existing connection.
- If the person requesting the connection owes Erie Thames money for distribution services, or for non-payment of a security deposit. Erie Thames shall give the person a reasonable opportunity to

(provide the security deposit consistent with Section 2.4.20 of the Distribution System Code.

2.1.4 Inspections Before Connections

Erie Thames has the right to request an inspection prior to any connection.

All customer electrical installations shall be inspected and approved by the Electrical Safety Authority, referred to herein as the ESA.

Erie Thames requires notification from the ESA of this approval prior to the connection of a customer's service.

Services that have been disconnected for a period of six months or longer shall also be re-inspected and approved by the ESA prior to reconnection.

Temporary services, for construction purposes, are approved by the ESA for a period of twelve months and must be re-inspected should the period of use exceed twelve months.

Erie Thames reserves the right to inspect and approve Transformer rooms, Vaults and Pads prior to during and following the installation of equipment.

Provision for metering shall be inspected and approved by Erie Thames prior to connection.

Customer owned substations must be inspected by both the Electrical Safety Authority and Erie Thames, prior to connection to the Distribution system.

Duct banks and road crossings shall be inspected and approved by Erie Thames prior to the pouring of concrete and again before backfilling.

Erie Thames reserves the right to inspect any underground trenches prior to backfilling.

Erie Thames reserves the right to approve the installation and location of all submarine cable. All documentation and permits required for laying of submarine cable must be provided to Erie Thames. The installation of submarine cable must meet the requirements of all governing legislation.

All work done on existing Distributor plant must be authorized by Erie Thames and carried out in accordance with all applicable safety acts and regulations.

In accordance with the Distribution System Code, if Erie Thames refuses to connect a building in its service territory that lies along one of its distribution lines, Erie Thames shall inform the person requesting the connection of the reasons for not connecting, and where Erie Thames is able to provide a remedy, make an offer to connect. If Erie Thames is unable to provide a remedy to resolve the issue, it is the responsibility of the customer to do so before a connection can be made.

2.1.5 Relocation of Plant

Erie Thames will, where feasible, accommodate requests to relocate electrical plant such as poles and metal enclosed equipment.

The customer will be required to pay all of the costs incurred by the relocation.

(Requests by civic authorities to relocate distribution facilities will be done so in accordance with the appropriate regulations.

2.1.6 Easements

To maintain the reliability, integrity and efficiency of the distribution system, Erie Thames has the right to have supply facilities on private property registered against title to the property. Easements are required whenever Erie Thames underground or overhead plant is to be located on private property or crosses over an adjacent private property to service a Customer.

The Customer shall acquire and grant in Erie Thames name, at no cost to Erie Thames, where required, an easement to permit installation and maintenance of service. The width and extent of this easement shall be determined by Erie Thames. The easement shall be granted prior to connection of the service.

The Owner shall furnish to Erie Thames, free and clear of all encumbrances, sufficient easements to enable the servicing of all existing or proposed developments or subdivisions from plants located on the Owners' property.

Sufficient property at suitable locations shall be made available for the purpose of the installation of distributors' assets.

The Customer will prepare at its own costs a reference plan and associated easement documents to the satisfaction of Erie Thames solicitor prior to its registration and register the easement plan. Details will be provided upon application for service.

Where surface restoration by Erie Thames is required following any repairs or maintenance to a service, Erie Thames will in so far as is practicable, restore the property to its original condition; and provide compensation for any damages caused by the entry that cannot be repaired.

2.1.7 Contracts

Standard Form of Contract - Connection to the electrical distribution system will be provided upon completion of a signed contract between the customer and Erie Thames, and receipt of approval by the Electrical Safety Authority ("ESA").

All customers will be required to complete and sign the standard form of contract to apply for the supply of an electrical energy connection. A Standard Contract for service shall be considered as being in force from the date it is signed by the Customer and Erie Thames and shall remain in force until terminated by either party.

Implied Contract - In all cases, notwithstanding the absence of a formal contract, the taking and using of electrical energy from Erie Thames by any Person or Persons constitutes the acceptance of the terms and conditions of all regulations, conditions and rates as established by Erie Thames. Such acceptance and use of energy shall be deemed to be the acceptance of a binding contract with Erie Thames and the Person so accepting shall be liable for payment for such energy and the contract shall be binding upon the Person's heirs, administrators, executors, successors or assigns.

Special Contracts - Special contracts that are customized in accordance with the service requested by the Customer normally include, but are not necessarily limited to, the following examples:

- *construction sites*

- (*mobile facilities*
- *non-permanent structures*
- *special occasions, etc.*
- *Generation*

Opening and Closing of Accounts – A property owner or occupant shall contact Erie Thames by telephone to make a request to open an account with Erie Thames. This will establish a contract with Erie Thames and the Customers acceptance of all responsibilities related to electricity charges applicable to the account. A Solicitor or person with Power of Attorney can agree on behalf of the Customer to the opening of an account.

Erie Thames shall open and or close an account for a property in the name of a person at the request of a third party consistent to Section 2.8 of the Distribution System Code and as outlined in Appendix 3 of these Conditions of Service, Policy 5.0 Opening and Closing of Accounts.

Erie Thames may require a security deposit consistent with Section 2.4.9 of the Distribution System Code and as outlined in Appendix 3 of these Conditions of Service, Policy 6.1 Security Deposits.

Customers requesting to close an account are required to provide reasonable notice to allow time to read the meter at the service address and issue a final bill. If a Customer requests to cancel a service agreement and no longer request electricity to be provided to the service address, Erie Thames may disconnect the electricity service. If a request is made for reconnection the new Customer setting up an account at the service address will incur the applicable costs to reconnect the service. If the electricity service has been disconnected from a premise for six months or longer, an ESA inspection is required.

In all cases, Erie Thames will not maintain availability of a meter and service without an active account and Customer. When a Customer advises Erie Thames they are no longer responsible for the account or requests to close an account, a final bill will be issued for the account. If, at that time, a new Customer has not assumed responsibility for services provided to the property, Erie Thames may disconnect the property.

Landlord and Tenant Agreement – When a tenant has opened an account at a property for the distribution of services they have agreed to be an Erie Thames Customer and have accepted responsibility for electricity charges provided to the service address. Therefore, the contract is with that tenant. When a tenant closes the account, Erie Thames will adhere to the date provided by the tenant, regardless of any agreements between the tenant and the landlord or owner, and a final bill will be issued for the account. Erie Thames shall not seek to recover any charges for service provided to that tenant at the rental unit after closure of the account from any person including the landlord/owner unless the person has agreed to assume responsibility for the charges.
Erie Thames may enter into an agreement with a landlord or owner whereby the landlord/owner agrees to assume responsibility for paying for continued service to the rental property after closure of a tenants account.

A landlord or owner may enter into the above mentioned agreement either by telephone or by written confirmation delivered by mail or email. A new account will be set up in the landlord/owner's, name pursuant to such an agreement, when:

- Erie Thames is advised that the tenant is vacating the property;
- the landlord/owner will be responsible for the new account(s) and any electricity charges for service provided at any and all units listed at a service address; and
- a new account set up charge will apply to new account(s), which will appear on the first

(electricity bill issued.

It is the responsibility of the landlord to ensure that Erie Thames is made aware of any changes in contact, mailing and/or billing information. Where landlord information is not known, the above agreement will not apply and Erie Thames may disconnection of the service.

2.2 Disconnection and Use of Load Control Devices

Erie Thames has the right and/or obligation to disconnect or limit the supply of electrical energy to a Customer consistent with the *Electricity Act* for causes including but not limited to:

- Adverse effect on the reliability and safety of the distribution system.
- Imposition of an unsafe worker situation beyond normal risks inherent in the operation of the distribution system.
- A material decrease in the efficiency of Erie Thames's distribution system.
- A materially adverse effect on the quality of distribution services received by an existing connection.
- Inability of Erie Thames to perform planned inspections and maintenance.
- Failure of the consumer or customer to comply with a directive of a distributor that Erie Thames makes for purposes of meeting its licence obligations.
- The customer owes Erie Thames money for distribution services, or for a security deposit. Erie Thames shall give the customer a reasonable opportunity to provide the security deposit consistent with Section 2.4.20 and 2.4.20Aof the Distribution System Code.
- Failure to notify Erie Thames of Customer responsibility for electricity account when a new party moves into an existing connected property and consumes electricity;

Without limiting the generality of the foregoing, prior to disconnecting a property for non-payment, Erie Thames shall provide to any person that receives notice of disconnection:

- The Fire Safety Notice of the Office of the Fire Marshal; and
- Any other public safety notices or information bulletins issued by public safety authorities provided to Erie Thames.

Appendix 3 of these Conditions of Service includes Erie Thames Disconnection Policy and Use of Load Control Devices Policy. The Policies describe Erie Thames disconnection and the use of load control devices practices.

Disconnection does not relieve the Customer of the responsibility to pay the overdue amounts. Erie Thames may recover from the Customer responsible for the disconnection reasonable costs associated with disconnection including costs for repairs of Erie Thames physical assets attached to the property in reconnecting the property.

Reconnection or restoration of the electricity service will occur only after the reason for disconnection or limitation has been remedied. Erie Thames may recover from the person requesting the reconnection any Erie Thames OEB approved reconnection charge.

2.3 Conveyance of Electricity

2.3.1 Guaranty of Supply

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

Customers requiring a higher degree of security than that of normal supply are responsible to provide their own back-up or standby facilities.

When power is interrupted, or the Customer is experiencing power quality problems the Customer or their electrical contractor shall first ensure that interruption is not due to problems within the customer owned installation. If after verifying that the cause of the problem does not reside on the customers' installation, the customer shall contact Erie Thames. Erie Thames will respond to and take reasonable steps to restore power. Erie Thames reserves the right to recover costs from the customer for making false claims of interruptions.

Although it is Erie Thames policy to minimize inconvenience to Customers, it is necessary to occasionally interrupt a Customers' supply to maintain or improve Erie Thames system, or to provide new or upgraded services to other Customers. Whenever practical and cost effective, as determined by Erie Thames, arrangements suitable to the Customer and Erie Thames may be made to minimize any inconvenience. Erie Thames will endeavor to provide the Customer with reasonable advance notice, except in cases of emergency, involving danger to life and limb, or impending severe equipment damage.

Erie Thames will endeavor to notify Customers prior to interrupting the supply to any individual service. However, if an unsafe or hazardous condition is found to exist, or if the use of electricity by apparatus, appliances, or other equipment is found to be unsafe or damaging to Erie Thames or the public, service may be discontinued without notice.

Depending on the outage duration and the number of Customers affected, Erie Thames may issue a news release to advise the general public of the outage.

2.3.2 Power Quality

Erie Thames will respond to and take reasonable steps to investigate consumer power quality complaints and report to the consumer on the results of the investigation. The method and level of investigation will be at the discretion of Erie Thames.

If the source of a power quality problem is caused by the consumer making the complaint, Erie Thames may seek reimbursement for the time and cost spent to investigate the complaint.

If the source of a power quality problem is caused by a consumer, Erie Thames may direct the consumer to take corrective action. If the Consumer does not take such action within a reasonable time, Erie Thames may disconnect the supply of power to the Customer. (*see section 2.2*)

2.3.3 Electrical Disturbances

There are levels of voltage fluctuation and other disturbances that can cause flickering lights and more serious difficulties for Customers connected to Erie Thames distribution system.

Some types of electronic equipment, such as video display terminals, can be affected by the close proximity of high electrical currents that may be present in transformer rooms.

No electrical equipment, which may produce an undesirable system disturbance, shall be connected by a customer to a customer's service without prior approval of Erie Thames.

Examples of equipment, which may cause disturbance, are large motors, welders and variable speed drives. In planning the installation of such equipment, the customer is required to consult with Erie Thames.

Erie Thames will endeavour to maintain voltage variation limits, under normal operating conditions, at the Customers' Delivery Points, as specified by the latest edition of the Canadian Standards Association, C235. However, more sensitive electronic equipment such as computers can be seriously affected by variations in quality of supply voltage. Customers who need electrical power of high quality and with rigid voltage tolerances are responsible for providing their own power conditioning equipment.

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

The customer shall provide such protective devices as may be necessary to protect his property or equipment from any disturbance beyond the control of Erie Thames.

2.3.4 Standard Voltage Offerings

2.3.4.1 For Secondary Voltage

The Supply Voltage governs the limit of supply capacity for any Customer. General guidelines for supply <u>from overhead street circuits are as follows</u>:

- *at 120/240 V. single phase, or*
- *347/600 V. three phase, four wire, or*
- *120/208 V three phase, four wire,*

OR

Where street circuits are buried, the Supply Voltage and limits will be determined upon application to Erie Thames.

OR

Where the Customer or Developer provides a pad on private property;

- *at 120/240 V single phase, or*
- *at 120/208 V three phase, four wire, or*
- *at 347/600 V three-phase, four-wire*

2.3.4.2 For Primary Voltage

Primary supplies to transformers or customer-owned substations will be one of the following as determined by Erie Thames:

- *2,400/4,160 volts 3 phase 4 wire*
- *4,800/8,320 volts 3 phase 4 wire*
- *7,200/12,400 volts 3 phase 4 wire*

(• *8,000/13,800 volts 3 phase 4 wire*
- *16,000/27,600 volts 3 phase 4 wire*
- *27,600 volts 3 phase 3 wire delta*
- *44,000 volts 3 phase 3 wire*

An electrical requirement in excess of 750 kVA may require a customer owned Substation supplied at the voltage as determined by Erie Thames.

2.3.5 Voltage Guidelines

Erie Thames maintains service voltage at the Customers' service entrance within the guidelines of C.S.A. Standard CAN3-C235 (latest edition) which allows variations from nominal voltage of:

6% for Normal Operating Conditions
8% for Extreme Operating Conditions

Where voltages lie outside the indicated limits for Normal Operating Conditions but within the indicated limits for Extreme Operating Conditions, improvement or corrective action will be taken on a planned and programmed basis, but not necessarily on an emergency basis.

Where voltages lie outside the indicated limits for Extreme Operating Conditions, improvement or corrective action will be taken on an emergency basis. The urgency for such action will depend on many factors such as the location and nature of load or circuit involved, the extent to which limits are exceeded with respect to voltage levels and duration, etc.

2.3.6 Back-up Generators

Customers with portable or permanently connected emergency generation capability shall comply with all applicable criteria of the Ontario Electrical Safety Code and in particular, shall ensure that customer emergency generation does not back-feed on Erie Thames system.

Customers with permanently connected emergency generation equipment shall notify Erie Thames regarding the presence of such equipment.

Erie Thames reserves the right to have the connection of this equipment inspected.

Generation systems found to be feeding into the Distribution system without proper approval of Erie Thames shall be subject to immediate disconnection.

2.3.7 Metering

2.3.7.1 General

2.3.7.1.1 Access

Erie Thames or its agents shall have the right to access and read any of Erie Thames electricity meters on the Customer's premises.

All metering installations shall be accessible from a public area.

(***2.3.7.1.2 Costs***

All Erie Thames metering equipment located on the Customer's premises are in the care and at the risk of the Customer and if destroyed or damaged, other than by normal usage, the Customer will pay for the cost of repair or replacement.

Regardless of any charges for metering installations, all meters and meter instrumentation equipment shall remain the property of Erie Thames and maintenance of this equipment shall be Erie Thames responsibility.

2.3.7.1.3 Voltage

Generally, metering will be at utilization voltage. Where Erie Thames provides primary transformation, primary voltage metering will be allowed only in special circumstances following full discussion with Erie Thames.

Customer-owned substations may require primary metering. The provisions required for these installations shall be specified and approved by Erie Thames for each application.

2.3.7.1.4 Primary / Bulk Metering

Primary metering units may be installed outdoors or within and electrical vault as outlined in the current Electrical Safety Code. Where the Owner prefers not to provide an approved electrical vault, Erie Thames at additional cost can provide a metering unit with non-flammable coolant.

Non-residential or mixed-use buildings will normally be bulk metered by a single meter. However, where specific areas are clearly and permanently defined and in other respects as a separate entity, individual metering of the loads will be considered.

In all installations where the Customer requests revenue metering remote from the secondary entrance equipment or downstream from a Customer-owned dry-core transformer, provisions are required for a bulk meter directly after the main switch. This bulk metering is required in addition to any public metering provisions. The Customer will be required to contribute to the cost of the metering installation.

Where more than one meter exists, the meters shall be grouped where practicable.

The customer/contractor shall permanently and legibly identify all metered services with respect to correct municipal 911 address and unit #. The identification shall be applied to all service switches and breakers and to all meter cabinets and meter mounting devices that are not immediately adjacent to the service switch. The customer/contractor shall insure that all service identifications are accurate and by not doing so will be held totally responsible. Erie Thames shall issue a Meter Verification Sheet for this purpose to the owner or contractor.

In any case, a copy of the metering layout plan shall be forwarded to Erie Thames for review and approval.

If the distribution of the metered load circuit is in dispute, (ie: circuits from one premise is found to supply a second premise) Erie Thames reserves the right to transfer all accounts into the Property Owners' name until such time as the problem has been resolved, and the individual metering can be clearly identified with the individual units.

2.3.7.1.5 Locks

All devices on the line side of Erie Thames metering shall have provisions for padlocking.

For commercial and industrial services the Customer's main switch shall have provisions for padlocking the switch handle in the open position and the switch cover or door in the closed position.

When a disconnect device has been locked in the "OFF" position by Erie Thames, under no circumstances shall anyone remove the lock and energize it without first receiving approval from Erie Thames.

At the discretion of Erie Thames, a dual locking arrangement, a master key arrangement, a key box arrangement, or a copy of the access key will be required for access.

2.3.7.2 Current Transformer Boxes

Where a current transformer box is required, it shall be CSA approved, of a size and type as stipulated by Erie Thames, and include a provision for padlocks. A removable plate shall be provided in the box for mounting the equipment.

As an alternative to a separate CT box and meter, a single enclosure combining both functions may be feasible. Contact Erie Thames for details.

In cases where the CTs only meter a portion of the metal clad switchgear (such as house loads), a separate disconnect switch must be installed ahead of the metering compartment so that the service can be de-energized without any interruption to the main service supply.

Generally, one house load meter only will be allowed. Additional house load meters will require authorization from Erie Thames.

Conductors should enter the current transformer box at the top and leave at the bottom, or vice versa. If this cannot be arranged, the next largest CT box must be used to enable conductors to be trained in place. Where parallel conductors are used, the sum of the conductors will determine the size of the CT box to use. In all cases the Customer shall supply suitable cable termination lugs.

On all electrical services that require current transformers and the neutral for metering, an isolated neutral block shall be provided in the current transformer box.

2.3.7.3 Interval Metering

The Distribution System Code, as amended from time to time, requires Erie Thames to meter Customers of specific load levels with pulse-recording meters, or interval meters, which are interrogated remotely. Erie Thames, at its' sole discretion, may also require such metering on any customer whose load characteristics may have a significant impact on the Net System Load Shape, or where reasonable access to the meter for the purpose of acquiring metering data may be limited due to location.

A customer that requests interval metering shall compensate a distributor for all incremental costs associated with that meter, including the capital cost of the interval meter, installation costs associated with the interval meter, ongoing maintenance (including allowance for meter failure), verification and (re-verification of the meter, installation and ongoing provision of communication line or communication link with the customer' s meter, and cost of metering made redundant by the customer requesting interval metering. The communication system utilized for interval meters shall be in accordance with Erie Thames requirements.

Where such metering exists Erie Thames will consider customer requests to provide a secondary pulse for load control or customer-owned metering at the customers' expense.

Where a customer submits a request to read their own interval meter, Erie Thames shall make this access available given the following conditions are met:

- The meter has the capability of read-only password protection
- The customer provides a signed copy of the "Interval Metering Access Agreement" to Erie Thames.

2.3.7.3.1 Interval Metering Communications

- Solid-state recorders and/or Electronic Interval Meters installed by Erie Thames have provision for remote interrogation over a telephone line. To accommodate this feature the Owner will provide shared access to a telephone line for Erie Thames metering purposes.
- At its' sole discretion, for metering installations where loss of metering data would cause a substantial impact on Erie Thames Settlement System, Erie Thames may require the phone line to be dedicated for metering purposes only.
- A voice quality telephone line, which is active 24 hours a day to the metering location extension jack, which is mounted on the metering board.
- Phone lines must be installed and functioning prior to the new service being energized.

2.3.7.3.2 Smart Metering

Erie Thames is replacing all its residential and small commercial meters with Smart Meters to comply with the governments' smart meter initiatives. With implementation of time-of-use pricing, the processes for meter consumption data retrieval and billing will align with applicable regulations and directions from the Smart Meter Entity.

2.3.7.4 Meter Reading

Erie Thames will read all meters on a regularly scheduled basis whenever possible. If an actual meter reading is not obtained, the Customer shall pay a sum based on an estimated demand and/or energy for electricity used since the last meter reading.

2.3.7.5 Final Meter Reading

When a service is no longer required, or the Customer is switching Energy Providers, the Customer shall provide Erie Thames sufficient notice of the date so that a final meter reading can be obtained. The Customer shall provide access to Erie Thames or its agents for this purpose.

If a final meter reading is not obtained, the Customer shall pay a sum based on an estimated demand and/or energy for electricity used since the last meter reading.

2.3.7.6 Faulty Registration of Meters

Metering electricity usage for the purpose of billing is governed by the Federal Electricity and Gas Inspection Act and associated regulations, under the jurisdiction of Measurement Canada, Industry Canada. Erie Thames revenue meters are required to comply with the accuracy specifications established by the regulations under the above Act.

In the event of incorrect electricity usage registration, Erie Thames will determine the correction factors based on the specific cause of the metering error and the Customer's electricity usage history. The Customer shall pay for all the energy supplied, a reasonable sum based on the reading of any meter formerly or subsequently installed on the premises by Erie Thames, due regard being given to any change in the character of the installation and/or the demand.

If the incorrect measurement is due to reasons other than the accuracy of the meter, such as incorrect meter connection, incorrect connection of auxiliary metering equipment, or incorrect meter multiplier used in the bill calculation, the correction will apply for the period defined in the Retail Settlement Code, Section 7.7. Erie Thames will correct the bills for that period in accordance with the regulations under the Electricity and Gas Inspection Act (Canada).

2.3.7.7 Meter Dispute Testing

Erie Thames will attempt to resolve billing enquiries. However, to give Customers confidence in the accuracy of electricity meters, Erie Thames will conduct an internal investigation to verify the accuracy of any meter the Customer believes to be recording incorrectly. If the internal investigation does not resolve the matter, the Customer or Erie Thames may request Measurement Canada to test the meter.

If the test indicates that the meter is not accurate, the Customer's historic billing will be adjusted, and Erie Thames shall pay the full costs of the meter dispute testing.

2.3.7.8 Location

The location of the indoor or outdoor meter shall be readily accessible at all times and acceptable to Erie Thames. If a meter is recessed or enclosed after installation, without the prior approval of Erie Thames, the service may be subject to disconnection.

The location of the service entrance, routing of duct banks, metering, and all other works will be established through consultation with Erie Thames. Failure to comply may result in relocation of the service plant at the Owner's expense.

In all locations where Commercial/Industrial revenue metering is accessible to the general public, a lockable enclosure or a room for service equipment and meters, shall be provided by the Owner at the discretion of Erie Thames, as follows:

- *An electrical room reserved solely for metering equipment or*
- *Metal enclosed switchgear approved by Erie Thames or*
- *A suitable metal metering cabinet or*
- *A vandal proof cage.*

2.3.7.9 (Meter Mounting Heights

Provision for metering shall facilitate a practical mounting height for revenue meters in compliance with all applicable codes and regulations.

2.3.7.10 Environment

The following requirements apply to the areas allocated for revenue metering.

The customer to the satisfaction of Erie Thames shall provide where there is the possibility of danger to workmen, or damage to equipment from moving machinery, dust, fumes, or moisture, protective arrangements.

A clear safe working space of not less than 1.2 m (48") in front of the installation from the floor to ceiling with a minimum ceiling height of 2.1 m (84") provided to insure the safety of Erie Thames or other authorized employee(s) who may be required to work on the installation.

Where excessive vibration may affect or damage metering equipment, adequate shock-absorbing mounting shall be provided and installed by the customer.

2.3.7.11 Meter Sockets

The owner will supply and install a meter socket as specified by Erie Thames. Meter sockets will be directly accessible to Erie Thames staff.

A listing of approved revenue metering sockets is available from Erie Thames.

2.3.7.12 Cabinets

Where required by these Conditions of Service the Owner shall supply and install a meter cabinet to Erie Thames requirements.

Meter cabinets shall be installed indoors, except where special permission is granted by Erie Thames to install the meter cabinet outside. In such cases, an approved weather proof, lockable, C.S.A. approved meter cabinet shall be provided by the Customer.

2.3.7.13 Metering Loops

Three-phase, four-wire services will require a loop for metering, within the meter cabinet, for all three phases.

Mineral insulated, solid, or hard drawn wire conductors are not acceptable as metering loops.

2.3.7.14 Metal Enclosed Switchgear

The following regulations apply to the installation of instrument transformers and metering equipment within metal enclosed switchgear.

Erie Thames will provide the following revenue metering equipment as required:

- Colour coded secondary wiring

(• Revenue meters

The Owner shall:

- consult with Erie Thames regarding the metering equipment to be provided which may include:

    - Potential transformers
    - Potential transformer fuse holders and fuses
    - Current transformers
    - Phone line for remote interrogation of meters
    - Duplicate Pulse Initiators
    - Provide complete shipping instructions for instrument transformers for those projects where these are to be provided by Erie Thames for installation by the switchboard manufacturer.
    - Install instrument transformers, metering cabinet and conduit.
    - Each main bus bar to be drilled and tapped (10-32) or (10-24) on the line side of the removable current transformer link.

- Submit two copies of the manufacturer's switchboard drawings, for approval, dimensioned to show provision for and arrangement of Erie Thames metering equipment.

Meters shall be installed by Erie Thames in a customer-owned metal cabinet of a size and type pre-approved by Erie Thames, mounted at an approved location separate from the switchgear.

Tamper proof or sealable rigid conduit or any equally approved conduit of a size and type specified by Erie Thames shall be installed between the CT compartment of the switchgear and the meter cabinet.

For conduit installations greater than 30 m (100'), in length or where several bends are necessary, larger conduits or other special provision may be required, at the discretion of Erie Thames.

2.3.7.15 Switchgear Connected to Wye Source

Where a Wye source neutral connection is to be used or grounded, the Owner shall provide a conductor sized to the requirements of the Ontario Electrical Safety Code from the instrument transformer compartment to the neutral connection.

2.3.7.16 Four Quadrant Metering (Generation)

All Ontario Energy Board-licensed generators connected to the distribution system that sell energy and settle through Erie Thames's retail settlement process shall be required to install metering that meets the requirements of the Distribution System Code as approved by the Ontario Energy Board, and/or the Market Rules as approved by the Independent Electricity Market Operator.

2.4 Tariffs and Charges

2.4.1 Service Connection

Charges for Service Connections are set out in Erie Thames approved rates, (Miscellaneous Rates and Charges) and may be obtained by request from Erie Thames. Notice of Rate revisions may be published in the local newspapers, on Erie Thames website and/or mailed out to all customers with the first billing issued at revised rates.

2.4.2 Energy Supply

Erie Thames shall provide Customers connected to the Distribution System with access to electricity through Standard Supply Service as defined in the Retail Settlement Code published by the OEB or as mandated though Legislation or Regulations issued by the Ministry of Energy.

Disputes arising from charges relating to Standard Supply Service shall be directed to Erie Thames.

Customers will be switched to their Retailer of choice only if the retailer has a Service Agreement with Erie Thames. The Customer's authorized Retailer through the Electronic Business Transaction system (EBT) must make the Service Transfer Request (STR) in accordance with the rules established and amended from time to time by the Ontario Energy Board.

Disputes arising from charges relating to Retailer Service shall be directed to the Retailer.

Erie Thames may, at its discretion, refuse to process a Service Transfer Request for a Customer to switch to a Retailer if that Customer owes money to Erie Thames for Distribution Services and or Standard Supply Service.

2.4.2.1 Wheeling of Power

Customers considering delivery of electricity through Erie Thames Distribution System shall contact Erie Thames for technical requirements and current applicable Rates.

2.4.3 Deposits

Whenever required by Erie Thames, the Customer shall provide and maintain security in an amount that Erie Thames has been mandated to collect, or deems necessary and reasonable. Erie Thames shall require security amounts based on Erie Thames existing Security Deposit Policies. The current Security Deposit policy is included as Appendix 3 – Policy 6.1 of these Conditions of Service.

Effective October 1, 2011, Erie Thames will waive the requirement to provide a security deposit for Eligible Low-Income Customer provided the Customer contacts Erie Thames to request such a waiver and their low-income eligibility is confirmed. Furthermore, where a social service agency or a government agency advises Erie Thames that it is assessing a Customer for eligibility as an Eligible Low-Income Customer, the due date for payment of the security deposit shall be extended for 21 days pending the eligibility decision. Additionally, an Eligible Low-Income Customer may, after October 1, 2011, request a refund of any security deposit previously paid to Erie Thames, after application of the security deposit to any outstanding arrears on said customer's account. The criteria for waiving and/or returning a security deposit are defined in Appendix 3 – Policy 6.1 Security Deposit of these Conditions of Service.

Where a customer proposes the development of premises that requires Erie Thames to place equipment orders for special projects, the customer is required to sign the necessary Supply Agreements and furnish a suitable deposit before such equipment is ordered by Erie Thames.

2.4.4 Billing

Erie Thames may, at its option, render bills to its Customers on either a monthly, bi-monthly, quarterly or annual basis. The option applicable to the customer shall be identified to the customer at the time of application for service.

Prorating of Service and Demand charges will be performed at the discretion of Erie Thames.

2.4.4.1 Competitive Charges:

Are based on rates as determined by:

i. the Hourly Ontario Spot Market Price (HOEP); or
ii. the utilities Weighted Average Price (WAP) as determined by net system load; or
iii. the customers retailer contract rate; or
iv. the rates published by the OEB; or
v. Legislation or Regulations issued by the Ministry of Energy.

2.4.4.2 Non-competitive Charges:

Non-competitive charges are based on rates approved by the Ontario Energy Board and fall outside the scope of this document. Approved rates as they relate to the transmission, distribution and other non-competitive elements may be attained through the utilities rate documents. These documents will be provided by the utility at the customer's request.

2.4.4.3 Billable Engineering Units:

Customers will be billed on:

i. actual or estimated meter reading data; or
ii. derived consumption data (Streetlights, sentinel lights and other scattered loads); or
iii. a flat rate, depending on the type of load being billed.

2.4.4.4 Use of Estimates:

In months where a bill is issued, but no reading is obtained, Erie Thames estimates usage in order to determine billing quantities. The estimate is based on historical usage for the premise, or a pre-determined quantity if there is no historical usage information available.

2.4.5 Payments and Late Payment Charges

Bills are rendered for distribution services and electrical energy used by the Customer. Bills are payable in full by the due date.

Bills are due when rendered by the utility. A customer may pay the bill without the application of a late payment charge up to a due date, which shall be a minimum of sixteen calendar days from the date of mailing or hand delivery of the bill. This due date shall be identified clearly on the customer's bill.

Where payment is made by mail, payment will be deemed to be made on the date post-marked. Where payment is made at a financial institution acceptable to the utility, payment will be deemed to be made when stamped/acknowledged by the financial institution or an equivalent transaction record is made.

A partial payment will be applied to any outstanding arrears before being applied to the current billing, unless special considerations have been made by the utility.

Outstanding bills are subject to the collection process and may ultimately lead to the service being discontinued or limited. Service will be restored once satisfactory payment has been made. Discontinuance of service does not relieve the Customer of the liability for arrears.

Erie Thames shall not be liable for any damage on the Customer's premises resulting from such discontinuance of service. A reconnection charge may apply where the service has been disconnected due to non-payment.

The Customer will be required to pay additional charges for the processing of non-sufficient fund (N.S.F.) cheques.

2.4.6 Unauthorized Energy Use

Erie Thames shall use its discretion in taking action to mitigate unauthorized energy use. Upon identification of possible unauthorized energy use, Erie Thames shall notify, if appropriate, Measurement Canada, The Electrical Safety Authority, Police Officials, Retailers that service customers affected by an authorized energy use, or other entities.

Erie Thames may recover from the parties responsible for the unauthorized energy use all costs incurred by Erie Thames arising from unauthorized energy use, including an estimate of the energy used, inspection and repair costs.

A service disconnected due to unauthorized use of energy shall not be reconnected until such time as all arrears resulting from the unauthorized use has been resolved to the satisfaction of Erie Thames.

Prior to reconnection, Erie Thames shall require proper authorization from applicable authorities.

2.5 Customer Information

Erie Thames reserves the right to request specific information from the customer in order to facilitate the normal operation of its business. Failure of a customer to supply such information may prevent the normal continuation of service.

The Retail Settlement Code as amended from time to time specifies the rights of customers and their retailers to access current and historical usage information and related data and the obligations of distributors in providing access to such information.

Under these requirements, Erie Thames shall upon authorization by a customer make the following information available to the Customer or the Retailer that provides electricity to a customer connected to Erie Thames distribution system:

- Erie Thames account number for the customer,
- Erie Thames meter number for the meter or meters located at the customer's service address
- The customer's service address,
- The date of the most recent meter reading,
- The date of the previous meter reading,
- Multiplied kilowatt-hours recorded at the time of the most recent meter reading,

- Multiplied kilowatt-hours recorded at the time of the previous meter reading,
- Multiplied kW for the billing period (if demand metered),
- Multiplied kVA for the billing period (if available),
- Usage (kWh's) for each hour during the billing period for interval-metered customers
- An indicator of the read type (e.g., distributor read, consumer read, distributor estimate, etc.)
- Average distribution loss factor for the billing period

This information will be provided to the Customer / Retailer upon request twice per year at no charge. Erie Thames may request a fee to recover costs for additional requests. A request is considered to be data delivered to a single address. Thus, a single request to send information to three locations is considered three requests.

Erie Thames acknowledges that no confidential information regarding its' customers shall be released to a third party without the expressed prior written consent of the customer unless the request is rightfully received from the third party requesting the information, or Erie Thames is legally required to disclose such information under the terms and in accordance with the Freedom of Information and Protection of Privacy Act, R.S.O. 1990, c. F.31.

SECTION 3 CUSTOMER SPECIFIC

3.1 Residential

This section refers to the supply of electrical energy to Customers residing in residential dwelling units.

3.1.1 General

Energy is generally supplied as single phase, 3-wire, 60-Hertz, having a nominal voltage of 120/240 Volts.

There shall be only one Delivery Point to a dwelling.

In circumstances where two existing services are installed to a dwelling, and one service is to be upgraded, the upgraded service will replace both of the existing services.

All new single-family homes will be required to install their primary and secondary service wires to the specifications contained within Erie Thames technical specification document.

Whether the method of supply will be overhead or underground will be at the discretion of Erie Thames. Erie Thames will adhere to any existing regulations subject to requirements of authorities.

Unless specifically documented otherwise to the Customer, where Erie Thames has taken ownership of such plant all services installed by Erie Thames or by an approved contractor using approved materials, will be maintained by Erie Thames.

3.1.2 Early Consultation

The Customer shall supply a completed Site Planning document and related information to Erie Thames well in advance of installation commencement. (see appendix) The information shall be supplied in a manner requested by Erie Thames at the time of the application.

3.1.3 Standard Connection Allowance

For the purposes of calculating customer connection fees, the Basic Connection for Residential consumers is defined as 100 amp 120/240 volt overhead service.

The basic connection for each customer shall include;

- **i.** supply and installation of overhead distribution transformation capacity or an equivalent credit for transformation equipment; and
- **ii.** up to 30 meters of overhead conductor or an equivalent credit for underground services.

In the case of an upgrade to an existing service, where the existing service is below the basic connection, the credit up to the basic connection will apply.

Secondary services exceeding the basic 30 meter length may require specific design approved by Erie Thames to ensure power quality.

3.1.4 Variable Connection Fees

Any requirements above the defined basic connection shall be subject to a variable connection charge to be calculated as the costs associated with the installation of connection assets above and beyond the basic connection. Erie Thames may recover this amount from a customer through a connection charge or equivalent payment.

3.1.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of Erie Thames.

The Customer must obtain a Demarcation Point Location from Erie Thames before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer’s expense.

Maintenance of the portion of the Secondary Service owned by Erie Thames includes repair and like-for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by Erie Thames.

3.1.5.1 Secondary Service Connections

The Point of Demarcation for residential services up to 400 amps is at the line side of the Meter Base for Underground services, and at the top of the stack for Overhead services, beyond which the customer bears full responsibility for installation and maintenance.

The Point of Demarcation for residential services over 400 amps is at the secondary side of the transformer.

For Secondary Services wholly owned and maintained by the Customer, the Demarcation Point is the secondary connection at the transformer or the service bus.

The Customer shall install, own, and maintain the secondary conductor under any of the following conditions:

(a) conductor terminations are inside the Customer’s building;
(b) conductor is installed beyond the service entrance;
(c) conductor is connected to a Primary Service; or
(d) conductor is a non-standard installation.

3.1.5.2 Primary Service Connections

For Primary Service, the Demarcation Point is the primary connection at Erie Thames’s Distribution system.

3.1.6 Supply Voltage

(a) A Residential building is supplied at one service voltage per land parcel.

(b) Depending upon the location of the building the supply voltage will be one of the following:

- o *120/240 Volts 1 Phase 3 Wire*
- o *120/208 Volts 1 Phase 3 Wire*
- o *120/208 Volts 3 Phase 4 Wire*
- o *347/600 Volts 3 Phase 4 Wire*

(c) The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by Erie Thames. The Owner shall obtain prior approval from Erie Thames for the use of any specific voltage at any specific location.

3.1.7 Access

At Erie Thames discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in Erie Thames name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to Erie Thames at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

3.1.8 Metering

The owner will supply and install a meter socket complete with collar acceptable to Erie Thames. Meter sockets will be directly accessible to Erie Thames and:

- Mounted 1.7 meters from the finished grade to the center of the meter and, either on the exterior of the front of the building or, within 3 meters of the front of the building on the driveway side.
- Installed ahead of (on the line side of) the main disconnect switch.
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact Erie Thames for specific location instructions prior to installation.

For more details refer to section 2.3.7 in these Conditions of Service.

3.1.9 Overhead Service

The Owner will provide service equipment to both Erie Thames and ESA requirements, and be of sufficient height to maintain proper minimum clearances. The Owner's main switch and the overhead service conductors will be of compatible capacity.

3.1.10 Underground Service

Underground secondary services will be installed at the Owners' expense, to Erie Thames's specifications. The Owner's main switch and the underground service conductors will be of compatible capacity.

3.1.11 Street Townhouses and Condominiums:

NOTE: Street Townhouses and Condominiums requiring centralized bulk metering will be covered under section 3.2 of these Conditions of Service. Also 3.1.11.2

3.1.11.1 Service Information:

The Owner will enter into a Servicing Agreement with Erie Thames, governing the terms and conditions under which the electrical distribution system and services will be designed and installed.

The Owner will provide all of the civil works to accommodate Erie Thames and will pay the complete cost of the electrical distribution system, design and services.

- The distribution system and services shall be underground unless otherwise approved.
- One service will be provided for each unit.
- The nominal service voltage will be 120/240 volts, 1 phase, 3 wire.
- Erie Thames will approve the location of duct banks, service routings and meter bases.
- Distribution plant shall not be installed until grade is at +/- 150 mm of final grade unless otherwise approved by Erie Thames.
- Street lighting will be to Municipal standards and installed at the Owner's expense.

3.1.11.2 Metering:

The Owner will supply and install meter sockets specified by Erie Thames.

Multiple or grouped meter bases will be accepted only when prior approval has been given by Erie Thames both as to type and proposed location. A completed meter verification form shall be provided to Erie Thames prior to energization.

Meter sockets will be located on the exterior front wall of the units and will be directly accessible to Erie Thames.

- Mounted on the front wall 1.7 metres above finished grade to the centre of the meter
- Installed ahead of (on the line side of) the main disconnect switch
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact Erie Thames for specific location instructions prior to installation.

Normally the service will not be energized until the outside finish in the area of the revenue meter has been completed. If exceptions are made to this, then the general contractor will be responsible for ensuring that the meter is suitably protected while work is being done on the exterior wall adjacent to the meter. The general contractor will be entirely responsible for all costs for materials and labour for repairing or replacing a damaged meter.

3.1.12 Seasonal and Remote Dwellings:

Due to the varied nature of Seasonal and Remote Dwellings some special arrangements may be required to service these locations. Arrangements will be made in such a manner to provide services such as restoring power, maintenance of equipment or new construction requests to water access or remote customers, without endangering personnel or the public.

3.1.12.1 (**Service Information**

The Owner will enter into a Servicing Agreement with Erie Thames, governing the terms and conditions under which the electrical distribution system services will be provided.

In the event of a power interruption, Erie Thames will respond to and take reasonable steps to restore power. Erie Thames reserves the right to recover costs from the customer for making false claims of interruptions.

3.1.12.2 Access:

- **Night crossings**

  Erie Thames transportation equipment will not be used to cross any water ½ hour before sunset and ½ hour after sunrise due to safety concerns. It will be at the discretion of Erie Thames whether they will board customer owned transportation equipment in these circumstances.

- **Ice conditions**

  Recognizing seasonal ice hazards, Erie Thames reserves the right to suspend water passage during freeze up and spring thaw, as well as any such time deemed unsafe by Erie Thames.

- **Severe weather conditions**

  Recognizing that severe weather conditions may pose undue safety hazards, Erie Thames reserves the right to postpone attempts to restore power until restoration can be performed in a safe manner.

3.1.13 Inspection

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by Erie Thames prior to connection.

Erie Thames or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of Erie Thames and subject to inspection by Erie Thames.

(Refer to section 2.1.4 for further inspection details)

3.2 General Service (Below 50 kW)

3.2.1 General

This section refers to the supply of electrical energy to General Service Buildings requiring a connection with a connected load less than 50 kW, and, Town Houses and Condominiums described in section 3.1.8 that require centralized bulk metering.

General Service buildings are defined as buildings that are used for purposes other than single-family dwellings.

3.2.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with Erie Thames in the early planning stages to ascertain Erie Thames requirements.

The Owner shall supply a completed Electrical Service Connection Form to Erie Thames well in advance of installation commencement to allow Erie Thames time for proper planning, ordering of equipment etc.

3.2.3 Standard Connection Allowance

All costs attributed to the connection of a new General Service customer (Below 50 kW) shall be recovered through a variable connection Fee.

3.2.4 Variable Connection Fees

All costs associated with the installation of connection assets shall be subject to a variable connection charge. Erie Thames may recover this amount from a customer through a connection charge or equivalent payment.

3.2.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of Erie Thames.

The Customer must obtain a Demarcation Point Location from Erie Thames before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Secondary Service owned by Erie Thames includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by Erie Thames.

Erie Thames shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by Erie Thames will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner's liability, maintenance and repair are at the Owners' expense

3.2.5.1 Secondary Service Demarcations

A General Service Customer Demarcation Point is at the secondary side of the transformer, or as otherwise set by Erie Thames, beyond which the customer bears full responsibility for installation and maintenance.

In some instances, where it is in the best interest of the operation of the distribution system, Erie

Thames may establish the Demarcation Point at the top of stack for overhead services or at the meter base for underground services.

The Demarcation Point might be located on an adjacent property. In such cases, a registered easement must exist.

3.2.5.2 Primary Service Demarcations

For Primary Service, the Demarcation Point is the primary connection at Erie Thames's Distribution system.

3.2.6 Supply Voltage

(a) A General Service building is supplied at one service voltage per land parcel.

(b) Depending upon the location of the building the supply voltage will be one of the following:

- *120/240 Volts 1 Phase 3 Wire*
- *120/208 Volts 1 Phase 3 Wire*
- *120/208 Volts 3 Phase 4 Wire*
- *347/600 Volts 3 Phase 4 Wire*

(c) The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by Erie Thames. The Owner shall obtain prior approval from Erie Thames for the use of any specific voltage at any specific location.

3.2.7 Access

At Erie Thames discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in Erie Thames name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to Erie Thames at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

3.2.8 Metering

The owner will supply and install a meter socket complete with collar acceptable to Erie Thames. Meter sockets will be directly accessible to Erie Thames and unless otherwise specified during the early consultation process:

- Mounted 1.7 meters from the finished grade to the center of the meter and, either on the exterior of the front of the building or, within 3 meters of the front of the building on the driveway side.
- Installed ahead of (on the line side of) the main disconnect switch.
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact Erie Thames for specific location instructions prior to installation.

For more details refer to section 2.3.7 in these Conditions of Service.

3.2.9 (Overhead Service

In circumstances where Commercial buildings cannot reasonably be supplied electrical energy by an underground service, Erie Thames shall use its'sole discretion based on acceptable industry practices in establishing the specific requirements for the service installation.

3.2.10 Underground Service:

Under normal circumstances, Commercial buildings are supplied electrical energy by an underground service through a single point of entry for each land parcel, at a location specified by Erie Thames.

3.2.11 Supply of Equipment

Erie Thames supplies, installs and maintains subject to the variable connection fee:

- Primary switchgear.
- Primary transformation equipment.
- Meter and secondary metering transformers.

The Owner shall supply, install and maintain any additional equipment required for the connection beyond the point of Demarcation.

3.2.12 Inspection

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by Erie Thames prior to connection.

Erie Thames or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of Erie Thames and subject to inspection by Erie Thames.

(Refer to section 2.1.4 for further inspection details)

3.3 General Service (Above 50 kW)

3.3.1 General

This section refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load greater than 50 kW.

3.3.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with Erie Thames in the early planning stages to ascertain Erie Thames requirements.

The Owner shall supply a completed Electrical Service Connection Form to Erie Thames well in advance of installation commencement to allow Erie Thames time for proper planning, ordering of equipment etc.

3.3.3 Standard Connection Allowance

All costs attributed to the connection of a new General Service customer (Above 50 kW) shall be recovered through a variable connection Fee.

3.3.4 Variable Connection Fees

All costs associated with the installation of connection assets shall be subject to a variable connection charge. Erie Thames may recover this amount from a customer through a connection charge or equivalent payment.

3.3.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of Erie Thames.

The Customer must obtain a Demarcation Point Location from Erie Thames before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Secondary Service owned by Erie Thames includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by Erie Thames.

Erie Thames shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by Erie Thames will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner's liability, maintenance and repair are at the Owners' expense

3.3.5.1 Secondary Service Connections

A General Service Customer Demarcation Point for customers above 50 kW is at the secondary side of the transformer, or as otherwise set by Erie Thames, beyond which the customer bears full responsibility for installation and maintenance.

In some instances, where it is in the best interest of the operation of the distribution system, Erie Thames may establish the Delivery point at the top of stack for overhead services or at the meter base for underground services.

The location of the service entrance, routing of duct banks and all other works will be established through consultation with Erie Thames. Failure to comply may result in relocation of the service plant at the Owner's expense.

The Demarcation Point might be located on an adjacent property. In such cases, a registered easement must exist.

3.3.5.2 Primary Service Connections

For Primary Service, the Demarcation Point is the primary connection at Erie Thames's Distribution system.

In some circumstances the owner may be required to construct a private pole line. Primary conductors will be terminated complete with cut-out(s) at the Demarcation Point by Erie Thames at the owners' expense.

Where a private pole line is to be constructed by the Owner with an approved contractor, this shall be constructed to the ESA and Erie Thames requirements.

An electrical requirement in excess of 300 kVA may require a customer owned substation.

In some instances primary metering may be required.

3.3.6 Supply Voltage

A General Service building is supplied at one service voltage per land parcel.
Depending upon the location of the building the supply voltage will be one of the following:

- *120/240 Volts 1 Phase 3 Wire*
- *120/208 Volts 3 Phase 4 Wire*
- *347/600 Volts 3 Phase 4 Wire*

Depending upon the location of the building Primary supplies to transformers and Customer owned Sub-Stations will be one of the following as determined by Erie Thames:

- *2,400/4,160 volts 3 phase 4 wire*
- *4,800/8,320 volts 3 phase 4 wire*
- *7,200/12,400 volts 3 phase 4 wire*
- *8,000/13,800 volts 3 phase 4 wire*
- *16,000/27,600 volts 3 phase 4 wire*
- *44,000 Volts - 3 Phase 3 Wire*

The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by Erie Thames. The Owner shall obtain prior approval from Erie Thames for the use of any specific voltage at any specific location.

3.3.7 Access

At Erie Thames discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in Erie Thames name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to Erie Thames at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

3.3.8 Metering

Meter installations will be directly accessible to Erie Thames. The owner will consult with Erie Thames well in advance of installation commencement to allow Erie Thames time for proper planning and ordering of equipment.

For more details refer to section 2.3.7 in these Conditions of Service.

3.3.9 Overhead Service

In circumstances where Commercial buildings cannot reasonably be supplied electrical energy by an underground service, Erie Thames shall use its'sole discretion based on acceptable industry practices in establishing the specific requirements for the service installation.

3.3.10 Underground Service

Under normal circumstances, Commercial buildings are supplied electrical energy by an underground service through a single point of entry for each land parcel, at a location specified by Erie Thames.

3.3.11 Sub-transmission Service

The Owner will pay for the full cost of sub-transmission services and may in some circumstances be required to construct a private pole line. Erie Thames will terminate sub-transmission conductors complete with live line loops and hardware at the Demarcation Point.

3.3.12 Supply of Equipment

Erie Thames supplies, installs and maintains subject to the variable connection fee:

- Primary switchgear.
- Primary transformation equipment.
- Meter and secondary metering transformers.

The Owner shall supply, install and maintain any additional equipment required for the connection beyond the point of Demarcation.

3.3.13 Short Circuit Capacity

The Owner shall ensure that the service entrance equipment has an adequate short-circuit interrupting capability.

3.3.14 Inspection

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by Erie Thames prior to connection.

Erie Thames or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of Erie Thames and subject to inspection by Erie Thames.

(Refer to section 2.1.4 for further inspection details)

3.4 General Service (Above 500 kW)

3.4.1 General

This section refers to the supply of electrical energy to General Service Services requiring a connection at a connected load greater than 500 kW.

3.4.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with Erie Thames in the early planning stages to ascertain Erie Thames requirements.

The Customer shall supply a completed Electrical Service Connection Form to Erie Thames well in advance of installation commencement to allow Erie Thames time for proper planning, ordering of equipment etc.

Erie Thames will:

- *Advise the customer of the suitability of the in-service date*
- *Arrange with the customer for a Service Contract*
- *Review the submitted drawings; return one set to the customer with comments and/or approval. If requested by Erie Thames, the customer shall resubmit the drawings where the comments are extensive and require major changes*
- *Specify the required main fuse link or relay setting for co-ordination with the system. In case of multiple transformer stations, a complete co-ordination study shall be submitted by the customer for approval.*
- *Make the final connection to the source of supply*
- *Determine metering requirements*
- *Advise the Transmitter of the particulars of the customer owned substation*

3.4.3 Standard Connection Allowance

All costs attributed to the connection of a new General Service customer (Above 500 kW) shall be recovered through a variable connection Fee.

3.4.4 Variable Connection Fees

All costs associated with the installation of connection assets shall be subject to a variable connection charge. Erie Thames may recover this amount from a customer through a connection charge or equivalent payment.

3.4.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of Erie Thames.

The Customer must obtain a Demarcation Point Location from Erie Thames before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer’s expense.

(Maintenance of the portion of the Primary Service owned by Erie Thames includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by Erie Thames.

Erie Thames shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by Erie Thames will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner's liability, maintenance and repair are at the Owners' expense

Erie Thames reserves the right to direct the operations of any customer owned switchgear connected to the distribution system including those located beyond the point of demarcation.

3.4.5.1 Service Installation

In General, the Demarcation Point for a General Service Customer with a demand of over 500 kW is on the primary side of the transformer at the first available distributor owned point of isolation, or as otherwise set by Erie Thames. This delivery point might be located on an adjacent property from which Erie Thames has an authorized easement. In all cases the final Demarcation Point will be the decision of Erie Thames.

The location of the service entrance, routing of duct banks, metering facilities, and all other works will be established through consultation with Erie Thames. Failure to comply may result in relocation of the service plant at the Owner's expense.

Erie Thames will install overhead supply lines and required cut-outs to the first point of support on private property. The location of this support must be approved by Erie Thames and shall be within 30 metres of Erie Thames existing overhead plant. All costs for materials and labour shall be at the customers' expense.

The service pole or first point of support on private property shall be considered self-supported and shall be complete with suitable hardware for attaching the suspension insulators. The Customer shall be responsible for all costs associated with equipment, installation, and inspection.

Where the customer wishes an underground supply, the customer shall supply and install the underground cables and termination pole complete with primary switch, fuses and lightning arresters. The installation shall be subject to ESA inspection and specific approval of Erie Thames. The customer owned termination pole must comply with items as prescribed by Erie Thames.

At Erie Thames discretion, the customers' underground service may be connected to a termination pole owned by Erie Thames. In such cases, Erie Thames shall supply and install at the customers expense, any required primary switch, fuses, and lightning arrestors.

When requested, the customer shall make provision in the substation switchgear or transformer, for loop feeding Erie Thames supply cables via load interrupter switches.

In some instances, primary metering may be required.

3.4.6 Supply Voltage

A General Service building is supplied at one service voltage per land parcel.

General Service connections above 500 kW may require a customer owned substation.

Depending upon the location of the building, primary supplies to transformers and Customer owned Sub-Stations will be one of the following as determined by Erie Thames:

- *2,400/4,160 volts 3 phase 4 wire*
- *4,800/8,320 volts 3 phase 4 wire*
- *7,200/12,400 volts 3 phase 4 wire*
- *8,000/13,800 volts 3 phase 4 wire*
- *16,000/27,600 volts 3 phase 4 wire*
- *44,000 Volts - 3 Phase 3 Wire*

The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by Erie Thames. The Owner shall obtain prior approval from Erie Thames for the use of any specific voltage at any specific location.

3.4.7 Access

At Erie Thames discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in Erie Thames name, or a “Letter of Permission “from the property owner(s) involved.

The Customer will provide unimpeded and safe access to Erie Thames at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

Where the high voltage interrupting switches are located inside a building, a direct outside entrance to the switchgear room must be provided.

The outside door providing direct access to the transformer or switchgear room must be compliant with all applicable codes and requirements, and of a quality to be approved by Erie Thames.

3.4.8 Metering

The owner will supply and install provisions for metering following the details outlined both in these Conditions of Service, and technical documents provided to the customer during the consultation process.

For more details refer to section 2.3.7 in these Conditions of Service.

3.4.9 Sub-transmission Service

The Owner will pay for the full cost of sub-transmission services and may in some circumstances be required to construct a private pole line.

Erie Thames will terminate sub-transmission conductors complete with live line loops and hardware at the Demarcation Point.

3.4.10 Short Circuit Capacity

The Owner shall ensure that the service entrance equipment has an adequate short-circuit interrupting capability.

3.4.11 Drawings

Apart from the regular drawings submission to the ESA, the customer shall provide two sets of the following drawings and details to Erie Thames.

Survey Plan: prepared by an Ontario Land Surveyor, showing the property limits, registered plan and existing buildings or easements if any.

Site Plan: showing the location of the station relative to buildings, structures and set backs from adjacent property lines. The site plan shall also include the exact location of existing Distributor owned plant and the proposed route of the incoming supply.

Schematic or Single-Line Diagram: indicating the major components of the station and their electrical ratings. Where additions or alterations are being made, these shall be clearly distinguished from unchanged portions of the installation.

Electrical Details: sufficient details shall be provided in order to enable fast processing and approval of the station drawings. The following represents the minimum data required.

- Plan, elevation and profile views of the station structure, switchgear, transformer(s), termination poles, duct banks, etc.
- Dimensions to clearly indicate the electrical, physical and working clearances as well as relative location of all equipment.
- Pole or structure for dead-ending Erie Thames lines shall be complete with suitable hardware for attaching the suspension insulators that will be supplied and installed by Erie Thames.
- Fencing arrangement.
- Grounding details. (In the case of indoor metal enclosed switchgear, when Erie Thames has operating control of any interrupter switches, the assembly shall further incorporate ground rod parking stands and stirrups per Erie Thames Specifications.)
- Details of vault construction (if indoor substation).
- Manufacturer's drawings of metal-enclosed switchgear showing internal arrangement of equipment, clearances, means of access, interlocking and provision for personal safety. Where Erie Thames cables terminate in the switchgear, the customer shall provide suitable terminators for the size and type of cable as specified by Erie Thames.
- When the customer's switchgear is used for loop feeding Erie Thames supply cables, provision for padlocking the in and out load interrupter switches and the associated bay doors shall be required.

- Indoor and outdoor switchgear assemblies shall contain a space heater and protective guard in each bay, along with thermostat(s), sized to promote air circulation and to prevent condensation from forming.

- At the discretion of Erie Thames, the customer shall make provisions for a future system neutral connection to the customer's dead-ending pole or structures installed by Erie Thames. Where Erie Thames neutral terminates in the customer's switchgear, the customer shall provide a suitable connector on the ground bus for the size and type of cable specified by Erie Thames.

3.4.12 Pre-Service Inspection

The customer shall present to Erie Thames a final "Pre-service Inspection Report" a minimum of 3 working days before connection can be affected.

The "Pre-Service Inspection Report" shall outline and document the results of all tests and inspection carried out on the substation components. The information contained in the report must be to the satisfaction of Erie Thames before connection can be authorized.

The "Pre-Service Inspection Report" shall be required in case of:

- ***New Substation****: in which case all components of the substation shall be reported upon.*

- ***Modified substation****: in which case all components of the substation shall be reported upon.*

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by Erie Thames prior to connection.

Erie Thames or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of Erie Thames and subject to inspection by Erie Thames.

(Refer to section 2.1.4 for further inspection details)

3.5 Embedded Generation

3.5.1 General

An Embedded Generator shall provide Erie Thames with proof of compliance of IESO or OEB registration Requirements, and appropriate Licences.

Erie Thames shall collect costs reasonably incurred with making an offer to connect a generator from the entity requesting the connection. Costs reasonably incurred include costs associated with:

- Preliminary review for connection requirements.
- Detailed study to determine connection requirements.
- Final proposal to the generator.

A Generator that is or wishes to become connected to Erie Thames distribution system shall enter into a

Connection Agreement with Erie Thames.

If damage or increased operating costs result from a connection with a Generator, the Generator shall reimburse Erie Thames for these costs.

The Embedded Generator is responsible for providing suitable embedded generator equipment to protect his plant and equipment for any conditions on Erie Thames and interconnected transmission systems such as reclosing, faults and voltage unbalance.

To incorporate the connection of embedded generator to the distribution system, the line/feeder protection including settings and breaker reclosing circuits must be reviewed and modified if necessary by Erie Thames or transmission authority. This process may be complex and may require significant time.

The embedded generator must submit a proposed single line diagram and protection scheme for review to Erie Thames contact as identified by Erie Thames.
Based on the transformer connection proposed by the embedded generator additional significant protection cost may be incurred (e.g. delta HV transformer winding may require 3 phase HV breaker / reclosure device). The embedded generator shall not order the protection equipment and transformer until the station line diagram is reviewed and accepted by Erie Thames.

The purpose of Erie Thames review is to establish that the embedded generator electrical interface design meets Erie Thames requirements.

The protection schemes shall incorporate adequate facilities for testing/maintenance.

Negative phase sequence protection shall be installed where required, to detect abnormal system condition as well as to protect the generator.

The embedded generator may be required to install utility grade relays for those protections that could affect Erie Thames or transmission authority system.

The embedded generator may be required to submit a Ground Potential Rise study for review by Erie Thames, if telecommunications circuits are specified for remote transfer trip protection.

3.5.2 Protection

The embedded generator should provide protection systems to cover the following conditions:

3.5.2.1 Internal Faults

The Generator should provide adequate protections to detect and isolate generator and station faults.

3.5.2.2 External Faults

The protection system should be designed to provide full feeder coverage complete with a reliable DC supply. In some cases redundancy in protection schemes may be required.

Normally the following fault detection devices are required for synchronous generator(s) installation(s).

3.5.2.3 Ground Faults

When the HV winding of the Generator station transformer is wye connected with the neutral solidly grounded, then ground over-current protection in the neutral is required to detect ground faults.

If the Embedded generator station transformer HV winding connected to Erie Thames system is ungrounded wye or delta, then ground under-voltage and ground over-voltage protections shall be required to detect ground faults.

Depending on the size, type of generator and point of connection, a distributor may require the relaying system to be duplicated, complete with separate auxiliary trip relays and separately fused DC supplies to ensure reliable protection operation and successful isolation of the embedded generator.

3.5.2.4 Phase Faults

To detect phase faults, at least one of the following protections should be installed with acceptable redundancy where required depending on fault values:

- Distance
- Phase directional over-current
- Voltage-restrained over-current
- Over-current
- Under-voltage

3.5.2.5 Islanding/Abnormal Conditions

Voltage and frequency protections are required to separate the embedded generator from the distribution system for an islanded condition and thus maintain the quality of supply to distribution system customers. This also will enable speedy restoration of the distribution system.

Typically, the protections required to detect islanding/abnormal conditions are:

- Over-voltage
- Under-voltage
- Over-frequency
- Under-frequency
- Voltage-balance

The above protections should be timed to allow them to ride through minor disturbances.

3.5.3 Induction Generator

Due to the operating characteristics of the induction generator the protection package required is normally less complex than the synchronous generator. An embedded generator should design the protection scheme to trip for the same conditions as stated for synchronous generators. An induction generator is an asynchronous machine that requires an external source such as a healthy distribution system to produce normal 60 Hz power. Alternatively, if there is an outage in the distribution system then there is unlikely to be 60 Hz output from the induction generator. In certain instances, an induction generator may continue to generate electric power after the source is removed. This phenomenon, known as self-excitation, can occur whenever there is sufficient capacitance in parallel with the induction generator to provide the necessary excitation and when the connected load has certain resistive characteristics.

3.5.4 DC Remote Tripping / Transfer Tripping

Remote or transfer tripping may be required between the Generator and the feeder circuit breaker if the Generator is connected at a critical location in the distribution system. This feature will provide for isolation of the embedded generator when certain faults or system disturbances are detected at the feeder circuit breaker location.

Additional Protection Features, such as Remote Trip and Generator end open signal, may be required in some applications.

3.5.5 Maintenance

An Embedded Generator shall have a regular scheduled maintenance plan to assure Erie Thames that all connection devices and protection & control systems are maintained in good working order. These provisions shall be included in the Connection Agreement. A complete copy of the inspection report shall be delivered to Erie Thames within 30 days.

In developing a maintenance plan, the Generator should consider the following requirements:

- Qualified personnel should carry out all inspections and repairs.
- Periodic tests should be performed on protection systems to verify that the system operates as designed. Testing intervals for protection systems should not exceed four (4) years for microprocessor-based systems and two (2) years for electro-mechanical based systems.
- Isolating devices at the point of connection should be operated at least once per year.
- The Generator facility should be inspected visually at least once per year to note obvious maintenance problems such as broken insulators or other damaged equipment.
- Any deficiencies identified during inspections shall be noted and repairs scheduled as soon as possible, with timing dependent on the severity of the problem, due diligence concerns (of both Erie Thames and the Generator) and financial and material requirements. Erie Thames shall be notified of any deficiencies involving critical protective equipment.
- Erie Thames shall be provided with copies of all relevant inspection and repair reports that may affect the protection and performance of Erie Thames systems. Erie Thames has the right to witness any relevant test being performed by the generator.

3.6 Embedded Market Participant

An Embedded Market Participant shall provide Erie Thames with proof of compliance of IESO registration Requirements, and appropriate Licences.

Where the Conditions of Service of this Distributor exceed the technical requirements of any other licence or participant obligations, these Conditions of Service shall take precedence.

The Embedded Market Participant must meet at a minimum, the standards as set out in these Conditions of Service in order to connect to Erie Thames distribution facilities.

3.7 Embedded Distributor

An Embedded Distributor shall provide Erie Thames with proof of compliance of IESO and OEB registration Requirements, and appropriate Licences.

Where the Conditions of Service of this Distributor exceed the technical requirements of any other licence or participant obligations, these Conditions of Service shall take precedence.

The Embedded Distributor must meet at a minimum, the standards as set out in these Conditions of Service in order to connect to Erie Thames distribution facilities.

3.8 Miscellaneous Small Services

This section pertains to the supply of electrical energy for Street Lighting, Traffic Signals, Bus Shelters, Telephone Booths, Cable T.V. Amplifiers, Decorative Street Lighting, Bill Boards, and other similar small loads.

3.8.1 General

At the discretion of Erie Thames, the service voltage will be:

120/240 volts, single phase three wire or
120 volts, single phase two wire or
347/600V three phase, four wire

The method and location of the supply will vary based on the conditions present on Erie Thames plant, and will be established for each application through consultation with Erie Thames.

Where specified by Erie Thames during the Early Consultation process, the Customer will provide underground ducts to Erie Thames specifications.
The Owner shall be responsible for all costs associated with the supply and installation of service conductors

Erie Thames at the Owners' expense will install required transformation.

Where at the discretion of Erie Thames, a meter is not installed, energy consumption will based on the connected wattage and the calculated hours of use.

Prior to energization of a service Erie Thames will require notification from the ESA that the installation has been inspected and approved for connection.

3.8.2 Early Consultation

The Owner shall supply a completed Electrical Service Connection Form to Erie Thames well in advance of installation commencement to allow Erie Thames time for proper planning, ordering of equipment etc. Information required includes:

- Required in-service date
- Requested Service Entrance Capacity and voltage rating of the service entrance equipment
- Locations of other services, gas, telephone, water and cable TV
- Survey plan and site plan indicating the proposed location of the service equipment with respect to public rights-of way and lot lines.

3.8.3 Street Lighting

Town street-lighting that is designed, installed, and maintained by Erie Thames shall be fully funded by the Municipality to ensure adherence to the Affiliate Relationship Code and Erie Thames Distribution Licence.

3.8.4 Traffic Signals

Traffic Signals and Crosswalk Lights are owned and maintained by the applicable road authority.

3.8.5 Bus Shelters

Bus Shelter Lighting is owned and maintained by the Customer.

3.8.6 Decorative Street Lighting

Such installations could be lighting for festive occasions or "neighbourhood character" street-scaping and will be maintained by the Customer.

SECTION 4 GLOSSARY OF TERMS

"Conditions of Service" means the document developed by Erie Thames in accordance with subsection 2.3 of the Distribution System Code, that describes the operating practices and connection rules for Erie Thames;

"Condominiums" are located on common land, which is the property of a condominium corporation or is owned by the Owner of all of the units (rental property). These units usually front onto internal roads that are also privately owned;

"Condominium Development" is a structure or complex of structures each containing more than two residential units. A single residential customer would occupy each unit and have direct outside access at ground level;

"Connection" means the process of installing and activating connection assets in order to distribute electricity;

"Connection Agreement" means an agreement entered into between a distributor and a person connected to its distribution system that delineates the conditions of the connection and delivery of electricity to or from that connection;

"Connection assets" means that portion of the distribution system used to connect a customer to the existing main distribution system, and consists of the assets between the point of connection on a distributors' main distribution system and the ownership Demarcation Point with that customer;

"Consumer" means a person who uses, for the person's own consumption, electricity that the person did not generate;

"Customer" means a person that has contracted for or intends to contract for connection of a building or an embedded generation facility. This includes developers of residential or commercial sub-divisions;

"Demand meter" means a meter that measures a consumers' peak usage during a specified period of time;

"Demarcation Point" means the point at which the obligation of Erie Thames ends and those of the Customer begin for the purposes of maintenance and repair of the distribution service;

"Disconnection" means a deactivation of connection assets, which results in cessation of distribution services to a consumer;

"Distribute", with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less;

"Distribution losses" means energy losses that result from the interaction of intrinsic characteristics of the distribution network such as electrical resistance with network voltages and current flows;

"Distribution loss factor" means a factor(s) by which metered loads must be multiplied such that when summed equal the total measured load at the supply point(s) to the distribution system.;

"Distribution services" means services related to the distribution of electricity and the services the

Board has required distributors to carry out.

"Distribution system / plant" means a system for distributing electricity, and includes any structures, equipment or other things used for that purpose. A distribution system is comprised of the main system capable of distributing electricity to many customers and the connection assets used to connect a customer to the main distribution system;

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

"Distributor" means a person who owns or operates a distribution system;

"*Electricity Act*" means the *Electricity Act, 199*8, S.O. 1998, c.15, Schedule A;

"Energy Competition Act" means the *Energy Competition Act, 199*8, S.O. 1998, c. 15;

"Electrical Safety Authority" or **"ESA"** means the person or body designated under the *Electricity Act* regulations as the Electrical Safety Authority;

"Embedded Distributor" means a distributor who is not a wholesale market participant and that is provided electricity by a host distributor;

'Embedded Generation Facility" means a generator whose generation facility is not directly connected to the IESO-controlled grid but instead is connected to a distribution system;

'Embedded Load Displacement Generation Facility" means an embedded generation facility connected to the customer side of the revenue meter where the generation facility does not inject electricity into the distribution system for the purpose of sale;

"Embedded Market Participant" means a consumer who is a wholesale market participant whose facility is not directly connected to the IESO-controlled grid but is connected to a distribution system;

"Emergency" means any abnormal system condition that requires remedial action to prevent or limit loss of a distribution system or supply of electricity, or that could adversely affect the reliability of the electricity system;

"Emergency backup generation facility" means a generation facility that has a transfer switch that isolates it from a distribution system;

"Enhancement" means a modification to an existing distribution system that is made for purposes of improving system operating characteristics such as reliability or power quality or for relieving system capacity constraints resulting, for example, from general load growth;

'Expansion" means an addition to a distribution system in response to a request for additional customer connections that otherwise could not be made; for example, by increasing the length of the distribution system;

'Four-quadrant Interval Meter" means an interval meter that records power injected into a distribution system and the amount of electricity consumed by the customer;

“Generate”, with respect to electricity, means to produce electricity or provide ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system;

“Generation Facility” means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system, and includes any structures, equipment or other things used for that purpose;

“Generator” means a person who owns or operates a generation facility;

“Geographic Distributor” with respect to a load transfer, means Erie Thames that is licensed to service a load transfer customer and is responsible for connecting and billing the load transfer customer;

“Good Utility Practice” means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America;

“Holiday” means a Saturday, Sunday, statutory holiday, or any day as defined in the Province of Ontario as a legal holiday;

“IESO” means the Independent Electricity Market Operator established under the *Electricity Act*;

‘IESO-Controlled Grid” means the transmission systems with respect to which, pursuant to agreements, the IESO has authority to direct operation;

“Interval meter” means a meter that measures and records electricity use on an hourly or sub-hourly basis;

“Large Embedded Generation Facility” means an embedded generation facility with a name-plate rated capacity of 10MW or more;

“Lies Along” means a property can be connected to Erie Thames distribution system without an expansion or enhancement, and meets the conditions listed in the Conditions of Service of Erie Thames who owns or operates the distribution line.

‘Load Transfer” means a network supply point of one distributor that is supplied through the distribution network of another distributor and where this supply point is not considered a wholesale supply or bulk sale point;

“Load Transfer Customer” means a customer that is provided distribution services through a load transfer;

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

"Measurement Canada" means the Special Operating Agency established in August 1996 by the *Electricity and Gas Inspection Ac*t, 1980-81-82-83, c. 87., and Electricity and Gas Inspection Regulations (SOR/86-131);

"Medium Sized Embedded Generation Facility" means an embedded generation facility with a name-plate rated capacity of less than 10 MW and:

a) more than 500 kW in the case of a facility connected to a less than 15kV line;
b) more than 1 MW in the case of a facility connected to a 15 kV or greater line;

"Meter Service Provider" means any entity that performs metering services on behalf of a distributor, generator, or registered market participant;

"Meter Installation" means the meter and, if so equipped, the instrument transformers, wiring, test links, fuses, lamps, loss of potential alarms, meters, data recorders, telecommunication equipment and spin-off data facilities installed to measure power past a meter point, provide remote access to the metered data and monitor the condition of the installed equipment;

"Metering Services" means installation, testing, reading and maintenance of meters;

"Micro Embedded Load Displacement Generation Facility" means an embedded load displacement generation facility with a name-plate rated capacity of 10 kW or less;

"Ontario Electrical Safety Code" means the code adopted by O. Reg. 164/99 as the Electrical Safety Code;

"Ontario Energy Board Act" means the *Ontario Energy Board Act, 199*8, S.O. 1998, c.15, Schedule B;

"Operational Demarcation Point" means the physical location at which a distributors' responsibility for operational control of distribution equipment including connection assets ends at the customer;

"Ownership Demarcation Point" means the physical location at which a distributors' ownership of distribution equipment including connection assets ends at the customer;

"Physical Distributor" with respect to a load transfer, means Erie Thames that provides physical delivery of electricity to a load transfer customer, but is not responsible for connecting and billing the load transfer customer directly;

"Point of Supply" with respect to an embedded generation facility, means the connection point where electricity produced by the generation facility is injected into a distribution system;

"Rate" means any rate, charge or other consideration, and includes a penalty for late payment;

'Rate Handbook" means the document approved by the Board that outlines the regulatory mechanisms that will be applied in the setting of distributor rates;

"Regulations" means the regulations made under the *Act or the Electricity Act*;

"Retail", with respect to electricity means,

a) (To sell or offer to sell electricity to a consumer
b) To act as agent or broker for a retailer with respect to the sale or offering for sale of electricity, or
c) To act or offer to act as an agent or broker for a consumer with respect to the sale or offering for sale of electricity.

"Retail Settlement Code" means the code approved by the Board and in effect at the relevant time, which, among other things, establishes a distributors' obligations and responsibilities associated with financial settlement among retailers and customers and provides for tracking and facilitating customer transfers among competitive retailers;

"Retailer" means a person who retails electricity;

"Service Area" with respect to a distributor, means the area in which Erie Thames is authorized by its license to distribute electricity;

"Small Embedded Generation Facility" means an embedded generation facility which is not a micro-embedded generation facility with a name-plate rated capacity of 500 kW or less in the case of a facility connected to a less than 15 kV line and 1MW or less in the case of a facility connected to a 15 kV or greater line;

"Total losses" means the sum of distribution losses and unaccounted for energy;

"Townhouses" are usually a free hold property, the land is owned by the individual Owners of each unit, fronting onto a municipal street;

"Townhouse Development" is a structure or complex of structures each containing more than two residential units. A single residential customer would occupy each unit, and have direct outside access at ground level;

"Transmission System" means a system for transmitting electricity, and includes any structures, equipment or other things used for that purpose;

"Transmission System Code" means the Board approved code that is in force at the relevant time, which regulates the financial and information obligations of the Transmitter with respect to its relationship with customers, as well as establishing the standards for connection of customers to, and expansion of a transmission system;

"Transmit" with respect to electricity, means to convey electricity at voltages of more than 50 kilovolts;

"Transmitter" means a person who owns or operates a transmission system;

"Unaccounted-for Energy" means all energy losses that cannot be attributed to distribution losses. These include measurement error, errors in estimates of distribution losses and un-metered loads, energy theft and non-attributable billing errors;

"Un-metered loads" means electricity consumption that is not metered and is billed based on estimated usage;

Validating, Estimating and Editing (VEE)" means the process used to validate, estimate and edit raw metering data to produce final metering data or to replicate missing metering data for settlement purposes;

"Wholesale Market Participant" means a person that sells or purchases electricity or ancillary services through the IESO-administered markets;

SECTION 5 APPENDICIES

Appendix 1 - Electrical Service Connection Form

Appendix 2 - Electric Service Meter Base/ Service Verification Form

Appendix 3 - Policies:

5.0 Opening and Closing of Accounts at the Request of a Third Party
6.1 Security Deposits
7.0 Collections Overview
7.1 Customer Collections
7.2 Retailer Collections
7.3 Use of Load Control Devices
8.0 Disconnection/Reconnection Overview
8.1 Disconnection/Reconnection
8.2 Disconnection/Reconnection by Request
8.3 Safety and Reliability
8.4 Unauthorized Use of Electricity

Appendix 4 – Summary of Changes

(**Appendix 1**

ERIE THAMES POWER

143 Bell Street, Box 157 Ingersoll ON N5C 3K5 (519)485-1820 Toll free 1866-875-0057 FAX 15194855838
www.eriethamespower.com

CUSTOMER REQUEST FOR INDUSTRIAL COMMERCIAL ELECTRICAL SERVICE CONNECTION

WO# ____________

PROJECT LOCATION

INGERSOLL	
AYLMER	
BEACHVILLE	
NORWICH	
TAVISTOCK	
THAMESFORD	
OTTERVILLE	
BURGESSVILLE	
PORT STANLEY	
BELMONT	
EMBRO	

BILLING INFORMATION

SERVICE ADDRESS	
NAME OF PROJECT:	
NAME OF APPLICANT:	
BILLING ADDRESS:	
TELEPHONE:	CELL:
EMAIL ADDRESS:	FAX:

CONTRACTOR INFORMATION

CONTACT NAME:	
TELEPHONE:	
FAX:	

TYPE OF SERVICE

NEW	
UPGRADE	

CUSTOMER ACCT#

6

MAIN SERVICE CONDUCTOR

SIZE: ____________
TYPE: ____________

SERVICE VOLTAGE

120/208 THREE PHASE	
347/600 THREE PHASE	
PRIMARY 27.6/16KV	
TRANSFORMER TYPE	
120/240 SINGLE PHASE	

MAIN SERVICE (AMPS)

100	
200	
400	
600	
800	
1000	
1200	
OTHER	

# CONDUCTORS PER PHASE	
MAIN BREAKER CAPACITY	
FUSED AT 80%	
CONNECTED KW	
ESTIMATED PEAK KW	

RESIDENTIAL	
GS <50KW	
GS>50KW NON INTER	
GS >50KW INTER	
GS >1000KW	
GS >4000KW	
GS >5000KW	

TRANSFORMER OWNER

ETP	CUSTOMER	SIZE kva

METERING

TOTAL # OF METERS	
SINGLE PHASE	

INSTRUMENT TRANSFORMERS LOCATION

UTILITY CABINET	
SWITCHGEAR	
NOT REQUIRED	

FORM COMPLETED EMAIL TO: E-MAIL TO SUPERVISORS

COMMENTS:

REQUIRED IN SERVICE DATE: ____________ SIGNATURE: ____________ 08-03

(**Appendix 2**

ERIE THAMES POWERLINES
CORPORATION

Electric Service Meter Base/ Billing Address Verification Form

This form must be completed by the Owner and/or their Electrical Contractor if applicable prior to service connection.

Electric Service Municipal Address: ____________________
Name of Owner: ____________________
Telephone: ( ) ____________ Fax: ( ) ____________
Name of Contractor: ____________________
Telephone: ( ) ____________ Fax: ( ) ____________

In area (A) provided below, carefully sketch the Front View layout of the Electric Meter Base(s).
Match the corresponding (B) BILLING ADDRESS for each meter base(s) shown in (A).

(A) FRONT VIEW OF ELECTRIC METER BASE(S)	(B) BILLING ADDRESS
	1)
	2)
	3)
	4)
	5)
	6)
	7)
	7)
	8)
	9)
	10)
	11)

I/We the undersigned, acknowledge the information provided above has been verified and is accurate.
Signature of Owner: ____________________ Date: ____________
Signature of Contractor: ____________________ Date: ____________

(**Appendix 3**

ERIE THAMES POWERLINES	**Policy # ETPL-2011-5.0**	Approved By: President Approved Date: January 2012
RRAM #:	**Opening and Closing of Accounts at the Request of a Third Party**	Revision: 1.0

5.0.1 PURPOSE:

The purpose of this policy is to document the rules described in the Distribution System Code -Section 2.8 Opening and Closing of Accounts to ensure that Erie Thames Powerlines complies with the rules when a request is received by a third party to open or close an account with Erie Thames Powerlines.

5.0.2 POLICY STATEMENT:

When Erie Thames opens or closes an account for a property in the name of a person at the **request of a third party**, Erie Thames shall:

- within 15 days of the opening of the account contact the person by telephone, if the person cannot be reached by telephone a letter will be hand delivered to the subject property advising of the opening of the account and requesting that the person confirm that he or she agrees to be the named customer;
- advise the third party that the account will not be set up as requested if Erie Thames does not receive confirmation from the intended customer prior to the scheduled move in date;
- not be required to send a letter advising of the opening of the account where the request to open the account is made in writing by the person's solicitor or person in possession of a valid Power of Attorney for the person;
- where Erie Thames has opened an account for a property in the name of a person at the request of a third party, Erie Thames shall not seek to recover from the third party any charges for service provided to the property unless the third party has agreed to be the customer of Erie Thames in relation to the property;
- where a request was received to close or transfer an account in relation to a rental unit from someone other than the occupant, Erie Thames shall not seek to recover any charges for service provided to that rental unit or residential property after closure of the account from any person other than the occupant, including the landlord for the residential complex or a new owner of the residential property, unless the person has agreed to assume responsibility for those charges.

Erie Thames may enter into an agreement with a landlord whereby the landlord agrees to assume responsibility for paying for continued service to the rental property after closure of a tenant's account.

The agreement with the landlord may be established by verbal request over the telephone. Erie Thames will document confirmation of the verbal request on the applicable account for the duration of the agreement with the landlord.

Erie Thames shall accept written agreements in electronic form (email) in accordance to the *Electronic Commerce Act, 2000.*

5.0.3 RESPONSIBILITIES:

Management of the company is responsible for ensuring that the corporation is protected from undue risk of bad debt.

5.0.4 REFERENCES:

Distribution System Code – The Ontario Energy Board

(	**Policy # ETPL-2011-6.1**	Approved By: President
		Approved Date: January
	Security Deposits	Revision: 3.1
RRAM #:		

6.0.1 PURPOSE:

This policy describes the terms and conditions Erie Thames Powerlines will use for collection, maintaining and returning customer security deposits which shall be consistent with the provisions described in the Distribution System Code.

In accordance with the Distribution System Code, Erie Thames Security Deposit Policy shall include:

- a list of all potential types/forms of security accepted;
- a detailed description of how the security is calculated;
- limits on the amount of security required;
- the planned frequency, process and timing of updating security;
- a description of how interest payable to customers is determined;
- criteria customers must meet to have security deposit waived and/or returned; and
- methods of enforcements where a security deposit is not paid.

6.0.2 POLICY STATEMENT:

Erie Thames Powerlines may use any risk mitigation options available to manage customer non-payment risk. Erie Thames Powerlines shall not discriminate among customers with similar risk profiles or risk related factors except where expressly permitted under the Distribution System Code.

Erie Thames Powerlines will comply with the deposit requirements as defined in the Distribution System Codes but may waive these requirements in favour of a customer or potential customer.

Erie Thames Powerlines will disclose to the customer the reasons for requiring the security deposit.

6.0.3 FORM OF SECURITY DEPOSIT:

Residential

The form of payment of a security deposit for a residential customer shall be cash or cheque at the discretion of the customer or such other form as is acceptable by Erie Thames Powerlines.

Erie Thames Powerlines shall permit a residential customer to pay a security deposit in equal installments over a 6 month period.

Erie Thames Powerlines shall allow a residential customer to repay a security deposit that was applied in full or in part to the residential customers account to offset amounts owing at that time as an attempt to avoid a disconnection notice for non-payment, in equal installments over a 6 month period.

The customer may elect to pay the security deposit over a shorter period of time.

General Service

The security deposit will be in the form of cash, cheque or an automatically renewing irrevocable letter of credit from a bank for non residential customers.

Erie Thames Powerlines may also accept other forms of security such as surety bonds and third party guarantees.

(Non-residential customer's shall pay the security deposit in equal installments over 4 months, the first installment being due on the implementation of an implied contract or the signing of service agreement. The customer may elect to pay the security deposit over a shorter period of time.

6.0.4 METHOD OF CALCULATION AND LIMIT OF SECURITY DEPOSIT:

The maximum amount of the security deposit that a customer is required to pay shall be calculated as follows:

- the billing cycle factor times the estimated bill based on the customer's average monthly load with Erie Thames Powerlines during the most recent 12 consecutive months within the past two years.
- Where relevant usage information is not available for the customer for 12 consecutive months within the past two years or the billing system is not capable of making the calculation, the customer's average monthly load shall be based on a reasonable estimate made by Erie Thames Powerlines.

Where a customer has a payment history which discloses more than one disconnection notice in a relevant 12 month period, Erie Thames Powerlines may use the customer's highest actual or estimated monthly load for the most recent 12 consecutive months within the past 2 years for the purposes of calculating the maximum amount of the security deposit.

For a low-volume consumer or designated consumer the price estimate used in calculating competitive electricity costs shall be the same as the price used by the IESO for the purpose of determining maximum net exposures and prudential support obligations for Erie Thames Powerlines.
If a non-residential customer with a >50kW demand rate can provide a credit rating from a recognized credit rating agency, the maximum amount of the security deposit required by Erie Thames Powerlines shall be reduced in accordance with the following table:

Credit Rating
(Using Standard and Poor's Rating Terminology)
Allowable Reduction in Security Deposit

AAA- and above or equivalent 100%
AA-, AA, AA+ or equivalent 95%
A-, From A, A+ to below AA or equivalent 85%
BBB-, From BBB, BBB+ to below A or equivalent 75%
Below BBB- or equivalent 0%

6.0.5 PLANNED FREQUENCY, PROCESS AND TIMING OF UPDATING SECURITY DEPOSITS:

Erie Thames Powerlines shall review every customer's security deposit at least once every calendar year to determine whether the entire amount of the security deposit is to be returned to the customer or adjusted based on a re-calculation of the maximum amount of the security deposit.

Where a residential customer has paid the security deposit in installments, Erie Thames shall conduct a review of the customer's security deposit in the calendar year in which the anniversary of the first installment occurs.

When Erie Thames Powerlines determines in conducting a review that the amount of the security deposit is to be adjusted upwards based on the recalculation of the maximum amount of the security deposit, Erie Thames Powerlines shall permit the customer to pay the adjusted amount in equal installments paid over a period off at least
6 months.

Erie Thames shall allow a customer to repay a security deposit that was applied to the customer's account to offset amounts owing in equal installments over at least 6 months.

Any security deposit received from the customer, upon closure of the customer account, shall be applied to the final bill prior to change in service and can be used to off-set other amounts owing by the customer to Erie Thames Powerlines. The balance shall be returned within six weeks of closure of the account.

(6.0.6 INTEREST PAYABLE:

The interest shall accrue monthly on security deposits made by cash or cheque commencing on receipt of the total deposit. The interest shall be at the Prime Business Rate as published on the Bank of Canada website less 2 percent, updated quarterly. The interest accrued shall be paid at least once every 12 months or on return or application of the security deposit or closure of the account, whichever comes first, and may be credited to the account.

6.0.7 CRITERIA REQUIRED FOR WAIVERED AND/OR RETURN OF SECURITY DEPOSIT:

Erie Thames Powerlines reserves the right to collect a security deposit from a customer that is not billed by a competitive retailer under retailer-consolidated billing unless the customer has a good payment history of:

- 1 year in the case of a residential customer,
- 5 years in the case of a non-residential customer in < 50 kW demand rate class, or
- 7 years in the case of a non-residential customer in any other rate class.

The time period that makes up the good payment history must be the most recent period of time and some of the time period must occur in the previous 24 months.

A customer is deemed to have a good payment history, unless, during the relevant time period the customer has received:

- more than one disconnection notice from the Erie Thames Powerlines, or
- more than one cheque given to the Erie Thames Powerlines by the customer has been returned for insufficient funds, or
- more than one pre-authorized payment to Erie Thames Powerlines has been returned for insufficient funds, or
- a disconnection/collection trip has occurred, or
- all or part of a security deposit held on file was applied to offset amounts owing by a residential customer prior to disconnection of their electricity service for non-payment of account and the customer is required by Erie Thames to pay back the security deposit.

Erie Thames Powerlines shall not require a security deposit if the customer provides the following prior to the implementation of service:

- the customer provides a letter from another distributor or gas distributor in Canada confirming a good payment history for the most recent relevant time period, some of this time period must have incurred within the last 24 months,
- a customer, other than a customer in a >5,000 kW demand rate class, that provides a satisfactory credit check made at the customer's expense,
- a customer has been qualified as an eligible low-income customer and requests a waiver,
- If a non-residential customer in any class other than <50kW demand rate can provide a credit rating from a recognized credit rating agency, the maximum amount of the security deposit required by Erie Thames Powerlines shall be reduced in accordance with the following table:

<u>**Credit Rating**</u>
(Using Standard and Poor's Rating Terminology)
Allowable Reduction in Security Deposit

AAA- and above or equivalent 100%
AA-, AA, AA+ or equivalent 95%
A-, From A, A+ to below AA or equivalent 85%
BBB-, From BBB, BBB+ to below A or equivalent 75%
Below BBB- or equivalent 0%

(In the case of a customer in a >5,000kW demand rate class, where the customer is now in a position that it would be exempt from paying a security deposit, however, had previously paid a security deposit to Erie Thames Powerlines, Erie Thames Powerlines is only required to return 50% of the security deposit.

Erie Thames shall give notice to all residential customers, at least annually, that any residential customer that qualifies as an eligible low-income customer may request and receive a refund of any security deposit previously paid to Erie Thames, after application of the security deposit to any outstanding amounts owing on the customer's account.

Erie Thames shall advise the eligible low-income customer that has requested a refund, within 10 days of the request, that the balance remaining after application of the security deposit to the customer's outstanding arrears will be credited to the customer's account if the remaining amount is less than one month's average billing. Where the remaining amount is equal to or greater than one month's average billing the customer may elect to receive the refund by cheque. Erie Thames will issue the cheque within 11 days of the customer's request for payment by cheque.

Erie Thames Powerlines shall apply all or part of any security deposit held on account against any amounts owing prior to issuing a disconnection notice to a residential customer for non-payment.

Erie Thames Powerlines may at its discretion reduce the amount of a security deposit for any reason including where the customer pays under an interim payment arrangement and where the customer makes pre-authorized payments.

Erie Thames shall promptly return any security deposit received from a customer within six weeks of the closure of the customer's account, subject to Erie Thames right to use the security deposit to set off other amounts owing by the customer to Erie Thames.

Erie Thames shall apply a security deposit to the final bill prior to the change in service where a customer changes from SSS to a competitive retailer that uses retailer-consolidated billing or a customer changes billing options from distributor-consolidated billing to split billing or retailer-consolidated billing, any remaining amounts will be promptly returned to the customer.

Erie Thames shall not pay any portion of a customer's security deposit to a competitive retailer.

Erie Thames may retain a portion of the security deposit where a change is made from distributor-consolidated billing to split billing that reflects the non-payment risk associated with the new billing options.

Where all or part of a security deposit has been paid by a third party on behalf of the customer, Erie Thames shall return the amount of the security deposit paid by the third party, including interest, where applicable, to the third party when:

- the third party paid all or part of the security deposit directly to Erie Thames;
- the third party requested at the time the security deposit was paid that Erie Thames return all of part of the security deposit to them rather than the customer;
- there is not then any amount overdue for payment by the customer that Erie Thames is permitted by Code to offset using the security deposit.

6.0.8 METHOD OF ENFORCEMENT WHERE SECURITY DEPOSIT IS NOT PAID:

Failure to pay the security deposit as required will result in the immediate implementation of Erie Thames Powerlines collection policy process which may lead to the discontinuation of electrical service.

6.0.9 DEFINITIONS:

"The Billing Cycle Factor" is 2.5 if the customer is billed monthly, 1.75 if the customer is billed bi-monthly and 1.5 if the customer is billed quarterly.

"Disconnection/Collection Trip" is a visit to a customer's premises by an employee or agent of the Erie Thames Powerlines to demand payment of an outstanding amount or to shut off or limit distribution of electricity of the customer failing payment.

(6.0.10 RESPONSIBILITIES:

The management of the company is responsible for ensuring that the corporation is protected from undue risk of bad debt.

6.0.11 REFERENCES:

The Electricity Act, 1998 – Province of Ontario, Ministry of Energy, Science and Technology

Market Rules – The Independent Electricity Market Operator

Distribution System Code – The Ontario Energy Board

Retail Settlement Code – The Ontario Energy Board

Distribution Rates Handbook – The Ontario Energy Board

(ERIE THAMES POWERLINES	Policy # ETPL-2010-7.0	Approved By: President, ETPL
		Approved Date: January 2012
	Collection Overview	Revision: 4.0
RRAM #:		

7.0.1 PURPOSE:

The purpose of this policy is to establish a process to ensure that every attempt has been made to avoid disconnection for non-payment of account and that money owed to Erie Thames Powerlines by consumers is collected.

7.0.2 POLICY STATEMENT:

Erie Thames Powerlines will collect all outstanding money owed from Customers and Retailers served by Erie Thames Powerlines distribution system in accordance with the principles defined in the *Electricity Act (1998)*, the Electricity Distribution Rate Handbook, Distribution System Code, Retail Settlement Code and Standard Supply Service Code.

The policies in this set are intended to provide guidance to Erie Thames Powerlines managers and staff, and to help them make operational decisions that are consistent with applicable codes and regulations.

7.1 Customer Collections
7.2 Retailer Collections
7.3 Use of Load Control Devices

7.0.3 DEFINITIONS:

Customer and Consumer will be understood herein as one and the same.

Distributor-Consolidated Billing is when a retailer marketer who has signed contracts in Erie Thames Powerlines service area and has opted for the distributor to do the billing and collection of the electricity commodity and all related non-competitive charges.

Disconnection/Collect Trip is a visit to a customer's premises by an employee or agent of Erie Thames to demand payment of an outstanding amount or to shut off or limit distribution of electricity to the customer failing payment.

Electricity Charges, for the purpose of this policy, are charges that appear under the sub-headings "Electricity, Delivery", "Regulatory Charges", and "Debt Retirement Charge" as described in Ontario Regulation 275/04 (Information on Invoices to Low-volume Consumers of Electricity) made under the Act, and all applicable taxes. Where applicable, charges prescribed by regulations under section 25.33 of the *Electricity Act, 1998* and all applicable taxes on those charges, and OEB approved late payment fees, specific service charges and such other charges and applicable taxes associated with the consumption of electricity as may be required by law to be included, as may be designated by the Ontario Energy Board, not including security deposits.

Eligible Low-Income Customer means a residential electricity customer who has a pre-tax household income at or below the pre-tax Low Income Cut-Off, according to Statistics Canada, plus 15%, taking into account family size and community size, as qualified by a Social Service agency or Government Agency; or a residential electricity customer who has been qualified for Emergency Financial Assistance.

Emergency Financial Assistance means any OEB approved emergency financial assistance program made available by a distributor or eligible low-income residential customers.

Errors and Omissions Excepted Erie Thames Powerlines shall reserve the right to make adjustments to any bill issued in error either in whole or in part.

Late Payment Charge is an OEB approved interest charge that is applied after a specified date or a due date on a customer's bill.

Licensed Competitive Retailer is a company that has a valid electricity retailer's license from the Ontario Energy Board.

(**Load Control Device** means a load limiter, timer load interrupter or similar device that limits or interrupts normal electricity service.

Load Limiter Device means a device that will allow a customer to run a small number of electrical items in his or her premises at any given time, and if the customer exceeds the limit of the load limiter, then the device will interrupt the power until it is reset.

Timed Load Interrupter Device means a device that will completely interrupt the customer's electricity intermittently for periods of time and allows full load capacity outside of the time periods that the electricity is interrupted.

Non-Payment Risk Mitigation Erie Thames Powerlines may use any risk mitigation options available under the law to manage consumer non-payment risk.

Retailer-Consolidated Billing is when the retail marketer opts to do the billing and collection of the electricity commodity and all related non-competitive charges.

Split Billing is when the retail marketer bills the customer for the electricity charges and Erie Thames Powerlines bills for the customer for non-competitive, debt retirement and distribution charges. The retailer and the distributor shall each be responsible for the collection of their own accounts.

Standard Service Supply Customer is a company or person who purchases electricity at spot market price or statutory pricing from Erie Thames Powerlines distribution system as a direct pass through from the IESO.

7.0.4 COLLECTION PAYMENT METHODS:

Erie Thames Powerlines may accept one or more of the following methods of payment but is not obligated to offer all methods:

Cash
Payment made through most Financial Institutions including telephone & computer banking
Certified Cheque
Money Order or Bank Draft
Credit Card issued by a Financial Institution
Preauthorized Payment Plan

7.0.5 RESPONSIBILTIES:

The management of the company is responsible for the approval of the policies contained in this manual.

7.0.6 REFERENCES:

The Electricity Act, 1998
Electricity Distribution Rate Handbook – The Ontario Energy Board
Retail Settlement Code– The Ontario Energy Board
Distribution Rate Handbook – The Ontario Energy Board
Distribution System Code – The Ontario Energy Board

(ERIE THAMES POWERLINES	**Policy # ETPL-2010-7.1**	Approved By: President, ETPL
		Approved Date: January 2012
	Customer Collections	Revision: 4.0
RRAM #:		

7.1.1 PURPOSE:

This policy confirms that Erie Thames must be prudent in their collection process to protect the Corporation from unpaid invoices. The detailed policies in this set are intended to establish and document a process that will provide guidance to Erie Thames management and staff, to help them make operational decisions to ensure that monies owed to Erie Thames by the consumer or retailer are collected in a timely manner.

7.1.2 POLICY STATEMENT:

Erie Thames will take steps to collect the total amount for the customer's bill, if not paid within the time specified in S.2.6.3 of the Distribution System Code, which shall be a minimum of sixteen calendar days from the date on which the bill was issued.

Erie Thames will deem the bill to have been issued to the customer:

a) if sent by mail, on the third day after the date on which the bill was printed;

b) if made available over the internet, on the date on which an e-mail is sent to the customer notifying the customer that the bill is available for viewing over the internet;

c) if sent by e-mail, on the date on which the e-mail is sent; or

d) if sent by more than one of the methods listed in (a) to (c), on whichever date of deemed issuance occurs lasts.

Erie Thames shall determine the date on which payment of the bill has been received from the customer:

a) if paid by mail, three days prior to the date on which the payment was received;

b) If paid at a financial institution or electronically, on the date on which the payment is acknowledged or recorded by the customers financial institution; or

c) if paid by credit card issued by a financial institution, on the date and at the time that the charge is accepted by the financial institution.

Erie Thames shall deem a bill issued to a customer as unpaid when the minimum payment period has elapsed. A late payment charge may be applied to the customer's account.

Erie Thames shall begin the collection process immediately following the application of late payment charge.

Erie Thames shall allocate any payment made by a residential customer whose bill includes charges for goods or services other than electricity charges first to the electricity charges and then if funds are remaining, to the other charges.

Erie Thames shall not impose a late payment charge, issue a disconnection notice or disconnect the customer's electricity supply if the payment on account is sufficient to cover the electricity charges.

Erie Thames shall treat all customers in the same rate class in a non-discriminatory fashion when collecting unpaid accounts.

7.1.3 Erie Thames shall make available to any residential customer who is unable to pay their outstanding electricity charges the opportunity to enter into an arrears payment agreement.

If the customer declines Erie Thames arrears payment agreement offer then Erie Thames will proceed with the collection process and disconnection if required. No further offer will be available to the customer after disconnection.

The arrears payment agreement shall include the following terms and conditions:

a) (Before entering into an arrears payment agreement Erie Thames shall apply any security deposit held on account of the customer against any electricity charges owing at the time.

b) When entering into the arrears payment agreement the customers may be required to make a down payment of up to 15%, an eligible low-income customers may be required to pay a down payment of up to 10%, of the accumulated electricity charge arrears, inclusive of any late payment charges but excluding other service charges.

c) The arrears payment agreement shall allow residential customers to pay all remaining electricity charges that are then overdue for payment, as well as the current bill amount if the customer requests to do so, after applying the security deposit and the down payment, including all electricity related service charges that have accrued to the date of the agreement, over the following periods:

   - a period of at least five months, where the total amount of the electricity charges remaining overdue for payment is less than twice the customer's average monthly bill; or
   - a period of at least ten months, where the total amount of the electricity charges remaining overdue for payment is equal to or exceeds twice the customer's average monthly billing amount.
   - In the case of an eligible low-income customer:
     - a period of at least 8 months, where the total amount of the electricity charges remaining overdue for payment is less than or equal to 2 times the customer's average monthly billing amount.
     - a period of at least 12 month where the total amount of the electricity charges remaining overdue for payment exceeds 2 times the customer's average monthly billing amount an is less than or equal to 5 times the customer's average monthly billing amount; or
     - a period of at least 16 months where the total amount of the electricity charges remaining overdue for payment exceeds 5 times the customer's average monthly billing amount.

   Erie Thames shall calculate the customer's average monthly billing amount by taking the aggregate of the total electricity charges billed to the customer in the preceding twelve months and dividing that value by twelve. If the customer has been a customer of Erie Thames for less than twelve months, the average monthly billing amount shall be based on a reasonable estimate made by Erie Thames.

d) Erie Thames has the right to cancel the arrears payment agreement if a customer defaults on more than one occasion in making payment in accordance with the arrears payment agreement or a payment on account of a current electricity charge billing, a security deposit amount due or an under-billing adjustment.

   - Erie Thames has the right to cancel the arrears payment agreement with an eligible low-income customer, if the eligible low-income customer defaults on more than two occasions in making a payment in accordance with an arrears payment agreement, or payment on account of a current electricity charge billing or under-billing adjustment.

   In both situations the defaults must occur over a period of at least 2 months before Erie Thames cancels the arrears payment agreement.

e) Erie Thames shall provide to the customer and to any third party designated by the customer, at least ten days written notice before the effective date of the cancellation.

f) Erie Thames shall provide notice of cancellation to any third party, if at the time of entering into an arrears payment agreement a customer has designated a third party to receive notice of cancellation of the arrears payment agreement.

g) Erie Thames shall accept the customer's notification of a designated third party by email or telephone communication.

h) The arrears payment agreement shall be reinstated if the customer makes payment of all amounts due pursuant to the arrears payment agreement on or before the cancellation date.

i) Erie Thames shall make available to residential electricity customers a second arrears payment agreement if the customer so requests, provided that two or more years have passed since the first arrears agreement was entered into and provided that the customer satisfied all obligations under the first arrears payment agreement.

   - Erie Thames shall allow an eligible low-income customer to enter into a subsequent arrears payment agreement if the terms described in S.2.7.5.1, 2.7.6 and 2.7.6A of the Distribution System Code has been met.

(Erie Thames reserves the right to refuse to enter into another arrears payment agreement with a residential customer who failed to perform their obligations under a previous arrears payment agreement until such time as 1 year has passed since the termination of the previous agreement.

Erie Thames shall have the right to limit or disconnect service for non-payment, theft of power, failing to keep payment arrangements, and/or default of the arrears payment agreement in accordance to the provisions described in the Distribution System Code.

A collection of account charge is applicable if a representative of the utility is dispatched to the customer's premise for the purpose of collecting overdue payment of the account.

The customer shall be subject to a Board approved reconnection charge when the electricity service has been interrupted for non-payment of account.

Erie Thames shall reserve the right to make adjustments to any bill issued in error either in whole or in part.

7.1.4 RESPONSIBILITIES:

The management of the company is responsible for ensuring that the corporation is protected from undue risk of bad debt.

7.1.5 REFERENCES:

The Electricity Act, 1998

Retail Settlement Code – The Ontario Energy Board

Distribution Rate Handbook – The Ontario Energy Board

Distribution System Code – The Ontario Energy Board

Electricity Gas and Inspection Act – Government of Canada

(ERIE THAMES POWERLINES	**Policy # ETPL-2010-7.2**	Approved By: President, ETPL Approved Date: December 2010
RRAM #:	**Retailer Collections**	Revision: 3.1

7.2.0 PURPOSE:

This policy describes the processes to collect outstanding balances from Retailers who have signed sales agreements with consumers served by Erie Thames Powerlines distribution system and to ensure that the Retailer meets the prudential requirements based on the billing option selected and the Retailer's magnitude of financial exposure. This process also applies to collection of past due Retail settlement and market participant invoices.

7.2.1 POLICY STATEMENT:

Erie Thames Powerlines requires Retailers to pay invoices on the due date as specified in the code.

Erie Thames Powerlines reserves the right to refuse service transaction requests, requests for information, invoices or other transactions from retailers with whom Erie Thames Powerlines does <u>not</u> have an up-to-date service agreement and/or financial security arrangements.

Erie Thames Powerlines shall review the required level of deposit from a Retailer for customers served through Distributor Consolidated Billing on a quarterly basis as a minimum.

Erie Thames Powerlines shall immediately notify the Retailer the day after a settlement payment was due if funds were not received and work with the Retailer to remedy the situation.

Erie Thames Powerlines shall not access the funds available through the relevant security arrangement, until five business days have elapsed.

Erie Thames Powerlines shall issue to the Retailer a Notice of Payment Default prior to returning the consumer that is signed with said Retailer back to Standard Service Supply (SSS).

7.2.2 RESPONSIBILITIES:

The management of the company is responsible for ensuring that prudential monitoring and payments from a Retailer are collected within the guidelines specified in the service agreement.

7.2.3 REFERENCES:

The Electricity Act, 1998

Market Rules – The Independent Electricity Market Operator

Retail Settlement Code – The Ontario Energy Board

Distribution Rate Handbook – The Ontario Energy Board

Distribution System Code – The Ontario Energy Board

Electricity Gas and Inspection Act – Government of Canada

(ERIE THAMES POWERLINES	**Policy # ETPL-2010-7.3**	Approved By: President, ETPL
		Approved Date: January 2012
	Use of Load Control Devices	Revision: 4.0
RRAM #:		

7.3.1 PURPOSE:

The purpose of this policy is to document guidelines that are consistent with the rules outlined in the Distribution System Code for management and staff when a load limiting device is installed as a means for collection of non-payment of an account rather than disconnection of the full electricity supply at a customer's premise.

7.3.2 POLICY STATEMENT:

Erie Thames at its discretion shall reserve the right to install a load control device at a customer's premise rather than disconnect the full electricity service if the customer fails to pay Erie Thames any outstanding amounts due and payable on account for the supply of electricity.

Erie Thames shall refrain from installing a load control device if notified by a Social Service Agency or Government Agency that the agency is assessing the customer for Emergency Financial Assistance for a period of 21 days after receiving the notification.

Erie Thames shall provide a written notice to the customer when the load control device is installed which will explain the operation of the device, the maximum capacity of the device, how to reset the device if the maximum capacity is exceeded and Erie Thames telephone contact number if the customer requires further information regarding the use of the device and an emergency contact number if the customer is unable to reset the device for any reason.

Erie Thames shall provide a 24 hour contact telephone number if Erie Thames installs a load limiter device that cannot be manually reset by the customer after the maximum limit is triggered so that the customer may call to have the load limiter device remotely reset.

Erie Thames shall provide written notice to a customer when a timed load interrupter is installed for non-payment explaining the effect of the device on service and a contact telephone number if the customer requires further information.

Erie Thames shall provide the following notices to a customer if Erie Thames installs a load control device for non-payment:

a) the Fire Safety Notice of the Office of the Fire Marshal; and
b) any other public safety notices or information bulletins issued by public safety authorities and provided to the distributor, which provide information to consumers respecting dangers associated with the disconnection of electricity service.

Erie Thames shall not install a load control device at a residential customer's property during the course of an arrears payment agreement, unless the agreement has been terminated in accordance to the provisions of the Distribution System Code.

Erie Thames shall remove the load control device installed at the customer's premise for the purpose of non-payment of account within two business days, from:

- the date that the residential customer entered into an arrears payment agreement;
- the date that the outstanding account was paid in full.

7.3.3 RESPONSIBILTIES:

The management of the company is responsible for ensuring that the corporation is protected from undue risk of bad debts and that the method used to collect overdue accounts complies with all applicable codes and regulations.

7.3.4 (REFERENCES:

The Electricity Act, 1998

Electricity Distribution Rate Handbook – The Ontario Energy Board

Retail Settlement Code– The Ontario Energy Board

Distribution Rate Handbook – The Ontario Energy Board

Distribution System Code – The Ontario Energy Board

(ERIE THAMES POWERLINES	**Policy # ETPL-2010-8.0**	Approved By: President Approved Date: Jan 2012
RRAM #:	**Policy 8.0** **DISCONNECTION/RECONNECTION OVERVIEW**	Revision: 4

8.0.1 PURPOSE:

The detailed policies in this set are intended to establish and document a process that specifies timing and means of notification consistent with the Electricity Act, 1998 that will provide guidance to Erie Thames management and staff when disconnecting and/or reconnecting the electrical service of a consumer.

8.0.2 POLICY STATEMENT:

Erie Thames shall follow the regulation and direction set out in the *Electricity Act (1998)*, Distribution System Code, Retail Settlement Code, and Standard Supply Service Code when implementing the disconnection and/or reconnection process.

Erie Thames will ensure that it has developed a physical and business process for reconnection of electricity supply ensuring safety and reliability as a primary requirement.

Erie Thames reserves the right to physically disconnect or limit the amount of electricity to a customer for any of the following reasons:

- Adverse effect on the reliability and safety of the distribution system.
- Imposition of an unsafe worker situation beyond normal risks inherent in the operation of the distribution system.
- A material decrease in the efficiency of the distributor's distribution system.
- A materially adverse effect on the quality of distribution services received by an existing connection.
- Inability of the distributor to perform planned inspections and maintenance.
- Failure of the consumer or customer to comply with a directive of a distributor that the distributor makes for purposes of meeting its licence obligations.
- The customer owes Erie Thames money for distribution services, or for a security deposit. Erie Thames shall give the customer a reasonable opportunity to provide the security deposit consistent with section 2.4.20 of the Distribution System Code.

Erie Thames shall recover from the customer responsible for the disconnection any reasonable costs associated with the disconnection, including but not limited to overdue amounts, late payment charges, reconnection fees, and any repairs to Erie Thames physical assets on the property damaged as a result of the disconnection.

Under no circumstances shall Erie Thames be held liable for any damage or loss to the customer or the customer's premises as a result of the disconnection.

8.1 Disconnection/Reconnection

8.2 Disconnection/Reconnection by Request

8.3 Safety and Reliability

8.4 Unauthorized Use of Electricity

8.0.3 DEFINITIONS:

Customer and Consumer will be understood herein as one and the same.

Disconnection means a deactivation of connection assets that result in termination of distribution services to a consumer.

Disconnect/collect trip is a visit to a customer's premises by an employee or agent of the distributor to demand payment of an outstanding amount or to shut off or limit distribution of electricity to the customer failing payment.

(**Eligible Low-Income Customer** means a residential electricity customer who has a pre-tax household income at or below the pre-tax Low Income Cut-Off, according to Statistics Canada, plus 15%, taking into account family size and community size, as qualified by a Social Service agency or Government Agency; or a residential electricity customer who has been qualified for Emergency Financial Assistance.

Emergency Financial Assistance means any OEB approved emergency financial assistance program made available by a distributor or eligible low-income residential customers.

Good utility practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgement in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America;

Reconnection is when a property or premise has electrical service energized or re-established by the distributor.

Security Deposit is an amount collected by the distributor and is held by the distributor to ensure that all monies owed to the Corporation are collected at the time of the final billing. Interest payments will be applied at least annually on all cash deposits.

8.0.4 RESPONSIBILTIES:

The management of the company is responsible for ensuring that the corporation is protected from undue risk of bad debt.

8.0.5 REFERENCES:

The Electricity Act, 1998

Electricity Distribution Rate Handbook – The Ontario Energy Board

Retail Settlement Code – The Ontario Energy Board

Distribution System Code – The Ontario Energy Board

Electricity Gas and Inspection Act – Government of Canada

(ERIE THAMES POWERLINES	**Policy # ETPL-2010-8.1**	Approved By:
		Approved Date: Jan. 2012
	Policy 8.1 DISCONNECTION/RECONNECTION	Revision: 4.0
RRAM #:		

8.1.1 PURPOSE:

This policy confirms that Erie Thames has established a process for the disconnection and/or reconnection of a property and/or premise consistent with the *Electricity Act, 1998*, and in accordance to all applicable rules and timelines as outlined in the Distribution System Code**.**

8.1.2. POLICY STATEMENT:

Erie Thames shall comply with all applicable regulation as defined in the Distribution System Code, Retail Settlement Code and Standard Supply Service Code when disconnection and/or reconnection of a customer's electrical service are required.

Erie Thames will ensure that it has developed a physical and business process for disconnection and/or reconnection ensuring safety and reliability as a primary requirement.

Erie Thames shall treat all customers in a non-discriminatory fashion when disconnecting and/or reconnecting an electrical service.

Erie Thames shall, pursuant to S.31 of the *Electricity Act*, provide reasonable notice of disconnection to residential customers if Erie Thames intends to disconnect the property for non-payment of account. The disconnection notice shall include, at a minimum, the information outlined in S.4.2.2 of the Distribution System Code.

Erie Thames shall provide, prior to disconnecting a property for non-payment, the Fire Safety Notice of the Office of the Fire Marshall; and any other public safety notices or information bulletins issued by public safety authorities to Erie Thames, which provides information to customers respecting dangers associated with the disconnection of electricity services.

Erie Thames shall not send or deliver the disconnection notice for non-payment in the same envelope as the customer's bill.

Erie Thames shall apply the rules described in S.2.6 of the Distribution System Code when determining the computation of time relating to bill issuance and application of payments.

Erie Thames shall follow the rules defined in S.4.2.3 of the Distributions System Code when determining the date a disconnection notice is deemed to have been received by a customer.

Erie Thames will not disconnect a customer until the minimum notice period defined in S.4.2.3 of the Distribution System Code has elapsed.

Erie Thames shall, at the request of a residential customer, send a copy of any disconnection notice issued to the customer for non-payment to a third party designated by the customer for that purpose. Provided that the request is made no later than the last day of the applicable minimum notice period as defined in S.4.2.3 of the Distribution Code as:

a) 60 days from the date on which the disconnection notice is received by the customer, in the case of a residential customer that has provided the distributor with documentation from a physician confirming that disconnection poses a risk of significant adverse effects on the physical health of the customer or on the physical health of the customer's spouse, dependent family member or other person that regularly resides with the customer; or

(b) 10 days from the date on which the disconnection notice is received, in all other cases.

Erie Thames shall notify the third party that the third party is not responsible for the payment of any charges for the provision of electricity service in relation to the customer's property, unless otherwise agreed by Erie Thames.

(S.2.6.4 and S.2.6.7 shall apply when determining the date of receipt of the disconnection notice by the third party, Erie Thames may modify the context if require.

Erie Thames shall at the request of a residential customer, at any time prior to disconnection, provide a copy of any future notice of disconnection to a third party designated by the customer. Such requests made by a residential customer shall be accepted by electronic mail (email) or telephone communications.

Erie Thames shall issue a new disconnection notice if a customer's electrical service was not disconnected 10 days from the date that the original disconnection notice was deemed to have been received by the customer or 60 days if a residential customer has provided documentation from a physician that disconnection poses a risk of significant adverse effects on the physical health of the customer or the customers spouse, dependent family member or other person that regularly resides with the customer.

Erie Thames shall determine the date the disconnection notice was received by the customer in accordance to S.4.2.3.1 of the Distribution System Code.

Erie Thames shall attempt to contact a residential customer either by telephone or in person 48 hours prior to the scheduled date of disconnection. At such time Erie Thames shall advise the customer:

- of the scheduled date of disconnection;
- if the disconnection will take place whether or not the customer is at the premises;
- if the disconnection will occur without attendance at the customer's premise;
- that payment can be made by credit card or any other form of payment that will be acceptable by Erie Thames and during what hours the payment must be received that would prevent the execution of the disconnection;
- that if Erie Thames attends the property to execute the disconnection payment will only be accepted by credit card issued by a financial institution, unless Erie Thames agrees to accept other forms of payment at that time;
- if the customer is eligible and if Erie Thames is prepared to enter into a Board-prescribed arrears payment program. Further information regarding the arrears payment program is detailed in S.2.7 of the Distribution System Code, and Erie Thames Policy 7.1 Customer Collections;
- if there are any additional options that Erie Thames can offer the customer that will avoid the execution of the disconnection.

Erie Thames shall post a copy of the disconnection notice for non-payment in a conspicuous place on or in the building promptly after issuance of the notice, if a disconnection notice is issued to a multi-unit or master-metered building.

Erie Thames shall suspend any disconnection action for a period of 21 days from the date of notification from a registered charity, government agency or social service agency that is determining if the residential customer is eligible to receive bill payment assistance, provided the notification is received within 10 days from the date on which the disconnection notice was received by the customer.

Where a residential customer requested prior to the issuance of the disconnection notice that a copy of any disconnection notice be provided to a third party, Erie Thames shall suspend any disconnection action for 21 days from the date of notification that the third party is attempting to arrange assistance with the bill payment, provided the notification is received within 10 days from the date the disconnection notice was received by the customer. If the registered charity, government agency, social service agency or any other third party decides the customer is not eligible and/or will not proceed with bill payment assistance Erie Thames will continue with the disconnection process. If 11 days has not expired since the previous disconnection notice a new disconnection notice will not be issue. Erie Thames will make every effort to contact the customer prior to executing the disconnection.

Erie Thames shall have the right to limit or discontinue service <u>without further notification</u> in accordance with a court order or for emergency, safety or system reliability reasons.

Erie Thames shall have the right to limit or discontinue service for non-payment of a security deposit from customers that have defaulted on payment arrangements.

Erie Thames shall have the right to refuse the reconnection if there are any outstanding amounts owed by the customer.

(Erie Thames shall have the right to disconnect and/or refuse the reconnection if the service is found to have an adverse effect on the safety and/or reliability of the distribution system.

Erie Thames shall have the right to disconnect and/or refuse the reconnection of the electrical service of a customer if it is found as an unsafe worker situation beyond normal risks inherent in the operation of the distribution system.

Erie Thames shall have the right to disconnect and/or refuse the reconnection of a customer for a material decrease in the efficiency of Erie Thames distribution system and/or an adverse effect on the quality of distribution services received by an existing connection.

Erie Thames shall have the right to disconnect a customer if Erie Thames is cannot perform planned inspections and maintenance when required.

Erie Thames has the right to disconnect and/or refuse to reconnect if a customer fails to comply with a directive of Erie Thames made for the purpose of meeting Erie Thames distribution licence obligations.

Erie Thames shall insist that electrical services that have been disconnected for six (6) or more months have an inspection certificate from the Electrical Safety Authority prior to reconnection. Notwithstanding, Erie Thames reserves the right to require, an Electrical Safety Authority inspection certificate at any time prior to reconnection at the expense of the customer.

Erie Thames shall insist that a responsible representative of the property be present in order for reconnection of service to be established.

8.1.3 RESPONSIBILITIES:

The management of the company is responsible for ensuring that the corporation is protected from undue risk of bad debt and any adverse effects on the reliability and safety of the distribution system.

8.1.4 REFERENCES:

The Electricity Act, 1998

Retail Settlement Code – The Ontario Energy Board

Distribution Rate Handbook – The Ontario Energy Board

Distribution System Code – The Ontario Energy Board

Electricity Gas and Inspection Act – Government of Canada

Condition of Service – Erie Thames Powerlines Corporation

(ERIE THAMES POWERLINES	**Policy # ETPL-2010-8.2**	Approved By: President Approved Date: Jan 2012
RRAM #:	**Policy 8.2** **DISCONNECTION/RECONNECTION BY REQUEST**	Revision: 4.0

8.2.1 PURPOSE:

This policy confirms that Erie Thames has established a process for the disconnection and/or reconnection of an electrical service when requested by a customer and/or an authorized authority.

8.2.2 POLICY STATEMENT:

Erie Thames shall respond to a customer's request for a disconnection and reconnection of an electrical service in a prompt and efficient manner.

Erie Thames shall disconnect a Customer immediately without notice, in accordance with a court order, a request by a fire department, Police, Electrical Safety Authority or for emergency, public safety (including potential for loss of life or limb), system reliability reasons or in order to inspect, maintain, repair, alter, remove, replace or disconnect wires or other facilities used to distribute electricity or where there is energy diversion, fraud or abuse on the part of the Customer.

Erie Thames shall have the right to refuse reconnection of the customer's electrical service if:

a) there is an outstanding amount of money owed by the consumer;
b) the connection is found to have an adverse effect on the safety and/or reliability of the distribution system;
c) the failure of the customer and/or their agent to obtain approval of the Electrical Safety Authority, if required.

Erie Thames requires that the Customer obtain the approval of the Electrical Safety Authority prior to Erie Thames reconnecting the electrical service:

a) where the service has been disconnected for a period of six (6) or more months;
b) where Erie Thames has reason to believe that the wiring may have been damaged or altered;
c) where service was disconnected for modification of Customer wiring;
d) where the service was disconnected as a result of an adverse effect on the reliability and safety of the Distribution system; or
e) where it is a requirement of the Electrical Safety Code.

Erie Thames shall insist that a responsible representative of the property be present when electrical service is energized or reconnected.

8.2.3 RESPONSIBILITIES:

The management of the company is responsible for ensuring that the corporation is protected from undue risk of bad debt and any adverse effects on the reliability and safety of Erie Thames Powerlines distribution system.

8.2.4 REFERENCES:

The Electricity Act, 1998
Retail Settlement Code – The Ontario Energy Board
Distribution System Code – The Ontario Energy Board
Condition of Service – Erie Thames Powerlines Corporation

(ERIE THAMES POWERLINES	Policy # ETPL-2010-8.3	Approved By: President
		Approved Date: January 2012
RRAM #:	Policy 8.3 SAFETY AND RELIABILITY	Revision: 4.0

8.3.1 PURPOSE:

This policy confirms that Erie Thames has established a process for ensuring the safety and reliability of Erie Thames Powerlines distribution system.

8.3.2 POLICY STATEMENT:

Erie Thames shall respond to and take reasonable steps to investigate all consumer power quality complaints and report to the consumer on the results of the investigation.

Erie Thames may direct a consumer connected to its distribution system to take corrective or preventive action on the consumer's electric system when there is a direct hazard to the public or the consumer is causing or could cause adverse effects on the reliability of Erie Thames's distribution system.

Erie Thames may require that any consumer conditions that adversely affect the distribution system be corrected immediately by the consumer and at the consumer's expense.

Erie Thames shall have the right to disconnect a customer from the distribution system if the customer does not remedy the situation as directed by Erie Thames within the time period specified by Erie Thames. Erie Thames shall provide notice of disconnection to the customer either by personal service, prepaid mail or by posting notice on the property in a conspicuous place.

Erie Thames shall have the right to disconnect a customer without notice if the service causes safety or reliability risk to Erie Thames distribution system.

Erie Thames shall insist that electrical services that have been disconnected for six (6) or more months have an inspection certificate from the Electrical Safety Authority prior to reconnection. Notwithstanding Erie Thames reserves the right to require an Electrical Safety Authority certificate at any time prior to reconnection at the customer expense.

Erie Thames shall have the right to refuse the reconnection of an electrical service to their distribution system if the connection is found to have an adverse effect on the safety and/or reliability of the system.

Erie Thames shall insist that a responsible representative of the property be present when electrical service is energized or reconnected.

8.3.3 RESPONSIBILITIES:

The management of the company is responsible for ensuring that the service quality of the distribution system is safe and reliable.

8.3.4 REFERENCES:

The Electricity Act, 1998

Retail Settlement Code – The Ontario Energy Board

Distribution Rate Handbook – The Ontario Energy Board

Condition of Service – Erie Thames Powerlines Corporation

(ERIE THAMES POWERLINES	**Policy # ETPL-2010-8.4**	Approved By: President
		Approved Date:
	Policy 8.4.0 **UNATHORIZED USE OF ELECTRICITY**	Revision: 1
RRAM #:		

8.4.1 PURPOSE:

This policy confirms that Erie Thames has established a process that management and staff can follow if it is discovered that there is unauthorized use of electricity.

8.4.2 POLICY STATEMENT:

Erie Thames shall use its discretion in taking action to mitigate unauthorized energy use. Upon identification of possible unauthorized energy use, Erie Thames shall notify, if appropriate, Measurement Canada, the Electrical Safety Authority, police officials, retailers that service consumers affected by the unauthorized energy use, or other entities.

Erie Thames shall monitor losses and unaccounted for energy use on an annual basis to detect any upward trends.

Erie Thames may recover from the parties responsible for the unauthorized energy use all energy and other applicable charges incurred by Erie Thames arising from the unauthorized energy use, including but not limited to inspections, administration fees and repair costs.

8.4.3 RESPONSIBILITIES:

The management of the company is responsible for monitoring losses and unaccounted energy use.

8.4.4 REFERENCES:

The Electricity Act, 1998

Retail Settlement Code – The Ontario Energy Board

Distribution System Code – The Ontario Energy Board

Conditions of Service – Erie Thames Powerlines Corporation

Appendix 4

Summary of Changes in Erie Thames Condition of Services

January 2012:

1.5.1 Contact Information
Updated Erie Thames contact information

2.1.7 Contracts
Opening and Closing of Accounts
Landlord and Tenant Agreements
This section has been included to reflect the amendments to the Distribution System Code regarding:

- customer acceptance of responsibility for account charges when opening an electricity account
- opening an account at the request of a third party
- agreements with landlord/owner for accountability for electricity to rental units when the units are not occupied by a tenant.

2.2 Disconnection
This section has been updated to reflect the amendments to the Distribution System Code.

2.2.1 Load Limiter Devices
This section has been added to document Erie Thames use of load limiter devices.

2.3.7.3.2 Smart Meter
This section has been added.

2.4.3 Deposits
This section has been updated to reflect the amendments to the Distribution System Code.

Appendix 3 – Policies – Erie Thames updated policies to reflect the amendments to the Distribution System Code and Standard Supply Service Code

PLANNED CHANGES IN CONDITIONS OF SERVICE AND SERVICE CHARGES

Erie Thames reviews its Conditions of Service periodically as required by the Distribution System Code.

Erie Thames is requesting no changes to its currently approved Specific Service Charges.

LIST OF WITNESSES

To be provided if oral hearing occurs.

SUMMARY OF THE APPLICATION

Introduction

Erie Thames estimates that its present rates will produce a Base Revenue Requirement of $9,173,991 and a deficiency in distribution revenue of $609,251 for the 2012 Test Year. This cost of service rate application is the first cost of service application since the amalgamation of Erie Thames, Clinton Power Corporation ("**CPC**") and West Perth Power Inc. ("**WPPI**"). Erie Thames was last rebased in 2008 and CPC and WPPI were rebased in 2010. The amalgamation of Erie Thames, CPC and WPPI was concluded on June 1st, 2011. Erie Thames has aggregated the numbers or the three distributors prior to the amalgamation in order to provide as accurate picture as possible to the requested changes.

Prior to the amalgamation, Erie Thames, CPC and WPPI each had their own rates and the rate categories were not consistent. As part of this application, Erie Thames is proposing to harmonize certain rate classifications and to have consistent rate categories across the entire service territory. In preparation for the Application, Erie Thames retained BDR to assist with cost allocation and rate design.

At the time of the 2008 rebasing, Erie Thames was a virtual distributor with a total of two employees that relied upon affiliates for the majority of its services. In 2009, the affiliate of Erie Thames was the subject of a prolonged strike, approximately 18 weeks, by the unionized employees. Following the strike, it was determined that the service company would be discontinued and the employees would be transferred to Erie Thames. Customer Service, Engineering, Metering, Regulatory and Accounting employees were transferred in 2009 and Operations employees were transferred in 2010. Along with the employees, certain assets were transferred as well.

Today, Erie Thames has 45 employees with the vast majority of services being provided by internal staff. Erie Thames does continue to rely upon its affiliate, Ecaliber, for billing services it shareholder for corporate/IT/HR services. A corporate organization chart may be found at Exhibit 1, Tab 1, Schedule 14.

Erie Thames retained Metsco Energy Solutions in 2011 to perform an Asset Condition Assessment and Assessment Management Plan Exhibit 2 Tab 5 Schedule 1. The need for the report at this time was the result of the acquisition of CPC and WPPI; the need for an independent review as to the appropriate funding level required to sustain the distribution system and in response to the PEG Report. Erie Thames has, according to the PEG Report, historically been one of the higher spending distributors in terms of O&M. Erie Thames assumed this was, in part, the result of an underspend on account of capital. As such, the Application provides for an increase in capital spending which will have an impact on future O&M.

During the fall of 2011, the OEB Auditors completed an audit of the deferral and variance accounts for West Perth Power, with lessons learned being applied to CPC, and ETPL.

Significant Customer Changes

The 2012 forecast incorporates small residential growth, offset by reduced demand in the commercial/industrial sector and the impact of existing conservation and demand management ("**CDM**"). In 2008, Erie Thames gained a new customer that was forecasted to be a large industrial customer, demand greater than 5,000kW but that demand has not materialized and the customer was re-classified to a GS<5000kW rate classification. Like many other small towns, Erie Thames has also felt the impact of the slowdown in the economy and automotive sector. A second large industrial customer, Fastenal, closed down in 2010. A third large industrial, Atlantic Packaging shut down in 2011. The Load Forecast was completed by a third party independent consultant.

The other factor is the inclusion of the CPC and WPPI customers in Erie Thames following the merger. As is evident from the Table below, there is a small growth in residential and GS<50kW rate classes.

Customer Count Summary

CUSTOMER COUNT TABLE							
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Residential	15,344	15,494	15,613	15,313	16,058	16,379	16,461
GS<50	1,819	1,837	1,847	1,696	1,842	1,858	1,860
GS>50 to 999 kW	170	175	178	175	175	176	176
Greater than 1,000 to 4,999 kW	8	8	8	7	7	5	5
Large Use	1	1	1	2	2	1	1
Unmetered Scattered Load	111	111	111	116	121	121	121
Sentinel Lighting	301	301	301	301	301	301	301
Street Lighting	4,197	4,197	4,283	4,283	4,283	4,283	4,283
Embedded Distributor	-	2	2	3	3	3	3
	21,951	***22,126***	***22,344***	***21,896***	***22,792***	***23,127***	***23,211***

PURPOSE AND NEED

Erie Thames estimates that its present rates will produce a deficiency in distribution revenue of $609,251 for the 2012 Test Year. To determine this amount, Erie Thames used its forecast throughput and demand allocated across the former territories of Erie Thames, CPC and WPPI using the existing rates applicable in each geographic region. Excluded from this estimate is the impact of energy costs. Erie Thames therefore seeks the Board's approval to revise its rates applicable to its distribution of electricity. The issues to be reviewed in this case, as Erie Thames Power sees them, are discussed below.

Through this Application, Erie Thames seeks:

- To recover:
    - Revenue deficiency arising from changes in OM&A, Amortization, Rate of Return and PILS
- To change:
    - Total Loss Factor
    - Retail Transmission Rates
    - Retail Low Voltage Rates
- To reflect:
    - Just and reasonable Distribution Rates that have been filed in accordance with the Ontario Energy Board Filing Requirements for Distribution Rate Applications

The information used in this Application is Erie Thames's forecasted results for its 2012 Test Year. With the rates presently in effect, Erie Thames estimates that its revenue for 2010 would not be sufficient to provide a reasonable return. Erie Thames is also presenting the historical actual information for fiscal 2008, 2009, 2010, and where available 2011.

TIMING

The financial information supporting the Test Year for this Application will be Erie Thames's fiscal year ending December 31, 2012 (the "2012 Test Year"). However, this information will be used to set rates for the period May 1, 2012 (or whenever approved) to April 30, 2013. The Test Year revenue requirement is that forecast by Erie Thames as needed to enable it to earn a reasonable return for fiscal 2012.

CUSTOMER IMPACT

Erie Thames will not have unacceptable impacts on the total distribution portion of the customer's bill and therefore Erie Thames is not proposing any rate mitigation measures.

The impact on each rate class is described below.

Residential:
The proposed changes to Residential are summarized below.

Erie Thames Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$14.19	$15.21	7%
Distribution Volumetric Rate	$.0144	$0.0168	0.2%

Former WPPI Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$13.61	$15.21	19%
Distribution Volumetric Rate	$.0113	$0.0168	0.5%

Former CPC Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$12.30	$15.21	23%
Distribution Volumetric Rate	$0.0174	$0.0168	0%

In order to adjust the fixed cost recovery through the monthly fixed charge, Erie Thames proposing to increase the monthly customer charge by $1.02 for ETPL, 2.91 for CPC and $2.60 for WPPI in the 2012 test year.

The impact on a typical residential customer is a decrease of 3.0% on total bill for ETPL, and increase of 4.0% for WPPI and an increase of 3% for CPC. The overall bill impact on a typical Residential customer is shown in detail in Exhibit 8, Tab 1, Schedule 8.

The low impact on total bill, compared to the change in the variable charge, is based on the reduction of retail transmission rates (details later in this exhibit). Note, smart meter rate adder is included at $1.10 per metered customer and LV retail rates have been adjusted on explained later in this exhibit.

Due to the relatively low impacts from the changes to network and connection rates, ETPL is proposing to harmonize the rates for this class effective immediately.

<u>GS<50 kW:</u>
The proposed changes to GS<50 kW are summarized below.

	2011 Board Approved	2012 Proposed	% change
Service Charge	$19.32	$20.94	8%
Distribution Volumetric Rate	$0.0107	$0.0173	60%

Former WPPI Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$11.95	$20.94	75%
Distribution Volumetric Rate	$0.0157	$0.0173	9%

Former CPC Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$24.17	$20.94	-13%
Distribution Volumetric Rate	$0.0161	$0.0173	6%

In order to adjust the fixed cost recovery through the monthly fixed charge, Erie Thames Powerlines is proposing to increase the monthly customer charge by $1.62 in the 2012 test year for ETPL, reduce the fixed charge by $3.22 for CPC and increase the fixed charge for WPPI by $9.00 . This proposed fixed charge remains well below the ceiling price detailed in the Cost Allocation Filing included in this application.

The impact on a typical GS<50 kW customer is a decrease of 0.2% on total bill for ETPL, a decrease of 9.9% for CPC and an increase of 2.6% for WPPI customers in the 2012 rate year. The overall bill impact on a typical GS<50 kW customer is shown in detail in Exhibit 8, Tab 1, Schedule 8.

The low impact on total bill, compared to the change in the variable charge, is based on the reduction of retail transmission rates (details later in this exhibit). Note, smart meter rate adder at $1.10 per metered customer and LV retail rates have been adjusted on explained later in this exhibit.

Due to the relatively low impacts from the changes to network and connection rates, ETPL is proposing to harmonize the rates for this class effective immediately.

GS>50 to 999 kW:

The proposed changes to GS>50 to 999 kW are summarized below.

	2011 Board Approved	2012 Proposed	% change
Service Charge	$209.85	$226.6	7.98%
Distribution Volumetric Rate	$5.6219	$4.2217	-24.91%

Former WPPI Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$204.84	$226.6	10%
Distribution Volumetric Rate	$2.6039	$4.2217	60%

Former CPC Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$42.44	$226.6	433%
Distribution Volumetric Rate	$5.9052	$4.2217	-30%

In order to adjust the fixed cost recovery through the monthly fixed charge, Erie Thames is proposing to increase the monthly customer charge by $16.75 in the 2012 test year, increase for CPC customers of $184.16 and increase of $21.76 for WPPI customers, despite the large increase for CPC customers the fixed charge proposed is a value well within the floor and ceiling rates calculated in Cost Allocation filing included in this application..

The impact on a typical GS>50 to 999 kW customer is a decrease of 10.9% on total bill for ETPL customers, a reduction of 19% for West Perth customers and a decrease of 10% for CPC customers. The overall bill impact on a typical GS>50 to 999 kW customer is shown in detail in Exhibit 8, Tab 1, Schedule 8.

The low impact on total bill, compared to the change in the variable charge, is based on the reduction of retail transmission rates (details later in this exhibit). Note, smart meter rate adder at $1.10 per metered customer and LV retail rates have been adjusted on explained later in this exhibit.

Due to the relatively low impacts from the changes to network and connection rates, ETPL is proposing to harmonize the rates for this class effective immediately.

GS>1000 to 4999 kW:

The proposed changes to GS>1000 to 4999 kW are summarized below.

	2011 Board Approved	2012 Proposed	% change
Service Charge	$2,340.80	$2,862.06	22.27%
Distribution Volumetric Rate	$3.1214	$3.6747	17.73%

In order to adjust the fixed cost recovery through the monthly fixed charge, Erie Thames is proposing to increase the monthly customer charge by $521.26 in the 2012 test year, which is a value well within the floor and ceiling rates calculated in Cost Allocation filing included in this application..

The impact on a typical GS>1000 to 4999 kW customer is a decrease of 7.5% on total bill. The overall bill impact on a typical GS>1000 to 4999 kW customer is shown in detail in Exhibit 8, Tab 1, Schedule 8.

The low impact on total bill, compared to the change in the variable charge, is based on the reduction of retail transmission rates (details later in this exhibit). Note, smart meter rate adder at $1.10 per metered customer and LV retail rates have been adjusted on explained later in this exhibit.

Large Use:

The proposed changes to Large Use are summarized below.

	2011 Board Approved	2012 Proposed	% change
Service Charge	$9,934.69	$10,715.28	7.86%
Distribution Volumetric Rate	$1.9245	$1.7778	-7.62%

Former WPPI Service Area

In order to adjust the fixed cost recovery through the monthly fixed charge, Erie Thames is proposing to increase the monthly customer charge by $780.59 in the 2012 test year, which is a value well within the floor and ceiling rates calculated in Cost Allocation filing included in this application..

The impact on a typical Large Use customer is a decrease of 10.0% on total bill. The overall bill impact on a typical Large Use customer is shown in detail in Exhibit 8, Tab 1, Schedule 8.

The low impact on total bill, compared to the change in the variable charge, is based on the reduction of retail transmission rates (details later in this exhibit). Note, smart meter rate adder at $1.10 per metered customer and LV retail rates have been adjusted on explained later in this exhibit.

Street Lighting:

The proposed changes to Street Lighting are summarized below.

Former ETPL Service Territory

	2011 Board Approved	2012 Proposed	% change
Service Charge	$3.77	$3.80	0.80%
Distribution Volumetric Rate	$11.1243	$15.6841	39 %

Former WPPI Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$0.31	$3.80	1125%
Distribution Volumetric Rate	$21.2036	$15.6841	-27%

Former CPC Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$12.09	$3.80	-68%
Distribution Volumetric Rate	$0.0185	$15.6841	kWh to kW

Explanation; In order to adjust the fixed cost recovery through the monthly fixed charge, Erie Thames is proposing to increase the monthly customer charge by $0.03 in the 2012 test year for ETPL customers, decrease by $8.29 for CPC customers and increase by $3.49 for WPPI customers.

The impact on a typical Street Lighting connection is an increase of 9% on total bill for ETPL, a reduction of 4.5% for WPPI customers and an increase of 20% for CPC customers. This large increase for CPC is not a realistic calculation as the variable rate is proposed to change from kWh to kW. The overall bill impact on a typical Street Lighting connection is shown in detail in Exhibit 8, Tab 1, Schedule 8.

Note LV retail rates and RTSR rates have been adjusted and explained later in this exhibit.

Sentinel Lighting:
The proposed changes to Sentinel Lighting are summarized below.

	2011 Board Approved	2012 Proposed	% change
Service Charge	$5.20	$5.25	1%
Distribution Volumetric Rate	$14.6906	$18.8735	22%

Former WPPI Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$0.00	$5.25	100%
Distribution Volumetric Rate	$8.3864	$18.8735	113%

Former CPC Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$0.28	$5.25	95%
Distribution Volumetric Rate	$2.0576	$18.8735	771%

Explanation; In order to adjust the fixed cost recovery through the monthly fixed charge, Erie Thames is proposing to increase the monthly customer charge by $0.05 in the 2012 test year, by $5.25 for WPPI and by $4.97 for CPC.

The impact on a typical Sentinel Lighting connection is a decrease of 69.7% on total bill. An increase of 93% for WPPI customers and a decrease of 45% for CPC customers. The overall bill impact on a typical Sentinel Lighting connection is shown in detail in Exhibit 8, Tab 1, Schedule 8.

Note LV retail rates and RTSR rates have been adjusted on explained later in this exhibit and significantly factor in to this impact.

Unmetered Scattered Load:
The proposed changes to Unmetered Scattered Load are summarized below.

	2011 Board Approved	2012 Proposed	% change
Service Charge	$2.81	$3.00	6.76%
Distribution Volumetric Rate	$0.0135	$0.1384	912%

Former WPPI Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$0.67	$3.00	347%
Distribution Volumetric Rate	$0.0289	$0.1384	373%

Former CPC Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$12.09	$3.00	-75%
Distribution Volumetric Rate	$0.0185	$0.1384	638%

Explanation; In order to adjust the fixed charge Erie Thames Powerlines is proposing to reduce the fixed charge by $0.19 per connection per month for ETPL customers, increase the fixed charge by $2.33 for WPPI customers and decrease the fixed charge by $9.09 for CPC customers.

The impact on a typical Unmetered Scattered Load customer is an increase of 267% on total bill for ETPL, and increase of 104% for WPPI customers and an increase of $278% for CPC customers. This large impact is a direct result of the change in cost allocation, and has been mitigated by the change in RTSR rates. ETPL will consider further rate mitigation steps as the Cost of Service process continues.

The overall bill impact on a typical Unmetered Scattered Load customer is shown in detail in Exhibit 8, Tab 1, Schedule 8.

<u>Embedded Distributor:</u>

The proposed changes to Embedded Distriubtors are summarized below.

	2011 Board Approved	2012 Proposed	% change
Service Charge	$2,254.63	$2,219.86	-1.54%
Distribution Volumetric Rate	$1.6717	$4.2995	157.19%

In order to adjust the fixed cost recovery through the monthly fixed charge, Erie Thames is proposing to decrease the monthly customer charge by $34.77 in the 2012 test year, which is a value well within the floor and ceiling rates calculated in Cost Allocation filing included in this application..

The impact on a typical Embedded Distributor customer is a decrease of 2.2% on total bill. The overall bill impact on a typical Embedded Distributor customer is shown in detail in Exhibit 8, Tab 1, Schedule 8.

The low impact on total bill, compared to the change in the variable charge, is based on the reduction of retail transmission rates (details later in this exhibit). Note, smart meter rate adder at $1.10 per metered customer and LV retail rates have been adjusted on explained later in this exhibit.

Specific Service Charges

Erie Thames proposes no change to its currently approved Specific Service Charges and a minor change to the loss factor listed below. Details can be found in Exhibit <>, Schedule <>, Tab <9>. The Charges are listed below.

Erie Thames Powerlines Corporation
Tariff of Rates and Charges
Effective May 1, 2012
Implementation Date To be Determined

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

Residential	**UOM**	**Rate**
Service Charge	$	$15.21
Smart Meter Charge	$	$1.1000
Distribution Volumetric Rate	$/kWh	$0.0143
Low Voltage Service Rate	$/kWh	$0.0021
ETPL Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kWh	$0.0004
CPC Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kWh	$0.0006
WPPI Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kWh	$0.0002
ETPL Rate Rider for Global Adjustment Sub-Account effective One Year from Implementation	$/kWh	$0.0010
ETPL Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kWh	-$0.0009
CPC Rate Rider for Global Adjustment Sub-Account effective Two years from Implementation	$/kWh	-$0.0114
CPC Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kWh	$0.0122
WPPI Rate Rider for Global Adjustment Sub-Account effective One Year from Implementaton	$/kWh	-$0.0029
WPPI Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kWh	-$0.0013
Retail Transmission Rate – Network Service Rate	$/kWh	$0.0059
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	$0.0040
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500
GS<50 kW		
Service Charge	$	$20.95
Smart Meter Charge	$	$1.1000
Distribution Volumetric Rate	$/kWh	$0.0151
Low Voltage Service Rate	$/kWh	$0.0020
ETPL Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kWh	$0.0004
CPC Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kWh	$0.0004
WPPI Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kWh	$0.0002
ETPL Rate Rider for Global Adjustment Sub-Account effective One Year from Implementation	$/kWh	$0.0013
ETPL Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kWh	-$0.0009
CPC Rate Rider for Global Adjustment Sub-Account effective Two years from Implementation	$/kWh	-$0.0115
CPC Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kWh	$0.0081
WPPI Rate Rider for Global Adjustment Sub-Account effective One Year from Implementaton	$/kWh	-$0.0023
WPPI Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kWh	-$0.0010
Retail Transmission Rate – Network Service Rate	$/kWh	$0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	$0.0036
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500

GS>50 to 999 kW		
Service Charge	$	$226.60
Smart Meter Charge	$	$1.1000
Distribution Volumetric Rate	$/kW	$3.4664
Low Voltage Service Rate	$/kW	$0.7099
ETPL Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.2647
CPC Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.3481
WPPI Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.1653
ETPL Rate Rider for Global Adjustment Sub-Account effective One Year from Implementation	$/kW	$2.6824
ETPL Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	-$0.6597
CPC Rate Rider for Global Adjustment Sub-Account effective Two years from Implementation	$/kW	-$4.7823
CPC Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	$6.6561
WPPI Rate Rider for Global Adjustment Sub-Account effective One Year from Implementaton	$/kW	-$2.9573
WPPI Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	-$0.9799
Rate Rider for Tax Change effective until April 30 2012	$/kW	-$0.0206
Retail Transmission Rate – Network Service Rate	$/kW	$2.4575
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.2953
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500
GS>1000 to 4999 kW		
Service Charge	$	$2,862.06
Smart Meter Charge	$	$1.1000
Distribution Volumetric Rate	$/kW	$3.9753
Low Voltage Service Rate	$/kW	$0.7635
ETPL Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.2091
ETPL Rate Rider for Global Adjustment Sub-Account effective One Year from Implementation	$/kW	$2.1192
ETPL Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	-$0.5212
Retail Transmission Rate – Network Service Rate	$/kW	$2.6692
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.3929
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500

Large Use		
Service Charge	$	$10,715.28
Smart Meter Charge	$	$1.1000
Distribution Volumetric Rate	$/kW	$1.9941
Low Voltage Service Rate	$/kW	$0.0733
ETPL Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.2149
ETPL Rate Rider for Global Adjustment Sub-Account effective One Year from Implementation	$/kW	$2.1775
ETPL Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	-$0.5355
Retail Transmission Rate – Network Service Rate	$/kW	$2.9591
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.5800
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500
Street Lighting		
Service Charge	$	$3.80
Distribution Volumetric Rate	$/kW	$14.9986
Low Voltage Service Rate	$/kW	$0.5482
ETPL Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.1093
CPC Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.1936
WPPI Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.0561
ETPL Rate Rider for Global Adjustment Sub-Account effective One Year from Implementation	$/kW	$1.1686
ETPL Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	-$0.2723
CPC Rate Rider for Global Adjustment Sub-Account effective Two years from Implementation	$/kW	-$3.5978
CPC Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	$2.1865
WPPI Rate Rider for Global Adjustment Sub-Account effective One Year from Implementaton	$/kW	-$1.0044
WPPI Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	-$0.3328
Retail Transmission Rate – Network Service Rate	$/kW	$1.8979
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.6533
Wholesale Market Service Rate	$/kW	$0.0052
Rural Rate Protection Charge	$/kW	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500

Sentinel Lighting		
Service Charge	$	$5.25
Distribution Volumetric Rate	$/kW	$17.3901
Low Voltage Service Rate	$/kW	$0.5482
ETPL Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.1373
CPC Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.1143
WPPI Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.1018
ETPL Rate Rider for Global Adjustment Sub-Account effective One Year from Implementation	$/kW	$0.0000
ETPL Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	-$0.3421
CPC Rate Rider for Global Adjustment Sub-Account effective Two years from Implementation	$/kW	-$3.5374
CPC Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	$3.7014
WPPI Rate Rider for Global Adjustment Sub-Account effective One Year from Implementaton	$/kW	-$1.0992
WPPI Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	-$0.6037
Retail Transmission Rate – Network Service Rate	$/kW	$1.8979
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.0003
Wholesale Market Service Rate	$/kW	$0.0052
Rural Rate Protection Charge	$/kW	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500
Embedded Distributor		
Service Charge	$	$2,219.86
Smart Meter Charge	$	$1.1000
Distribution Volumetric Rate	$/kW	$4.2434
ETPL Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.2744
ETPL Rate Rider for Global Adjustment Sub-Account effective One Year from Implementation	$/kW	$2.7806
ETPL Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	-$0.6839
Retail Transmission Rate – Network Service Rate	$/kW	$3.5709
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.8369
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500

Unmetered Scattered Load		
Service Charge	$	$3.00
Distribution Volumetric Rate	$/kWh	$0.1347
Low Voltage Service Rate	$/kWh	$0.0020
ETPL Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kWh	$0.0004
CPC Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kWh	$0.0006
WPPI Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kWh	$0.0000
ETPL Rate Rider for Global Adjustment Sub-Account effective One Year from Implementation	$/kWh	$0.0005
ETPL Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kWh	-$0.0009
CPC Rate Rider for Global Adjustment Sub-Account effective Two years from Implementation	$/kWh	-$0.0123
CPC Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kWh	$0.0113
WPPI Rate Rider for Global Adjustment Sub-Account effective One Year from Implementaton	$/kWh	-$0.0004
WPPI Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kWh	-$0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	$0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	$0.0036
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500
microFIT Genertator Service Classification		
Service Charge	$	$5.2500
Arrears Certificate	$	15.00
Easement Letter	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank Charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special Meter Reads	$	30.00
Meter dispute charge plus Measurement Canada Fees (if meter found correct)	$	30.00
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

Temporary Service Install & Remove - overhead - no transformer	$	500.00
Temporary Service Install & Remove - underground - no transformer	$	300.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35
Transformer Allowance for Ownership - per kW of billing demand/month	$	(0.60)
Primary Metering allowance for transformer losses - applied to measured demand and energy	%	(1.00)
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)
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
Total Loss Factor -- Secondary Metered Customer < 5,000 kW		1.0483
Total Loss Factor -- Secondary Metered Customer > 5,000 kW		1.0161
Total Loss Factor -- Primary Metered Customer < 5,000 kW		1.0379
Total Loss Factor -- Primary Metered Customer >5,000 kW		1.0060

BUDGET DIRECTIVES

Revenue Forecast

Energy sales and revenue forecasts were compiled to reflect the most recent information available. Historical sales were normalized for a weather correction as outlined in Exhibit 3, Schedule 2. The normalized consumption was used to prepare the revenues sales and throughput volume and revenue forecast at existing rates for fiscal 2011.

Operating and Maintenance Expense Forecast

The operating and maintenance expenses for fiscal 2011 Bridge year and the 2012 Test year have been incorporated into the revenue requirement contained within this application.

Capital Budget

All capital expenditures are budgeted on a line by line basis based on need and forecasted customer growth. Details on capital projects can be found in Exhibit 2, Tab 2, Schedule 3.

CHANGES IN METHODOLOGY

The following is a summary of the changes in methodology requested by Erie Thames in the current proceeding:

a) Capital Structure
Erie Thames plans to use the Board's deemed structure.

b) Return on Equity
Erie Thames has used the most recent Board approved methodology for determining the return on equity in this Application.

c) Return on Debt
Erie Thames has applied the most recent Board prescribed rates for short and long-term debt.

d) Interest Rate Applicable to Deferral/Variance Accounts
Erie Thames has applied no change to the current methodology in existence for Deferral/Variance Account interest rates in this application.

e) Cost Allocation & Fully Allocated Costing Study
Erie Thames did complete a cost allocation study. Erie Thames has included in this application a Cost Allocation study that meets with the guidelines.

DETAILS OF CAUSES OF DEFICIENCY IN 2012 TEST YEAR

The deficiency of $609,251 (Exhibit 6) is the result of the combination of a number of factors – some of which are identified below.

Factors that tended to reduce the revenue requirement include:

1) The lower overall cost of capital resulting from lower debt rates and the lower return on equity;

2) The elimination of certain expenses as a result of the amalgamation of WPPI, CPC and Erie Thames such as audit fees, registrations.

Factors which have tended to increase the revenue requirement:

1) The increased asset base resulting from the increase in assets from the reorganization prior to the amalgamation;
2) The increased asset base resulting from the increase in assets from construction of expansions and the replacement of facilities;

3) Inflation; and,

4) Additional requirements related to smart meters and other regulatory changes and requirements.

Another factor that has contributed to the deficiency is the change in forecast for the large industrial customers that have left the system or reduce their demand and consumption.

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Service Quality Indicators 2010 Clinton Power

Service Reliability Indices with Code 2 Outages

Month	Total Customer Hours of Interruption	Total Customer Interruptions	Total Number of Customers	SAIDI	SAIFI	CAIDI
January	21	28	1671	0.01	0.02	0.75
February	3	12	1671	0.00	0.01	0.25
March	2	4	1671	0.00	0.00	0.50
April	3	11	1671	0.00	0.01	0.27
May	54	72	1671	0.03	0.04	0.75
June	0	0	1671	0.00	0.00	0.00
July	0	0	1671	0.00	0.00	0.00
August	516	1032	1671	0.31	0.62	0.50
September	1	1	1671	0.00	0.00	1.00
October	12	16	1671	0.01	0.01	0.75
November	34	27	1671	0.02	0.02	1.26
December	1	1	1671	0.00	0.00	1.00
Totals	**647**	**1204**	**1671**			

Service Reliability Indices without Code 2 Outages

Month	Total Customer Hours of Interruption	Total Customer Interruptions	Total Number of Customers	SAIDI	SAIFI	CAIDI
January	21	28	1671	0.01	0.02	0.75
February	3	12	1671	0.00	0.01	0.25
March	2	4	1671	0.00	0.00	0.50
April	3	11	1671	0.00	0.01	0.27
May	54	72	1671	0.03	0.04	0.75
June	0	0	1671	0.00	0.00	0.00
July	0	0	1671	0.00	0.00	0.00
August	516	1032	1671	0.31	0.62	0.50
September	1	1	1671	0.00	0.00	1.00
October	12	16	1671	0.01	0.01	0.75
November	34	27	1671	0.02	0.02	1.26
December	1	1	1671	0.00	0.00	1.00
Totals	**647**	**1204**	**1671**			

Service Quality Indicators 2010 West Perth Power

Service Reliability Indices with Code 2 Outages

Month	Total Customer Hours of Interruption	Total Customer Interruptions	Total Number of Customers	SAIDI	SAIFI	CAIDI
January	0	0	2199	0.00	0.00	0.00
February	1781	475	2199	0.81	0.22	3.75
March	19	16	2199	0.01	0.01	1.19
April	3	3	2199	0.00	0.00	1.00
May	176	153	2199	0.08	0.07	1.15
June	13	8	2199	0.01	0.00	1.62
July	239	475	2199	0.11	0.22	0.50
August	22	22	2199	0.01	0.01	1.00
September	0	0	2199	0.00	0.00	0.00
October	104	139	2199	0.05	0.06	0.75
November	84	105	2199	0.04	0.05	0.80
December	1	1	2199	0.00	0.00	1.00
Totals	**2442**	**1397**	**2199**			

Service Reliability Indices without Code 2 Outages

Month	Total Customer Hours of Interruption	Total Customer Interruptions	Total Number of Customers	SAIDI	SAIFI	CAIDI
January	0	0	2199	0.00	0.00	0.00
February	1781	475	2199	0.81	0.22	3.75
March	19	16	2199	0.01	0.01	1.19
April	3	3	2199	0.00	0.00	1.00
May	176	153	2199	0.08	0.07	1.15
June	13	8	2199	0.01	0.00	1.62
July	239	475	2199	0.11	0.22	0.50
August	22	22	2199	0.01	0.01	1.00
September	0	0	2199	0.00	0.00	0.00
October	104	139	2199	0.05	0.06	0.75
November	84	105	2199	0.04	0.05	0.80
December	1	1	2199	0.00	0.00	1.00
Totals	**2442**	**1397**	**2199**			

Service Quality Indicators 2010 Erie Thames Powerlines

Service Reliability Indices with Code 2 Outages

Month	Total Customer Hours of Interruption	Total Customer Interruptions	Total Number of Customers	SAIDI	SAIFI	CAIDI
January	2953	1808	14463	0.20	0.13	1.63
February	2877	1778	14469	0.20	0.12	1.62
March	3147	1894	14472	0.22	0.13	1.66
April	3184	1916	14475	0.22	0.13	1.66
May	5747	2986	14477	0.40	0.21	1.92
June	6609	4626	14479	0.46	0.32	1.43
July	21970	8464	14481	1.52	0.58	2.60
August	22070	8518	14483	1.52	0.59	2.59
September	22046	8517	14485	1.52	0.59	2.59
October	22120	8585	14487	1.53	0.59	2.58
November	24158	9860	14490	1.67	0.68	2.45
December	25382	11021	14495	1.75	0.76	2.30
Totals	**162263**	**69973**	**14495**			

Service Reliability Indices without Code 2 Outages

Month	Total Customer Hours of Interruption	Total Customer Interruptions	Total Number of Customers	SAIDI	SAIFI	CAIDI
January	108	48	14463	0.01	0.00	2.25
February	31	18	14469	0.00	0.00	1.72
March	301	134	14472	0.02	0.01	2.25
April	338	156	14475	0.02	0.01	2.17
May	345	159	14477	0.02	0.01	2.17
June	552	246	14479	0.04	0.02	2.24
July	1267	596	14481	0.09	0.04	2.13
August	1366	650	14483	0.09	0.04	2.10
September	1343	649	14485	0.09	0.04	2.07
October	1416	717	14487	0.10	0.05	1.97
November	2550	1194	14490	0.18	0.08	2.14
December	3774	2355	14495	0.26	0.16	1.60
Totals	**13391**	**6922**	**14495**			

AUDITED FINANCIAL STATEMENTS

ERIE THAMES POWERLINES CORPORATION

FINANCIAL STATEMENTS

DECEMBER 31, 2010

Your Hometown Utility

ERIE THAMES POWERLINES CORPORATION
INDEX TO AUDITED FINANCIAL STATEMENTS
DECEMBER 31, 2010

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Erie Thames Powerlines Corporation

We have audited the accompanying financial statements of Erie Thames Powerlines Corporation, which comprise the balance sheet as at December 31, 2010 and the statements of income, retained earnings, and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform an audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Erie Thames Powerlines Corporation as at December 31, 2010, and its results of operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

May 20, 2011

London, Canada

ERIE THAMES POWERLINES CORPORATION
BALANCE SHEET
AS AT DECEMBER 31, 2010

ASSETS

	2010	2009
Current Assets		
Cash	$ -	$ 682,426
Accounts receivable (note 3)	8,229,893	7,064,002
Inventory	79,556	66,683
Prepaid expenses	72,494	54,232
Payment in lieu of income taxes recoverable	-	91,567
Due from related parties (note 9)	92,092	-
	8,474,035	7,958,910
Property, Plant and Equipment (note 4)	18,548,964	18,258,685
Future Payment in Lieu of Income Tax Asset (note 16)	362,000	297,000
Regulatory Assets (note 5)	3,449,910	2,064,755
Goodwill (note 6)	76,667	76,667
	$30,911,576	$28,656,017

LIABILITIES AND SHAREHOLDER'S EQUITY

	2010	2009
Current Liabilities		
Demand operating loan (note 7)	$ 547,485	$ -
Accounts payable and accrued liabilities	5,926,677	5,408,735
Customer deposits (note 8)	993,088	792,265
Payments in lieu of income taxes payable	205,377	-
Due to related parties (note 9)	5,101,657	5,429,675
Current portion of long-term debt (note 11)	208,591	13,726
	12,982,875	11,644,401
Related Party Long-term Debt (note 10)	8,038,524	8,038,524
Long-term Debt (note 11)	368,693	52,129
Regulatory Liabilities (note 5)	32,202	32,202
Future Regulatory Taxes Payable (note 5)	362,000	297,000
Post-Retirement Benefit Obligation (note 12)	514,103	255,227
Shareholder's Equity		
Share capital (note 13)	8,038,524	8,038,524
Retained earnings	574,655	298,010
	8,613,179	8,336,534
	$30,911,576	$28,656,017

Contingent Liabilities (notes 14, 15 and 17)
Commitments (note 18)
Subsequent Events (note 21)

APPROVED ON BEHALF OF THE BOARD:

_______________ Director   _______________ Director

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION
STATEMENT OF RETAINED EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2010

	2010	2009
Balance, Beginning of Year	$ 298,010	$ 583,233
Change in Accounting Policy (note 2(f)(iii))	-	(161,000)
Restated Opening Retained Earnings	298,010	422,233
Assumption of Employee Future Benefit Obligation (note 12)	(250,474)	(253,227)
Net Income	527,119	129,004
Balance, End of Year	$ 574,655	$ 298,010

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION
STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2010

	2010	%	2009	%
Electricity Revenue	$39,293,536		$36,428,344	
Cost of Power	33,038,373		30,739,578	
Distribution Revenue	6,255,163	100.00	5,688,766	100.00
Expenses				
Billing and collecting	972,550	15.55	768,233	13.51
Community relations	214,264	3.43	152,494	2.68
Direct operation	2,280,082	36.45	1,950,030	34.28
Office and administration	674,550	10.78	574,166	10.09
Regulatory and professional	254,553	4.07	780,244	13.72
	4,395,999	70.28	4,225,167	74.28
Income from Operations Before the Following	1,859,164	29.72	1,463,599	25.72
Amortization	1,177,338	18.82	1,017,711	17.89
Interest income on regulatory assets	(37,184)	(0.59)	(65,261)	(1.15)
Interest	778,186	12.44	811,789	14.27
Income from Operations Before Other Income and Tax	(59,176)	(0.95)	(300,640)	(5.29)
Other Income				
Interest income	14,842	0.24	5,941	0.10
Service revenue	758,453	12.13	511,703	8.98
Gain on sale of equipment	-	-	4,000	-
	773,295	12.37	521,644	9.08
Income Before Income Tax	714,119	11.42	221,004	3.79
Payments in Lieu of Income Taxes (note 16)				
Current	187,000	2.99	92,000	1.62
Net Income	$ 527,119	8.43	$ 129,004	2.17

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION
STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2010

	2010	2009
Cash Flows from Operating Activities		
Net income	$ 527,119	$ 129,004
Items not requiring an outlay of cash:		
Amortization	1,177,338	1,017,711
Gain on sale of equipment	-	(4,000)
Post retirement benefit obligation	8,402	2,000
	1,712,859	1,144,715
Changes in non-cash working capital balances:		
Accounts receivable	(1,165,891)	(588,649)
Inventory	(12,873)	(66,683)
Prepaid expenses	(18,262)	4,262
Payment in lieu of income taxes	296,944	(196,860)
Regulatory assets	(1,385,155)	70,775
Accounts payable and accrued liabilities	517,942	206,757
Customer deposits	200,823	(53,470)
Due to related parties	(420,110)	2,885,715
Net Cash Provided by (Used in) Operating Activities	(273,723)	3,406,562
Cash Flows from Financing Activities		
Increase in long-term debt	511,429	65,855
Cash Flows from Investing Activities		
Additions to property, plant and equipment	(1,467,617)	(1,794,153)
Proceeds on disposal of equipment	-	9,000
Intangible assets	-	(16,838)
Net Cash Used in Investing Activities	(1,467,617)	(1,801,991)
Net Increase (Decrease) in Cash	(1,229,911)	1,670,426
Cash (Bank Indebtedness), Beginning of Year	682,426	(988,000)
Cash (Bank Indebtedness), End of Year	$ (547,485)	$ 682,426
Supplemental Cash Flow Information		
Interest paid	$ 923,892	$ 811,789
Payment in lieu of income taxes	$ (109,824)	$ 494,237

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

1. Nature of Operations

The Ontario Government enacted the Energy Competition Act, 1998 to introduce competition to the Ontario electricity market by the year 2000. Under the terms of this legislation, the Ontario Energy Board (the "OEB") regulates industry participants by issuing licences for the right to generate, transmit, distribute or retail electricity. These licences require compliance with established market rules and codes. The Ontario Government opened the Ontario electricity market to competition on May 1, 2002.

Erie Thames Powerlines Corporation ("the Company") is wholly owned by ERTH Corporation who is in turn owned by the following nine municipalities, each of whom has one voting common share: Aylmer, Central Elgin, East-Zorra Tavistock, Ingersoll, Norwich, South-West Oxford, Zorra, West Perth and Central Huron.

The Company carries on the business of distributing electricity to the following communities: Aylmer, Beachville, Belmont, Burgessville, Embro, Ingersoll, Norwich, Otterville, Port Stanley, Tavistock, and Thamesford.

2. Significant Accounting Policies

The financial statements of the Company have been prepared by management in accordance with Canadian generally accepted accounting principles, as modified by regulations and policies set forth in the Ontario Energy Board Accounting Procedures Handbook. Those policies that are considered to be particularly significant are outlined below:

(a) Property, Plant and Equipment

Property, plant and equipment are recorded at the fair market value of the assets transferred from the Municipal Hydro Electric Commissions to the Company on August 31, 2000, and subsequent to August 31, 2000, at cost on the date of purchase. Property, plant and equipment are amortized over their useful lives using the straight-line method over the following periods:

Buildings	25 years
Plant and equipment	
Automotive equipment	8 years
Computer equipment	5 years
Service, office and other equipment	10 years
Transmission and distribution system	25 years

Construction work in progress are recorded at cost until such time that the asset is completed and available for use at which point it is amortized over its useful life.

ERIE THAMES POWERLINES CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

2. Significant Accounting Policies (cont.)

(b) Contributions to Property, Plant and Equipment

Contributions are received from developers and contractors for capital costs incurred by the Company. These contributions are included as a reduction to the cost of the related Property, Plant or Equipment when those assets are placed in service.

(c) Revenue Recognition

(i) Electricity Sales

The Company follows the practice of cycle billing of customer's accounts and revenue is recognized in the period consumed. Estimated customer usage from the last billing date to the year end (unbilled revenue) is included in revenue.

(ii) Interest Income

Interest income on outstanding customer accounts is recognized on a time proportion basis, taking account of the principal outstanding and the effective rate over the period to maturity, when it is determined that such income will accrue to the Company.

(iii) Service Revenue

Service revenue is recognized as service is performed.

(d) Pension and Other Retirement Benefit Plans

(i) The actuarial determination of the accrued benefit obligations for other retirement benefits uses the projected benefit method prorated on service, which incorporates management's best estimate of cost escalation, retirement ages of employees and actuarial factors.

(ii) Past service costs arising from plan amendments are deferred and amortized on a straight-line basis using the corridor method over the average remaining service period of employees active at the date of amendment.

(iii) When the restructuring of a benefit plan gives rise to both a curtailment and a settlement of obligations, the curtailment is accounted for prior to the settlement.

ERIE THAMES POWERLINES CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

2. Significant Accounting Policies (cont.)

(e) Financial Instruments

The Company's financial assets and financial liabilities are classified and measured as follows:

- Cash is classified as held for trading and is measured at fair value. Gains and losses related to periodical revaluation are recorded in net income.
- Accounts receivable and regulatory assets are classified as loans and receivables and are initially measured at fair value and, subsequently, at amortized cost using the effective interest rate method.
- Accounts payable and accrued liabilities, regulatory liabilities, customer deposits, due to related party and long-term debt are classified as other liabilities and are initially measured at fair value and, subsequently, at amortized cost using the effective interest rate method.

(f) Financial Effects of Distribution Rate Regulation

The financial results presented are in accordance with generally accepted accounting principles and within that framework the Company accounts for the impact of regulatory actions in the following manner:

(i) Regulatory Decisions to Adjust Distribution Rates

In the event that a regulatory decision is rendered, providing regulatory approval and certainty to the recognition of an asset or creation of a liability and culminating in an adjustment to the Company's distribution rates, such occurrences are immediately reflected in the Company's accounts.

(ii) Regulatory Direction and Practice

In the absence of regulatory decision impacting rates, and where the Company is required by regulatory accounting practice or direction to accumulate balances for future rate recovery or create liabilities for future discharge, those amounts are recorded in accordance with that regulatory direction. Management assesses the future uncertainty with respect to the final regulatory disposition of those amounts and to the extent required, makes accounting provisions to reduce the deferred balances accumulated or to increase the recorded liabilities. Upon rendering of the final regulatory decisions adjusting distribution rates, the provisions are adjusted to reflect the final impact of that decision, and such adjustment is reflected in net earnings for the period.

Amounts currently confirmed by final regulatory decision, and amounts currently accounted for in the absence of final regulatory decision together with related provisions for future uncertainty, are more fully described in note 5 to the financial statements.

ERIE THAMES POWERLINES CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

2. Significant Accounting Policies (cont.)

(iii) Regulatory balances

Effective January 1, 2009, the Company adopted the changes to CICA Handbook Section 1100 - *Generally Accepted Accounting Principles*. The amendment to this section removed the temporary exemption pertaining to the application of the section to the recognition and measurement of assets and liabilities arising from rate regulation. In response to the removal of the exemption, the Company established accounting policies for the recognition and measurement of assets and liabilities arising from rate regulation. In accordance with the Canadian GAAP hierarchy guidance framework outlined in CICA Handbook Section 1100, the company has determined that its assets and liabilities arising from rate regulation qualify for recognition under Canadian GAAP and this recognition is constant with U.S. Statement of Financial Accounting Standards No. 71, *Accounting for Effects of Certain Types of Regulations* ("FAS71"). The company concluded that its policies for assets and liabilities arising from rate regulation were consistent with the primary sources of Canadian GAAP and were developed through the exercise of professional judgment.

(iv) Income tax expense

Effective January 1, 2009, the Company adopted the changes to CICA Handbook Section 3465 - *Income Taxes*, which states that, as a rate regulated entity, future income tax assets will be returned to customers as they are recovered. As a result, all increases or decreases in future income tax assets are offset by a regulatory liability. As at December 31, 2011 the Company has recorded a future income tax assets of $362,000 and a corresponding regulatory liability of $362,000 (note 5).

(v) Rate Setting

The distribution rates of the Corporation are based on a revenue requirement that provides a regulated Maximum Allowable Return on Equity ("MARE") on the amount of shareholders' equity supporting the business of electricity distribution, which is also determined by regulation. The Company files a rate application with the OEB annually. Rates are typically effective May 1 to April 30 of the following year. Accordingly, for the first four months of 2010, distribution revenue is based on the rates approved for 2009. Once every four years, the Company files an Electricity Distribution Rate application ("EDR") where rates are rebased through a cost of service review. In the intervening years an Incentive Rate Mechanism application ("IRM") is filed. A cost of service EDR application is based upon a forecast of the amount of operating and capital expenses, debt and shareholder's equity required to support the Company's business. An IRM application results in a formulaic adjustment to distribution rates to increase distribution rates for the annual change in the GDP IPI-FDD net of a productivity factor and a "Stretch Factor" determined by the relative efficiency of an electricity distributor.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

2. Significant Accounting Policies (cont.)

The Company's last cost of service EDR application was made in 2008 and approved on October 27, 2009 with rates effective December 1, 2008. Such decision provided for 2008 service distribution revenue requirement and rate base of $6,578,355 and $22,246,774 respectively. Such amounts do not include provision for the investment of the Company in the Smart Meter Initiative, further elaborated below.

The Company has filed IRM applications to adjust its rates effective May 1, 2009 and May 1, 2010. Accordingly, the Companys' rates were increased by 0.98% effective May 1, 2009. The Company's 2010 IRM application was approved on June 29, 2010 with an increase in distribution rates for the annual change in the GDP IPI-FDD of 1.20% net of a productivity factor of 0.72% and a "Stretch Factor" of 0.60% determined by the relative efficiency of the Company.

In December 2009, the OEB concluded a Cost of Capital proceeding with the issuance of a final report. The report principally dealt with the adequacy and determination of the Maximum Allowable Return on Equity ("MARE"). The Board has acknowledged that it needs to refine and reset its current formula for determining MARE to:

i) acknowledge and incorporate a utility spread off of Canada long-bonds within the Equity Risk Premium ("ERP") to better reflect utility borrowing costs (initially 141.5bps);
ii) to include a 50bps "transaction cost" component within the ERP to reflect estimated transaction costs related to utility borrowings; and
iii) reduce MARE volatility from annual changes in the Canada long-bond and i) by reducing the annual adjustment factor from 0.75 to 0.5; and
iv) reflect a more realistic and "fair" base risk premium for Local Distribution Companies.

The method of transition to the new MARE is through a Cost of Service Application similar to the 2006 EDR Application. The Corporation will file such an application in 2011 with an effective date of May 1, 2012.

(vi) Smart Meter Initiative

The Province of Ontario has committed to have "Smart Meter" electricity meters installed in all homes and small businesses throughout Ontario by the end of 2010. Smart Meters permit consumption to be recorded within specific time intervals and specific tariffs to be levied within such intervals.

In support of this initiative, the Company completed its deployment of Smart Meters throughout 2009, 2010 and early 2011, with 13,116 Smart Meters deployed by the end of 2010. Successful testing with the provincial Meter Data Management Repository ("MDMR") will be completed in 2011.

ERIE THAMES POWERLINES CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

2. Significant Accounting Policies (cont.)

In December or 2010, the Company submitted an application to the OEB for the consideration and approval of a Utility-Specific Smart Meter Funding Adder in accordance with the Smart Meter Funding and Cost Recovery Guideline of the OEB. On April 7, 2011, the Application was approved as filed. The Application provided for a new rate adder of $1.74 per metered customer per month, beginning May 1, 2011.

(vii) Green Energy and Green Economy Act

In early 2009, the government tabled the Green Energy and Green Economy Act ("GEGEA"). This new legislation makes fundamental changes to the roles and responsibilities of LDC's in the areas of renewable power generation, conservation and demand management delivery, and the development of smart distribution grids.

The Green Energy and Green Economy Act provides LDC's with the freedom to own and operate a portfolio of renewable power generation and will permit them to provide district heating services in their communities through co-generation. LDC's will also bear added responsibilities to assist and enable consumers to reduce their peak demand and conserve energy in an effort to meet provincial conservation targets. LDC's will also gain new responsibilities in transforming their local distribution networks into smart grids harnessing advanced technologies to facilitate the connection of small-scale generators and the two-way flow of information.

(viii) New LDC License Requirements - Conservation and Demand Management Targets

On November 12, 2010, the OEB amended LDC licenses to include requirements for achieving certain CDM targets over a four year period commencing January 1, 2011. The Company's CDM targets include a demand reduction target of 4.28MW and a consumption reduction target of 18,600MWh. LDC's must also comply with a new CDM Code of the OEB, which provides LDC requirements for the development and delivery of CDM Strategy to the OEB for the achievement of LDC-specific CDM targets, annual accounting and reporting to the OEB, and eligibility criteria for performance incentive payments. The Company has filed its CDM Strategy with the OEB.

(g) Payments in Lieu of Income Taxes (PILs)

The Company uses the liability method for accounting for PILs. Under this method, future payment in lieu of income tax assets and liabilities are recognized for differences between the carrying value of assets and liabilities for accounting purposes and their respective values for payment in lieu of income tax purposes. These differences are measured using substantively enacted tax rates applicable for the period in which those differences are expected to be recovered or settled. To the extent that there is uncertainty regarding the recovery of a future payment in lieu of income tax asset, a valuation allowance reducing the future payment in lieu of income tax asset is recorded.

ERIE THAMES POWERLINES CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

2. Significant Accounting Policies (cont.)

(h) Goodwill and Intangible Assets

Goodwill and intangible assets acquired individually or as part of a group of other assets are initially recognized and measured at cost. The cost of a group of intangible assets acquired in a transaction, including those acquired in a business combination, are allocated to the individual assets based on their relative fair value. Intangible assets with finite lives are amortized on a straight-line basis over their estimated useful lives. Organizational charges are amortized over five years. Goodwill and intangible assets with indefinite useful lives are not amortized and are tested for impairment annually or more frequently if events and changes in circumstances indicate that an asset might be impaired.

(i) Inventory

Inventories consist primarily of materials and supplies. Items considered to be major future components of property, plant and equipment are transferred to property, plant and equipment. Inventories are carried at the lower of cost and net realizable value, with cost determined on an average cost basis net of a provision for obsolescence.

(j) Impairment of Long-lived Assets

Long-lived assets are tested for recoverability when events or changes in circumstances indicate that their carrying value may not be recoverable. An impairment loss is recognized when the carrying value exceeds the total undiscounted cash flow expected from their use and eventual disposition. The amount of the impairment loss is determined as the excess of the carrying value of the asset over its fair value.

(k) Use of Estimates

The preparation of the financial statements of the Company in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the balance sheet date and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates.

ERIE THAMES POWERLINES CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

2. Significant Accounting Policies (cont.)

(l) Future Accounting Changes

(i) International Financial Reporting Standards ("IFRS")

On February 13, 2008, the Canadian Accounting Standards Board confirmed the publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. On September 10, 2010, the AcSB decided to permit rate-regulated entities to defer their IFRS implementation date to January 1, 2012.

The Company has an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its financial statements. Although the impact of the adoption to IFRS on the Company's Balance Sheet and Income Statement is not yet reasonablydeterminable or estimable, the company does expect a significant increase in financial statement disclosure requirements resulting from the adoption of IFRS, and is designing the systems and related process changes, which will be required in order to provide the additional information required to make these disclosures.

Given the continued uncertainty around the timing, scope and eventual adoption of a rate-regulated accounting standard under IFRS and the potential material impact of these standards on the Company's financial statements, the Company has decided to apply IFRS to its financial statements ending December 31, 2012 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011, for comparative purposes. The company continues to assess the impact of the conversion to IFRS on its results of operation. At this time, the impact on the Company's future financial statements cannot be determined.

3. Accounts Receivable

	2010	**2009**
Energy, water and sewer	$ 3,738,066	$ 3,075,903
Unbilled energy	4,128,009	3,506,353
Service revenues	363,818	481,746
	$ 8,229,893	$ 7,064,002

The amounts shown above are net of allowance for doubtful accounts of $250,000 (2009 - $214,589.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

4. Property, Plant and Equipment

	Cost 2010	Accumulated Amortization	Net 2010	Net 2009
Land	$ 128,928	$ -	$ 128,928	$ 128,684
Buildings	136,363	47,224	89,139	88,050
Plant and equipment	1,074,034	577,384	496,650	451,050
Transmission and distribution system	24,872,275	7,312,025	17,560,250	17,034,536
Construction work in progress	-	-	-	556,365
Equipment under capital leases	364,964	90,967	273,997	-
	$26,576,564	$ 8,027,600	$18,548,964	$18,258,685

During the year, the Company recorded amortization of $1,174,067 (2009 - $1,017,711).

5. Regulatory Assets and Liabilities

Regulatory assets consist of the following:

	2010	2009
Retail settlement variances (a)	$ 1,768,703	$ 2,658,784
Special purpose charge variance (b)	50,305	-
Late payment penalties settlement (c)	51,909	-
	1,870,917	2,658,784
Recovery of regulatory assets	1,578,993	(594,029)
	$ 3,449,910	$ 2,064,755

Regulatory liabilities consist of the following:

	2010	2009
Regulatory assets recovery account	$ 32,202	$ 32,202
Future payment in lieu of income tax liability	362,000	297,000
	$ 394,202	$ 329,202

The OEB approved an Interim Rate Order for May 1, 2008, that effectively removed the recovery allocation of the regulatory assets amounts until the final Cost of Service Rate Application was approved. The new Cost of Service Rate Order approved by the OEB, effective December 1, 2008, includes an allocation of the recovery of the low voltage energy variances. The remainder of the regulatory assets will be recovered based on future rate orders.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

5. Regulatory Assets and Liabilities (cont.)

(a) Retail settlement variances represent amounts accumulated since the opening of the electricity market on May 1, 2002. These variances are comprised of variances between amounts charged by the Independent Electricity Market Operator and amounts billed to customers plus variances from settlement and transmission charges. In the absence of rate regulations, these costs (revenues) would be charged to the period incurred.

(b) On April 9, 2010, the OEB informed electricity distributors of a Special Purpose Charge assessment under Section 26.1 of the Ontario Energy Board Act, 1998, for the Ministry of Energy and Infrastructure conservation and renewable energy program costs. The OEB assessed the Company $152,675 for their apportioned share of the total provincial amount of the Special Purpose Charge of $53,695,000 in accordance with the rules set out in Ontario Regulation 66/10. In accordance with Section 9 of the Special Purpose Charge Regulation, the Company is allowed to recover this balance. The recovery is expected to be achieved over a one-year period, which began on May 1, 2010.

(c) The late payment penalties settlement account relates to the settlement costs accrual associated with the late payment charges class action (note 17 and 21). All of the Municipal Electricity Utilities ("MEU") involved in the settlement, including the Company, have requested an order from the OEB allowing for the future recovery from customers of all costs related to the settlement.

(d) Demand side management ("DSM") amounts are expenses incurred in accordance with OEB rules and regulations and represent costs to the Company of literature provided to its customers and capital expenditures to provide energy conservation. In the absence of rate regulations, these costs would be charged to the period incurred.

6. Goodwill

	Cost 2010	Accumulated Amortization	Net 2010	Net 2009
Goodwill	$ 100,000	$ 23,333	$ 76,667	$ 76,667

At year end, management tested goodwill and determined that there was no impairment of goodwill.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

7. Demand Operating Loan

Through a mirror banking agreement with its parent company the Company has available to its use a $6,000,000 revolving line of credit. The Company provides a guarantee on this facility, as outlined in note 14.

8. Customer Deposits

Customer deposits are obtained as security for energy consumption. On an annual basis, interest is calculated and credited to the customers' utility accounts. Also included are security deposits received for construction projects.

9. Related Parties

The Company has a contract with ERTH Corporation for management services and rental of facilities used by the Company.

The Company has contracted CRU Solutions Inc., Ecaliber (Canada) Inc., and ERTH360 Generation & Consulting Inc., companies under common control, to provide the following services: maintenance and upgrades to the existing capital infrastructure of the Company, billing and collection services and administrative services.

The contracts between the Company, CRU Solutions Inc., Ecaliber (Canada) Inc., ERTH360 Generation & Consulting Inc., and ERTH Corporation are measured at the exchange amount, which is the amount of consideration paid or received as established and agreed to by the related parties, unless noted otherwise.

During the year, CRU Solutions Inc. transferred to the Company five bucket trucks and one backhoe under capital lease at the carrying amount of the assets recorded in CRU Solutions Inc. accounts (note 11(a)). In exchange the Company agreed to assume the remaining lease obligations of the capital leases at the carrying amount of the liability.

The revenue reflected in the financial statements includes the electricity revenue for the sale of electricity to ERTH Corporation, CRU Solutions Inc., ERTH360 Generation & Consulting Inc., and the municipal facilities located in the communities of Aylmer, Beachville, Belmont, Burgessville, Embro, Ingersoll, Norwich, Otterville, Port Stanley, Tavistock, and Thamesford in the amount of $1,671,856 (2009 - $1,327,226). These transactions are in the normal course of operations at rates approved by the Ontario Energy Board.

ERIE THAMES POWERLINES CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

9. Related Parties (cont.)

During the year, the Company purchased and sold the following services from related parties.

	2010	2009
CRU Solutions Inc.		
Purchase of capitalized items	$ 52,211	$1,234,009
Sale of operations, maintenance and administrative services	(130,618)	-
Purchase of operations, maintenance and administrative services	132,487	557,552
	$ 54,080	$1,791,561
ERTH360 Generation and Consulting Inc.		
Purchase of capitalized items	$ 367,184	$ -
Purchase of operations, maintenance and administrative services	4,588	-
	$ 371,772	$ -
The SPi Group Inc.		
Purchase of consulting services	$ 22,139	$ -
ERTH Corporation		
Purchase of management services	$ 973,210	$ 919,157
Rent	267,433	144,522
	$1,240,643	$1,063,679
Ecaliber (Canada) Inc.		
Purchase of capitalized items	$ 12,050	$ -
Sale of operations and administrative services	(116,784)	-
Purchase of operations, maintenance and administrative services	809,267	1,069,763
	$ 704,533	$1,069,763
Utilismart Corporation		
Purchase of capitalized items	$ 9,095	$ 4,197
Purchase of consulting services	106,593	110,856
	$ 115,688	$ 115,053
Clinton Power Corporation		
Sale of operations and maintenance	$ 88,794	$ -
West Perth Power Inc.		
Sale of operations and maintenance	$ 38,648	$ -

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

9. Related Parties (cont.)

At the end of the year, amounts due from related parties are as follows:

	2010	2009
CRU Solutions Inc.	$ 34,202	$ -
West Perth Power Inc.	7,849	-
Clinton Power Corporation	47,823	-
Coutler Water Meter Service Inc.	2,218	-
	$ 92,092	$ -

At the end of the year, amounts due to related parties are as follows:

	2010	2009
ERTH Corporation	$ 4,433,584	$ 4,415,348
CRU Solutions Inc.	-	311,037
Ecaliber (Canada) Inc.	404,964	491,800
Oncor Utility Solutions (Canada) Ltd.	-	2,813
Utilismart Corporation	11,242	3,689
The SPi Group Inc.	510	-
ERTH360 Generation & Consulting Inc.	117,088	79,282
Abicus Management Solutions Inc.	-	1,575
Town of Aylmer	134,269	124,131
	$ 5,101,657	$ 5,429,675

The companies are related as follows:

ERTH Corporation owns 100% of the issued and outstanding shares of West Perth Power Inc., Clinton Power Corporation, CRU Solutions Inc. and ERTH Holdings Inc.

Ecaliber (Canada) Inc., ERTH360 Generation & Consulting Inc. Coulter Water Service Meter Inc. and The SPi Group Inc. are wholly-owned subsidiaries of ERTH Holdings Inc.

Oncor Utility Solutions (Canada) Ltd. is a wholly-owned subsidiary of Abicus Management Solutions Inc., which is jointly controlled by ERTH Holdings Inc.

Utilismart Corporation is jointly controlled by ERTH Holdings Inc.

The Town of Aylmer is a shareholder of ERTH Corporation.

10. Related Party Long-Term Debt

The long-term debt represents amounts owing to the municipal shareholders of ERTH Corporation for purchase of the respective Municipality's Hydro Electric Commission's net assets. The rate of interest is currently 7.25% and is set by the Board of Directors, from time to time. There are no fixed repayment terms associated with the principle outstanding and no principal amounts are anticipated to be paid over the next twelve months. The loan is secured by a second position General Security Agreement covering accounts receivable, inventory and equipment, including motor vehicles.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

10. Related Party Long-Term Debt (cont.)

The amounts owing to the municipalities are as follows:

	2010	2009
Aylmer	$ 1,694,863	$ 1,694,863
Central Elgin	806,436	806,436
East Zorra Tavistock	569,073	569,073
Ingersoll	3,402,080	3,402,080
Norwich	763,755	763,755
Southwest Oxford	192,062	192,062
Zorra	610,255	610,255
	$ 8,038,524	$ 8,038,524

During 2010, $582,793 was charged to interest expense for interest on related party long-term debt (2009 - $583,322). The fair market value of this note payable at December 31, 2010 is $11,279,711.

11. Long Term Debt

	2010	2009
Capital lease obligation (a)	$ 524,919	$ -
Bank loans (b)	52,365	65,855
	577,284	65,855
Less: current portion of long-term debt (c)	(208,591)	(13,726)
	$ 368,693	$ 52,129

a) Capital Lease Obligation

During the year, the Company transferred from CRU Solutions Inc., a related party, the remaining capital lease obligations of five Freightliner bucket trucks and a backhoe. The vehicles are being leased for a period of six to seven years on various contracts that began between 2005 to 2009. The interest rate imputed in these leases range from 2.5%-8.8%.

The following is a schedule of the future minimum lease payments of the capital leases, together with the balance of the obligation.

Year ending December 31, 2011	$ 219,931
2012	181,216
2013	118,051
2014	46,284
2015	15,709
Total minimum lease payments	581,191
Less: amount representing interest	56,272
Balance of obligations	524,919
Less: current portion	(194,741)
	$ 330,178

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

11. Long Term Debt (cont.)

b) Bank Loans

	2010	2009
Financing Loan repayable in monthly instalments of $604, with a 0% interest rate maturing August 2014	31,725	38,687
Financing Loan repayable in monthly instalments of $579, with a 1.9% interest rate maturing September 2014.	20,640	27,168
	52,365	65,855
Less: Current Portion	(13,850)	(13,726)
	$ 38,515	$ 52,129

c) Current Portion of Long-term Debt

	2010	2009
Capital lease obligation	$ 194,741	$ -
Bank loans	13,850	13,726
	$ 208,591	$ 13,726

The aggregate principal portion of long-term debt and capital lease payments required in each of the next five years are as follows:

Year ending	December 31, 2011	$ 208,591
	December 31, 2012	180,414
	December 31, 2013	124,972
	December 31, 2014	48,380
	December 31, 2015	14,927
		$ 577,284

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

12. Post-Retirement Benefit Obligation

During the year, the Company underwent a corporate reorganization resulting in the movement of employees from certain affiliated entities to the Company. Per company policy, this resulted in the Company assuming future benefit obligations of those retrenched employees. As a result of this change, opening retained earnings decreased by $250,474 and postretirement benefit obligation increased by $250,474 at January 1, 2010.

a) Pension Plan

The Company has a pension agreement with the Ontario Municipal Employees Retirement System Funds ("OMERS"), which is a multi-employer plan, on behalf of its employees.

The plan is a contributory, defined benefit plan which specifies the amount of retirement benefits to be received by the employees based on the length of service and rates of pay. As the plan is a multi-employer plan, it is accounted for as a defined contribution plan as allowed under Canadian Generally Accepted Accounting Principals. Contributions by the Company are 6.4% for employee earnings below the year's maximum personable earnings and 9.7% thereafter.

For the year ended December 31, 2010, the Company's OMERS current service pension costs were $141,468 (2009 - $106,415).

b) Employee Future Benefits Other than Pension

The Company provides medical and life insurance benefit coverage to certain retirees of the Company. Eligible retirees are provided health coverage until the age of 65 and life insurance coverage is provided to retirees who have at least 10 years of eligible service. The obligation under these plans is funded by the Company and expensed in the year that it is paid. Benefits paid in 2010 amounted to $17,876 (2009 - $15,199).

Post-retirement benefits, other than pensions, are accrued during the years which employees provide service to certain of the companies.

i) Total Cash Payments

Total cash payments for employee future benefits for 2010, consist of cash contributed by the Company to its funded pension plans, cash payments directly to beneficiaries for its unfunded other benefit plans, cash contributed to its defined contribution plans and cash contributed to its defined plan was $156,667 (2009 - $121,614).

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

12. Post-retirement Benefit Obligation (cont.)

ii) Measurement Actuarial Valuations Dates

Plan assets and the accrued benefit obligation were measured based on the actuarial valuation completed as of December 31, 2010. The next required valuation will be as of December 31, 2011.

Accrued Benefit Obligation

	2010	2009
Assumption of benefit obligation	$ 541,368	$ 243,949
Service cost	7,200	15,199
Interest on projected plan benefits	18,700	17,788
Actuarial loss	35,173	23,722
Benefits paid	(17,876)	(9,764)
Benefit obligation at end of year	$ 584,565	$ 290,894

Reconciliation of the Accrued Benefit Obligation to the Balance Sheet Accrued Benefits Liability

	2010	2009
Accrued benefit obligation	$ 584,565	$ 290,439
Unrecognized net actuarial loss	(70,462)	(35,212)
Accrued benefits liability	$ 514,103	$ 255,227

Significant Assumptions

The significant assumptions used are as follows:

	2010	2009
Discount rates applicable to post-retirement benefits other than pensions and benefit costs	5.75%	6.50%
Rate of compensation increase	3.50%	3.50%
Ultimate dental care cost	4.00%	4.00%

For December 31, 2010, medical costs are assumed to increase at 10% reduced by 0.5% per year to 5% over 10 years.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

13. Share Capital

Authorized

Unlimited number of common shares

	2010	2009
Issued capital		
10,000 common shares	$ 8,038,524	$ 8,038,524

14. Guarantee

The Company has guaranteed the operating and term loans of its parent company ERTH Corporation up to 25% of the Company's equity or $2,153,295. The loans are secured by a General Security Agreement covering all assets of the Company and a pledge of the shares of the Company. As the Company does not expect to be in a position where it would need to honour this guarantee in the foreseeable future, no liability has been recorded in these financial statements.

15. Prudential Support Requirements

Erie Thames Powerlines Corporation, as a Local Distribution Company under the Energy Competition Act, 1998, R.S.O., posted prudential support obligations on market opening, May 1, 2002 with the Electric Independent Market Operator. The prudential support obligation as at June 24, 2008 was $1,586,703 and had not changed as at December 31, 2010. The prudential support requirement is honoured through a letter of credit.

16. Payments in Lieu of Income Taxes

The provision for payments in lieu ("PILs") of income taxes differs from amounts which would be calculated by applying the Company's combined statutory income tax rate as follows:

	2010	2009
Income from continuing operations before PILs	$ 714,119	$ 221,004
Statutory Canadian Federal and Provincial income tax rate	31.00 %	33.00 %
Basic rate applied to income before PILs	221,377	72,931
Other	(34,377)	19,069
Provision for payment in lieu of income tax	$ 187,000	$ 92,000
Effective tax rate	26.19 %	41.63 %

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

16. Payments in Lieu of Income Taxes (cont.)

The Company as of December 31, 2011 has recorded a future payment in lieu of income tax asset of $362,000 (2009 - $297,000) and future income tax regulatory liability of $362,000 (2009 - $297,000), based on substantively enacted income tax rates.

Significant components of the Company's future income tax assets and regulatory liability are as follows:

	2010	2009
Property, plant and equipment	$ 150,000	$ 89,000
Intangible assets	63,000	70,000
Regulatory adjustments	78,000	72,000
Post-retirement Benefits Obligation	71,000	66,000
	$ 362,000	$ 297,000

17. Contingent Liability

Electric Distributors Association

By Order dated July 22, 2010, the Ontario Superior Court of Justice consolidated and approved the settlement of two class actions against the Company, one commenced in 1994 and the other, against all Ontario MEUs, in 1998. The actions sought $500,000,000 and $64,000,000, respectively, in restitution for late payment charges collected by them from their customers that were in excess of the interest limit stipulated in section 347 of the Criminal Code. The claims made against the Company and the definition of the plaintiff classes were identical in both actions such that any damages payable by the Company in the first action would reduce the damages payable by the Company in the second action, and vice versa.

The July 22, 2010 court order formalized a settlement pursuant to which the defendant MEUs will pay the amount of $17,000,000 plus costs and taxes in settlement of all claims. The amount allocated for payment by each MEU is its proportionate share of the settlement amount based on its percentage of distribution service revenue over the period for which it has exposure for repayment of late payment penalties exceeding the interest rate limit in the Criminal Code. the Company's share of the settlement amount was expected to be $51,909 payable on June 30, 2011. Under the settlement, all the MEUs involved in the settlement, including the Company, have requested an order from the OEB allowing for the future recovery from customers of all costs related to the settlement. The Company has accrued a liability and a corresponding regulatory asset in the amount of the above (note 21).

ERIE THAMES POWERLINES CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

18. Commitments

Lease commitments

The Company has entered into various operating lease agreements. The future minimum annual payments under operating leases are as follows:

Year ending	December 31, 2011	$ 4,368
	December 31, 2012	4,368
	December 31, 2013	4,368
	December 31, 2014	4,368
	December 31, 2015	4,368
	December 30, 2016	2,358
		$ 24,198

Purchase commitments

In light of the forth coming adoption of the IFRS standards, management undertook an assessment of their curent financial reporting system. It was determined that the current system would not be IFRS compliant and a new system would be required. After the appropriate due diligence was performed, the Company signed a purchase commitment for the installation of a new financial reporting system. This conversion will take place during 2011.

19. Financial Instruments

As a rate-regulated entity, the nature of the Company's operations are defined and restricted by regulation. Financial operations and risks are also substantially influenced by regulation, limiting the necessity to engage in risk mitigation strategies involving the use of derivatives or hedges, and the Company did not engage in those activities during the fiscal year.

The company has adopted CICA Handbook Section 3861- *Financial Instruments* for disclosure purposes as the Company's financial instruments are not subject to disclosure requirements under Section 3862 or 3863 of the CICA Handbook

a) Credit Risk

By regulation, the Company is responsible for collecting both the distribution and energy portions of the electricity bill. On average, 16% of amounts billed to customers are for distribution charges and 84% of the bill is energy related. Unless the retailer elects to bill the customers directly for the energy portion of the bill, the Company is exposed to a credit risk substantiallygreater then their portion of the electricitybill.

Mitigation of substantial losses is provided through the opportunity to apply for recovery for those losses through distribution rate adjustments in future years, if approved by the regulator. Additionally, regulation provides for certain customers to provide security deposits for a prescribed period of period to mitigate collection loss.

The Company is not exposed to a significant concentration of credit risk within any customer segment or individual customer.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

19. Financial Instruments (cont.)

b) Fair Values

The fair values of the Company's financial assets and liabilities approximate their book values unless otherwise disclosed.

c) Interest Rate Risk

The Company is subject to the risks associated with debt financing, including the risk that existing indebtedness secured by the property may not be refinanced or that the terms of such refinancing may not be as favourable as the terms of existing indebtedness. The Company is exposed to interest rate risk as its assets are held as security for the parent company's commercial loan facilities. The Company does not use any hedging instruments to mitigate its risk.

20. Capital Disclosures

The Company's main objective is to ensure ongoing access to funding to maintain and improve the electricity distribution system of the Company.

As at December 31, 2010 the Company's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2010, shareholders' equity amounts to $8,613,179 (2009 - $8,336,534) and long-term debt amounts to $8,615,808 (2009 - $8,104,379). The Company's structure as at December 31, 2010 is 50% debt and 50% equity (2009 - 49% debt and 51% equity). There have been no changes in the Company's approach to capital management during the year.

21. Subsequent Events

Late Payment Class Action

On February 22, 2011, the OEB issued its final decision allowing for LDC to recover the settlement amount of $51,909 for the Company from customers over the period commencing May 1, 2011 and ending April 30, 2012.

Amalgamation of Rate Regulated Entities

Subsequent to year end, the Company entered into formal proceedings to amalgamate Erie Thames Powerlines Corporation, West Perth Power Inc. and Clinton Power Corporation. Final OEB approval was received in late March 2011 to amalgamate these entities. The amalgamation is expected to be completed in June 2011.

22. Comparative Figures

Certain comparative figures have been reclassified to conform with the financial statement presentation adopted in the current year.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION

FINANCIAL STATEMENTS

DECEMBER 31, 2009

ERIE THAMES POWERLINES CORPORATION

INDEX TO AUDITED FINANCIAL STATEMENTS

DECEMBER 31, 2009

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AUDITORS' REPORT

To the Shareholders of Erie Thames Powerlines Corporation

We have audited the balance sheet of Erie Thames Powerlines Corporation as at December 31, 2009 and the statements of income, retained earnings, and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

The comparative amounts were audited by another firm of Chartered Accountants.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

London, Canada
April 23, 2010

ERIE THAMES POWERLINES CORPORATION

BALANCE SHEET

AS AT DECEMBER 31, 2009

ASSETS

	2009	2008
Current Assets		
Cash	$ 682,426	$ -
Accounts receivable (note 3)	7,064,002	6,475,354
Inventory	66,683	-
Prepaid expenses	54,256	41,797
Payment in lieu of income taxes recoverable	91,567	-
	7,958,934	6,517,151
Property, Plant and Equipment (note 4)	18,258,685	17,487,244
Future Payment in Lieu of Income Tax Asset	297,000	161,000
Regulatory Assets (note 5)	2,064,731	2,135,506
Goodwill (note 6)	76,667	76,667
	$28,656,017	$26,377,568

LIABILITIES AND SHAREHOLDER'S EQUITY

	2009	2008
Current Liabilities		
Demand operating loan	$ -	$ 988,000
Accounts payable and accrued liabilities	5,474,592	5,201,979
Regulatory liabilities (note 5)	329,202	32,202
Customer deposits (note 7)	792,265	845,736
Payments in lieu of income taxes payable	-	105,413
Due to related party (note 8)	5,429,675	2,543,959
	12,025,734	9,717,289
Long-term Debt (note 9)	8,038,524	8,038,524
Post Retirement Benefit Obligation (note 10)	255,227	-
Shareholder's Equity		
Share capital (note 11)	8,038,524	8,038,524
Retained earnings	298,008	583,231
	8,336,532	8,621,755
	$28,656,017	$26,377,568

Contingent Liabilities (notes 12, 14 and 16)

APPROVED ON BEHALF OF THE BOARD:

B. [signature] Director

[signature] Director

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION

STATEMENT OF RETAINED EARNINGS

FOR THE YEAR ENDED DECEMBER 31, 2009

	2009	2008
Balance, Beginning of Year	$ 583,231	$ 23,943
Change in Accounting Policy (note 2(l)(ii))	(161,000)	-
Assumption of Employee Future Benefit Obligation (note 10)	(253,227)	-
Restated Opening Retained Earnings	169,004	23,943
Net Income	129,004	559,288
Balance, End of Year	$ 298,008	$ 583,231

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION

STATEMENT OF INCOME

FOR THE YEAR ENDED DECEMBER 31, 2009

	2009	%	2008	%
Electricity Revenue (note 13)	$36,428,344		$34,786,250	
Cost of Power	30,739,578		28,047,757	
Distribution Revenue	5,688,766	100.00	6,738,493	100.00
Expenses				
Billing and collecting	768,233	13.50	586,492	8.71
Community relations	152,494	2.68	47,320	0.70
Direct operation	1,950,030	34.28	3,585,005	53.20
Office and administration	574,166	10.09	244,599	3.63
Regulatory and professional	780,244	13.72	415,854	6.17
	4,225,167	74.27	4,879,270	72.41
Income from Operations Before the Following	1,463,599	25.73	1,859,223	27.59
Amortization	1,017,711	17.89	949,932	14.10
Interest income on regulatory assets	(65,261)	(1.15)	(142,864)	(2.12)
Interest	811,789	14.27	711,075	10.55
Income from Operations Before Other Income and Tax	(300,640)	(5.28)	341,080	5.06
Other Income				
Interest income	5,941	0.10	16,764	0.25
Service revenue	511,703	8.99	573,964	8.51
Gain on sale of equipment	4,000	0.07	-	-
	521,644	9.16	590,728	8.76
Income Before Income Tax	221,004	3.88	931,808	13.82
Payments in Lieu of Income Taxes (note 15)				
Current	92,000	1.62	348,520	5.17
Future	-	-	24,000	0.36
	92,000	1.62	372,520	5.53
Net Income	$ 129,004	2.26	$ 559,288	8.29

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION

STATEMENT OF CASH FLOWS

FOR THE YEAR ENDED DECEMBER 31, 2009

	2009	2008
Cash Flows from Operating Activities		
Net income	$ 129,004	$ 559,288
Items not requiring an outlay of cash:		
Amortization	1,017,711	949,932
Gain on sale of equipment	(4,000)	-
Future payment in lieu of tax asset	-	24,000
Post retirement benefit obligation	2,000	-
	1,144,715	1,533,220
Changes in non-cash working capital balances:		
Accounts receivable	(588,649)	507,000
Inventory	(66,683)	-
Prepaid expenses	(12,578)	7,445
Payment in lieu of income taxes	(196,860)	(195,206)
Regulatory assets	70,775	161,185
Accounts payable and accrued liabilities	272,613	617,062
Regulatory liabilities	-	(265,560)
Customer deposits	(53,470)	63,934
Due to related parties	2,885,716	(2,031,331)
Net Cash Provided by Operating Activities	3,455,579	397,749
Cash Flows from Investing Activities		
Additions to property, plant and equipment	(1,794,153)	(1,819,528)
Proceeds on disposal of equipment	9,000	-
Decrease in note receivable	-	29,304
Net Cash Used in Investing Activities	(1,785,153)	(1,790,224)
Net Increase (Decrease) in Cash	1,670,426	(1,392,475)
Cash (Bank Indebtedness), Beginning of Year	(988,000)	404,475
Cash (Bank Indebtedness), End of Year	$ 682,426	$ (988,000)
Supplemental Cash Flow Information		
Interest paid	$ 971,123	$ 817,926
Payment in lieu of income taxes	$ 288,860	$ 543,726

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

1. Nature of Operations

The Ontario Government enacted the Energy Competition Act, 1998 to introduce competition to the Ontario electricity market by the year 2000. Under the terms of this legislation, the Ontario Energy Board (the "OEB") regulates industry participants by issuing licences for the right to generate, transmit, distribute or retail electricity. These licences require compliance with established market rules and codes. The Ontario Government opened the Ontario electricity market to competition on May 1, 2002.

The Company is wholly owned by the following seven municipalities, each of whom has one voting common share: Aylmer, Central Elgin, East-Zorra Tavistock, Ingersoll, Norwich, South-West Oxford and Zorra.

Erie Thames Powerlines Corporation carries on the business of distributing electricity to the following communities: Aylmer, Beachville, Belmont, Burgessville, Embro, Ingersoll, Norwich, Otterville, Port Stanley, Tavistock, and Thamesford.

2. Significant Accounting Policies

The financial statements of the Company have been prepared by management in accordance with Canadian generally accepted accounting principles, as modified by regulations and policies set forth in the Ontario Energy Board Accounting Procedures Handbook. Those policies that are considered to be particularly significant are outlined below:

(a) Property, Plant and Equipment

Property, plant and equipment are recorded at the fair market value of the assets transferred from the Municipal Hydro Electric Commissions to the Company on August 31, 2000, and subsequent to August 31, 2000, at cost on the date of purchase. Property, plant and equipment are amortized over their useful lives using the straight-line method over the following periods:

Buildings	25 years
Plant and equipment	
Automotive equipment	8 years
Computer equipment	5 years
Service, office and other equipment	10 years
Transmission and distribution system	25 years

Construction work in progress are recorded at cost until such time that the asset is completed and available for use.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

2. Significant Accounting Policies (cont.)

(b) Contributions to Property, Plant and Equipment

Contributions are received from developers and contractors for capital costs incurred by the Company. These contributions are included as a reduction to the cost of the related Property, Plant or Equipment when those assets are placed in service.

(c) Revenue Recognition

(i) Electricity Sales

The Company follows the practice of cycle billing of customer's accounts and revenue is recognized in the period consumed. Estimated customer usage from the last billing date to the year end (unbilled revenue) is included in revenue.

(ii) Interest Income

Interest income is recognized on a time proportion basis, taking account of the principal outstanding and the effective rate over the period to maturity, when it is determined that such income will accrue to the Company.

(iii) Service Revenue

Service revenue is recognized as service is performed.

(d) Pension and Other Retirement Benefit Plans

(i) The actuarial determination of the accrued benefit obligations for other retirement benefits uses the projected benefit method prorated on service, which incorporates management's best estimate of cost escalation, retirement ages of employees and actuarial factors.

(ii) Past service costs arising from plan amendments are deferred and amortized on a straight-line basis using the corridor method over the average remaining service period of employees active at the date of amendment.

(iii) When the restructuring of a benefit plan gives rise to both a curtailment and a settlement of obligations, the curtailment is accounted for prior to the settlement.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

2. Significant Accounting Policies (cont.)

(e) Financial Instruments

The Company's financial assets and financial liabilities are classified and measured as follows:

- Cash is classified as held for trading and is measured at fair value. Gains and losses related to periodical revaluation are recorded in net income.
- Accounts receivable and regulatory assets are classified as loans and receivables and are initially measured at fair value and, subsequently, at amortized cost using the effective interest rate method.
- Accounts payable and accrued liabilities, regulatory liabilities, customer deposits, due to related party and long-term debt are classified as other liabilities and are initially measured at fair value and, subsequently, at amortized cost using the effective interest rate method.

(f) Financial Effects of Distribution Rate Regulation

The financial results presented are in accordance with generally accepted accounting principles and within that framework the Company accounts for the impact of regulatory actions in the following manner:

(i) Regulatory Decisions to Adjust Distribution Rates

In the event that a regulatory decision is rendered, providing regulatory approval and certainty to the recognition of an asset or creation of a liability and culminating in an adjustment to the Company's distribution rates, such occurrences are immediately reflected in the Company's accounts.

(ii) Regulatory Direction and Practice

In the absence of regulatory decision impacting rates, and where the Company is required by regulatory accounting practice or direction to accumulate balances for future rate recovery or create liabilities for future discharge, those amounts are recorded in accordance with that regulatory direction. Management assesses the future uncertainty with respect to the final regulatory disposition of those amounts and to the extent required, makes accounting provisions to reduce the deferred balances accumulated or to increase the recorded liabilities. Upon rendering of the final regulatory decisions adjusting distribution rates, the provisions are adjusted to reflect the final impact of that decision, and such adjustment is reflected in net earnings for the period.

Amounts currently confirmed by final regulatory decision, and amounts currently accounted for in the absence of final regulatory decision together with related provisions for future uncertainty, are more fully described in note 5 to the financial statements.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

2. Significant Accounting Policies (cont.)

(g) Payments in Lieu of Income Taxes (PILs)

The Company uses the liability method for accounting for PILs. Under this method, future payment in lieu of income tax assets and liabilities are recognized for differences between the carrying value of assets and liabilities for accounting purposes and their respective values for payment in lieu of income tax purposes. These differences are measured using substantively enacted tax rates applicable for the period in which those differences are expected to be recovered or settled. To the extent that there is uncertainty regarding the recovery of a future payment in lieu of income tax asset, a valuation allowance reducing the future payment in lieu of income tax asset is recorded.

(h) Goodwill and Intangible Assets

Goodwill and intangible assets acquired individually or as part of a group of other assets are initially recognized and measured at cost. The cost of a group of intangible assets acquired in a transaction, including those acquired in a business combination, are allocated to the individual assets based on their relative fair value. Intangible assets with finite lives are amortized on a straight-line basis over their estimated useful lives. Goodwill and intangible assets with indefinite useful lives are not amortized and are tested for impairment annually or more frequently if events and changes in circumstances indicate that an asset might be impaired.

(i) Inventories

Effective January 1, 2008, the Company adopted Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3031 - *Inventories*, which is based on the International Accounting Standards Board's International Accounting Standard 2 and replaced existing CICA Handbook Section 3030. Under this new standard, inventories are required to be measured at the lower of cost and net realizable value and any items considered to be major future components of property, plant and equipment are to be transferred to property, plant and equipment. The new standard also provides updated guidance on the appropriate methods of determining cost and the impact of any write-downs to net realizable value. The implementation of this standard did not have any impact on the Company's results of operations.

Inventories consist primarily of materials and supplies. Inventories are carried at the lower of cost and net realizable value, with cost determined on an average cost basis net of a provision for obsolescence.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

2. Significant Accounting Policies (cont.)

(j) Use of Estimates

The preparation of the financial statements of the Company in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the balance sheet date and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates.

(k) Impairment of Long-lived Assets

Long-lived assets are tested for recoverability when events or changes in circumstances indicate that their carrying value may not be recoverable. An impairment loss is recognized when the carrying value exceeds the total undiscounted cash flow expected from their use and eventual disposition. The amount of the impairment loss is determined as the excess of the carrying value of the asset over its fair value.

(l) Accounting Changes

(i) Generally Accepted Accounting Principles

Effective January 1, 2009, the Company adopted the changes to CICA Handbook Section 1100 - *Generally Accepted Accounting Principles*. The amendment to this section removed the temporary exemption pertaining to the application of the section to the recognition and measurement of assets and liabilities arising from rate regulation. In response to the removal of the exemption, the Company established accounting policies for the recognition and measurement of assets and liabilities arising from rate regulation. In accordance with the Canadian GAAP hierarchy guidance framework outlined in CICA Handbook Section 1100, the company has determined that its assets and liabilities arising from rate regulation qualify for recognition under Canadian GAAP and this recognition is constant with U.S. Statement of Financial Accounting Standards No. 71, *Accounting for Effects of Certain Types of Regulations* ("FAS71"). The company concluded that its policies for assets and liabilities arising from rate regulation were consistent with the primary sources of Canadian GAAP and were developed through the exercise of professional judgment. As a result there was no changes in the Company's opening retained earnings as at January 1, 2009 or the Company's results from operations for the year ended December 31, 2009 as a result of the adoption of this section.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

2. Significant Accounting Policies (cont.)

(l) Accounting Changes (cont.)

(ii) Income tax expense

Effective January 1, 2009, the Company adopted the changes to CICA Handbook Section 3465 - *Income Taxes*, which states that, as a rate regulated entity, Future Income Tax Assets will be returned to customers as they are recovered. As a result, all increases or decreases in Future Income Tax Assets are offset by a Regulatory Liability.

This change has been applied on a retroactive basis without restatement of prior periods. As as result of this change, opening retained earnings decreased by $161,000 and regulatory liabilities and future income tax assets increased by $297,000 and $136,000 respectively at January 1, 2009.

(m) Future Accounting Changes

(i) International Financial Reporting Standards ("IFRS")

On February 13, 2008, the Accounting Standards Board of Canada ("AcSB") confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011.

A limited number of converged or IFRS-based standards will be incorporated into Canadian GAAP prior to 2011, with the remaining standards to be adopted at the change over date.

The Company has an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its financial statements. Although the impact of the adoption to IFRS on the Company's Balance Sheet and Income Statement is not yet reasonably determinable or estimable, the company does expect a significant increase in financial statement disclosure requirements resulting from the adoption of IFRS, and is designing the systems and related process changes, which will be required in order to provide the additional information required to make these disclosures.

In July 2009, the International Accounting Standards Board ("IASB") issued an exposure draft on rate regulated activities. The IASB staff has postponed presenting their analysis of the responses to the IASB. This presentation may include options for the next steps of the rate regulated activities project. It is unclear at this time what the outcome of the IASB's deliberations will be and how that will impact the Company's reporting under IFRS.

At this time, the impact on the Company's future financial statements cannot be determined.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

3. Accounts Receivable

	2009	2008
Energy, water and sewer	$ 3,075,903	$ 2,961,158
Unbilled energy	3,506,353	3,217,084
Service revenues	481,746	297,112
	$ 7,064,002	$ 6,475,354

The amounts shown above are net of allowance for doubtful accounts of $214,589 (2008 - $839,837).

4. Property, Plant and Equipment

	Cost 2009	Accumulated Amortization	Net 2009	Net 2008
Land	$ 128,684	$ -	$ 128,684	$ 133,684
Buildings	130,071	42,021	88,050	80,754
Plant and equipment	1,672,471	463,077	1,209,394	405,653
Transmission and distribution system	22,625,078	6,348,885	16,276,193	16,867,153
Construction work in progress	556,364	-	556,364	-
	$25,112,668	$ 6,853,983	$18,258,685	$17,487,244

During the year, the Company recorded amortization of $1,017,711 ($949,932 - 2008).

5. Regulatory Assets and Liabilities

Regulatory assets consist of the following:

	2009	2008
Retail settlement variances	$ 2,658,760	$ 2,735,781
Demand side management expenses	-	140,828
	2,658,760	2,876,609
Recovery of regulatory assets	(594,029)	(741,103)
	$ 2,064,731	$ 2,135,506

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

5. Regulatory Assets and Liabilities (cont.)

Regulatory liabilities consist of the following:

	2009	2008
Regulatory assets recovery account	$ 32,202	$ 32,202
Future payment in lieu of income tax liability	297,000	-
	$ 329,202	$ 32,202

The OEB approved an Interim Rate Order for May 1st, 2008, that effectively removed the recovery allocation of the regulatory assets amounts until the final Cost of Service Rate Application was approved. The new Cost of Service Rate Order approved by the OEB, effective December 1st, 2008, includes an allocation of the recovery of the low voltage energy variances. The remainder of the regulatory assets will be recovered based on future rate orders.

(a) Retail settlement variances represent amounts accumulated since the opening of the electricity market on May 1, 2002. These variances are comprised of variances between amounts charged by the Independent Electricity Market Operator and amounts billed to customers plus variances from settlement and transmission charges. In the absence of rate regulations, these costs (revenues) would be charged to the period incurred.

(b) Demand side management ("DSM") amounts are expenses incurred in accordance with OEB rules and regulations and represent costs to the Company of literature provided to its customers and capital expenditures to provide energy conservation. In the absence of rate regulations, these costs (revenues) would be charged to the period incurred.

6. Goodwill

	Cost 2009	Accumulated Amortization	Net 2009	Net 2008
Goodwill	$ 100,000	$ 23,333	$ 76,667	$ 76,667

At year end, management tested goodwill using an undiscounted cash flow methodology and determined that there was no impairment of goodwill and therefore no writedown was required.

7. Customer Deposits

Customer deposits are obtained as security for energy consumption. On an annual basis, interest is calculated and credited to the customers' utility accounts. Also included are security deposits received for construction projects.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

8. Related Parties

The Company has a contract with ERTH Corporation for management services and rental of facilities used by the Company.

The Company has contracted CRU Solutions Inc., Ecaliber (Canada) Inc., and ERTH360 Generation & Consulting Inc., companies under common control, to provide the following services: maintenance and upgrades to the existing capital infrastructure of the Company, billing and collection services and administrative services.

The contracts between the Company, CRU Solutions Inc., Ecaliber (Canada) Inc., ERTH360 Generation & Consulting Inc., and ERTH Corporation are measured at the exchange amount, which is the amount of consideration paid or received as established and agreed to by the related parties, unless noted otherwise.

The revenue reflected in the financial statements includes the electricity revenue for the sale of electricity to ERTH Corporation, CRU Solutions Inc., ERTH360 Generation & Consulting Inc., and the municipal facilities located in the communities of Aylmer, Beachville, Belmont, Burgessville, Embro, Ingersoll, Norwich, Otterville, Port Stanley, Tavistock, and Thamesford in the amount of $1,327,226 ($1,166,913 in 2008). These transactions are in the normal course of operations at rates approved by the Ontario Energy Board.

During the year, the Company purchased the following services from related parties.

CRU Solutions Inc.	**2009**	**2008**
Purchase of capitalized items	$1,234,009	$2,921,071
Purchase of operations, maintenance and administrative services	557,552	2,866,680
	$1,791,561	$5,787,751

ERTH Corporation	**2009**	**2008**
Purchase of management services	$ 919,157	$ 864,201
Rent	144,522	99,009
	$1,063,679	$ 963,210

Ecaliber (Canada) Inc.	**2009**	**2008**
Purchase of operations, maintenance and administrative services	$1,069,763	$ -

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

8. **Related Parties (cont.)**

At the end of the year, amounts due to related parties are as follows:

	2009	2008
ERTH Corporation	$4,415,348	$1,430,406
CRU Solutions Inc.	311,037	837,875
Ecaliber (Canada) Inc.	491,800	-
Oncor Utility Solutions (Canada) Ltd.	2,813	-
Utilismart Corporation	3,689	1,653
RDI Consulting Corporation	-	117,720
ERTH360 Generation & Consulting Inc.	79,282	-
Abicus Management Solutions Inc.	1,575	-
Town of Aylmer	124,131	156,305
	$ 5,429,675	$2,543,959

The companies are related as follows:

ERTH Corporation owns 100% of the issued and outstanding shares of the Company, CRU Solutions Inc. and ERTH Holdings Inc.

RDI Consulting Inc. is a wholly-owned subsidiary of Erie Thames Solutions Inc.

Ecaliber (Canada) Inc.and Erie Thames Solutions Inc. are wholly-owned subsidiaries of ERTH Holdings Inc.

ERTH360 Generation & Consulting Inc. is a wholly-owned subsidiary of RDI Consulting Inc.

Oncor Utility Solutions (Canada) Ltd. is a wholly-owned subsidiary of Abicus Management Solutions Inc., which is jointly controlled by Erie Thames Solutions Inc.

Utilismart Corporation is jointly controlled by CRU Solutions Inc. and RDI Consulting Inc.

The Town of Aylmer is a shareholder of ERTH Corporation.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

9. Long-Term Debt

The long-term debt represents amounts owing to the municipal shareholders of ERTH Corporation for purchase of the respective Municipality's Hydro Electric Commission's net assets. The debt is convertible to Class B shares at the fair market value of the Class B shares of the Company divided by the number of Class B shares issued and outstanding. The rate of interest is currently 7.25% and is set by the Board of Directors, from time to time. There are no fixed repayment terms associated with the principle outstanding and no principal amounts are anticipated to be paid over the next twelve months. The loan is secured by a second position General Security Agreement covering accounts receivable, inventory and equipment, including motor vehicles.

The amounts owing to the municipalities are as follows:

	2009	2008
Aylmer	$ 1,694,863	$ 1,694,863
Central Elgin	806,436	806,436
East Zorra Tavistock	569,073	569,073
Ingersoll	3,402,080	3,402,080
Norwich	763,755	763,755
Southwest Oxford	192,062	192,062
Zorra	610,255	610,255
	$ 8,038,524	$ 8,038,524

During 2009, $583,321 was charged to interest expense for interest on related party long-term debt ($585,793 in 2008). The fair market value of this note payable at December 31, 2009 is $9,133,419.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

10. Post-retirement Benefit Obligation

In prior years, post retirement benefit obligations for the employees of the Company had been recorded and expensed in the books of the Parent company. During 2009, management decided that the liability for its employees should be recorded in the Company's books and not that of the Parent. This decision was made to provide management with a more accurate picture of the Company's true cost of labour.

This change has been applied on a retroactive basis without restatement of prior periods. As as result of this change, opening retained earnings decreased by $253,227 and post retirement benefit obligation increased by $253,227 at January 1, 2009.

a) Pension Plan

The Company has a pension agreement with the Ontario Municipal Employees Retirement System Funds ("OMERS"), which is a multi-employer plan, on behalf of its employees.

The plan is a contributory, defined benefit plan which specifies the amount of retirement benefits to be received by the employees based on the length of service and rates of pay. As the plan is a multi-employer plan, it is accounted for as a defined contribution plan as allowed under Canadian Generally Accepted Accounting Principals. Contributions by the Company are 6.0% for employee earnings below the year's maximum personable earnings and 8.8% thereafter.

For the year ended December 31, 2009, the Company's OMERS current service pension costs were $106,415 (2008 - $Nil).

b) Employee Future Benefits Other than Pension

The Company provides medical and life insurance benefit coverage to certain retirees of the Company. Eligible retirees are provided health coverage until the age of 65 and life insurance coverage is provided to retirees who have at least 10 years of eligible service. The obligation under these plans is funded by the Company and expensed in the year that it is paid. Benefits paid in 2009 amounted to $15,199 (2008 - $Nil).

Post-retirement benefits, other than pensions, are accrued during the years which employees provide service to certain of the companies.

i) Total Cash Payments

Total cash payments for employee future benefits for 2009, consist of cash contributed by the Company to its funded pension plans, cash payments directly to beneficiaries for its unfunded other benefit plans, cash contributed to its defined contribution plans and cash contributed to its defined plan was $121,614 (2008 - $Nil).

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

10. **Post-retirement Benefit Obligation** (cont.)

ii) Measurement Actuarial Valuations Dates

Plan assets and the accrued benefit obligation were measured based on the actuarial valuation for funding purposes completed as of December 31, 2009. The most recent actuarial valuation for funding purposes was as of December 31, 2009 and the next required valuation will be as of December 31, 2010.

Accrued Benefit Obligation

	2009
Assumption of benefit obligation	$ 243,494
Service cost	15,199
Interest on projected plan benefits	17,788
Actuarial loss	23,722
Benefits paid	(9,764)
Benefit obligation at end of year	$ 290,439

Reconciliation of the Accrued Benefit Obligation to the Balance Sheet Accrued Benefits Liability

	2009
Accrued benefit obligation	$ 290,439
Unrecognized net actuarial loss	(35,212)
Accrued benefits liability	$ 255,227

Significant Assumptions

The significant assumptions used are as follows:

	2009
Discount rates applicable to post-retirement benefits other than pensions and benefit costs	6.50%
Rate of compensation increase	3.50%
Ultimate dental care cost	4.00%

For December 31, 2009, medical costs are assumed to increase at 10% reduced by 0.5% per year to 5% over 10 years.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

11. Share Capital

Authorized

Unlimited number of common shares

	2009	2008
Issued capital		
10,000 common shares	$ 8,038,524	$ 8,038,524

12. Guarantee

The Company has guaranteed the operating and term loans of its parent company ERTH Corporation up to 25% of the Company's equity. The loans are secured by a General Security Agreement covering all assets of the Company and a pledge of the shares of the Company. As at December 31, 2009, the operating line amounted to $3,348,300 and the revolving term loan amounted to $17,000,000. As the Company does not expect to be in a position where it would need to honour this guarantee in the foreseeable future, no liability has been recorded in these financial statements.

13. Electricity Revenue

	2009	%	2008	%
Sale of electricity	$25,114,718	68.94	$20,919,974	60.14
Distribution charges	5,688,766	15.62	6,738,493	19.37
Transmission charges	3,275,601	8.99	3,837,987	11.03
Retailer energy sales	2,349,259	6.45	3,289,796	9.46
	$36,428,344	100.00	$34,786,250	100.00

14. Prudential Support Requirements

Erie Thames Powerlines Corporation, as a Local Distribution Company under the Energy Competition Act, 1998, R.S.O., posted prudential support obligations on market opening, May 1, 2002 with the Electric Independent Market Operator. The prudential support obligation as at June 24, 2008 was $1,586,703 and had not changed as at December 31, 2009. The prudential support requirement is honoured through a letter of credit.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

15. Payments in Lieu of Income Taxes

The provision for payments in lieu ("PILs") of income taxes differs from amounts which would be calculated by applying the Company's combined statutory income tax rate as follows:

	2009	2008
Income from continuing operations before PILs	$ 221,004	$ 931,808
Statutory Canadian Federal and Provincial income tax rate	33.00 %	33.50 %
Basic rate applied to income before PILs	72,931	312,156
Other	19,069	60,364
Provision for payment in lieu of income tax	$ 92,000	$ 372,520
Effective tax rate	41.63 %	39.98 %

The Company as of December 31, 2009 has recorded a future payment in lieu of income tax asset of $297,000 (2008 - $161,000) and future income tax regulatory liability of $297,000 (2008 - $Nil), based on substantively enacted income tax rates of 33%.

Significant components of the Company's future income tax assets and regulatory liability are as follows:

	2009	2008
Property, plant and equipment	$ 89,000	$ 71,668
Intangible assets	70,000	69,032
Regulatory adjustments	72,000	20,300
Post-retirement Benefits Liability	66,000	-
	$ 297,000	$ 161,000

16. Contingent Liability

On March 2, 2010 the Electric Distributors Association ("EDA") presented to it's members and all electric distributors in Ontario, the terms of a tentative settlement with respect to a pending class action lawsuit against all local distribution company's ("LDC's") regarding the charging of late payment penalties ("LPP's") which are alleged to have contravened Section 347 of the Criminal Code. It is contended that LPP's are "interest" as defined in the Criminal Code and that, in certain circumstances, the implied rate of interest exceeds the prescribed limit of 60%.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

16. Contingent Liability (cont.)

The plaintiffs seek repayment of all improper LPP charges. This litigation has been pending since 1994 in the case of Toronto Hydro, and since 1998 in the case of all the other LDC's. Similar class actions were also brought against Enbridge/Consumers Gas and Union Gas. On each of these occasions, the Supreme Court of Canada has made rulings which were favourable to the plaintiffs and which deprived the defendant utilities of most of their defences to these claims.

In light of the settlement in the other cases, industry counsel instruction by an Ad Hoc Committee of the EDA recently participated in a court-supervised mediation process to explore possible settlement of the case against the LDC's. A settlement in principle of the litigation on behalf of all LDC's has now been reached. The tentative settlement agreement requires the unanimous consent and approval of all LDC's. All LDC's must indicate their acceptance of the settlement on or before April 5, 2010. If a unanimous acceptance of this offer is indicated by all LDC's; the Ontario Superior court of Justice will convene a hearing on May 26, 2010 to consider the settlement of the class action suit.

17. Financial Instruments

As a rate-regulated entity, the nature of the Company's operations are defined and restricted by regulation. Financial operations and risks are also substantially influenced by regulation, limiting the necessity to engage in risk mitigation strategies involving the use of derivatives or hedges, and the Company did not engage in those activities during the fiscal year.

The company has adopted CICA Handbook Section 3861- *Financial Instruments* for disclosure purposes as the Company's financial instruments are not subject to disclosure requirements under Section 3862 or 3863 of the CICA Handbook

a) Credit Risk

By regulation, the Company is responsible for collecting both the distribution and energy portions of the electricity bill. On average, 16% of amounts billed to customers are for distribution charges and 84% of the bill is energy related. Unless the retailer elects to bill the customers directly for the energy portion of the bill, the Company is exposed to a credit risk substantially greater then their portion of the electricity bill.

Mitigation of substantial losses is provided through the opportunity to apply for recovery for those losses through distribution rate adjustments in future years, if approved by the regulator. Additionally, regulation provides for certain customers to provide security deposits for a prescribed period of period to mitigate collection loss.

The Company is not exposed to a significant concentration of credit risk within any customer segment or individual customer.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

17. Financial Instruments (cont.)

b) Fair Values

The fair values of the Company's financial assets and liabilities approximate their book values unless otherwise disclosed.

c) Interest Rate Risk

The Company is subject to the risks associated with debt financing, including the risk that existing mortgage indebtedness secured by the property may not be refinanced or that the terms of such refinancing may not be as favourable as the terms of existing indebtedness. The Company is exposed to interest rate risk as its assets are held as security for the parent company's commercial loan facilities. The Company does not use any hedging instruments to mitigate its risk.

18. Capital Disclosures

The Company's main objective is to ensure ongoing access to funding to maintain and improve the electricity distribution system of the Company.

As at December 31, 2009 the Company's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2009, shareholders' equity amounts to $8,336,532 (2008 - $8,621,755) and long-term debt amounts to $8,038,524 (2008 - $8,038,524). The Company's structure as at December 31, 2009 is 49% debt and 51% equity (2008 - 48% debt and 52% equity). There have been no changes in the Company's approach to capital management during the year.

19. Comparative Figures

Certain comparative figures have been reclassified to conform with the statement presentation adopted in the current year.

ERIE THAMES POWERLINES CORPORATION

FINANCIAL STATEMENTS

DECEMBER 31, 2008

ERIE THAMES POWERLINES CORPORATION

INDEX TO AUDITED FINANCIAL STATEMENTS

DECEMBER 31, 2008

Davis Martindale LLP
CHARTERED ACCOUNTANTS

AUDITORS' REPORT

To the Board of Directors of:
Erie Thames Powerlines Corporation

We have audited the balance sheet of Erie Thames Powerlines Corporation as at December 31, 2008 and the statements of income, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2008 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Davis Martindale LLP

London, Ontario
April 3, 2009

Chartered Accountants
Licensed Public Accountants

ERIE THAMES POWERLINES CORPORATION

BALANCE SHEET

AS AT DECEMBER 31, 2008

ASSETS

	2008	2007
Current Assets		
Cash	$ -	$ 404,475
Accounts receivable (note 3)	6,475,354	6,982,354
Prepaid expenses	41,797	49,242
Note receivable	-	29,304
	6,517,151	7,465,375
Property, Plant and Equipment (note 4)	17,487,244	16,617,648
Future Payment in Lieu of Income Tax Asset	161,000	185,000
Regulatory Assets (note 5)	2,135,506	2,296,691
Intangible Assets (note 6)	76,667	76,667
	$26,377,568	$26,641,381

LIABILITIES AND SHAREHOLDER'S EQUITY

	2008	2007
Current Liabilities		
Demand operating loan (note 7)	$ 988,000	$ -
Accounts payable and accrued liabilities	5,201,979	4,584,917
Regulatory liabilities (note 8)	32,202	297,762
Customer deposits (note 9)	845,736	781,802
Payments in lieu of income taxes payable	105,413	300,619
Due to related party (note 10)	2,543,959	4,575,290
	9,717,289	10,540,390
Long-term Debt (note 11)	8,038,524	8,038,524
Shareholder's Equity		
Share capital (note 12)	8,038,524	8,038,524
Retained earnings	583,231	23,943
	8,621,755	8,062,467
	$26,377,568	$26,641,381

Contingent Liabilities (note 13, 15 and 17)

APPROVED ON BEHALF OF THE BOARD:

Director

Director

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION

STATEMENT OF RETAINED EARNINGS

FOR THE YEAR ENDED DECEMBER 31, 2008

	2008	2007
Balance, Beginning of Year	$ 23,943	$ 503,504
Net Income	559,288	760,439
	583,231	1,263,943
Dividends	-	1,240,000
Balance, End of Year	$ 583,231	$ 23,943

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION

STATEMENT OF INCOME

FOR THE YEAR ENDED DECEMBER 31, 2008

	2008	%	2007	%
Electricity Revenue (note 14)	$34,786,250		$36,161,180	
Cost of Power	28,047,757		28,804,903	
Distribution Revenue	6,738,493	100.00	7,356,277	100.00
Expenses				
Billing and collecting	586,492	8.70	901,442	12.26
Community relations	47,320	0.70	33,374	0.45
Direct operation	3,585,005	53.20	3,728,293	50.68
Office and administration	244,599	3.63	223,720	3.04
Regulatory and professional	415,854	6.17	543,266	7.39
	4,879,270	72.40	5,430,095	73.82
Income from Operations Before the Following	1,859,223	27.60	1,926,182	26.18
Amortization	949,932	14.10	884,677	12.03
Interest income on regulatory assets	(142,864)	(2.12)	(214,501)	(2.92)
Interest	711,075	10.55	733,392	9.97
Income from Operations Before Other Income and Tax	341,080	5.07	522,614	7.10
Other Income				
Interest income	16,764	0.25	23,755	0.32
Service revenue	573,964	8.52	550,609	7.47
Gain on sale of equipment	-	-	19,019	-
	590,728	8.77	593,383	7.79
Income Before Income Tax	931,808	13.86	1,115,997	14.89
Payment in Lieu of Income Taxes				
Current	348,520	5.17	350,058	4.76
Future tax expense	24,000	0.36	5,500	0.07
	372,520	5.53	355,558	4.83
Net Income	$ 559,288	8.31	$ 760,439	10.06

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION

STATEMENT OF CASH FLOWS

FOR THE YEAR ENDED DECEMBER 31, 2008

	2008	2007
Cash Flows from Operating Activities		
Net income	$ 559,288	$ 760,439
Items not requiring an outlay of cash:		
Amortization	949,932	884,677
Gain on sale of equipment	-	(19,019)
Future payment in lieu of tax asset	24,000	5,500
	1,533,220	1,631,597
Changes in non-cash working capital balances:		
Accounts receivable	507,000	95,503
Regulatory assets	161,185	(839,048)
Prepaid expenses and deferred charges	7,445	31,631
Accounts payable and accrued liabilities	617,062	(93,758)
Regulatory liabilities	(265,560)	297,762
Payment in lieu of income taxes	(195,206)	295,195
Customer deposits	63,934	(115,519)
Due to related parties	(2,031,331)	1,030,095
Net Cash Provided by Operating Activities	397,749	2,333,458
Cash Flows from Financing Activities		
Dividends	-	(1,240,000)
Cash Flows from Investing Activities		
Additions to property, plant and equipment	(1,819,528)	(1,125,723)
Proceeds on disposal of equipment	-	46,236
Decrease in note receivable	29,304	29,304
Net Cash Used in Investing Activities	(1,790,224)	(1,050,183)
Net Increase (Decrease) in Cash	(1,392,475)	43,275
Cash, Beginning of Year	404,475	361,200
Cash (Bank Indebtedness), End of Year	$ (988,000)	$ 404,475
Supplemental Cash Flow Information		
Interest paid	$ 817,926	$ 864,081
Payment in lieu of income taxes	$ 543,726	$ 395,332

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2008

1. Nature of Operations

The Ontario Government enacted the Energy Competition Act, 1998 to introduce competition to the Ontario electricity market by the year 2000. Under the terms of this legislation, the Ontario Energy Board (the "OEB") regulates industry participants by issuing licences for the right to generate, transmit, distribute or retail electricity. These licences require compliance with established market rules and codes. The Ontario Government opened the Ontario electricity market to competition on May 1, 2002.

The Company is wholly owned by the following seven municipalities, each of whom has one voting common share: Aylmer, Central Elgin, East-Zorra Tavistock, Ingersoll, Norwich, South-West Oxford and Zorra.

Erie Thames Powerlines Corporation carries on the business of distributing electricity to the following communities: Aylmer, Beachville, Belmont, Burgessville, Embro, Ingersoll, Norwich, Otterville, Port Stanley, Tavistock, and Thamesford.

In December 2003, the government of Ontario enacted Bill 4, the OEB Amendment Act (Electricity pricing). Bill 4 was enacted in response to the Electricity Pricing, Conservation and Supply Act 2002, which froze commodity rates at 4.3 cents per kilowatt hour (kWh). This act did not, in the government's opinion, reflect the true cost of electricity. Future electricity pricing was to be billed using a block structure. The block structure applies to residential consumers, small businesses and other consumers designated by the Ontario government, such as municipalities, schools, universities and hospitals. It does not, however, apply to large commercial or industrial consumers who use over 250,000 kWhs per year.

The new block structure implemented in 2005 resulted in a change to the block structure for residential customers only. From November 1, 2007 to April 30, 2008, the first 1,000 kWhs consumed per month were charged at 5.0 cents per kWh and the remaining consumption was billed at 5.9 cents per kWh. The rates from May 1, 2008 to October 31, 2008 remained at 5.0 cents per kWh for the first 600 kWhs and to 5.9 cents per kWh for the remainder of the monthly consumption. The block structure from November 1, 2008 to April 30, 2009 applied to the first 1,000 kWhs consumed per month were charged at 5.6 cents per kWh and the remaining consumption was billed at 6.5 cents per kWh.

Non-residential regulated price plan ("RPP") customers are charged based on a block structure of 750 kWhs per month. The rates up to April 30, 2008, were 5.0 cents per kWh on the first 750 kWhs and 5.9 cents per kWh on the remainder of the month's consumption. From May 1, 2008 to October 31, 2008, the rates remained at 5.0 cents for the first 750 kWhs and 5.9 cents on the remainder. Effective November 1, 2008 to April 30, 2009, the rates were increased to 5.6 cents for the first 750 kWhs and 6.5 cents on the remainder.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2008

1. Nature of Operations (cont.)

Local Distribution Companies are required to charge their customers for the following amounts (all of which, other than the distribution rate, represent a pass through of amounts payable to third parties):

(a) Electricity Price and Related Rebates: the electricity price and related rebates represent a pass through of the commodity cost of electricity.

(b) Distribution Rate: the distribution rate is designed to recover the costs incurred by the Local Distribution Company ("LDC") in delivering electricity to customers plus the OEB allowed rate of return. Distribution rates are regulated by the OEB and are typically comprised of a fixed charge and a usage-based (consumption) charge. The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (principally sustained periods of hot or cold weather which increase the consumption of electricity and sustained periods of moderate weather which decrease the consumption of electricity).

(c) Retail Transmission Rate: the retail transmission rate represents a pass through of wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

(d) Wholesale Market Service Charge: the wholesale market service charge represents a pass through of various wholesale market support costs. Retail rates for the recovery of wholesale market service charges are regulated by the OEB.

On December 18, 2003, the Ontario Energy Board renewed the LDC's distribution license for a 20 year period.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2008

2. **Significant Accounting Policies**

The financial statements of the Company have been prepared by management in accordance with Canadian generally accepted accounting principles, as modified by regulations and policies set forth in the Ontario Energy Board Accounting Procedures Handbook. Those policies that are considered to be particularly significant are outlined below:

(a) Property, Plant, Equipment and Amortization

Property, plant and equipment are recorded at the fair market value of the assets transferred from the Municipal Hydro Electric Commissions to the Company on August 31, 2000, and subsequent to August 31, 2000, at cost on the date of purchase. Property, plant and equipment are amortized over their useful lives using the straight-line method over the following periods:

Automotive equipment	8 years
Buildings	25 years
Computer equipment	5 years
Transmission and distribution system	25 years
Service, office and other equipment	10 years

(b) Revenue Recognition

(i) Electricity Sales

The Company follows the practice of cycle billing of customer's accounts and revenue is recognized in the period consumed. Estimated customer usage from the last billing date to the year end (unbilled revenue) is included in revenue.

(ii) Interest Income

Interest income is recognized on a time proportion basis, taking account of the principal outstanding and the effective rate over the period to maturity, when it is determined that such income will accrue to the Company.

(iii) Service Revenue

Service revenue is recognized as service is performed.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2008

2. Significant Accounting Policies (cont.)

(c) Financial Instruments

The Company's financial assets and financial liabilities are classified and measured as follows:

- Cash and cash equivalents are classified as held for trading and are measured at fair value. Gains and losses related to periodical revaluation are recorded in net income.
- Accounts receivable, regulatory assets and notes receivable are classified as loans and receivables and are initially measured at fair value and, subsequently, at amortized cost using the effective interest rate method.
- Accounts payable, accrued liabilities, regulatory liabilities, customer deposits, due to related party and long-term debt are classified as other liabilities and are initially measured at fair value and, subsequently, at amortized cost using the effective interest rate method.

(d) Payments in Lieu of Income Taxes (PILs)

The Company uses the liability method for accounting for PILS. Under this method, future payment in lieu of income tax assets and liabilities are recognized for differences between the carrying value of assets and liabilities for accounting purposes and their respective values for payment in lieu of income tax purposes. These differences are measured using substantially enacted tax rates applicable for the period in which those differences are expected to be recovered or settled. To the extent that there is uncertainty regarding the recovery of a future payment in lieu of income tax asset, a valuation allowance reducing the future payment in lieu of income tax asset is recorded.

(e) Use of Estimates

The preparation of the financial statements of the Company in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the balance sheet date and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates.

(f) Impairment of Long-lived Assets

Long-lived assets are tested for recoverability when events or changes in circumstances indicate that their carrying value may not be recoverable. An impairment loss is recognized when the carrying value exceeds the total undiscounted cash flow expected from their use and eventual disposition. The amount of the impairment loss is determined as the excess of the carrying value of the asset over its fair value.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2008

2. Significant Accounting Policies (cont.)

(g) Accounting Changes

Capital Disclosures

Effective January 1, 2008, the Company adopted CICA Handbook Section 1535 - "Capital Disclosures" which requires disclosure of the Company's objectives, policies and processes for managing capital as well as its compliance with any external capital requirements. The implementation of this standard did not have any impact on the Company's results of operations or financial position. The resulting disclosures from implementation are presented below (Note 19).

(h) Future Accounting Changes

(i) Changes for Rate-Regulated Entities

The AcSB has decided that since International Financial Reporting Standards do not specifically address rate-regulated enterprises, it has discontinued its project of addressing standards specifically for rate regulated enterprises. As a result, the temporary exemptions to CICA Handbook Section 1100 - Generally Accepted Accounting Principles and Section 3465 - Income Taxes will be removed. As a result, the Company will be expected to apply section 1100 to their assets and liabilities arising from rate regulation. Also, as a result of applying section 3465, the Company will be required to recognize future income tax assets and liabilities for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers. These changes are effective for year ends ending on or after December 31, 2009. The Company has not yet assessed the impact of these changes on their financial statements.

(ii) Goodwill and Intangible Assets

In fiscal 2009, the Company will be required to adopt the CICA Handbook Section 3064 - Goodwill and Intangible Assets. This new section is a replacement of CICA Handbook Sections 3062 and 3450. Included in the new standard is enhanced guidance on the recognition and measurement of intangible assets and development costs, specifically regarding internally generated intangible assets. The Company has not yet assessed the impact of this new section on its financial statements.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2008

2. Significant Accounting Policies (cont.)

(h) Future Accounting Changes (cont.)

(iii) International Financial Reporting Standards ("IFRS")

On February 13, 2008, the AcSB confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. A limited number of converged or IFRS-based standards will be incorporated into Canadian GAAP prior to 2011, with the remaining standards to be adopted at the change over date. The Company has an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its consolidated financial statements. At this time, the impact on the Company's future financial statements cannot be determined.

3. Accounts Receivable

	2008	2007
Energy, water and sewer	$ 2,961,158	$ 3,653,742
Unbilled energy	3,217,084	2,996,580
Service revenues	297,112	332,032
	$ 6,475,354	$ 6,982,354

The amounts shown above are net of allowance for doubtful accounts of $839,837 (2007 - $849,300).

4. Property, Plant and Equipment

	Cost 2008	Accumulated Amortization	Net 2008	Net 2007
Land	$ 133,684	$ -	$ 133,684	$ 133,684
Building	117,817	37,064	80,753	85,466
Plant and equipment	774,505	368,852	405,653	296,676
Transmission and distribution system	22,298,905	5,431,751	16,867,154	16,101,822
	$23,324,911	$ 5,837,667	$17,487,244	$16,617,648

During the year, the Company recorded amortization of $949,932 ($884,677 - 2007).

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2008

5. Regulatory Assets

	2008	2007
Retail settlement variances	$ 2,735,781	$ 1,776,237
Demand side management expenses	140,828	271,231
	2,876,609	2,047,468
Recovery of regulatory assets	(741,103)	249,223
	$ 2,135,506	$ 2,296,691

The OEB approved an Interim Rate Order for May 1st, 2008, that effectively removed the recovery allocation of the regulatory assets amounts until the final Cost of Service Rate Application was approved. The new Cost of Service Rate Order approved by the OEB, effective December 1st, 2008, includes an allocation of the recovery of the low voltage energy variances. The remainder of the regulatory assets will be recovered based on future rate orders.

(a) Retail settlement variances represent amounts accumulated since the opening of the electricity market on May 1, 2002. These variances are comprised of variances between amounts charged by the Independent Electricity Market Operator and amounts billed to customers plus variances from settlement and transmission charges.

In the absence of rate regulations, these costs (revenues) would be charged to the period incurred. In 2008, revenues would have been $30,783 higher; in 2007, expenditures would have been $752,548 higher.

(b) Demand side management ("DSM") amounts are expenses incurred in accordance with OEB rules and regulations and represent costs to the Company of literature provided to its customers and capital expenditures to provide energy conservation.

In the absence of rate regulations, these costs (revenues) would be charged to the period incurred. In 2008, net income would have been $156,406 higher, given expenses of $207,304 incurred and offset by revenues of $363,709 received from the Ontario Power Authority ("OPA") for DSM programs; in 2007, expenses would have been $11,449 higher.

6. Intangible Assets

	Cost 2008	Accumulated Amortization	Net 2008	Net 2007
Goodwill	$ 100,000	$ 23,334	$ 76,667	$ 76,667

At year end, management tested goodwill using a discounted cash flow and cost methodology and determined that there was no impairment of goodwill and no amortization or writedown was required.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2008

7. **Demand Operating Loan**

During 2008, the Company increased its demand operating loan to $3,250,000 (2007 – $2,500,000) with the bank to finance operating expenditures, bearing interest at Commercial Bank Prime and due 364 days from issuance. The operating loan operates as a mirror account for the following related parties: ERTH Corporation, Erie Thames Services Corporation, RDI Consulting Inc. and Coulter Water Meter Services Inc. As of December 31, 2008, $1,893,443 of this loan facility has been drawn upon ($2,227,985 in 2007) in total. The loan is secured by a first position General Security Agreement covering all Company assets excluding real property. The credit agreement includes covenants whereby a debt service coverage ratio must be maintained at 1.20 times and a third party debt to capitalization ratio under 0.6:1 be maintained. The covenants are to be tested on a rolling four quarter basis.

8. **Regulatory Liabilities**

Regulatory liabilities represent the regulatory assets approved by the OEB to be recovered from the Company by Hydro One.

9. **Customer Deposits**

Customer deposits are obtained as security for energy consumption. On an annual basis, interest is calculated and credited to the customers' utility accounts. Also included are security deposits received for construction projects.

10. **Related Parties**

The Company has a contract with ERTH Corporation for management services and rental of facilities used by the Company.

The Company has contracted Erie Thames Services Corporation, a company under common control, to provide the following services: maintenance and upgrades to the existing capital infrastructure of the Company, billing and collection services and administrative services.

The contracts between the Company and Erie Thames Service Corporation and ERTH Corporation are measured at the exchange amount, which is the amount of consideration paid or received as established and agreed to by the related parties, unless noted otherwise.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2008

10. Related Parties (cont.)

The revenue reflected in the financial statements includes the electricity revenue for the sale of electricity to ERTH Corporation, Erie Thames Services Corporation and the municipal facilities located in the communities of Aylmer, Beachville, Belmont, Burgessville, Embro, Ingersoll, Norwich, Otterville, Port Stanley, Tavistock, and Thamesford in the amount of $1,166,913 ($1,282,265 in 2007). These transactions are in the normal course of operations at rates approved by the Ontario Energy Board.

During the year, the Company purchased the following services from related parties.

Erie Thames Services Corporation	**2008**	**2007**
Purchase of capitalized items	$2,921,071	$2,114,129
Purchase of operations, maintenance and administrative services	2,866,680	3,107,611
	$5,787,751	$5,221,740

ERTH Corporation	**2008**	**2007**
Purchase of management services	$ 864,201	$ 967,000
Rent	99,009	99,009
	$ 963,210	$1,066,009

The contracts with ERTH Corporation for management services and facilities rental and with Erie Thames Services Corporation for maintenance and upgrades to the existing capital infrastructure of the Company, billing and collection services, and administrative services are being reviewed and amended as necessary to ensure compliance under the revised Affiliate Relationship Code issued in 2008 by the Ontario Energy Board.

At the end of the year, amounts due to (from) related parties are as follows:

	2008	**2007**
ERTH Corporation	$1,430,406	$3,255,683
Erie Thames Services Corporation	994,180	1,201,951
Erie Thames Solutions Corporation	-	(36,331)
Oncor Utility Solutions (Canada) Ltd.	-	2,982
Utilismart Corporation	1,653	-
RDI Consulting Corporation	117,720	2,523
Shareholders of Parent Corporation (interest)		148,482
	$ 2,543,959	$4,575,290

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2008

10. Related Parties (cont.)

The companies are related as follows:

ERTH Corporation owns 100% of the issued and outstanding shares of the Company and Erie Thames Services Corporation.

Erie Thames Solutions Inc. is a wholly-owned subsidiary of Erie Thames Services Corporation.

RDI Consulting Inc., Coulter Water Meter Service Inc. and Quadra Technology Services Inc. are wholly-owned subsidiaries of Erie Thames Solutions Inc.

Oncor Utility Solutions (Canada) Ltd. is a wholly-owned subsidiary of Abicus Management Solutions Inc., which is jointly controlled by Erie Thames Solutions Inc.

Utilismart Corporation is jointly controlled by the Erie Thames Services Corporation and RDI Consulting Inc.

11. Long-Term Debt

The long-term debt represents amounts owing to the municipal shareholders for purchase of the respective Municipality's Hydro Electric Commission's net assets. The debt is convertible to Class B shares at the fair market value of the Class B shares of the Company divided by the number of Class B shares issued and outstanding. The rate of interest is currently 7.25% and is set by the Board of Directors, from time to time. The term of the debt is undefined and no principal amounts are anticipated to be paid over the next twelve months. The loan is secured by a second position General Security Agreement covering accounts receivable, inventory and equipment, including motor vehicles.

The amounts owing to the municipalities are as follows:

	2008	2007
Aylmer	$ 1,694,863	$ 1,694,863
Central Elgin	806,436	806,436
East Zorra Tavistock	569,073	569,073
Ingersoll	3,402,080	3,402,080
Norwich	763,755	763,755
Southwest Oxford	192,062	192,062
Zorra	610,255	610,255
	$ 8,038,524	$ 8,038,524

During 2008, $582,793 was charged to interest expense for interest on related party long-term debt ($585,388 in 2007). The fair market value of this note payable at December 31, 2008 is $9,324,688.

The attached Auditors' Report and notes form an integral part of these audited financial statements

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2008

12. Share Capital

Authorized
Unlimited number of Class "A" voting shares without nominal or par value
Unlimited number of Class "B" non-voting shares without nominal or par value, redeemable, with non-cumulative dividend entitlements

Unlimited number of common shares

	2008	2007
Issued capital		
7 Class "A" shares	$ 7	$ 7
18,000,000 Class "B" shares (10,000 - 2007)	8,038,517	8,038,517
	$ 8,038,524	$ 8,038,524

During the year, the 10,000 Class B shares were split on a 1,800:1 basis, thereby increasing the total number of issued and outstanding Class B shares from 10,000 to 18,000,000.

13. Guarantee

The Company has guaranteed the operating and term loans of its parent company ERTH Corporation. The loans are secured by a General Security Agreement covering all assets of the Company. As at December 31, 2008, the operating line amounted to $905,443 and the term loans amounted to $7,206,785.

14. Electricity Revenue

	2008	%	2007	%
Sale of electricity	$20,919,973	60.14	$21,782,871	60.24
Distribution charges	6,738,494	19.37	7,356,278	20.34
Transmission charges	3,837,987	11.03	3,835,533	10.61
Retailer energy sales	3,289,796	9.46	3,186,498	8.81
	$34,786,250	100.00	$36,161,180	100.00

15. Prudential Support Requirements

Erie Thames Powerlines Corporation, as a Local Distribution Company under the Energy Competition Act, 1998, R.S.O., posted prudential support obligations on market opening, May 1, 2002 with the Electric Independent Market Operator. The prudential support obligation as at June 24, 2008 was $1,586,703 and had not changed as at December 31, 2008. The prudential support requirement is honoured through a letter of credit.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2008

16. Payments in Lieu of Income Taxes

The provision for payments in lieu ("PILs") of income taxes differs from amounts which would be calculated by applying the Company's combined statutory income tax rate as follows:

	2008	2007
Income from continuing operations before PILs	$ 931,808	$ 1,115,997
Statutory Canadian Federal and Provincial income tax rate	33.50 %	36.12 %
Basic rate applied to income before PILs	312,156	403,098
Other	36,364	(53,040)
Provision for payment in lieu of income tax	$ 348,520	$ 350,058
Effective tax rate	37.40 %	31.37 %

The Company as of December 31, 2008 has recorded a future payment in lieu of income tax assets of $161,000 (2007 - $185,000), based on substantially enacted income tax rates of 33%. Such future payment in lieu of income tax assets relate to the tax basis of depreciable assets being higher than the amounts recorded for accounting purposes.

17. Contingent Liabilities

A class action lawsuit claiming $500 million in restitutionary payments, plus interest, was served on Toronto Hydro on November 18, 1998. The action was initiated against Toronto Hydro Electric Commission as the representative of the Defendant Class consisting of all municipal electric utilities in Ontario which have charged late payment charges on overdue utility bills at any time after April 1, 1981. The claim is that late payment penalties resulted in the municipal electric utilities receiving interest at effective rates in excess of 60% per year, which is illegal under Section 347 (1)(b) of the Criminal Code. The action has not yet been certified as a class action and no discoveries have been held. The Electricity Distributors Association is undertaking the defence of this action.

This case was delayed pending the resolution of a similar case against Enbridge Gas Distribution Inc. On April 22, 2004, the Supreme Court of Canada released a decision in the Enbridge Gas case rejecting all of the defences which had been raised by Enbridge, although the Court did not permit the plaintiff class to recover damages for any period prior to the issuance of the Statement of Claim in 1994. The Supreme Court remanded the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in a settlement of the damages payable by Enbridge.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2008

17. Contingent Liabilities (cont.)

After the release by the Supreme Court of Canada of its 2004 decision in the Enbridge Gas case, the plaintiffs in the LDC late payment penalties class action indicated their intention to proceed with their litigation against the LDC's. To date, no formal steps have been taken to move the action forward. The electric utilities intend to respond to the action if, and when, it proceeds on the basis that the LDC's situation may be distinguishable from that of Enbridge Gas. The Ontario Energy Board has ruled that the settlement amounts are recoverable by Enbridge Gas through future rates.

At this time, management is unable to quantify the effect, if any, on the financial statement of the Company.

18. Financial Instruments

a) Credit Risk

Credit risk is the risk of customers defaulting on their obligations. The Company monitors and limits its exposure to customers with lower credit ratings and evaluates its customers credit exposure on a continuous basis.

The Company provides for an allowance for doubtful accounts to absorb credit losses.

b) Fair Values

The fair values of the Company's financial assets and liabilities approximate their book values unless otherwise disclosed.

c) Interest Rate Risk

The Company is subject to the risks associated with debt financing, including the risk that existing mortgage indebtedness secured by the property may not be refinanced or that the terms of such refinancing may not be as favourable as the terms of existing indebtedness. The Company is exposed to cardinal interest rate risk as its assets are held as security for the parent company's commercial loan facilities. The Company does not use any hedging instruments to mitigate its risk.

ERIE THAMES POWERLINES CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2008

19. Capital Disclosures

The Company's main objective is to ensure ongoing access to funding to maintain and improve the electricity distribution system of the Company.

As at December 31, 2008 the Company's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2008, shareholders' equity amounts to $8,621,755 (2007 - $8,062,467) and long-term debt amounts to $8,038,524 (2007 - $8,038,524). The Company's structure as at December 31, 2008 is 48% debt and 52% equity (2007 - 50% debt and 50% equity). There have been no changes in the Company's approach to capital management during the year.

20. Comparative Figures

Certain comparative figures have been reclassified to conform with the statement presentation adopted in the current year.

WEST PERTH POWER INC.

FINANCIAL STATEMENTS

DECEMBER 31, 2010

WEST PERTH POWER

CLINTON POWER

Your Hometown Utility

WEST PERTH POWER INC.

INDEX TO AUDITED FINANCIAL STATEMENTS

DECEMBER 31, 2010

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of West Perth Power Inc.

We have audited the accompanying financial statements of West Perth Power Inc., which comprise the balance sheet as at December 31, 2010 and the statements of income, retained earnings, and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform an audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of West Perth Power Inc. as at December 31, 2010 and its results of operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

May 20, 2011

London, Canada

WEST PERTH POWER INC.

BALANCE SHEET

AS AT DECEMBER 31, 2010

ASSETS

	2010	2009
Current Assets		
Cash	$ 474,286	$ 824,449
Investment (note 3)	11,677	11,677
Accounts receivable (note 4)	1,054,700	1,360,656
Inventory	54,405	75,542
Prepaid expenses	1,678	99,418
Due from related parties (note 7)	599,352	25,435
	2,196,098	2,397,177
Plant and Equipment (note 5)	1,981,557	1,708,907
Future Payment in Lieu of Income Tax Asset (note 13)	979,000	881,000
Regulatory Assets (note 6)	506,104	350,742
	$ 5,662,757	$ 5,337,826

LIABILITIES AND SHAREHOLDER'S EQUITY

	2010	2009
Current Liabilities		
Accounts payable and accrued liabilities	$ 793,020	$ 893,110
Demand note payable (note 9)	1,183,391	1,183,391
Customer deposits (note 8)	67,794	64,988
Payments in lieu of income taxes payable	3,135	7,000
Due to related party (note 7)	470,130	-
	2,517,470	2,148,489
Regulatory Liabilities (note 6)	716,707	543,708
Future Regulatory Taxes Payable (note 6)	979,000	881,000
Shareholder's Equity		
Share capital (note 11)	2,118,274	2,118,274
Retained earnings (deficit)	(680,370)	(365,321)
Accumulated other comprehensive income (AOCI)	11,676	11,676
	1,449,580	1,764,629
	$ 5,662,757	$ 5,337,826

Contingent Liabilities (notes 10, 12 and 16)
Commitments (note 14)
Subsequent Events (note 18)

APPROVED ON BEHALF OF THE BOARD:

_______________ Director .... Director

The attached Auditors' Report and notes form an integral part of these audited financial statements

WEST PERTH POWER INC.

STATEMENT OF RETAINED EARNINGS (DEFICIT)

FOR THE YEAR ENDED DECEMBER 31, 2010

	Deficit	AOCI	2010	2009
Balance, Beginning of Year	$ (365,321)	$ 11,676	$ (353,645)	$ (307,715)
Net Loss	(315,049)	-	(315,049)	(46,628)
Other Comprehensive Income (Loss)	-	-	-	698
Balance, End of Year	$ (680,370)	$ 11,676	$ (668,694)	$ (353,645)

The attached Auditors' Report and notes form an integral part of these audited financial statements.

WEST PERTH POWER INC.

STATEMENT OF INCOME (LOSS)

FOR THE YEAR ENDED DECEMBER 31, 2010

	2010	%	2009	%
Electricity Revenue	$ 5,770,909		$ 4,993,954	
Cost of Power	4,982,335		4,235,624	
Distribution Revenue	788,574	100.00	758,330	100.00
Expenses				
Billing and collecting	85,484	10.84	97,622	12.88
Community relations	44,782	5.68	80,213	10.58
Direct operation	527,679	66.92	351,030	46.29
Office and administration	90,180	11.44	105,628	13.93
Regulatory and professional	244,080	30.95	166,125	21.91
	992,205	125.83	800,618	105.59
Loss from Operations before Interest, Amortization and Other	(203,631)	(25.83)	(42,288)	(5.59)
Amortization	221,456	28.08	206,127	27.18
Interest	99,808	12.66	87,706	11.57
Income (Loss) from Operations Before Other Income	(524,895)	(66.57)	(336,121)	(44.34)
Other Income				
Interest income	10,247	1.30	6,326	0.83
Service revenue	199,599	25.31	283,167	37.33
	209,846	26.61	289,493	38.16
Net Income (Loss)	$ (315,049)	(39.96)	$ (46,628)	(6.18)

The attached Auditors' Report and notes form an integral part of these audited financial statements.

WEST PERTH POWER INC.

STATEMENT OF CASH FLOWS

FOR THE YEAR ENDED DECEMBER 31, 2010

	2010	2009
Cash Provided by (Used in) Operating Activities		
Net Income (loss)	$ (315,049)	$ (46,628)
Items not requiring an outlay of cash:		
Amortization	221,456	206,127
	(93,593)	159,499
Changes in non-cash working capital balances:		
Accounts receivable	305,956	(451,294)
Inventory	21,140	(6,475)
Prepaid expenses	97,740	(86,251)
Payment in lieu of income taxes	(3,865)	7,000
Accounts payable and accrued liabilities	(100,090)	8,738
Regulatory liabilities	17,637	(6,307)
Customer deposits	2,806	(2,239)
Due from related parties	(103,787)	(7,153)
Net Cash Provided by (Used in) Operating Activities	143,944	(384,482)
Cash Flows from Investing Activities		
Additions to plant and equipment	(494,107)	(266,037)
Net Decrease in Cash	(350,163)	(650,519)
Cash, Beginning of Year	824,449	1,474,968
Cash, End of Year	$ 474,286	$ 824,449
Supplemental Cash Flow Information		
Interest paid	$ 164,155	$ 23,359

The attached Auditors' Report and notes form an integral part of these audited financial statements.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2010

1. Nature of Operations

The Ontario Government enacted the Energy Competition Act, 1998 to introduce competition to the Ontario electricity market by the year 2000. Under the terms of this legislation, the Ontario Energy Board (the "OEB") regulates industry participants by issuing licences for the right to generate, transmit, distribute or retail electricity. These licences require compliance with established market rules and codes. The Ontario Government opened the Ontario electricity market to competition on May 1, 2002.

West Perth Power Inc. ("the Company") is wholly owned by ERTH Corporation who is in turn owned by the following nine municipalities, each of whom has one voting common share: Aylmer, Central Elgin, East-Zorra Tavistock, Ingersoll, Norwich, South-West Oxford, Zorra, West Perth and Central Huron.

The Company is in the business of distributing electricity to the communities of Mitchell and Dublin.

2. Significant Accounting Policies

The financial statements of the Company have been prepared by management in accordance with Canadian generally accepted accounting principles, as modified by regulations and policies set forth in the Ontario Energy Board Accounting Procedures Handbook. Those policies that are considered to be particularly significant are outlined below:

(a) Plant and Equipment

Plant and equipment are recorded at the fair market value of the assets transferred from the Municipal Hydro Electric Commissions to the Company on August 31, 2000, and subsequent to August 31, 2000, at cost on the date of purchase. Plant and equipment are amortized over their useful lives using the straight-line method over the following periods:

Plant and equipment	
Automotive equipment	5 years
Computer equipment	5 years
Service, office and other equipment	10 years
Leasehold improvements	5 years
Transmission and distribution system	5 - 25 years

Construction work in progress is recorded at cost until such time that the asset is completed and available for use at which point it is amortized over its useful life.

(b) Contributions to Plant and Equipment

Contributions are received from developers and contractors for capital costs incurred by the Company. These contributions are included as a reduction to the cost of the related plant or equipment when those assets are placed in service.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2010

2. Significant Accounting Policies (cont.)

(c) Revenue Recognition

(i) Electricity Sales

The Company follows the practice of cycle billing of customer's accounts and revenue is recognized in the period consumed. Estimated customer usage from the last billing date to the year end (unbilled revenue) is included in revenue.

(ii) Interest Income

Interest income on outstanding customer accounts is recognized on a time proportion basis, taking account of the principal outstanding and the effective rate over the period to maturity, when it is determined that such income will accrue to the Company.

(iii) Service Revenue

Service revenue is recognized as service is performed.

(d) Financial Instruments

The Company's financial assets and financial liabilities are classified and measured as follows:

- Cash is classified as held for trading and is measured at fair value. Gains and losses related to periodical revaluation are recorded in net income.
- Accounts receivable are classified as loans and receivables and are initially measured at fair value and, subsequently, at amortized cost using the effective interest rate method.
- Investments are classified as available for sale and are measured at fair value. Gains and losses related to periodical revaluation are recorded in AOCI.
- Accounts payable and accrued liabilities, regulatory liabilities, customer deposits, due from related party and demand note payable are classified as other liabilities and are initially measured at fair value and, subsequently, at amortized cost using the effective interest rate method.

(e) Financial Effects of Distribution Rate Regulation

The financial results presented are in accordance with generally accepted accounting principles and within that framework the Company accounts for the impact of regulatory actions in the following manner:

(i) Regulatory Decisions to Adjust Distribution Rates

In the event that a regulatory decision is rendered, providing regulatory approval and certainty to the recognition of an asset or creation of a liability and culminating in an adjustment to the Company's distribution rates, such occurrences are immediately reflected in the Company's accounts.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2010

2. Significant Accounting Policies (cont.)

(ii) Regulatory Direction and Practice

In the absence of regulatory decision impacting rates, and where the Company is required by regulatory accounting practice or direction to accumulate balances for future rate recovery or create liabilities for future discharge, those amounts are recorded in accordance with that regulatory direction. Management assesses the future uncertainty with respect to the final regulatory disposition of those amounts and to the extent required, makes accounting provisions to reduce the deferred balances accumulated or to increase the recorded liabilities. Upon rendering of the final regulatory decisions adjusting distribution rates, the provisions are adjusted to reflect the final impact of that decision, and such adjustment is reflected in net earnings for the period.

Amounts currently confirmed by final regulatory decision, and amounts currently accounted for in the absence of final regulatory decision together with related provisions for future uncertainty, are more fully described in note 6 to the financial statements.

(iii) Income tax expense

Effective January 1, 2009, the Company adopted the changes to CICA Handbook Section 3465 - *Income Taxes*, which states that, as a rate regulated entity, future income tax assets will be returned to customers as they are recovered. As a result, all increases or decreases in future income tax assets are offset by a regulatory liability. As at December 31, 2010 the Company has recorded a future income tax assets of $979,000 and a corresponding regulatory liability of $979,000 (note 6).

(iv) Regulatory balances

Effective January 1, 2009, the Company adopted the changes to CICA Handbook Section 1100 - *Generally Accepted Accounting Principles*. The amendment to this section removed the temporary exemption pertaining to the application of the section to the recognition and measurement of assets and liabilities arising from rate regulation. In response to the removal of the exemption, the Company established accounting policies for the recognition and measurement of assets and liabilities arising from rate regulation. In accordance with the Canadian GAAP hierarchy guidance framework outlined in CICA Handbook Section 1100, the company has determined that its assets and liabilities arising from rate regulation qualify for recognition under Canadian GAAP and this recognition is constant with U.S. Statement of Financial Accounting Standards No. 71, *Accounting for Effects of Certain Types of Regulations* ("FAS71"). The company concluded that its policies for assets and liabilities arising from rate regulation were consistent with the primary sources of Canadian GAAP and were developed through the exercise of professional judgment.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2010

2. Significant Accounting Policies (cont.)

(v) Rate Setting

The distribution rates of the Corporation are based on a revenue requirement that provides a regulated Maximum Allowable Return on Equity ("MARE") on the amount of shareholders' equity supporting the business of electricity distribution, which is also determined by regulation. The Company files a rate application with the OEB annually. Rates are typically effective May 1 to April 30 of the following year. Accordingly, for the first four months of 2010, distribution revenue is based on the rates approved for 2009. Once every four years, the Company files an Electricity Distribution Rate application ("EDR") where rates are rebased through a cost of service review. In the intervening years an Incentive Rate Mechanism application ("IRM") is filed. A cost of service EDR application is based upon a forecast of the amount of operating and capital expenses, debt and shareholder's equity required to support the Company's business. An IRM application results in a formulaic adjustment to distribution rates to increase distribution rates for the annual change in the GDP IPI-FDD net of a productivity factor and a "Stretch Factor" determined by the relative efficiency of an electricity distributor.

The Company's last cost of service EDR application was made in 2010 and approved on January 19, 2011 with rates effective December 1, 2010 and implemented on January 1, 2011. Such decision provided for 2010 service distribution revenue requirement and rate base of $983,928 and $2,665,649 respectively. Such amounts do not include provision for the investment of the Company in the Smart Meter Initiative, further elaborated below.

In December 2009, the OEB concluded a Cost of Capital proceeding with the issuance of a final report. The report principally dealt with the adequacy and determination of the Maximum Allowable Return on Equity ("MARE"). The Board has acknowledged that it needs to refine and reset its current formula for determining MARE to:

i) acknowledge and incorporate a utility spread off of Canada long-bonds within the Equity Risk Premium ("ERP") to better reflect utility borrowing costs (initially 141.5bps);
ii) to include a 50bps "transaction cost" component within the ERP to reflect estimated transaction costs related to utility borrowings; and
iii) reduce MARE volatility from annual changes in the Canada long-bond and i) by reducing the annual adjustment factor from 0.75 to 0.5; and
iv) reflect a more realistic and "fair" base risk premium for Local Distribution Companies.

The method of transition to the new MARE is through a Cost of Service Application similar to the 2006 EDR Application. The Corporation will file such an application in 2011 with an effective date of May 1, 2012.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2010

2. Significant Accounting Policies (cont.)

(vi) Smart Meter Initiative

The Province of Ontario has committed to have "Smart Meter" electricity meters installed in all homes and small businesses throughout Ontario by the end of 2010. Smart Meters permit consumption to be recorded within specific time intervals and specific tariffs to be levied within such intervals.

In support of this initiative, the Company completed its deployment of Smart Meters throughout 2009, 2010 and early 2011, with 2,000 Smart Meters deployed by the end of 2010. Successful testing with the provincial Meter Data Management Repository ("MDMR") will be completed in 2011.

(vii) Green Energy and Green Economy Act

In early 2009, the government tabled the Green Energy and Green Economy Act ("GEGEA"). This new legislation makes fundamental changes to the roles and responsibilities of LDC's in the areas of renewable power generation, conservation and demand management delivery, and the development of smart distribution grids.

The Green Energy and Green Economy Act provides LDC's with the freedom to own and operate a portfolio of renewable power generation and will permit them to provide district heating services in their communities through co-generation. LDC's will also bear added responsibilities to assist and enable consumers to reduce their peak demand and conserve energy in an effort to meet provincial conservation targets. LDC's will also gain new responsibilities in transforming their local distribution networks into smart grids harnessing advanced technologies to facilitate the connection of small-scale generators and the two-way flow of information.

(viii) New LDC License Requirements - Conservation and Demand Management Targets

On November 12, 2010, the OEB amended LDC licenses to include requirements for achieving certain CDM targets over a four year period commencing January 1, 2011. The Company's CDM targets include a demand reduction target of 0.62MW and a consumption reduction target of 2,990MWh. LDC's must also comply with a new CDM Code of the OEB, which provides LDC requirements for the development and delivery of CDM Strategy to the OEB for the achievement of LDC-specific CDM targets, annual accounting and reporting to the OEB, and eligibility criteria for performance incentive payments. The Company has filed its CDM Strategy with the OEB.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2010

2. Significant Accounting Policies (cont.)

(f) Payments in Lieu of Income Taxes ("PILs")

The Company uses the liability method for accounting for PILs. Under this method, future payment in lieu of income tax assets and liabilities are recognized for differences between the carrying value of assets and liabilities for accounting purposes and their respective values for payment in lieu of income tax purposes. These differences are measured using substantively enacted tax rates applicable for the period in which those differences are expected to be recovered or settled. To the extent that there is uncertainty regarding the recovery of a future payment in lieu of income tax asset, a valuation allowance reducing the future payment in lieu of income tax asset is recorded.

(g) Inventory

Inventories consist primarily of materials and supplies. Items considered to be major future components of property, plant and equipment are transferred to property, plant and equipment. Inventories are carried at the lower of cost and net realizable value, with cost determined on an average cost basis net of a provision for obsolescence.

(h) Impairment of Long-lived Assets

Long-lived assets are tested for recoverability when events or changes in circumstances indicate that their carrying value may not be recoverable. An impairment loss is recognized when the carrying value exceeds the total undiscounted cash flow expected from their use and eventual disposition. The amount of the impairment loss is determined as the excess of the carrying value of the asset over its fair value.

(i) Use of Estimates

The preparation of the financial statements of the Company in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the balance sheet date and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2010

2. Significant Accounting Policies (cont.)

(j) Future Accounting Changes

(i) International Financial Reporting Standards ("IFRS")

On February 13, 2008, the Canadian Accounting Standards Board confirmed the publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. On September 10, 2010, the AcSB decided to permit rate-regulated entities to defer their IFRS implementation date to January 1, 2012.

The Company has an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its financial statements. Although the impact of the adoption to IFRS on the Company's Balance Sheet and Income Statement is not yet reasonably determinable or estimable, the company does expect a significant increase in financial statement disclosure requirements resulting from the adoption of IFRS, and is designing the systems and related process changes, which will be required in order to provide the additional information required to make these disclosures.

Given the continued uncertainty around the timing, scope and eventual adoption of a rate-regulated accounting standard under IFRS and the potential material impact of these standards on the Company's financial statements, the Company has decided to apply IFRS to its financial statements ending December 31, 2012 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011, for comparative purposes. The company continues to assess the impact of the conversion to IFRS on its results of operation. At this time, the impact on the Company's future financial statements cannot be determined.

3. Investment

	2010	2009
386 common shares in Sunlife Financial, at market value (cost - $1)	$ 11,677	$ 11,677

4. Accounts Receivable

	2010	2009
Energy, water and sewer	$ 449,614	$ 520,689
Unbilled energy	605,086	796,050
Service revenues	-	43,917
	$ 1,054,700	$ 1,360,656

The amounts shown above are net of allowance for doubtful accounts of $132,122 (2009 - $139,768).

The attached Auditors' Report and notes form an integral part of these audited financial statements.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2010

5. Plant and Equipment

	Cost	Accumulated Amortization	Net 2010	Net 2009
Land	$ 3,745	$ -	$ 3,745	$ 3,745
Plant and equipment	641,543	301,406	340,137	60,368
Transmission and distribution system	4,566,027	2,928,352	1,637,675	1,644,794
	$ 5,211,315	$ 3,229,758	$ 1,981,557	$ 1,708,907

During the year, the Company recorded amortization of $221,456 (2009 - $206,127).

6. Regulatory Liabilities

Regulatory assets consist of the following:

	2010	2009
Deferred charges	$ 507,090	$ 367,616
Special purpose payments (b)	7,693	-
Late payment penalties settlement (c)	8,514	-
	523,297	367,616
Recovery of regulatory assets	17,193	16,874
	$ 506,104	$ 350,742

Regulatory liabilities consist of the following:

	2010	2009
Retail settlement variances (a)	$ 716,707	$ 543,708
Future payment in lieu of income tax liability	979,000	881,000
	$ 1,695,707	$ 1,424,708

The OEB approved an Interim Rate Order for May 1, 2008, that effectively removed the recovery allocation of the regulatory assets amounts until the final Cost of Service Rate Application was approved. The new Cost of Service Rate Order approved by the OEB, effective December 1, 2008, includes an allocation of the recovery of the low voltage energy variances. The remainder of the regulatory assets will be recovered based on future rate orders.

(a) Retail settlement variances represent amounts accumulated since the opening of the electricity market on May 1, 2002. These variances are comprised of variances between amounts charged by the Independent Electricity Market Operator and amounts billed to customers plus variances from settlement and transmission charges. In the absence of rate regulations, these costs (revenues) would be charged to the period incurred.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2010

6. Regulatory Assets and Liabilities (cont.)

(b) On April 9, 2010, the OEB informed electricity distributors of a Special Purpose Charge assessment under Section 26.1 of the Ontario Energy Board Act, 1998, for the Ministry of Energy and Infrastructure conservation and renewable energy program costs. The OEB assessed the Company $22,930 for their apportioned share of the total provincial amount of the Special Purpose Charge of $53,695,000 in accordance with the rules set out in Ontario Regulation 66/10. In accordance with Section 9 of the Special Purpose Charge Regulation, the Company is allowed to recover this balance. The recovery is expected to be achieved over a one-year period, which began on May 1, 2010.

(c) The late payment penalties settlement account relates to the settlement costs accrual associated with the late payment charges class action (note 16 and 18). All of the Municipal Electricity Utilities ("MEU") involved in the settlement, including the Company, have requested an order from the OEB allowing for the future recovery from customers of all costs related to the settlement.

(d) Demand side management ("DSM") amounts are expenses incurred in accordance with OEB rules and regulations and represent costs to the Company of literature provided to its customers and capital expenditures to provide energy conservation. In the absence of rate regulations, these costs (revenues) would be charged to the period incurred.

7. Related Party Transactions

The revenue reflected in the financial statements includes the electricity revenue for the sale of electricity to the Municipality of West Perth for $295,026. These transactions are in the normal course of operations at rates approved by the Ontario Energy Board. The Municipality charges the Company for taxes and tree trimming in the amount of $4,757 and $3,126 respectively.

The Company has a contract with ERTH Corporation for management services.

The Company has contracted CRU Solutions Inc., Ecaliber (Canada) Inc., and ERTH360 Generation & Consulting Inc., companies under common control, to provide the following services: maintenance and upgrades to the existing capital infrastructure of the Company, billing and collection services and administrative services.

The contracts between the Company, CRU Solutions Inc., Ecaliber (Canada) Inc., ERTH360 Generation & Consulting Inc., and ERTH Corporation are measured at the exchange amount, which is the amount of consideration paid or received as established and agreed to by the related parties, unless noted otherwise.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2010

7. Related Parties (cont.)

During the year, the Company purchased the following services from related parties.

ERTH360 Generation and Consulting Inc.	**2010**
Purchase of capitalized items	$ 141,767
Purchase of operations, maintenance and administrative services	4,200
	$ 145,967
The SPi Group Inc.	
Purchase of consulting services	$ 4,370
CRU Solutions Inc.	
Purchase of operations, maintenance and consulting services	$ 16,424
ERTH Corporation	
Purchase of management services	$ 283,924
Ecaliber (Canada) Inc.	
Purchase of operations, maintenance and administrative services	$ 117,511
Utilismart Corporation	
Purchase of consulting services	$ 13,915
Erie Thames Powerlines Corporation	
Purchase of consulting services	$ 38,648
Clinton Power Corporation	
Purchase of capitalized items	$ 3,115
Sale of operations and administrative services	(87,227)
	(84,112)

At the end of the year, amounts due from the related party is as follows:

	2010	**2009**
Clinton Power Corporation	$ 599,352	$ -
Corporation of the Municipality of West Perth	-	25,435
	$ 599,352	$ 25,435

The attached Auditors' Report and notes form an integral part of these audited financial statements.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2010

7. Related Parties (cont.)

At the end of the year, amounts due to the related party is as follows:

	2010	2009
ERTH Corporation	$ 283,924	$ -
CRU Solutions Inc	880	-
Ecaliber (Canada) Inc.	36,218	-
The SPi Group Inc.	146	-
Erie Thames Powerlines Corporation	16,881	-
ERTH360 Generation & Consulting Inc.	20,445	-
Utilismart Corporation	1,204	-
Corporation of the Municipality of West Perth	110,432	-
	$ 470,130	$ -

The balances are interest free and payable on demand.

The companies are related as follows:

ERTH Corporation owns 100% of the issued and outstanding shares of the Company West Perth Power Inc., Clinton Power Corporation, CRU Solutions Inc. and ERTH Holdings Inc.

Ecaliber (Canada) Inc., ERTH360 Generation & Consulting Inc. Coulter Water Service Meter Inc. and The SPi Group Inc. are wholly-owned subsidiaries of ERTH Holdings Inc.

Oncor Utility Solutions (Canada) Ltd. is a wholly-owned subsidiary of Abicus Management Solutions Inc., which is jointly controlled by ERTH Holdings Inc.

Utilismart Corporation is jointly controlled by ERTH Holdings Inc.

The Municipality of West Perth is a shareholder of ERTH Corporation.

8. Customer Deposits

Customer deposits are obtained as security for energy consumption. On an annual basis, interest is calculated at a rate of 1.5% and credited to the customers' utility accounts. Also included are security deposits received for construction projects.

9. Demand Note Payable

The demand note payable interest rate is currently 7.25% and is set by the Board of Directors, from time to time. There are no fixed repayment terms associated with the principle outstanding and no principal amounts are anticipated to be paid over the next twelve months.

During 2010, $85,796 was charged to interest expense for interest on related party long-term debt (2009 - $85,796).

The attached Auditors' Report and notes form an integral part of these audited financial statements.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2010

10. Guarantee

The Company has guaranteed the operating and term loans of its parent company ERTH Corporation up to 25% of the Company's equity or $362,395. The loans are secured by a General Security Agreement covering all assets of the Company and a pledge of the shares of the Company. As the Company does not expect to be in a position where it would need to honour this guarantee in the foreseeable future, no liability has been recorded in these financial statements.

11. Share Capital

Authorized

Unlimited number of common shares

	2010	2009
Issued capital		
550 common shares	$ 2,118,274	$ 2,118,274

12. Prudential Support Requirements

The Company, as a Local Distribution Company under the Energy Competition Act, 1998, R.S.O., posted prudential support obligations on market opening, May 1, 2002 with the Electric Independent Market Operator. The prudential support obligation as at October 2006 was $382,227 and had not changed as at December 31, 2010. The prudential support requirement is honoured through a letter of credit.

13. Payments in Lieu of Income Taxes

The provision for payments in lieu ("PILs") of income taxes differs from amounts which would be calculated by applying the Company's combined statutory income tax rate as follows:

	2010	2009
Income (loss) from continuing operations before PILs	$ (315,049)	$ (46,628)
Statutory Canadian Federal and Provincial income tax rate	31.00 %	33.00 %
Basic rate applied to income before PILs	(97,665)	(15,387)
Other	97,665	15,387
Provision for payment in lieu of income tax	$ -	$ -
Effective tax rate	- %	- %

The attached Auditors' Report and notes form an integral part of these audited financial statements.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2010

13. Payments in Lieu of Income Taxes (cont.)

The Company as of December 31, 2010 has recorded a future payment in lieu of income tax asset of $979,000 (2009 - $881,000) and future income tax regulatory liability of $979,000 (2009- $881,000), based on future substantively enacted income tax rates.

Significant components of the Company's future income tax assets and regulatory liability are as follows:

	2010	2009
Plant and equipment	$ 557,000	$ 547,000
Regulatory adjustments	243,000	287,000
Non-Capital loss carryforwards	179,000	47,000
	$ 979,000	$ 881,000

In addition, the Company has accumulated non-capital losses for tax purposes of $714,000, which are available to offset income in the future. These non-capital loss carry forwards of $120,000, $61,000 and $533,000 will expire in 2015, 2029 and 2030 respectively.

14. Lease Commitments

The Company has entered into various contractual agreements. The future minimum annual payments under contractual agreements are as follows:

Year ending	December 31, 2011	$ 88,354

15. Capital Disclosures

The Company's main objective is to ensure ongoing access to funding to maintain and improve the electricity distribution system of the Company.

As at December 31, 2010 the Company's definition of capital includes shareholder's equity. As at December 31, 2010, shareholders' equity amounts to $1,449,580 (2009 - $1,764,629) and long-term debt amounts to $1,183,391 (2009 - $1,183,391). The Company's structure as at December 31, 2010 is 45% debt and 55% equity (2009 - 40% debt and 60% equity). There have been no changes in the Company's approach to capital management during the year.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2010

16. Contingent Liability

Electric Distributors Association

By Order dated July 22, 2010, the Ontario Superior Court of Justice consolidated and approved the settlement of two class actions against the Company, one commenced in 1994 and the other, against all Ontario MEUs, in 1998. The actions sought $500,000,000 and $64,000,000, respectively, in restitution for late payment charges collected by them from their customers that were in excess of the interest limit stipulated in section 347 of the Criminal Code. The claims made against the Company and the definition of the plaintiff classes were identical in both actions such that any damages payable by the Company in the first action would reduce the damages payable by the Company in the second action, and vice versa.

The July 22, 2010 court order formalized a settlement pursuant to which the defendant MEUs will pay the amount of $17,000,000 plus costs and taxes in settlement of all claims. The amount allocated for payment by each MEU is its proportionate share of the settlement amount based on its percentage of distribution service revenue over the period for which it has exposure for repayment of late payment penalties exceeding the interest rate limit in the Criminal Code. the Company's share of the settlement amount was expected to be $8,514 payable on June 30, 2011. Under the settlement, all the MEUs involved in the settlement, including the Company, have requested an order from the OEB allowing for the future recovery from customers of all costs related to the settlement. The Company has accrued a liability and a corresponding regulatory asset in the amount of the above (note 18).

17. Financial Instruments

As a rate-regulated entity, the nature of the Company's operations are defined and restricted by regulation. Financial operations and risks are also substantially influenced by regulation, limiting the necessity to engage in risk mitigation strategies involving the use of derivatives or hedges, and the Company did not engage in those activities during the fiscal year.

The company has adopted CICA Handbook Section 3861- *Financial Instruments* for disclosure purposes as the Company's financial instruments are not subject to disclosure requirements under Section 3862 or 3863 of the CICA Handbook

a) Credit Risk

By regulation, the Company is responsible for collecting both the distribution and energy portions of the electricity bill. On average, 16% of amounts billed to customers are for distribution charges and 84% of the bill is energy related. Unless the retailer elects to bill the customers directly for the energy portion of the bill, the Company is exposed to a credit risk substantially greater then their portion of the electricity bill.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2010

17. Financial Instruments (cont.)

a) Credit Risk (cont.)

Mitigation of substantial losses is provided through the opportunity to apply for recovery for those losses through distribution rate adjustments in future years, if approved by the regulator. Additionally, regulation provides for certain customers to provide security deposits for a prescribed period of period to mitigate collection loss.

The Company is not exposed to a significant concentration of credit risk within any customer segment or individual customer.

b) Fair Values

The fair values of the Company's financial assets and liabilities approximate their book values unless otherwise disclosed.

c) Interest Rate Risk

The Company is subject to the risks associated with debt financing, including the risk that existing indebtedness secured by the property may not be refinanced or that the terms of such refinancing may not be as favourable as the terms of existing indebtedness. The Company does not use any hedging instruments to mitigate its risk.

18. Subsequent Events

Late Payment Class Action

On February 22, 2011, the OEB issued its final decision allowing for LDC to recover the settlement amount of $8,514 for the Company from customers over the period commencing May 1, 2011 and ending April 30, 2012.

Amalgamation of Rate Regulated Entities

Subsequent to year end, the Company entered into formal proceedings to amalgamate Erie Thames Powerlines Corporation, West Perth Power Inc. and Clinton Power Corporation. Final OEB approval was received in late March 2011 to amalgamate these entities. The amalgamation is expected to be completed in June 2011.

19. Comparative Figures

Certain comparative figures have been reclassified to conform with the financial statement presentation adopted in the current year.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

WEST PERTH POWER INC.

FINANCIAL STATEMENTS

DECEMBER 31, 2009

WEST PERTH POWER INC.

INDEX TO AUDITED FINANCIAL STATEMENTS

DECEMBER 31, 2009

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AUDITORS' REPORT

To the Shareholders of West Perth Power Inc.

We have audited the balance sheet of West Perth Power Inc. as at December 31, 2009 and the statements of income, retained earnings, and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

The comparative amounts were audited by another firm of Chartered Accountants.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

London, Canada

October 15, 2010

KPMG LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity. KPMG Canada provides services to KPMG LLP.

WEST PERTH POWER INC.

BALANCE SHEET

AS AT DECEMBER 31, 2009

ASSETS

	2009	2008
Current Assets		
Cash	$ 824,449	$ 1,474,968
Investment (note 6)	11,677	10,978
Accounts receivable (note 3)	1,360,656	909,362
Inventory	12,095	5,620
Prepaid expenses	99,418	13,167
Due from related party (note 8)	39,312	10,998
	2,347,607	2,425,093
Property, Plant and Equipment (note 4)	1,772,354	1,712,445
Future Payment in Lieu of Income Tax Asset (note 12)	881,000	-
	$ 5,000,961	$ 4,137,538

LIABILITIES AND SHAREHOLDER'S EQUITY

	2009	2008
Current Liabilities		
Accounts payable and accrued liabilities	$ 913,987	$ 877,090
Demand note payable (note 9)	1,183,391	1,183,391
Regulatory liabilities (note 5)	1,073,966	199,272
Customer deposits (note 7)	64,988	67,227
	3,236,332	2,326,980
Shareholder's Equity		
Share capital (note 10)	2,118,274	2,118,274
Retained earnings (deficit)	(365,321)	(318,694)
Accumulated other comprehensive income (AOCI)	11,676	10,978
	1,764,629	1,810,558
	$ 5,000,961	$ 4,137,538

Contingent Liabilities (notes 11 and 16)
Commitments (note 13)
Subsequent event (note 15)

APPROVED ON BEHALF OF THE BOARD:

_______ Director

_______ Director

The attached Auditors' Report and notes form an integral part of these audited financial statements

WEST PERTH POWER INC.

STATEMENT OF RETAINED EARNINGS (DEFICIT)

FOR THE YEAR ENDED DECEMBER 31, 2009

	Deficit	AOCI	2009	2008
Balance, Beginning of Year	$ (318,693)	$ 10,978	$ (307,716)	$ (233,481)
Net Loss	(46,628)	-	(46,628)	(63,709)
Other Comprehensive Income (Loss)	-	698	698	(10,526)
Balance, End of Year	$ (365,321)	$ 11,676	$ (353,646)	$ (307,716)

The attached Auditors' Report and notes form an integral part of these audited financial statements.

WEST PERTH POWER INC.

STATEMENT OF INCOME (LOSS)

FOR THE YEAR ENDED DECEMBER 31, 2009

	2009	%	2008	%
Electricity Revenue	$ 4,993,954		$ 5,481,954	
Cost of Power	4,235,624		4,746,465	
Distribution Revenue	758,330	100.00	735,489	100.00
Expenses				
Billing and collecting	97,622	12.87	152,844	20.79
Community relations	80,213	10.58	(16)	-
Direct operation	351,030	46.29	360,895	49.07
Office and administration	105,628	13.93	64,531	8.77
Regulatory and professional	166,125	21.91	63,894	8.69
	800,618	105.58	642,148	87.32
Net Income (Loss) from Operations Before Interest, Amortization and Other	(42,288)	(5.58)	93,341	12.68
Amortization	206,127	27.18	185,168	25.18
Interest	87,706	11.57	93,970	12.78
Income (Loss) from Operations Before Other Income	(336,121)	(44.33)	(185,797)	(25.28)
Other Income				
Interest income	6,326	0.83	56,654	7.70
Service revenue	283,167	37.34	65,434	8.89
	289,493	38.17	122,088	16.59
Net Income (Loss)	$ (46,628)	(6.16)	$ (63,709)	(8.69)

The attached Auditors' Report and notes form an integral part of these audited financial statements.

WEST PERTH POWER INC.

STATEMENT OF CASH FLOWS

FOR THE YEAR ENDED DECEMBER 31, 2009

	2009	2008
Cash Flows from Operating Activities		
Net Income (loss)	$ (46,628)	$ (63,709)
Items not requiring an outlay of cash:		
Amortization	206,127	185,168
	159,499	121,459
Changes in non-cash working capital balances:		
Accounts receivable	(451,293)	339,320
Inventory	(6,475)	372
Prepaid expenses	(86,251)	6,426
Accounts payable and accrued liabilities	36,897	144
Regulatory liabilities	(6,306)	182,765
Customer deposits	(2,239)	(14,407)
Due from related party	(28,314)	-
Net Cash Provided by (Used in) Operating Activities	(384,482)	636,079
Cash Flows from Investing Activities		
Additions to property, plant and equipment	(266,037)	(180,411)
Net Increase (Decrease) in Cash	(650,519)	455,668
Cash, Beginning of Year	1,474,968	1,019,300
Cash, End of Year	$ 824,449	$ 1,474,968
Supplemental Cash Flow Information		
Interest paid	$ 23,359	$ 93,970

The attached Auditors' Report and notes form an integral part of these audited financial statements.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

1. Nature of Operations

The Ontario Government enacted the Energy Competition Act, 1998 to introduce competition to the Ontario electricity market by the year 2000. Under the terms of this legislation, the Ontario Energy Board (the "OEB") regulates industry participants by issuing licences for the right to generate, transmit, distribute or retail electricity. These licences require compliance with established market rules and codes. The Ontario Government opened the Ontario electricity market to competition on May 1, 2002.

The Company is wholly owned by the Municipality of the Corporation of West Perth. West Perth Power Inc. ("the Company") is in the business of distributing electricity to the communities of Mitchell and Dublin.

2. Significant Accounting Policies

The financial statements of the Company have been prepared by management in accordance with Canadian generally accepted accounting principles, as modified by regulations and policies set forth in the Ontario Energy Board Accounting Procedures Handbook. Those policies that are considered to be particularly significant are outlined below:

(a) Property, Plant and Equipment

Property, plant and equipment are recorded at the fair market value of the assets transferred from the Municipal Hydro Electric Commissions to the Company on August 31, 2000, and subsequent to August 31, 2000, at cost on the date of purchase. Property, plant and equipment are amortized over their useful lives using the straight-line method over the following periods:

Plant and equipment	
Automotive equipment	5 years
Computer equipment	5 years
Service, office and other equipment	10 years
Leasehold improvements	5 years
Transmission and distribution system	5 - 25 years

Construction work in progress is recorded at cost until such time that the asset is completed and available for use.

(b) Contributions to Property, Plant and Equipment

Contributions are received from developers and contractors for capital costs incurred by the Company. These contributions are included as a reduction to the cost of the related Property, Plant or Equipment when those assets are placed in service.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

2. Significant Accounting Policies (cont.)

(c) Revenue Recognition

(i) Electricity Sales

The Company follows the practice of cycle billing of customer's accounts and revenue is recognized in the period consumed. Estimated customer usage from the last billing date to the year end (unbilled revenue) is included in revenue.

(ii) Interest Income

Interest income is recognized on a time proportion basis, taking account of the principal outstanding and the effective rate over the period to maturity, when it is determined that such income will accrue to the Company.

(iii) Service Revenue

Service revenue is recognized as service is performed.

(iii) When the restructuring of a benefit plan gives rise to both a curtailment and a settlement of obligations, the curtailment is accounted for prior to the settlement.

(d) Financial Instruments

The Company's financial assets and financial liabilities are classified and measured as follows:

- Cash is classified as held for trading and is measured at fair value. Gains and losses related to periodical revaluation are recorded in net income.
- Accounts receivable are classified as loans and receivables and are initially measured at fair value and, subsequently, at amortized cost using the effective interest rate method.
- Investments are classified as available for sale and are measured at fair value. Gains and losses related to periodical revaluation are recorded in AOCI.
- Accounts payable and accrued liabilities, regulatory liabilities, customer deposits, due from related party and demand note payable are classified as other liabilities and are initially measured at fair value and, subsequently, at amortized cost using the effective interest rate method.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

2. Significant Accounting Policies (cont.)

(e) Financial Effects of Distribution Rate Regulation

The financial results presented are in accordance with generally accepted accounting principles and within that framework the Company accounts for the impact of regulatory actions in the following manner:

(i) Regulatory Decisions to Adjust Distribution Rates

In the event that a regulatory decision is rendered, providing regulatory approval and certainty to the recognition of an asset or creation of a liability and culminating in an adjustment to the Company's distribution rates, such occurrences are immediately reflected in the Company's accounts.

(ii) Regulatory Direction and Practice

In the absence of regulatory decision impacting rates, and where the Company is required by regulatory accounting practice or direction to accumulate balances for future rate recovery or create liabilities for future discharge, those amounts are recorded in accordance with that regulatory direction. Management assesses the future uncertainty with respect to the final regulatory disposition of those amounts and to the extent required, makes accounting provisions to reduce the deferred balances accumulated or to increase the recorded liabilities. Upon rendering of the final regulatory decisions adjusting distribution rates, the provisions are adjusted to reflect the final impact of that decision, and such adjustment is reflected in net earnings for the period.

Amounts currently confirmed by final regulatory decision, and amounts currently accounted for in the absence of final regulatory decision together with related provisions for future uncertainty, are more fully described in note 5 to the financial statements.

(f) Payments in Lieu of Income Taxes ("PILs")

The Company uses the liability method for accounting for PILs. Under this method, future payment in lieu of income tax assets and liabilities are recognized for differences between the carrying value of assets and liabilities for accounting purposes and their respective values for payment in lieu of income tax purposes. These differences are measured using substantively enacted tax rates applicable for the period in which those differences are expected to be recovered or settled. To the extent that there is uncertainty regarding the recovery of a future payment in lieu of income tax asset, a valuation allowance reducing the future payment in lieu of income tax asset is recorded.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

2. Significant Accounting Policies (cont.)

(g) Inventories

Effective January 1, 2008, the Company adopted Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3031 - *Inventories*, which is based on the International Accounting Standards Board's International Accounting Standard 2 and replaced existing CICA Handbook Section 3030. Under this new standard, inventories are required to be measured at the lower of cost and net realizable value and any items considered to be major future components of property, plant and equipment are to be transferred to property, plant and equipment. The new standard also provides updated guidance on the appropriate methods of determining cost and the impact of any write-downs to net realizable value. The implementation of this standard did not have any impact on the Company's results of operations.

Inventories consist primarily of materials and supplies. Inventories are carried at the lower of cost and net realizable value, with cost determined on an average cost basis net of a provision for obsolescence.

(h) Use of Estimates

The preparation of the financial statements of the Company in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the balance sheet date and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates.

(i) Impairment of Long-lived Assets

Long-lived assets are tested for recoverability when events or changes in circumstances indicate that their carrying value may not be recoverable. An impairment loss is recognized when the carrying value exceeds the total undiscounted cash flow expected from their use and eventual disposition. The amount of the impairment loss is determined as the excess of the carrying value of the asset over its fair value.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

2. Significant Accounting Policies (cont.)

(j) Accounting Changes

(i) Generally Accepted Accounting Principles

Effective January 1, 2009, the Company adopted the changes to CICA Handbook Section 1100 - *Generally Accepted Accounting Principles*. The amendment to this section removed the temporary exemption pertaining to the application of the section to the recognition and measurement of assets and liabilities arising from rate regulation. In response to the removal of the exemption, the Company established accounting policies for the recognition and measurement of assets and liabilities arising from rate regulation. In accordance with the Canadian GAAP hierarchy guidance framework outlined in CICA Handbook Section 1100, the company has determined that its assets and liabilities arising from rate regulation qualify for recognition under Canadian GAAP and this recognition is constant with U.S. Statement of Financial Accounting Standards No. 71, *Accounting for Effects of Certain Types of Regulations* ("FAS71"). The company concluded that its policies for assets and liabilities arising from rate regulation were consistent with the primary sources of Canadian GAAP and were developed through the exercise of professional judgment. As a result there was no changes in the Company's opening retained earnings as at January 1, 2009 or the Company's results from operations for the year ended December 31, 2009 as a result of the adoption of this section.

(ii) Income tax expense

Effective January 1, 2009, the Company retroactively adopted the liability method for accounting for income taxes and restated prior period amounts. Under this method, future income tax assets are recognized for the differences between the financial statement carrying amounts of existing assets and liabilities and their respective values for income tax purposes. These differences are measured using substantively enacted tax rates in effect in the period in which these differences are expected to be recovered or settled. As a rate regulated entity, future income taxes will be returned to customers as they are recovered. As a result, all increases or decreases in future income tax assets are offset by a regulatory liability. As a result of the adoption of this standard, future income tax assets of $635,000 were determined to exist, however given the uncertainty about the Company's ability to utilize those assets, a full valuation allowance was taken. There was no impact to prior period earnings as a result of adopting this standard.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

2. Significant Accounting Policies (cont.)

(k) Future Accounting Changes

(i) International Financial Reporting Standards ("IFRS")

On February 13, 2008, the Accounting Standards Board of Canada ("AcSB") confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2012.

A limited number of converged or IFRS-based standards will be incorporated into Canadian GAAP prior to 2012, with the remaining standards to be adopted at the change over date.

The Company has an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its financial statements. Although the impact of the adoption to IFRS on the Company's Balance Sheet and Income Statement is not yet reasonably determinable or estimable, the company does expect a significant increase in financial statement disclosure requirements resulting from the adoption of IFRS, and is designing the systems and related process changes, which will be required in order to provide the additional information required to make these disclosures.

In July 2009, the International Accounting Standards Board ("IASB") issued an exposure draft on rate regulated activities. The IASB staff has postponed presenting their analysis of the responses to the IASB. This presentation may include options for the next steps of the rate regulated activities project. It is unclear at this time what the outcome of the IASB's deliberations will be and how that will impact the Company's reporting under IFRS.

At this time, the impact on the Company's future financial statements cannot be determined.

3. Accounts Receivable

	2009	2008
Energy, water and sewer	$ 520,689	$ 334,885
Unbilled energy	796,050	574,477
Service revenues	43,917	-
	$ 1,360,656	$ 909,362

The amounts shown above are net of allowance for doubtful accounts of $139,768 (2008 - $49,079).

The attached Auditors' Report and notes form an integral part of these audited financial statements.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

4. Property, Plant and Equipment

	Cost	Accumulated Amortization	Net 2009	Net 2008
Land	$ 3,745	$ -	$ 3,745	$ 3,745
Plant and equipment	344,860	284,492	60,368	44,431
Transmission and distribution system	4,444,051	2,735,810	1,708,241	1,664,269
	$ 4,792,656	$ 3,020,302	$ 1,772,354	$ 1,712,445

During the year, the Company recorded amortization of $206,127 (2008 - $185,168).

5. Regulatory Liabilities

Regulatory liabilities consist of the following:

	2009	2008
Retail settlement variances	$ 543,708	$ 409,435
Deferred charges	(367,616)	(156,042)
Demand side management expenses	-	(70,609)
Future payment in lieu of income tax liability	881,000	-
	1,057,092	182,784
Recovery of regulatory assets	(16,874)	(16,488)
	$ 1,073,966	$ 199,272

The OEB approved an Interim Rate Order for May 1, 2008, that effectively removed the recovery allocation of the regulatory assets amounts until the final Cost of Service Rate Application was approved. The new Cost of Service Rate Order approved by the OEB, effective December 1, 2008, includes an allocation of the recovery of the low voltage energy variances. The remainder of the regulatory assets will be recovered based on future rate orders.

(a) Retail settlement variances represent amounts accumulated since the opening of the electricity market on May 1, 2002. These variances are comprised of variances between amounts charged by the Independent Electricity Market Operator and amounts billed to customers plus variances from settlement and transmission charges. In the absence of rate regulations, these costs (revenues) would be charged to the period incurred.

(b) Demand side management ("DSM") amounts are expenses incurred in accordance with OEB rules and regulations and represent costs to the Company of literature provided to its customers and capital expenditures to provide energy conservation. In the absence of rate regulations, these costs (revenues) would be charged to the period incurred.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

6. Investment

	2009	2008
386 common shares in Sunlife Financial, at market value (cost - $1).	$ 11,677	$ 10,978

7. Customer Deposits

Customer deposits are obtained as security for energy consumption. On an annual basis, interest is calculated at a rate of 1.5% and credited to the customers' utility accounts. Also included are security deposits received for construction projects.

8. Related Party Transactions

The companies are related as follows:

The Municipality of the Corporation of West Perth owns all the outstanding common shares of West Perth Power Inc.

The revenue reflected in the financial statements includes the electricity revenue for the sale of electricity to the Corporation of the Municipality of West Perth. These transactions are in the normal course of operations at rates approved by the Ontario Energy Board.

The following table summarizes the company's related party transactions for the year.

	2009
Revenues	$ 67,621
Expenses	$ 104,081

At the end of the year, amounts due to the related party is as follows:

	2009	2008
Corporation of the Municipality of West Perth	$1,144,079	$1,172,393

The balances are interest free and payable on demand.

9. Demand Note Payable

The demand note payable interest rate is currently 7.25% and is set by the Board of Directors, from time to time. There are no fixed repayment terms associated with the principle outstanding and no principal amounts are anticipated to be paid over the next twelve months.

During 2009, $85,796 was charged to interest expense for interest on related party long-term debt ($86,004 - 2008).

The attached Auditors' Report and notes form an integral part of these audited financial statements.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

10. Share Capital

Authorized

Unlimited number of common shares

	2009	2008
Issued capital		
550 common shares	$ 2,118,274	$ 2,118,274

11. Prudential Support Requirements

The Company, as a Local Distribution Company under the Energy Competition Act, 1998, R.S.O., posted prudential support obligations on market opening, May 1, 2002 with the Electric Independent Market Operator. The prudential support obligation as at October 2006 was $382,227 and had not changed as at December 31, 2009. The prudential support requirement is honoured through a letter of credit.

12. Payments in Lieu of Income Taxes

The provision for payments in lieu ("PILs") of income taxes differs from amounts which would be calculated by applying the Company's combined statutory income tax rate as follows:

	2009	2008
Income (loss) from continuing operations before PILs	$ (46,628)	$ (63,709)
Statutory Canadian Federal and Provincial income tax rate	33.00 %	33.50 %
Basic rate applied to income before PILs	(15,387)	(21,343)
Other	15,387	21,343
Provision for payment in lieu of income tax	$ -	$ -
Effective tax rate	- %	- %

The Company as of December 31, 2009 has recorded a future payment in lieu of income tax asset of $881,000 (2008 - $Nil) and future income tax regulatory liability of $881,000 (2008- $Nil), based on future substantively enacted income tax rates.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

12. Payments in Lieu of Income Taxes (cont.)

Significant components of the Company's future income tax assets and regulatory liability are as follows:

	2009	2008
Property, plant and equipment	$ 547,000	$ 555,000
Regulatory adjustments	287,000	50,000
Non-Capital loss carryforwards	47,000	30,000
	881,000	635,000
Valuation allowance	-	(635,000)
	$ 881,000	$ -

In addition, the Company has accumulated non-capital losses for tax purposes of $188,000, which are available to offset income in the future. These non-capital loss carry forwards of $120,000 and $68,000 will expire in 2015 and 2029 respectively.

13. Lease Commitments

The Company has entered into various contractual agreements. The future minimum annual payments under contractual agreements are as follows:

Year ending		$ 88,354
	December 31, 2011	88,354
		$ 176,708

14. Capital Disclosures

The Company's main objective is to ensure ongoing access to funding to maintain and improve the electricity distribution system of the Company.

As at December 31, 2009 the Company's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2009, shareholders' equity amounts to $1,764,629 (2008 - $1,810,558) and long-term debt amounts to $1,183,391 (2008 - $1,183,391). The Company's structure as at December 31, 2009 is 40% debt and 60% equity (2008 - 40% debt and 60% equity). There have been no changes in the Company's approach to capital management during the year.

15. Subsequent Event

Subsequent to year end, the Company sold 100% of its issued and outstanding shares for $1,693,000, which was funded through the issuance of shares of the purchaing Company. As part of the purchase consideration, the Company agreed to purchase and subscribe for one voting Class "A" share of the purchaser for consideration of one dollar.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

16. Contingent Liability

On March 2, 2010 the Electric Distributors Association ("EDA") presented to it's members and all electric distributors in Ontario, the terms of a tentative settlement with respect to a pending class action lawsuit against all local distribution company's ("LDC's") regarding the charging of late payment penalties ("LPP's") which are alleged to have contravened Section 347 of the Criminal Code. It is contended that LPP's are "interest" as defined in the Criminal Code and that, in certain circumstances, the implied rate of interest exceeds the prescribed limit of 60%.

The plaintiffs seek repayment of all improper LPP charges. This litigation has been pending since 1994 in the case of Toronto Hydro, and since 1998 in the case of all the other LDC's. Similar class actions were also brought against Enbridge/Consumers Gas and Union Gas. On each of these occasions, the Supreme Court of Canada has made rulings which were favourable to the plaintiffs and which deprived the defendant utilities of most of their defences to these claims.

In light of the settlement in the other cases, industry counsel instruction by an Ad Hoc Committee of the EDA recently participated in a court-supervised mediation process to explore possible settlement of the case against the LDC's. A settlement in principle of the litigation on behalf of all LDC's has now been reached. The tentative settlement agreement requires the unanimous consent and approval of all LDC's. All LDC's must indicate their acceptance of the settlement on or before April 5, 2010. The Ontario Superior court of Justice convened a hearing on May 26, 2010 to consider the settlement of the class action suit at which a tentative resolution was reached. Specific details related to the Company's liabilities are not yet available at this time.

17. Financial Instruments

As a rate-regulated entity, the nature of the Company's operations are defined and restricted by regulation. Financial operations and risks are also substantially influenced by regulation, limiting the necessity to engage in risk mitigation strategies involving the use of derivatives or hedges, and the Company did not engage in those activities during the fiscal year.

The company has adopted CICA Handbook Section 3861- *Financial Instruments* for disclosure purposes as the Company's financial instruments are not subject to disclosure requirements under Section 3862 or 3863 of the CICA Handbook

a) Credit Risk

By regulation, the Company is responsible for collecting both the distribution and energy portions of the electricity bill. On average, 16% of amounts billed to customers are for distribution charges and 84% of the bill is energy related. Unless the retailer elects to bill the customers directly for the energy portion of the bill, the Company is exposed to a credit risk substantially greater then their portion of the electricity bill.

WEST PERTH POWER INC.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

17. Financial Instruments (cont.)

a) Credit Risk (cont.)

Mitigation of substantial losses is provided through the opportunity to apply for recovery for those losses through distribution rate adjustments in future years, if approved by the regulator. Additionally, regulation provides for certain customers to provide security deposits for a prescribed period of period to mitigate collection loss.

The Company is not exposed to a significant concentration of credit risk within any customer segment or individual customer.

b) Fair Values

The fair values of the Company's financial assets and liabilities approximate their book values unless otherwise disclosed.

c) Interest Rate Risk

The Company is subject to the risks associated with debt financing, including the risk that existing indebtedness secured by the property may not be refinanced or that the terms of such refinancing may not be as favourable as the terms of existing indebtedness. The Company does not use any hedging instruments to mitigate its risk.

18. Comparative Figures

Certain comparative figures have been reclassified to conform with the statement presentation adopted in the current year.

West Perth Power Inc.

Financial Statements
For the year ended December 31, 2008

West Perth Power Inc.
Financial Statements
For the year ended December 31, 2008

Contents

BDO Dunwoody LLP
Chartered Accountants
and Advisors

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Auditors' Report

To the Shareholder of
West Perth Power Inc.

We have audited the balance sheet of West Perth Power Inc. as at December 31, 2008 and the statements of (loss) income and other comprehensive (loss) income, equity (deficit) and cash flows for the year then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2008 and the results of its operations and cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

BDO Dunwoody LLP

Chartered Accountants, Licensed Public Accountants

Stratford, Ontario
June 16, 2009

West Perth Power Inc.
Balance Sheet

December 31	2008	2007
Assets		
Current		
Cash and bank	$ 1,474,968	$ 1,019,300
Investments (Note 1)	10,978	21,504
Accounts receivable	346,032	607,151
Inventory	5,620	5,692
Unbilled revenue	574,477	652,678
Prepaid expenses	13,167	19,501
	2,425,242	2,326,216
Capital assets (Note 2)	1,712,444	1,717,202
	$ 4,137,686	$ 4,045,418
Liabilities and Shareholder's Equity		
Current		
Accounts payable and accruals	$ 877,238	$ 877,095
Demand note payable (Note 5)	1,183,391	1,183,391
Customer deposits	67,227	81,634
	2,127,856	2,142,120
Regulatory liabilities (Note 3)	199,271	18,506
	2,327,127	2,158,623
Shareholder's equity		
Share capital (Note 6)	2,118,274	2,118,274
Deficit	(318,693)	(254,986)
Accumulated other comprehensive income (AOCI)	10,978	21,504
	1,810,559	1,884,792
	$ 4,137,686	$ 4,043,418

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

West Perth Power Inc.
Statement of Equity (Deficit)

For the year ended December 31	Deficit	AOCI	2008	2007
Balance, beginning of year	$ (254,986)	$ 21,504	$ **(233,482)**	$ (270,956)
Change in accounting policy (Note 11)	-	-	-	19,038
	(254,986)	21,504	**(233,482)**	(251,918)
Net (loss) income	(63,707)	-	**(63,707)**	55,970
Other comprehensive (loss) income	-	(10,526)	**(10,526)**	2,466
Dividends	-	-	-	(40,000)
Balance, end of year	$ (318,693)	$ 10,978	$ **(307,715)**	$ (233,482)

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

West Perth Power Inc.
Statement of (Loss) Income and Other Comprehensive (Loss) Income

For the year ended December 31		2008		2007
Revenue				
Distribution revenue	$	736,511	$	737,724
Interest		56,650		54,928
Rentals		15,385		12,898
Miscellaneous		50,049		72,052
		858,595		877,602
Expenses				
Amortization		185,168		195,751
Billing, data processing and collection		196,898		155,556
Bad debts		10,940		20,798
General administration		71,001		51,220
Operating and maintenance		372,291		312,303
		836,298		735,628
Income before interest expense		22,297		141,974
Interest expense		86,004		86,004
Net (loss) income for the year		(63,707)		55,970
Other comprehensive (loss) income				
Change in unrealized (loss) gain on investments classified as available for sale		(10,526)		2,466
Comprehensive (loss) income	$	(74,233)	$	58,436

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

West Perth Power Inc.
Statement of Cash Flows

For the year ended December 31		2008		2007
Cash flows from operating activities				
Net (loss) income for the year	$	(63,707)	$	55,970
Adjustments for:				
Amortization		185,168		195,751
		121,461		251,721
Changes in non-cash working capital balances				
Accounts receivable		261,119		(134,219)
Inventory		372		907
Unbilled revenue		78,201		(101,863)
Prepaid expenses		6,424		(9,210)
Accounts payable and accruals		144		166,252
Customer deposits		(14,407)		15,713
		453,314		179,301
Cash flows from investing activities				
Purchase of capital assets		(180,411)		(118,966)
Decrease (increase) in regulatory assets/liabilities		182,765		372,581
		2,354		253,615
Cash flows from financing activities				
Dividends		-		(40,000)
Increase in cash and cash equivalents for the year		455,668		392,916
Cash and cash equivalents, beginning of year		1,019,300		626,384
Cash and cash equivalents, end of year	$	1,474,968	$	1,019,300

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements

West Perth Power Inc.
Summary of Significant Accounting Policies

December 31, 2008

Nature of Business

West Perth Power Inc. was incorporated under the Business Corporations Act (Ontario) pursuant to Section 142 of the Electricity Act 1998 on January 21, 2000, and is wholly owned by the Corporation of the Municipality of West Perth. The principal businesses of West Perth Power Inc. are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

Rate Setting

The rates of the Company's electricity transmission and distribution businesses are subject to regulation by the OEB. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. Specific regulatory assets and liabilities are disclosed in Note 3.

The company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

West Perth Power Inc.
Summary of Significant Accounting Policies

December 31, 2008

Inventory

Effective January 1, 2008 the company adopted CICA Handbook Section 3031 - Inventories, which is based on the International Accounting Standards Board's International Accounting Standard 2 and replaced existing CICA Handbook Section 3030. Under this new standard, inventories are required to be measured at the lower of cost and net realizable value. Any items considered to be major future components of property, plant and equipment are to be transferred to property, plant and equipment. The new standard also provides updated guidance on the appropriate methods of determining cost and the impact of any write-downs of net realizable value. The implementation of this standard resulted in transferring certain inventory items such as poles and wire into property, plant and equipment. The implementation of this standard did not have any impact on the company's statement of income.

Inventory is valued at the lower of cost and net realizable value. Cost is based upon the FIFO basis.

Investments

Investments are recorded at fair value.

Capital Assets

Capital assets are recorded in the accounts on a fully allocated cost basis and are amortized on the straight-line basis at varying rates estimated to write off the cost of each asset over its useful life. The rates are as follows:

	Life in Estimated Years
Transmission - underground	25
Distribution lines - overhead	25
Distribution lines - underground	25
Transformers	25
Meters	25
Transportation equipment	4
Miscellaneous assets	10
Computer equipment	5

Amounts received in aid of construction are deducted from the cost of the related capital assets. The Corporation retains ownership of the related assets.

West Perth Power Inc.
Summary of Significant Accounting Policies

December 31, 2008

Revenue Recognition

Transmission revenues are collected through OEB approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as power is transmitted and delivered to customers. Distribution revenues attributable to the delivery of electricity are based on OEB approved distribution tariff rates and are recognized as electricity is delivered to customers.

Billings from the last meter reading date are adjusted based on a number of historical factors to reflect estimated usage to the year-end date. These estimates are reflected on the statement of financial position as unbilled revenue. Unbilled revenue is the amount of electricity that has been used by customers, but not billed, by the end of the year.

Distribution revenue also includes an amount relating to rate protection for rural residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential and remote customers by reducing the electricity rates that would otherwise apply.

Corporate Income Taxes

Accounting for payments in lieu of corporate income taxes is on a taxes payable basis as disclosed in Note 4.

Power Purchases

The power bill received from the Independent Electricity System Operator is recorded in the period to which it refers and not in the period in which it is received.

Financial Instruments

The company's financial instruments include cash, accounts receivable, unbilled revenue, accounts payable and accruals, demand note payable and customer deposits. Due to their nature or capacity for prompt liquidation, the fair values of these financial instruments approximate their carrying value. It is management's opinion that the company is not exposed to significant interest rate, currency or credit risks arising from these financial instruments.

Disclosure related to other financial instruments is found in note [illegible] - Investments.

West Perth Power Inc.
Summary of Significant Accounting Policies

December 31, 2008

Use of Estimates

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from management's best estimates as additional information becomes available in the future.

New Accounting Pronouncements

Recent accounting pronouncements that have been issued but are not yet effective, and have a potential implication for the company are as follows:

International financial reporting standards

The CICA plans to converge Canadian GAAP with International Financial Reporting Standards ("IFRS") over a transition period expected to end in 2011. The impact of the transition to IFRS on the company's financial statements has yet to be determined.

3. Regulatory Liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process. West Perth Power Inc. has recorded the following assets and liabilities.

		2008		2007
Retail settlement variance accounts	$	(446,191)	$	(208,172)
Asset recovered through rates		(16,488)		43,761
Other		263,408		147,905
	$	(199,271)	$	(16,506)

Retail settlement variance accounts are included in allowed rates on a forecast basis. For rate-setting purposes, differences between forecast and actual purchased power and retail settlement costs in the rate year are held until the following year, when their final disposition is decided. West Perth Power Inc. recognizes retail settlement variances as a regulatory asset, based on the expectation that amounts held from one year to the next for rate-setting purposes will be approved for collection from, or refund to, future customers. In the absence of rate regulation, Canadian generally accepted accounting principles would require that actual purchased power costs be recognized as an expense when incurred. In this case, operating results for 2008 would have been $182,755 higher (2007 - $372,581 higher).

For the regulatory items identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to ultimate authority of the regulator in determining the item's treatment for rate-setting purposes. For example, West Perth Power Inc.'s treatment of retail settlement variance accounts is dependent on the continued use of an automatic adjustment mechanism for regulatory purposes, and would require reconsideration if the regulator decided to discontinue the use of this mechanism or require the Company to absorb cost variances in a particular year.

4. Corporate Income and Capital Taxes

Under the *Electricity Act 1998*, West Perth Power Inc. is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) as modified by the *Electricity Act 1998* and related regulations.

The company follows the asset/liability method of accounting for income taxes. Under this method, current income taxes are recognized for the estimated income taxes payable for the current year. As well, future income tax assets that are likely to be realized and future income tax liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities.

Future tax amounts are measured at enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled.

The company has losses carried forward for tax purposes of $119,634, which will expire in 2015.

5. Demand Note Payable

The Corporation issued a promissory note to its sole shareholder the Corporation of Municipality of West Perth on January 1, 2002 in the amount of $1,183,391. This note bears an interest rate of 7.25% and is payable on demand.

Interest paid on the note during the year amounted to $86,004 (2007 - $86,004).

6. Share Capital

Authorized

Unlimited number of common shares

Issued

	2008	2007
550 Common shares	$ 2,118,274	$ 2,118,274

West Perth Power Inc.
Notes to Financial Statements

December 31, 2008

7. Reciprocal Insurance Exchange

West Perth Power Inc. is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). The exchange is a separate entity managed directly by the Electricity Distributors Association (EDA).

The members' share in both the payment of claims and the operational costs associated with the exchange. The maximum limit of liability of the Exchange will be twenty million dollars per incident and is not to exceed 1/2 of 1% of the total annual revenue of the members.

8. Commitment - Prudential Support

As a purchaser of electricity through the Independent Electricity Market Operator (IMO), West Perth Power Inc. is required to provide security to minimize the risk of default, based on its expected activity in the market. The IMO may draw on this security if the Corporation fails to make a payment required by a default notice issued by the IMO. In October 2008, to satisfy the requirement, the Corporation provided the IMO with a letter of credit in the amount of $382,227. This prudential support continued to be held by the IMO at December 31, 2008.

9. Related Party Transactions

West Perth Power Inc. is related to the following entities:

Municipality of the Corporation of West Perth who owns all the outstanding common shares of West Perth Power Inc.

The company, through the regular course of its operations, supplies power to its parent the Corporation of the Municipality of West Perth at the company's standard rates.

At the end of the year, the amounts due to related parties are as follows:

	2008	2007
Corporation of the Municipality of West Perth	**$ 1,434,865**	$ 1,429,328

These balances are interest free and payable on demand, except for the amount disclosed in note 5, which is included in these balances.

10. Commitments

West Perth Power Inc. has entered into contractual agreements for the provision of billing and management services. These commitments are as follows:

Billing services

2009	$	88,354
2010		88,354
2011		88,354
	$	265,062

The above amounts can be adjusted to reflect additional billing services provided to West Perth Power Inc. and a reasonable annual increase.

11. Change in Accounting Policy

In April 2005, the Accounting Standards Board issued new Handbook standards on financial instruments, Section 3855 and Section 3861. Section 3855 Financial Instruments - Recognition and Measurement addresses when financial instruments should be recognized and how they should be measured. Section 3861 Financial Instruments - Disclosure and Presentation provides standards for how financial instruments should be classified on financial statements and the disclosure requirements. The company adopted both of the standards for the fiscal year ended December 31, 2007. As a result of adopting these new standards, the company recorded a non-cash credit of $10,036 to accumulated other comprehensive income for the change in accounting for financial assets classified as available for sale and measured at fair value rather than cost at the commencement of the 2007 fiscal year.

12. Pension Agreements

West Perth Power Inc. contributes to the Ontario Municipal Employees Retirement System (O.M.E.R.S.) which is a multi-employer plan, on behalf of 3 members of its staff. The plan is a defined benefit plan which specifies the amount of retirement benefit to be received by the employees based on their length of service and rates of pay.

The contribution for current services for the year ended December 31, 2008 was $21,972 (2007 - $17,870). This amount is included as an expenditure on the statement of operations.

13. Capital Disclosures

The company's main objectives when managing capital are to:

a) Ensure ongoing access to funding to maintain and improve the electricity distribution system of West Perth Power Inc. and to meet capital needs as they arise; and
b) Ensure compliance with covenants related to its credit facilities.

As at December 31, 2008, the company's definition of capital includes shareholders' equity $1,810,559 (2007 - $1,884,792) and the demand note payable $1,183,391 (2007 - $1,183,391). There have been no changes in the company's approach to capital management during the year.

The company's covenants require the current ratio to be greater than 0.8:1 and the debt to equity ratio to be less than 0.5:1. At December 31, 2008, the company is in compliance with these covenants.

14. Contingent Liabilities

An action has been brought under the Class Proceedings Act, 1992. The plaintiff class seeks $500 million in restitution for amount paid to Toronto Hydro and to other Ontario local distribution companies ("LDCs") who received late payment penalties which constitute interest at an effective rate in excess of 60% per year contrary to section 347 of the Criminal Code. Pleadings have closed in this action. The action has not yet been certified as a class action and no discoveries have been held as the parties were awaiting the outcome of a similar proceedings brought against Enbridge Gas Distribution. The Electricity Distributors Association is undertaking the defence of this class action.

On April 22, 2004, the Supreme Court of Canada released a decision in the Consumers Gas case rejecting all of the defences which had been raised by the Enbridge Gas, although the Court did not permit the Plaintiff class to recover damages for any period prior to the issuance of the Statement of Claim in 1994 challenging the validity of late payment penalties. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of damages payable by Enbridge.

After the release by the Supreme Court of Canada of its 2004 decision in the Enbridge Gas case, the plaintiffs in the LDC late payment penalties class action indicated their intention to proceed with their litigation against the LDCs. To date, no formal steps have been taken to move the action forward. The electric utilities intend to respond to the action if and when it proceeds on the basis that the LDCs' situation may be distinguishable from that of Enbridge Gas.

At this time, it is not possible to quantify the effect, if any, on the financial statements of the company.

15. Merger with ERTH Corporation

On March 6, 2008, The Municipality of West Perth signed a term sheet with ERTH Corporation (formerly Erie Thames Power Corporation). This term sheet proposes that ERTH Corporation would acquire all of the issued and outstanding shares of West Perth Power Inc. from The Municipality of West Perth in exchange for shares of ERTH Corporation.

16. Comparative Information

Certain comparative figures have been reclassified to conform with the current year presentation.

CLINTON POWER CORPORATION

FINANCIAL STATEMENTS

DECEMBER 31, 2010

WEST PERTH POWER

CLINTON POWER

CLINTON POWER CORPORATION
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KPMG LLP
Chartered Accountants
[illegible]
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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Clinton Power Corporation

We have audited the accompanying financial statements of Clinton Power Corporation, which comprise the balance sheet as at December 31, 2010 and the statements of income, retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform an audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Clinton Power Corporation as at December 31, 2010, and its results of operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

May 20, 2011

London, Canada

CLINTON POWER CORPORATION
BALANCE SHEET
AS AT DECEMBER 31, 2010
ASSETS

	2010	2009
Current Assets		
Cash	$ -	$ 450,558
Accounts receivable (note 3)	968,874	977,447
Inventory	10,149	14,005
Prepaid expenses	-	10,760
Due from related parties (note 7)	-	39,286
	979,023	1,492,056
Plant and Equipment (note 4)	1,587,589	1,326,085
Future Payment in Lieu of Income Tax Asset (note 11)	67,000	40,000
Regulatory Assets (note 5)	475,999	290,770
	$3,109,611	$3,148,911

LIABILITIES AND SHAREHOLDER'S EQUITY

	2010	2009
Current Liabilities		
Demand operating loan	$ 210,014	$ -
Accounts payable and accrued liabilities	407,911	1,647,562
Customer deposits (note 6)	54,754	55,426
Payments in lieu of income taxes payable	1,611	3,000
Due to related parties (note 7)	937,002	-
Related party note payable (note 8)	900,000	770,958
	2,511,292	2,476,946
Future Regulatory Taxes Payable (note 5)	67,000	40,000
Regulatory Liabilities (note 5)	38,857	38,857
Shareholder's Equity		
Share capital (note 9)	698,786	698,786
Retained earnings (deficit)	(206,324)	(105,678)
	492,462	593,108
	$3,109,611	$3,148,911

Contingent liabilities (notes 10, 12 and 13)
Subsequent Events (note 14)

APPROVED ON BEHALF OF THE BOARD:

__________ Director   __________ Director

The attached Auditors' Report and notes form an integral part of these audited financial statements

CLINTON POWER CORPORATION
STATEMENT OF RETAINED EARNINGS (DEFICIT)
FOR THE YEAR ENDED DECEMBER 31, 2010

	2010	2009
Balance, Beginning of Year	$ (105,678)	$ (66,819)
Net Loss	(100,646)	(38,859)
Balance, End of Year	$ (206,324)	$ (105,678)

The attached Auditors' Report and notes form an integral part of these audited financial statements.

CLINTON POWER CORPORATION
STATEMENT OF INCOME (LOSS)

FOR THE YEAR ENDED DECEMBER 31, 2010

	2010	%	2009	%
Electricity Revenue	$ 2,730,868		$ 2,547,559	
Cost of Power	2,220,809		2,036,176	
Distribution Revenue	510,059	100.00	511,383	100.00
Expenses				
Billing and collecting	2,962	0.58	56,418	11.04
Community relations	2,287	0.45	13,398	2.62
Direct operation	297,072	58.24	264,490	51.72
Office and administration	56,563	11.09	93,104	18.21
Regulatory and professional	190,513	37.35	59,670	11.67
	549,397	107.71	487,080	95.26
Net Income (Loss) from Operations Before before Interest, Amortization and Other	(39,338)	(7.71)	24,303	4.74
Amortization	79,194	15.53	72,107	14.10
Interest	87,083	17.07	40,333	7.89
Income (Loss) from Operations Before Other Income and Tax	(205,615)	(40.31)	(88,137)	(17.25)
Other Income				
Interest income	6,547	1.28	9,220	1.80
Service revenue	98,422	19.30	40,058	7.82
	104,969	20.58	49,278	9.62
Net Income (Loss)	$ (100,646)	(19.73)	$ (38,859)	(7.63)

The attached Auditors' Report and notes form an integral part of these audited financial statements.

CLINTON POWER CORPORATION
STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2010

	2010	2009
Cash Provided by (Used in) Operating Activities		
Net Income (loss)	$ (100,646)	$ (38,859)
Items not requiring an outlay of cash:		
Amortization	79,194	72,107
	(21,452)	33,248
Changes in non-cash working capital balances:		
Accounts receivable	8,573	(75,973)
Inventory	3,856	66,272
Prepaid expenses	10,760	-
Payment in lieu of income taxes	-	3,000
Regulatory assets	(185,229)	(59,653)
Accounts payable and accrued liabilities	(1,239,651)	377,891
Regulatory liabilities	-	(36,935)
Customer deposits	(672)	2,936
Payment in lieu of income taxes payable	(1,389)	-
Due to related party	1,105,329	62,705
Net Cash Provided by (Used in) Operating Activities	(319,875)	373,491
Cash Flows from Investing Activities		
Additions to property, plant and equipment	(340,697)	(215,068)
Net Increase (Decrease) in Cash	(660,572)	158,423
Cash, Beginning of Year	450,558	292,135
Cash (Bank Indebtedness), End of Year	$ (210,014)	$ 450,558
Supplemental Cash Flow Information		
Interest paid	$ 87,083	$ 21,830

The attached Auditors' Report and notes form an integral part of these audited financial statements.

CLINTON POWER CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

1. Nature of Operations

The Ontario Government enacted the Energy Competition Act, 1998 to introduce competition to the Ontario electricity market by the year 2000. Under the terms of this legislation, the Ontario Energy Board (the "OEB") regulates industry participants by issuing licences for the right to generate, transmit, distribute or retail electricity. These licences require compliance with established market rules and codes. The Ontario Government opened the Ontario electricity market to competition on May 1, 2002.

Clinton Power Corporation ("the Company") is wholly owned by ERTH Corporation who is in turn owned by the following nine municipalities, each of whom has one voting common share: Aylmer, Central Elgin, East-Zorra Tavistock, Ingersoll, Norwich, South-West Oxford, Zorra, West Perth and Central Huron. The Company carries on the business of distributing electricity to the town of Clinton.

2. Significant Accounting Policies

The financial statements of the Company have been prepared by management in accordance with Canadian generally accepted accounting principles, as modified by regulations and policies set forth in the Ontario Energy Board Accounting Procedures Handbook. Those policies that are considered to be particularly significant are outlined below:

(a) Plant and Equipment

Plant and equipment are recorded at the fair market value of the assets transferred from the Municipal Hydro Electric Commissions to the Company on August 31, 2000, and subsequent to August 31, 2000, at cost on the date of purchase. Plant and equipment are amortized over their useful lives using the straight-line method over the following periods:

Plant and equipment	
Automotive equipment	10 years
Computer equipment	10 years
Service, office and other equipment	10 years
Transmission and distribution system	25-30 years

Construction work in progress is recorded at cost until such time that the asset is completed and available for use at which point it is amortized over its useful life.

(b) Contributions to Plant and Equipment

Contributions are received from developers and contractors for capital costs incurred by the Company. These contributions are included as a reduction to the cost of the related plant or equipment when those assets are placed in service.

CLINTON POWER CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

2. Significant Accounting Policies (cont.)

(c) Revenue Recognition

(i) Electricity Sales

The Company follows the practice of cycle billing of customer's accounts and revenue is recognized in the period consumed. Estimated customer usage from the last billing date to the year end (unbilled revenue) is included in revenue.

(ii) Interest Income

Interest income on outstanding customer accounts is recognized on a time proportion basis, taking account of the principal outstanding and the effective rate over the period to maturity, when it is determined that such income will accrue to the Company.

(iii) Service Revenue

Service revenue is recognized as service is performed.

(d) Financial Instruments

The Company's financial assets and financial liabilities are classified and measured as follows:

- Cash is classified as held for trading and is measured at fair value. Gains and losses related to periodical revaluation are recorded in net income.
- Accounts receivable and regulatory assets are classified as loans and receivables and are initially measured at fair value and, subsequently, at amortized cost using the effective interest rate method.
- Accounts payable and accrued liabilities, regulatory liabilities, customer deposits, and long-term debt are classified as other liabilities and are initially measured at fair value and, subsequently, at amortized cost using the effective interest rate method.

(e) Financial Effects of Distribution Rate Regulation

The financial results presented are in accordance with Canadian generally accepted accounting principles and within that framework the Company accounts for the impact of regulatory actions in the following manner:

(i) Regulatory Decisions to Adjust Distribution Rates

In the event that a regulatory decision is rendered, providing regulatory approval and certainty to the recognition of an asset or creation of a liability and culminating in an adjustment to the Company's distribution rates, such occurrences are immediately reflected in the Company's accounts.

CLINTON POWER CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

2. Significant Accounting Policies (cont.)

(ii) Regulatory Direction and Practice

In the absence of regulatory decision impacting rates, and where the Company is required by regulatory accounting practice or direction to accumulate balances for future rate recovery or create liabilities for future discharge, those amounts are recorded in accordance with that regulatory direction. Management assesses the future uncertainty with respect to the final regulatory disposition of those amounts and to the extent required, makes accounting provisions to reduce the deferred balances accumulated or to increase the recorded liabilities. Upon rendering of the final regulatory decisions adjusting distribution rates, the provisions are adjusted to reflect the final impact of that decision, and such adjustment is reflected in net earnings for the period.

Amounts currently confirmed by final regulatory decision, and amounts currently accounted for in the absence of final regulatory decision together with related provisions for future uncertainty, are more fully described in note 5 to the financial statements.

(iii) Regulatory Balances

Effective January 1, 2009, the Company adopted the changes to CICA Handbook Section 1100 - *Generally Accepted Accounting Principles*. The amendment to this section removed the temporary exemption pertaining to the application of the section to the recognition and measurement of assets and liabilities arising from rate regulation. In response to the removal of the exemption, the Company established accounting policies for the recognition and measurement of assets and liabilities arising from rate regulation. In accordance with the Canadian GAAP hierarchy guidance framework outlined in CICA Handbook Section 1100, the company has determined that its assets and liabilities arising from rate regulation qualify for recognition under Canadian GAAP and this recognition is constant with U.S. Statement of Financial Accounting Standards No. 71, *Accounting for Effects of Certain Types of Regulations* ("FAS71"). The company concluded that its policies for assets and liabilities arising from rate regulation were consistent with the primary sources of Canadian GAAP and were developed through the exercise of professional judgment.

(iv) Income Tax Expense

Effective January 1, 2009, the Company adopted the changes to CICA Handbook Section 3465 - *Income Taxes*, which states that, as a rate regulated entity, future income tax assets will be returned to customers as they are recovered. As a result, all increases or decreases in future income tax assets are offset by a regulatory liability. As at December 31, 2010 the Company has recorded a future income tax assets of $67,000 and a corresponding regulatory liability of $67,000 (note 5).

CLINTON POWER CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

2. Significant Accounting Policies (cont.)

(v) Rate Setting

The distribution rates of the Corporation are based on a revenue requirement that provides a regulated Maximum Allowable Return on Equity ("MARE") on the amount of shareholders' equity supporting the business of electricity distribution, which is also determined by regulation. The Company files a rate application with the OEB annually. Rates are typically effective May 1 to April 30 of the following year. Accordingly, for the first four months of 2010, distribution revenue is based on the rates approved for 2009. Once every four years, the Company files an Electricity Distribution Rate application ("EDR") where rates are rebased through a cost of service review. In the intervening years an Incentive Rate Mechanism application ("IRM") is filed. A cost of service EDR application is based upon a forecast of the amount of operating and capital expenses, debt and shareholder's equity required to support the Company's business. An IRM application results in a formulaic adjustment to distribution rates to increase distribution rates for the annual change in the GDP IPI-FDD net of a productivity factor and a "Stretch Factor" determined by the relative efficiency of an electricity distributor.

The Company's last cost of service EDR application was made in 2010 and approved on January 19, 2011 with rates effective December 1, 2010 and implemented on January 1, 2011. Such decision provided for 2010 service distribution revenue requirement and rate base of $737,312 and $1,812,953 respectively. Such amounts do not include provision for the investment of the Company in the Smart Meter Initiative, further elaborated below.

In December 2009, the OEB concluded a Cost of Capital proceeding with the issuance of a final report. The report principally dealt with the adequacy and determination of the Maximum Allowable Return on Equity ("MARE"). The Board has acknowledged that it needs to refine and reset its current formula for determining MARE to:

i) acknowledge and incorporate a utility spread off of Canada long-bonds within the Equity Risk Premium ("ERP") to better reflect utility borrowing costs (initially 141.5bps);
ii) to include a 50bps "transaction cost" component within the ERP to reflect estimated transaction costs related to utility borrowings; and
iii) reduce MARE volatility from annual changes in the Canada long-bond and i) by reducing the annual adjustment factor from 0.75 to 0.5; and
iv) reflect a more realistic and "fair" base risk premium for Local Distribution Companies.

The method of transition to the new MARE is through a Cost of Service Application similar to the 2006 EDR Application. The Corporation such an application in 2011 with an effective date of May 1, 2012.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

CLINTON POWER CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

2. Significant Accounting Policies (cont.)

(vi) Smart Meter Initiative

The Province of Ontario has committed to have "Smart Meter" electricity meters installed in all homes and small businesses throughout Ontario by the end of 2010. Smart Meters permit consumption to be recorded within specific time intervals and specific tariffs to be levied within such intervals.

In support of this initiative, the Company completed its deployment of Smart Meters throughout 2009, 2010 and early 2011, with 1,500 Smart Meters deployed by the end of 2010. Successful testing with the provincial Meter Data Management Repository ("MDMR") will be completed in 2011.

(vii) Green Energy and Green Economy Act

In early 2009, the government tabled the Green Energy and Green Economy Act ("GEGEA"). This new legislation makes fundamental changes to the roles and responsibilities of LDCs in the areas of renewable power generation, conservation and demand management delivery, and the development of smart distribution grids.

The Green Energy and Green Economy Act provides LDCs with the freedom to own and operate a portfolio of renewable power generation and will permit them to provide district heating services in their communities through co-generation. LDCs will also bear added responsibilities to assist and enable consumers to reduce their peak demand and conserve energy in an effort to meet provincial conservation targets. LDCs will also gain new responsibilities in transforming their local distribution networks into smart grids harnessing advanced technologies to facilitate the connection of small-scale generators and the two-way flow of information.

(viii) New LDC License Requirements - Conservation and Demand Management Targets

On November 12, 2010, the OEB amended LDC licenses to include requirements for achieving certain CDM targets over a four year period commencing January 1, 2011. The Company's CDM targets include a demand reduction target of 0.32MW and a consumption reduction target of 1,380MWh. LDCs must also comply with a new CDM Code of the OEB, which provides LDC requirements for the development and delivery of CDM Strategy to the OEB for the achievement of LDC-specific CDM targets, annual accounting and reporting to the OEB, and eligibility criteria for performance incentive payments. The Company has filed its CDM Strategy with the OEB.

CLINTON POWER CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

2. Significant Accounting Policies (cont.)

(f) Payments in Lieu of Income Taxes ("PILs")

The Company uses the liability method for accounting for PILs. Under this method, future payment in lieu of income tax assets and liabilities are recognized for differences between the carrying value of assets and liabilities for accounting purposes and their respective values for payment in lieu of income tax purposes. These differences are measured using substantively enacted tax rates applicable for the period in which those differences are expected to be recovered or settled. To the extent that there is uncertainty regarding the recovery of a future payment in lieu of income tax asset, a valuation allowance reducing the future payment in lieu of income tax asset is recorded.

(g) Inventory

Inventories consist primarily of materials and supplies. Items considered to be major future components of property, plant and equipment are transferred to property, plant and equipment. Inventories are carried at the lower of cost and net realizable value, with cost determined on an average cost basis net of a provision for obsolescence.

(h) Impairment of Long-lived Assets

Long-lived assets are tested for recoverability when events or changes in circumstances indicate that their carrying value may not be recoverable. An impairment loss is recognized when the carrying value exceeds the total undiscounted cash flow expected from their use and eventual disposition. The amount of the impairment loss is determined as the excess of the carrying value of the asset over its fair value.

(i) Use of Estimates

The preparation of the financial statements of the Company in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the balance sheet date and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

CLINTON POWER CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

2. Significant Accounting Policies (cont.)

(j) Future Accounting Changes

(i) International Financial Reporting Standards ("IFRS")

On February 13, 2008, the Canadian Accounting Standards Board confirmed the publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. On September 10, 2010, the AcSB decided to permit rate-regulated entities to defer their IFRS implementation date to January 1, 2012.

The Company has an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its financial statements. Although the impact of the adoption to IFRS on the Company's Balance Sheet and Income Statement is not yet reasonably determinable or estimable, the company does expect a significant increase in financial statement disclosure requirements resulting from the adoption of IFRS, and is designing the systems and related process changes, which will be required in order to provide the additional information required to make these disclosures.

Given the continued uncertainty around the timing, scope and eventual adoption of a rate-regulated accounting standard under IFRS and the potential material impact of these standards on the Company's financial statements, the Company has decided to apply IFRS to its financial statements ending December 31, 2012 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011, for comparative purposes. The company continues to assess the impact of the conversion to IFRS on its results of operation. At this time, the impact on the Company's future financial statements cannot be determined.

3. Accounts Receivable

	2010	**2009**
Energy, water and sewer	$ 755,210	$ 685,361
Unbilled energy	213,664	292,086
	$ 968,874	$ 977,447

The amounts shown above are net of allowance for doubtful accounts of $89,231 (2009 - $174,709).

The attached Auditors' Report and notes form an integral part of these audited financial statements.

CLINTON POWER CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

4. Plant and Equipment

	Cost 2010	Accumulated Amortization	Net 2010	Net 2009
Plant and equipment	$ 269,183	$ 102,270	$ 166,913	$ 157,514
Transmission and distribution system	1,879,633	458,957	1,420,676	1,168,571
	$ 2,148,816	$ 561,227	$ 1,587,589	$ 1,326,085

During the year, the Company recorded amortization of $79,194 (2009 - $72,107).

5. Regulatory Assets and Liabilities

Regulatory assets consist of the following:

	2010	2009
Retail settlement variances (a)	$ 371,680	$ 214,010
Special purpose charge variance (b)	5,360	-
Other regulatory assets	94,257	76,760
Late payment penalties settlement (c)	4,702	-
	$ 475,999	$ 290,770

Regulatory liabilities consist of the following:

	2010	2009
Regulatory assets recovery account	$ 38,857	$ 38,857
Future payment in lieu of income tax liability	67,000	40,000
	$ 105,857	$ 78,857

The OEB approved an Interim Rate Order for May 1, 2008, that effectively removed the recovery allocation of the regulatory assets amounts until the final Cost of Service Rate Application was approved. The new Cost of Service Rate Order approved by the OEB, effective December 1, 2008, includes an allocation of the recovery of the low voltage energy variances. The remainder of the regulatory assets will be recovered based on future rate orders.

CLINTON POWER CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

5. Regulatory Assets and Liabilities (cont.)

(a) Retail settlement variances represent amounts accumulated since the opening of the electricity market on May 1, 2002. These variances are comprised of variances between amounts charged by the Independent Electricity Market Operator and amounts billed to customers plus variances from settlement and transmission charges. In the absence of rate regulations, these costs (revenues) would be charged to the period incurred.

(b) On April 9, 2010, the OEB informed electricity distributors of a Special Purpose Charge assessment under Section 26.1 of the Ontario Energy Board Act, 1998, for the Ministry of Energy and Infrastructure conservation and renewable energy program costs. The OEB assessed the Company $11,920 for their apportioned share of the total provincial amount of the Special Purpose Charge of $53,695,000 in accordance with the rules set out in Ontario Regulation 66/10. In accordance with Section 9 of the Special Purpose Charge Regulation, the Company is allowed to recover this balance. The recovery is expected to be achieved over a one-year period, which began on May 1, 2010.

(c) The late payment penalties settlement account relates to the settlement costs accrual associated with the late payment charges class action (note 13 and 14). All of the Municipal Electricity Utilities ("MEU") involved in the settlement, including the Company, have requested an order from the OEB allowing for the future recovery from customers of all costs related to the settlement.

(d) Demand side management ("DSM") amounts are expenses incurred in accordance with OEB rules and regulations and represent costs to the Company of literature provided to its customers and capital expenditures to provide energy conservation. In the absence of rate regulations, these costs (revenues) would be charged to the period incurred.

6. Customer Deposits

Customer deposits are obtained as security for energy consumption. On an annual basis, interest is calculated at a rate of 1.5% and credited to the customers' utility accounts. Also included are security deposits received for construction projects.

7. Related Party Transactions

The revenue reflected in the financial statements includes the electricity revenue for the sale of electricity to the Municipality of Central Huron for $311,735.

The Company has a contract with ERTH Corporation for management services.

The Company has contracted CRU Solutions Inc., Ecaliber (Canada) Inc., and ERTH360 Generation & Consulting Inc., companies under common control, to provide the following services: maintenance and upgrades to the existing capital infrastructure of the Company, billing and collection services and administrative services.

CLINTON POWER CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

7. Related Party Transactions (cont.)

The contracts between the Company, CRU Solutions Inc., Ecaliber (Canada) Inc., ERTH360 Generation & Consulting Inc., and ERTH Corporation are measured at the exchange amount, which is the amount of consideration paid or received as established and agreed to by the related parties, unless noted otherwise.

The revenue reflected in the financial statements includes the electricity revenue for the sale of electricity to the Municipality of Central Huron. These transactions are in the normal course of operations at rates approved by the Ontario Energy Board. In addition, the Municipality of Central Huron charges the Company for management, labour and facilities costs.

During the year, the Company purchased the following services from related parties.

	2010
ERTH360 Generating and Consulting Inc.	
Purchase of capitalized items	$ 45,237
Purchase of operations, maintenance and administrative services	53,905
	$ 99,142
The SPi Group Inc.	
Purchase of capitalized items	$ 4,123
CRU Solutions Inc.	
Purchase of capitalized items	$ 31,675
Purchase of operations, maintenance and administrative services	14,940
	$ 46,615
Erie Thames Powerlines Corporation	
Purchase of capitalized items	$ 56,472
Purchase of operations, maintenance and administrative services	32,322
	$ 88,794
ERTH Corporation	
Purchase of management services	$ 236,643
Ecaliber (Canada) Inc.	
Purchase of operations, maintenance and administrative services	$ 161,607
West Perth Power Inc.	
Purchase of capitalized items	$ 69,259
Sale of operations services	(3,115)
Purchase of operations, maintenance and administrative services	17,968
	$ 84,112

CLINTON POWER CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

7. Related Party Transactions (cont.)

The contracts with ERTH Corporation for management services and facilities rental and with CRU Solutions Inc. and Ecaliber (Canada) Inc. for maintenance and upgrades to the existing capital infrastructure of the Company, billing and collection services, and administrative services are being reviewed and amended as necessary to ensure compliance under the revised Affiliate Relationship Code issued in 2008 by the Ontario Energy Board.

At the end of the year, amounts due from related parties is as follows:

	2010	2009
Municipality of Central Huron	$ -	$ 39,286

At the end of the year, amounts due to related parties is as follows:

	2010	2009
ERTH Corporation	$ 205,266	$ -
ERTH360 Generation and Consulting Inc.	31,878	-
Ecaliber (Canada) Inc.	9,331	-
CRU Solutions Inc.	5,104	-
Erie Thames Powerlines Corporation	24,221	-
Clinton Power Corporation	362	-
West Perth Power Inc.	593,391	-
Municipality of Central Huron	67,449	-
	$ 937,002	$ -

The companies are related as follows:

ERTH Corporation owns 100% of the issued and outstanding shares of the Company West Perth Power Inc., Clinton Power Corporation, CRU Solutions Inc. and ERTH Holdings Inc.

Ecaliber (Canada) Inc., ERTH360 Generation & Consulting Inc. Coulter Water Service Meter Inc. and The SPi Group Inc. are wholly-owned subsidiaries of ERTH Holdings Inc.

Oncor Utility Solutions (Canada) Ltd. is a wholly-owned subsidiary of Abicus Management Solutions Inc., which is jointly controlled by ERTH Holdings Inc.

Utilismart Corporation is jointly controlled by ERTH Holdings Inc.

The Municipality of Central Huron is a shareholder of ERTH Corporation.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

CLINTON POWER CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

8. Related Party Note Payable

	2010	2009
Interest only demand note payable to the Municipality of Central Huron bearing interest at the municipality's prime borrowing rate.	$ -	$ 698,786
Interest only demand loan payable to the Municipality of Central Huron bearing interest at the annual average prime rate.	-	72,172
7% demand promissory note payable to the Municipality of West Perth. This note is unsecured.	900,000	-
	$ 900,000	$ 770,958

During 2010, $67,467 was charged to interest expense for interest on related party debt (2009 - $18,503).

9. Share Capital

Authorized

Unlimited number of common shares

	2010	2009
Issued capital		
2,000 common shares	$ 698,786	$ 698,786

10. Prudential Support Requirements

The Company, as a Local Distribution Company under the Energy Competition Act, 1998, R.S.O., posted prudential support obligations on market opening, May 1, 2002 with the Electric Independent Market Operator. The prudential support obligation as at December 31, 2008 was $189,900 and had not changed as at December 31, 2010. The prudential support requirement is honoured through a letter of credit.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

CLINTON POWER CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

11. Payments in Lieu of Income Taxes

The provision for payments in lieu ("PILs") of income taxes differs from amounts which would be calculated by applying the Company's combined statutory income tax rate as follows:

	2010	2009
Income (loss) from continuing operations before PILs	$ (100,646)	$ (38,859)
Statutory Canadian Federal and Provincial income tax rate	31.00 %	33.00 %
Basic rate applied to income before PILs	(31,200)	(12,823)
Other	31,200	12,823
Provision for payment in lieu of income tax	$ -	$ -
Effective tax rate	- %	- %

The Company as of December 31, 2010 has recorded a future payment in lieu of income tax asset of $67,000 (2009 - $40,000) and future income tax regulatory liability of $67,000 (2009 - $40,000), based on future substantively enacted income tax rates.

Significant components of the Company's future income tax assets and regulatory liability are as follows:

	2010	2009
Plant and equipment	$ 16,000	$ 8,000
Regulatory adjustments	17,000	10,000
Non-Capital loss	34,000	22,000
	$ 67,000	$ 40,000

The Company has accumulated non-capital losses for tax purposes of $137,000, which are available to offset income in the future. These non-capital loss carry forwards of $11,000, $73,000 and $53,000 will expire in 2028, 2029 and 2030 respectively.

12. Guarantee

The Company has guaranteed the operating and term loans of its parent company ERTH Corporation up to 25% of the Company's equity or $123,116. The loans are secured by a General Security Agreement covering all assets of the Company and a pledge of the shares of the Company. As the Company does not expect to be in a position where it would need to honour this guarantee in the foreseeable future, no liability has been recorded in these financial statements.

CLINTON POWER CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

13. Contingent Liability

Electric Distributors Association

By Order dated July 22, 2010, the Ontario Superior Court of Justice consolidated and approved the settlement of two class actions against LDC, one commenced in 1994 and the other, against all Ontario MEUs, in 1998. The actions sought $500,000,000 and $64,000,000, respectively, in restitution for late payment charges collected by them from their customers that were in excess of the interest limit stipulated in section 347 of the Criminal Code. The claims made against LDC and the definition of the plaintiff classes were identical in both actions such that any damages payable by LDC in the first action would reduce the damages payable by LDC in the second action, and vice versa.

The July 22, 2010 court order formalized a settlement pursuant to which the defendant MEUs will pay the amount of $17,000,000 plus costs and taxes in settlement of all claims. The amount allocated for payment by each MEU is its proportionate share of the settlement amount based on its percentage of distribution service revenue over the period for which it has exposure for repayment of late payment penalties exceeding the interest rate limit in the Criminal Code. LDC's share of the settlement amount was expected to be $4,702 payable on June 30, 2011. Under the settlement, all the MEUs involved in the settlement, including LDC, have requested an order from the OEB allowing for the future recovery from customers of all costs related to the settlement. LDC has accrued a liability and a corresponding regulatory asset in the amount of the above (note 14).

14. Subsequent Events

Late Payment Class Action

On February 22, 2011, the OEB issued its final decision allowing for LDC to recover the settlement amount of $4,702 for the Company from customers over the period commencing May 1, 2011 and ending April 30, 2012.

Amalgamation of Rate Regulated Entities

Subsequent to year end, the Company entered into formal proceedings to amalgamate Erie Thames Powerlines Corporation, West Perth Power Inc. and Clinton Power Corporation. Final OEB approval was received in late March 2011 to amalgamate these entities. The amalgamation is expected to be completed in June 2011.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

CLINTON POWER CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

15. Capital Disclosures

The Company's main objective is to ensure ongoing access to funding to maintain and improve the electricity distribution system of the Company.

As at December 31, 2010 the Company's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2010, shareholder's equity amounts to $492,462 (2009 - $593,108) and long-term debt amounts to $900,000 (2009 - $770,958). The Company's structure as at December 31, 2010 is 65% debt and 35% equity (2009 - 55% debt and 45% equity). There have been no changes in the Company's approach to capital management during the year.

16. Financial Instruments

As a rate-regulated entity, the nature of the Company's operations are defined and restricted by regulation. Financial operations and risks are also substantially influenced by regulation, limiting the necessity to engage in risk mitigation strategies involving the use of derivatives or hedges, and the Company did not engage in those activities during the fiscal year.

The company has adopted CICA Handbook Section 3861- *Financial Instruments* for disclosure purposes as the Company's financial instruments are not subject to disclosure requirements under Section 3862 or 3863 of the CICA Handbook.

a) Credit Risk

By regulation, the Company is responsible for collecting both the distribution and energy portions of the electricity bill. On average, 16% of amounts billed to customers are for distribution charges and 84% of the bill is energy related. Unless the retailer elects to bill the customers directly for the energy portion of the bill, the Company is exposed to a credit risk substantially greater then their portion of the electricity bill.

Mitigation of substantial losses is provided through the opportunity to apply for recovery for those losses through distribution rate adjustments in future years, if approved by the regulator. Additionally, regulation provides for certain customers to provide security deposits for a prescribed period of period to mitigate collection loss.

The Company is not exposed to a significant concentration of credit risk within any customer segment or individual customer.

b) Fair Values

The fair values of the Company's financial assets and liabilities approximate their book values unless otherwise disclosed.

CLINTON POWER CORPORATION
NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2010

16. Financial Instruments (cont.)

c) Interest Rate Risk

The Company is subject to the risks associated with debt financing, including the risk that existing indebtedness secured by the property may not be refinanced or that the terms of such refinancing may not be as favourable as the terms of existing indebtedness. The Company does not use any hedging instruments to mitigate its risk.

17. Comparative Figures

Certain comparative figures have been reclassified to conform with the financial statement presentation adopted in the current year.

CLINTON POWER CORPORATION

FINANCIAL STATEMENTS

DECEMBER 31, 2009

CLINTON POWER CORPORATION

INDEX TO AUDITED FINANCIAL STATEMENTS

DECEMBER 31, 2009

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AUDITORS' REPORT

To the Shareholders of Clinton Power Corporation

We have audited the balance sheet of Clinton Power Corporation as at December 31, 2009 and the statements of income, retained earnings, and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

The comparative amounts were audited by another firm of Chartered Accountants.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

London, Canada

October 15, 2010

KPMG LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity. KPMG Canada provides services to KPMG LLP.

CLINTON POWER CORPORATION

BALANCE SHEET

AS AT DECEMBER 31, 2009

ASSETS

	2009	2008
Current Assets		
Cash	$ 450,558	$ 292,135
Accounts receivable (note 3)	977,447	894,190
Inventory	14,005	80,277
Due from related party (note 7)	74,250	140,993
	1,516,260	1,407,595
Property, Plant and Equipment (note 4)	1,326,085	1,183,124
Future Payment in Lieu of Income Tax Asset (note 11)	40,000	-
Regulatory Assets (note 5)	301,530	164,942
	$3,183,875	$2,755,661

LIABILITIES AND SHAREHOLDER'S EQUITY

	2009	2008
Current Liabilities		
Accounts payable and accrued liabilities	$1,685,525	$1,261,388
Regulatory liabilities (note 5)	78,857	38,857
Customer deposits (note 6)	55,426	52,490
Current portion of due to related party (note 8)	770,958	-
	2,590,766	1,352,735
Due to Related Party (note 8)	-	770,958
Shareholder's Equity		
Share capital (note 9)	698,786	698,786
Retained earnings (deficit)	(105,677)	(66,818)
	593,109	631,968
	$3,183,875	$2,755,661

Contingent liabilities (notes 10 and 12)
Subsequent event (note 13)

APPROVED ON BEHALF OF THE BOARD:

_______________ Director   _______________ Director

The attached Auditors' Report and notes form an integral part of these audited financial statements

CLINTON POWER CORPORATION

STATEMENT OF RETAINED EARNINGS (DEFICIT)

FOR THE YEAR ENDED DECEMBER 31, 2009

	2009	2008
Balance, Beginning of Year	$ (66,818)	$ 54,389
Net Loss	(38,859)	(121,207)
Balance, End of Year	$ (105,677)	$ (66,818)

The attached Auditors' Report and notes form an integral part of these audited financial statements.

CLINTON POWER CORPORATION

STATEMENT OF INCOME (LOSS)

FOR THE YEAR ENDED DECEMBER 31, 2009

	2009	%	2008	%
Electricity Revenue	$ 2,547,559		$ 2,655,621	
Cost of Power	2,036,176		2,184,360	
Distribution Revenue	511,383	100.00	471,261	100.00
Expenses				
Billing and collecting	56,418	11.03	132,837	28.20
Community relations	13,398	2.62	(3,603)	(0.76)
Direct operation	264,490	51.72	196,051	41.60
Office and administration	93,104	18.21	54,349	11.53
Regulatory and professional	59,670	11.67	281,389	59.71
	487,080	95.25	661,023	140.28
Net Income (Loss) from Operations Before before Interest, Amortization and Other	24,303	4.75	(189,762)	(40.28)
Amortization	72,107	14.10	59,186	12.56
Interest	40,333	7.89	62,149	13.19
Income (Loss) from Operations Before Other Income and Tax	(88,137)	(17.24)	(311,097)	(66.03)
Other Income				
Interest income	9,220	1.80	29,593	6.28
Service revenue	40,058	7.83	160,297	34.00
	49,278	9.63	189,890	40.28
Net Income (Loss)	$ (38,859)	(7.61)	$ (121,207)	(25.75)

The attached Auditors' Report and notes form an integral part of these audited financial statements.

CLINTON POWER CORPORATION

STATEMENT OF CASH FLOWS

FOR THE YEAR ENDED DECEMBER 31, 2009

	2009	2008
Cash Flows from Operating Activities		
Net Income (loss)	$ (38,859)	$ (121,207)
Items not requiring an outlay of cash:		
Amortization	72,107	59,186
	33,248	(62,021)
Changes in non-cash working capital balances:		
Accounts receivable	(83,257)	(68,441)
Inventory	66,272	(24,635)
Regulatory assets	(136,588)	-
Accounts payable and accrued liabilities	424,137	349,948
Customer deposits	2,936	10,550
Due to related party	66,743	4,189
Net Cash Provided by Operating Activities	373,491	209,590
Cash Flows from Investing Activities		
Additions to property, plant and equipment	(215,068)	(190,026)
Net Increase in Cash	158,423	19,564
Cash, Beginning of Year	292,135	272,571
Cash, End of Year	$ 450,558	$ 292,135
Supplemental Cash Flow Information		
Interest paid	$ 21,830	$ -

The attached Auditors' Report and notes form an integral part of these audited financial statements.

CLINTON POWER CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

1. Nature of Operations

The Ontario Government enacted the Energy Competition Act, 1998 to introduce competition to the Ontario electricity market by the year 2000. Under the terms of this legislation, the Ontario Energy Board (the "OEB") regulates industry participants by issuing licences for the right to generate, transmit, distribute or retail electricity. These licences require compliance with established market rules and codes. The Ontario Government opened the Ontario electricity market to competition on May 1, 2002.

The Company is wholly owned by the Municipality of Central Huron and carries on the business of distributing electricity to the town of Clinton.

2. Significant Accounting Policies

The financial statements of the Company have been prepared by management in accordance with Canadian generally accepted accounting principles, as modified by regulations and policies set forth in the Ontario Energy Board Accounting Procedures Handbook. Those policies that are considered to be particularly significant are outlined below:

(a) Property, Plant and Equipment

Property, plant and equipment are recorded at the fair market value of the assets transferred from the Municipal Hydro Electric Commissions to the Company on August 31, 2000, and subsequent to August 31, 2000, at cost on the date of purchase. Property, plant and equipment are amortized over their useful lives using the straight-line method over the following periods:

Plant and equipment	
Automotive equipment	10 years
Computer equipment	10 years
Service, office and other equipment	10 years
Transmission and distribution system	25-30 years

Construction work in progress is recorded at cost until such time that the asset is completed and available for use.

(b) Contributions to Property, Plant and Equipment

Contributions are received from developers and contractors for capital costs incurred by the Company. These contributions are included as a reduction to the cost of the related Property, Plant or Equipment when those assets are placed in service.

CLINTON POWER CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

2. Significant Accounting Policies (cont.)

(c) Revenue Recognition

(i) Electricity Sales

The Company follows the practice of cycle billing of customer's accounts and revenue is recognized in the period consumed. Estimated customer usage from the last billing date to the year end (unbilled revenue) is included in revenue.

(ii) Interest Income

Interest income is recognized on a time proportion basis, taking account of the principal outstanding and the effective rate over the period to maturity, when it is determined that such income will accrue to the Company.

(iii) Service Revenue

Service revenue is recognized as service is performed.

(d) Financial Instruments

The Company's financial assets and financial liabilities are classified and measured as follows:

- Cash is classified as held for trading and is measured at fair value. Gains and losses related to periodical revaluation are recorded in net income.
- Accounts receivable and regulatory assets are classified as loans and receivables and are initially measured at fair value and, subsequently, at amortized cost using the effective interest rate method.
- Accounts payable and accrued liabilities, regulatory liabilities, customer deposits, and long-term debt are classified as other liabilities and are initially measured at fair value and, subsequently, at amortized cost using the effective interest rate method.

CLINTON POWER CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

2. Significant Accounting Policies (cont.)

(e) Financial Effects of Distribution Rate Regulation

The financial results presented are in accordance with Canadian generally accepted accounting principles and within that framework the Company accounts for the impact of regulatory actions in the following manner:

(i) Regulatory Decisions to Adjust Distribution Rates

In the event that a regulatory decision is rendered, providing regulatory approval and certainty to the recognition of an asset or creation of a liability and culminating in an adjustment to the Company's distribution rates, such occurrences are immediately reflected in the Company's accounts.

(ii) Regulatory Direction and Practice

In the absence of regulatory decision impacting rates, and where the Company is required by regulatory accounting practice or direction to accumulate balances for future rate recovery or create liabilities for future discharge, those amounts are recorded in accordance with that regulatory direction. Management assesses the future uncertainty with respect to the final regulatory disposition of those amounts and to the extent required, makes accounting provisions to reduce the deferred balances accumulated or to increase the recorded liabilities. Upon rendering of the final regulatory decisions adjusting distribution rates, the provisions are adjusted to reflect the final impact of that decision, and such adjustment is reflected in net earnings for the period.

Amounts currently confirmed by final regulatory decision, and amounts currently accounted for in the absence of final regulatory decision together with related provisions for future uncertainty, are more fully described in note 5 to the financial statements.

(f) Payments in Lieu of Income Taxes ("PILs")

The Company uses the liability method for accounting for PILs. Under this method, future payment in lieu of income tax assets and liabilities are recognized for differences between the carrying value of assets and liabilities for accounting purposes and their respective values for payment in lieu of income tax purposes. These differences are measured using substantively enacted tax rates applicable for the period in which those differences are expected to be recovered or settled. To the extent that there is uncertainty regarding the recovery of a future payment in lieu of income tax asset, a valuation allowance reducing the future payment in lieu of income tax asset is recorded.

CLINTON POWER CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

2. Significant Accounting Policies (cont.)

(g) Inventories

Effective January 1, 2008, the Company adopted Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3031 - *Inventories*, which is based on the International Accounting Standards Board's International Accounting Standard 2 and replaced existing CICA Handbook Section 3030. Under this new standard, inventories are required to be measured at the lower of cost and net realizable value and any items considered to be major future components of property, plant and equipment are to be transferred to property, plant and equipment. The new standard also provides updated guidance on the appropriate methods of determining cost and the impact of any write-downs to net realizable value. The implementation of this standard did not have any impact on the Company's results of operations.

Inventories consist primarily of materials and supplies. Inventories are carried at the lower of cost and net realizable value, with cost determined on an average cost basis net of a provision for obsolescence.

(h) Use of Estimates

The preparation of the financial statements of the Company in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the balance sheet date and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates.

(i) Impairment of Long-lived Assets

Long-lived assets are tested for recoverability when events or changes in circumstances indicate that their carrying value may not be recoverable. An impairment loss is recognized when the carrying value exceeds the total undiscounted cash flow expected from their use and eventual disposition. The amount of the impairment loss is determined as the excess of the carrying value of the asset over its fair value.

CLINTON POWER CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

2. Significant Accounting Policies (cont.)

(j) Accounting Changes

(i) Generally Accepted Accounting Principles

Effective January 1, 2009, the Company adopted the changes to CICA Handbook Section 1100 - *Generally Accepted Accounting Principles*. The amendment to this section removed the temporary exemption pertaining to the application of the section to the recognition and measurement of assets and liabilities arising from rate regulation. In response to the removal of the exemption, the Company established accounting policies for the recognition and measurement of assets and liabilities arising from rate regulation. In accordance with the Canadian GAAP hierarchy guidance framework outlined in CICA Handbook Section 1100, the company has determined that its assets and liabilities arising from rate regulation qualify for recognition under Canadian GAAP and this recognition is constant with U.S. Statement of Financial Accounting Standards No. 71, *Accounting for Effects of Certain Types of Regulations* ("FAS71"). The company concluded that its policies for assets and liabilities arising from rate regulation were consistent with the primary sources of Canadian GAAP and were developed through the exercise of professional judgment. As a result there was no changes in the Company's opening retained earnings as at January 1, 2009 or the Company's results from operations for the year ended December 31, 2009 as a result of the adoption of this section.

(ii) Income tax expense

Effective January 1, 2009, the Company retroactively adopted the liability method for accounting for income taxes and restated prior period amounts. Under this method, future income tax assets are recognized for the differences between the financial statement carrying amounts of existing assets and liabilities and their respective values for income tax purposes. These differences are measured using substantively enacted tax rates in effect in the period in which these differences are expected to be recovered or settled. As a rate regulated entity, future income taxes will be returned to customers as they are recovered. As a result, all increases or decreases in future income tax assets are offset by a regulatory liability. As a result of the adoption of this standard, future income tax assets of $19,000 were determined to exist, however given the uncertainty about the Company's ability to utilize those assets, a full valuation allowance was taken. There was no impact to prior period earnings as a result of adopting this standard.

CLINTON POWER CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

2. Significant Accounting Policies (cont.)

(k) Future Accounting Changes

(i) International Financial Reporting Standards ("IFRS")

On February 13, 2008, the Accounting Standards Board of Canada ("AcSB") confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2012.

A limited number of converged or IFRS-based standards will be incorporated into Canadian GAAP prior to 2012, with the remaining standards to be adopted at the change over date.

The Company has an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its financial statements. Although the impact of the adoption to IFRS on the Company's Balance Sheet and Income Statement is not yet reasonably determinable or estimable, the company does expect a significant increase in financial statement disclosure requirements resulting from the adoption of IFRS, and is designing the systems and related process changes, which will be required in order to provide the additional information required to make these disclosures.

In July 2009, the International Accounting Standards Board ("IASB") issued an exposure draft on rate regulated activities. The IASB staff has postponed presenting their analysis of the responses to the IASB. This presentation may include options for the next steps of the rate regulated activities project. It is unclear at this time what the outcome of the IASB's deliberations will be and how that will impact the Company's reporting under IFRS.

At this time, the impact on the Company's future financial statements cannot be determined.

3. Accounts Receivable

	2009	**2008**
Energy, water and sewer	$ 685,361	$ 692,234
Unbilled energy	292,086	201,956
	$ 977,447	$ 894,190

The amounts shown above are net of allowance for doubtful accounts of $174,709 (2008 - $195,110).

The attached Auditors' Report and notes form an integral part of these audited financial statements.

CLINTON POWER CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

4. Property, Plant and Equipment

	Cost 2009	Accumulated Amortization	Net 2009	Net 2008
Plant and equipment	$ 246,847	$ 89,333	$ 157,514	$ 170,224
Transmission and distribution system	1,561,272	392,701	1,168,571	1,012,900
	$ 1,808,119	$ 482,034	$ 1,326,085	$ 1,183,124

During the year, the Company recorded amortization of $72,107 ($59,186 - 2008).

5. Regulatory Assets and Liabilities

Regulatory assets consist of the following:

	2009	2008
Retail settlement variances	$ 224,770	$ 164,942
Organizational costs	76,760	-
	$ 301,530	$ 164,942

Regulatory liabilities consist of the following:

	2009	2008
Regulatory assets recovery account	$ 38,857	$ 38,857
Future payment in lieu of income tax liability	40,000	-
	$ 78,857	$ 38,857

The OEB approved an Interim Rate Order for May 1, 2008, that effectively removed the recovery allocation of the regulatory assets amounts until the final Cost of Service Rate Application was approved. The new Cost of Service Rate Order approved by the OEB, effective December 1, 2008, includes an allocation of the recovery of the low voltage energy variances. The remainder of the regulatory assets will be recovered based on future rate orders.

CLINTON POWER CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

5. Regulatory Assets and Liabilities (cont.)

(a) Retail settlement variances represent amounts accumulated since the opening of the electricity market on May 1, 2002. These variances are comprised of variances between amounts charged by the Independent Electricity Market Operator and amounts billed to customers plus variances from settlement and transmission charges. In the absence of rate regulations, these costs (revenues) would be charged to the period incurred.

(b) Demand side management ("DSM") amounts are expenses incurred in accordance with OEB rules and regulations and represent costs to the Company of literature provided to its customers and capital expenditures to provide energy conservation. In the absence of rate regulations, these costs (revenues) would be charged to the period incurred.

6. Customer Deposits

Customer deposits are obtained as security for energy consumption. On an annual basis, interest is calculated at a rate of 1.5% and credited to the customers' utility accounts. Also included are security deposits received for construction projects.

7. Related Party Transaction

The companies are related as follows:

The Municipality of Central Huron owns all the outstanding common shares of Clinton Power Corporation.

The revenue reflected in the financial statements includes the electricity revenue for the sale of electricity to the Municipality of Central Huron. In addition, the Municipality of Central Huron charges the Company for management, labour and facilities costs. These transactions are in the normal course of operations at rates approved by the Ontario Energy Board.

The following table summarizes the company's related party transactions for the year.

	2009
Revenues	$ 52,112
Expenses	$ 230,996

At the end of the year, amounts due from related party is as follows:

	2009	**2008**
Municipality of Central Huron	$ 74,250	$ 140,993

The attached Auditors' Report and notes form an integral part of these audited financial statements.

CLINTON POWER CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

8. Due to Related Party

	2009	2008
Interest only demand note payable to the Municipality of Central Huron bearing interest at the municipality's prime borrowing rate.	$ 698,786	$ 698,786
Interest only demand loan payable to the Municipality of Central Huron bearing interest at the annual average prime rate.	72,172	72,172
	770,958	770,958
Less: current portion	(770,958)	-
	$ -	$ 770,958

The municipality's prime borrowing rate as at December 31, 2009 is 2.4%. During 2009, $37,006 was charged to interest expense for interest on related party long-term debt ($42,920 - 2008).

9. Share Capital

Authorized

Unlimited number of common shares

	2009	2008
Issued capital		
2,000 common shares	$ 698,786	$ 698,786

10. Prudential Support Requirements

The Company, as a Local Distribution Company under the Energy Competition Act, 1998, R.S.O., posted prudential support obligations on market opening, May 1, 2002 with the Electric Independent Market Operator. The prudential support obligation as at December 31, 2008 was $189,900 and had not changed as at December 31, 2009. The prudential support requirement is honoured through a letter of credit.

CLINTON POWER CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

11. Payments in Lieu of Income Taxes

The provision for payments in lieu ("PILs") of income taxes differs from amounts which would be calculated by applying the Company's combined statutory income tax rate as follows:

	2009	2008
Income (loss) from continuing operations before PILs	$ (38,859)	$ (121,207)
Statutory Canadian Federal and Provincial income tax rate	33.00 %	33.50 %
Basic rate applied to income before PILs	(12,823)	(40,604)
Other	12,823	40,604
Provision for payment in lieu of income tax	$ -	$ -
Effective tax rate	- %	- %

The Company as of December 31, 2009 has recorded a future payment in lieu of income tax asset of $40,000 (2008 - $Nil) and future income tax regulatory liability of $40,000 (2008 - $Nil), based on future substantively enacted income tax rates.

Significant components of the Company's future income tax assets and regulatory liability are as follows:

	2009	2008
Property, plant and equipment	$ 8,000	$ 16,000
Regulatory adjustments	10,000	-
Non-Capital loss	22,000	3,000
	40,000	19,000
Valuation allowance	-	(19,000)
	$ 40,000	$ -

The Company has accumulated non-capital losses for tax purposes of $88,000, which are available to offset income in the future. These non-capital loss carry forwards of $11,000 and $77,000 will expire in 2028 and 2029 respectively.

CLINTON POWER CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

12. Contingent Liability

On March 2, 2010 the Electric Distributors Association ("EDA") presented to it's members and all electric distributors in Ontario, the terms of a tentative settlement with respect to a pending class action lawsuit against all local distribution company's ("LDC's") regarding the charging of late payment penalties ("LPP's") which are alleged to have contravened Section 347 of the Criminal Code. It is contended that LPP's are "interest" as defined in the Criminal Code and that, in certain circumstances, the implied rate of interest exceeds the prescribed limit of 60%.

The plaintiffs seek repayment of all improper LPP charges. This litigation has been pending since 1994 in the case of Toronto Hydro, and since 1998 in the case of all the other LDC's. Similar class actions were also brought against Enbridge/Consumers Gas and Union Gas. On each of these occasions, the Supreme Court of Canada has made rulings which were favourable to the plaintiffs and which deprived the defendant utilities of most of their defences to these claims.

In light of the settlement in the other cases, industry counsel instruction by an Ad Hoc Committee of the EDA recently participated in a court-supervised mediation process to explore possible settlement of the case against the LDC's. A settlement in principle of the litigation on behalf of all LDC's has now been reached. The tentative settlement agreement requires the unanimous consent and approval of all LDC's. All LDC's must indicate their acceptance of the settlement on or before April 5, 2010. The Ontario Superior court of Justice convened a hearing on May 26, 2010 to consider the settlement of the class action suit at which a tentative resolution was reached. Specific details related to the Company's liabilities are not yet available at this time.

13. Subsequent Event

Subsequent to year end, the Company sold 100% of its issued and outstanding shares for $782,007, which was funded through the issuance of shares of the purchasing Company. As part of the purchase consideration, the Company agreed to purchase and subscribe for one voting Class "A" share of the purchaser for consideration of one dollar.

14. Capital Disclosures

The Company's main objective is to ensure ongoing access to funding to maintain and improve the electricity distribution system of the Company.

As at December 31, 2009 the Company's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2009, shareholders' equity amounts to $593,109 (2008 - $631,968) and long-term debt amounts to $770,958 (2008 - $770,958). The Company's structure as at December 31, 2009 is 55% debt and 45% equity (2008 - 55% debt and 45% equity). There have been no changes in the Company's approach to capital management during the year.

CLINTON POWER CORPORATION

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2009

15. Financial Instruments

As a rate-regulated entity, the nature of the Company's operations are defined and restricted by regulation. Financial operations and risks are also substantially influenced by regulation, limiting the necessity to engage in risk mitigation strategies involving the use of derivatives or hedges, and the Company did not engage in those activities during the fiscal year.

The company has adopted CICA Handbook Section 3861- *Financial Instruments* for disclosure purposes as the Company's financial instruments are not subject to disclosure requirements under Section 3862 or 3863 of the CICA Handbook.

a) Credit Risk

By regulation, the Company is responsible for collecting both the distribution and energy portions of the electricity bill. On average, 16% of amounts billed to customers are for distribution charges and 84% of the bill is energy related. Unless the retailer elects to bill the customers directly for the energy portion of the bill, the Company is exposed to a credit risk substantially greater then their portion of the electricity bill.

Mitigation of substantial losses is provided through the opportunity to apply for recovery for those losses through distribution rate adjustments in future years, if approved by the regulator. Additionally, regulation provides for certain customers to provide security deposits for a prescribed period of period to mitigate collection loss.

The Company is not exposed to a significant concentration of credit risk within any customer segment or individual customer.

b) Fair Values

The fair values of the Company's financial assets and liabilities approximate their book values unless otherwise disclosed.

c) Interest Rate Risk

The Company is subject to the risks associated with debt financing, including the risk that existing indebtedness secured by the property may not be refinanced or that the terms of such refinancing may not be as favourable as the terms of existing indebtedness. The Company does not use any hedging instruments to mitigate its risk.

16. Comparative Figures

Certain comparative figures have been reclassified to conform with the statement presentation adopted in the current year.

CLINTON POWER CORPORATION

FINANCIAL STATEMENTS

DECEMBER 31, 2008

VODDEN, BENDER & SEEBACH LLP
Chartered Accountants

Vodden, Bender & Seebach LLP
Chartered Accountants

P.O. Box 758
41 Ontario Street
CLINTON, ONTARIO N0M 1L0
Tel: (519) 482-7979
Fax: (519) 482-5761
vbs@vbsca.ca

AUDITOR'S REPORT

To the Shareholder:

We have examined the balance sheet for Clinton Power Corporation as at December 31, 2008 and the statements of operations and retained earnings and of cash flow for the year then ended. These financial statements are the responsibility of the corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of Clinton Power Corporation as at December 31, 2008 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Vodden, Bender & Seebach LLP
Chartered Accountants
Licensed Public Accountants
Clinton, Ontario
July 10, 2009

CLINTON POWER CORPORATION

BALANCE SHEET

see accompanying notes to financial statements

As at December 31		2008	2007
ASSETS			
Current assets			
Cash		292,135	272,57[illegible]
Accounts receivable		660,119	653,288
Accrued unbilled revenue		201,856	18[illegible],237
Due from Municipality of Central Huron		277,548	216,730
Inventories		80,277	55,642
Deferred charges		10,760	21,520
		1,512,793	1,395,988
Regulatory assets	note 3	200,913	257,922
Property, plant and equipment	note 4	1,183,125	1,052,265
		$ 2,896,831	$ 2,710,195
LIABILITIES AND SHAREHOLDER'S EQUITY			
Current liabilities			
Accounts payable and accrued liabilities		714,462	487,358
Due to Municipality of Central Huron		634,356	392,097
Due to Clinton Hydro Electric Retail Affiliate Inc.		31,719	27,530
Hydro One regulatory assets payable		38,857	186,469
Note payable - Erie Thames Services	note 5	21,867	40,668
Notes payable - Municipality of Central Huron	note 6	770,958	770,958
Customer deposits		52,490	41,9[illegible]0
		2,264,699	1,957,020
Shareholder's equity			
Common shares		698,768	698,768
Retained earnings (deficit)		(66,654)	54,369
		632,132	753,175
		$ 2,896,831	$ 2,710,195

On behalf of the Board:

director

director

CLINTON POWER CORPORATION

STATEMENT OF OPERATIONS AND RETAINED EARNINGS (DEFICIT)

see accompanying notes to financial statements

For the year ended December 31	2008	2007
Service revenue	2,608,519	2,810,243
Energy cost	2,184,360	2,291,937
Distribution revenue	424,159	515,306
Other revenue		
Interest and late payment charges	41,009	44,546
Other rentals, materials and charges	19,781	17,684
	484,949	580,536
Expenditure		
Distribution system	147,758	123,165
Billing and collecting	118,521	106,369
Bad debt expense	42,456	31,286
Administration	62,822	62,582
Regulatory and professional	107,866	145,314
Building operation	5,235	34,078
Amortization of capital assets	59,186	56,026
Interest on long-term debt	42,920	47,061
Other interest	19,229	11,045
	605,992	638,926
Net earnings (loss) for year	(121,043)	(58,390)
Retained earnings beginning of year	$ 54,389	$ 112,779
Retained earnings (deficit) end of year	($ 66,654)	$ 54,389

CLINTON POWER CORPORATION

STATEMENT OF CASH FLOW

see accompanying notes to financial statements

For the year ended December 31	2008	2007
Operating activities		
Net earnings (loss) for year	**(121,043)**	(58,390)
Add: Amortization of capital assets	**59,186**	56,026
Working capital provided by (used for) operations	**(61,857)**	(2,364)
Cash provided by (used for) changes in working capital		
Accounts receivable	**(58,647)**	(295,353)
Unbilled revenue	**(20,718)**	377,083
Inventories	**(24,635)**	(14,224)
Prepaid expenses	-	4,200
Deferred charges	**10,760**	10,760
Regulatory amounts recoverable	**67,009**	209,212
Hydro One regulatory assets payable	**(147,612)**	(147,612)
Accounts payable	**469,353**	380,500
Consumer deposits	**10,550**	(8,154)
Due to Clinton Hydro Electric Retail Affiliate Inc.	**4,189**	(4,760)
Cash provided by (used for) operations	**228,391**	489,268
Investment activities		
Additions to capital assets	**(190,026)**	(82,831)
Cash used for investments	**(190,026)**	(82,831)
Financing activities		
Change in notes payable	**(18,801)**	(13,132)
Cash provided by financing	**(18,801)**	(13,132)
Increase (decrease) in cash	**19,564**	393,305
Net cash (bank overdraft) beginning of year	**272,571**	(120,734)
Net cash (bank overdraft) end of year	**$ 292,135**	$ 272,571
Supplementary cash flow information		
Interest paid	-	40,600
Payments in lieu of corporate taxes	-	-

CLINTON POWER CORPORATION
NOTES TO FINANCIAL STATEMENTS

For the Year Ended December 31, 2008

1. Business operations

The Clinton Power Corporation is a wholly owned subsidiary company of the Municipality of Central Huron providing electrical distribution services to inhabitants of the Town of Clinton as regulated by the Ontario Energy Board.

2. Significant accounting policies

The financial statements of the corporation are the representation of management prepared in accordance with Canadian generally accepted accounting principles including accounting principles prescribed by the Ontario Energy Board ("OEB") in the handbook "Accounting Procedures Handbook for Electric Distribution Utilities".

Inventories
Inventories are stated at lower of cost and net realizable value.

Regulatory assets
Costs incurred, but expected to be recovered from future revenues, are, by OEB regulatory authority, recorded as regulatory assets. Costs deferred are mainly those relating to variances between the cost of energy purchased, transmission and connection and energy sales. Disposition of these deferred charges will be determined by the OEB.

Capital assets
Capital assets are stated at cost less accumulated amortization. The cost is amortized on the straight line basis over the estimated useful lives of the assets as follows:

Distribution system	25-30 years
Trucks and equipment	10 years

Contributions to capital assets are included as a reduction to the cost of the related asset.

Revenue recognition
Service revenue is recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year.

Income taxes
As a wholly owned subsidiary company of the Municipality of Central Huron, the company is exempt from income taxes under the Income Tax Act (Canada). Under the Electricity Act (1998) (Ontario), the company is required to make payments in lieu of taxes to the Ontario Electricity Financial Corporation equivalent to taxes that would be payable if the company was a taxable corporation under the Income Tax Act (Canada). The corporation provides for payments in lieu of taxes using the taxes payable method as permitted by the OEB and CICA. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of the regulated business at that time.

Measurement of uncertainty
The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that effect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities at the date of the financial statements. Due to these uncertainties, actual results might differ from those estimates. The impact will be reported in the period that the results become known.

3. Regulatory assets

Regulatory assets consist mainly of settlement variances between amounts charged by the Independent Market Operator for the operation of the wholesale electricity market and the supply and transmission of energy commodities and the amounts billed to customers based on the OEB approved rates.

4. Property, plant and equipment

	Cost	Accumulated Amortization	Net Book Value	2007
Distribution stations	197,858	47,663	150,195	156,790
Overhead distribution lines	502,196	104,062	398,134	303,867
Underground distribution system	548,773	154,398	394,375	396,444
Distribution transformers	146,629	38,468	108,161	97,936
Distribution meters	137,720	29,578	108,142	68,237
Transportation equipment	28,565	10,053	18,512	23,791
Tools and equipment	31,308	25,702	5,606	2,220
	1,593,049	409,924	1,183,125	1,052,285

5. Note payable to Erie Thames Services Corporation

Under a contract in effect until December 2009, the Clinton Power Corporation has incurred costs for conversion to and operation of a software application system. Unless terminated, the balance as at December 31, 2008 will be payable in monthly payments of $1,709 including interest at 5% maturing December 2009. The corporation also pays certain software operation costs of approximately $8,500 per month. Of the conversion and operating costs 40% is recovered from other users.

6. Payments in lieu of taxes

Amortization of property, plant and equipment reported in the financial statements has exceeded that claimed for taxation purposes. The company incurred a loss for tax purposes which my be carried forward to deduct from taxable income of subsequent years. The net future income tax asset related to temporary differences, which would have been recognized using the liability method rather than the taxes payable method, is approximately $11,900. No amount is included in the financial statements for future income taxes.

7. Notes payable to Municipality of Central Huron

696,786	issued November 2000 with no specified maturity date, bearing interest at the municipality's prime borrowing rate.
72,172	demand note issued February 2006, bearing interest at the annually averaged prime rate, as consideration for contributions in 2003 for distribution system line construction

8. Related party transactions

The Municipality of Central Huron supplies management, labour and certain facilities for the operation of Clinton Power Corporation power distribution business on a cost recovery basis.

9. **Financial instruments and Credit risk**

Financial instruments

Management estimates that the fair values of all financial assets and liabilities are not materially different from their carrying values.

Credit risk

Credit risk is the risk that a counter party will fail to discharge its obligation to the company reducing the expected cash inflow from the company assets recorded at the balance sheet date. The company has assessed that there are no significant concentrations of credit risk other than the present uncertainty relating to collection of regulatory amounts recoverable which are subject to regulatory approval and disposition.

10. **Credit arrangement**

The Clinton Power Corporation has approved a $189,900 line of credit through its banker in favour of the Independent Electricity System Operator.

11. **Subsequent events**

The shareholder of the corporation has signed an agreement to sell its shares the consideration for which would be shares of the purchasing corporation.

12. **Adjustments re: prior periods**

The current years reported service revenue includes a write down of $45,993 in regulatory assets to the amount approved for recovery by the Ontario Energy Board. Expenditures include an adjustment for costs of property, plant and equipment previously included in expenditure. The net effect on total assets, shareholder's equity and net income (loss) for the year is not material.

ERIE THAMES POWERLINES CORPORATION
PROFORMA BALANCE SHEET
AS AT DECEMBER 31 2012

	Current Period
ASSETS	
	YTD
	20112
Current	
Bank	$ -
Accounts Receivable	9,075,952
Inventory	809,291
Prepaid Expenses	72,494
	9,957,737
Capital Assets	24,537,717
Regulatory Assets	3,449,910
Future Payment in Lieu of Income Tax Asset	362,000
Goodwill	76,667
	$ 38,384,029
LIABILITIES AND SHAREHOLDER'S EQUITY	
Current	
Accounts Payable and Accrued Liabilities	$ 12,333,181
Bank Overdraft	$ 547,485
Regulatory Liabilities	400,102.75
PILS Payable	557,212
Current Portion of Long-Term Debt	
Customer Deposits	780,947
	14,618,927
Long-term Debt	
Related Party Note Payable	8,524,439
Long Term Loan	577,284
Post Retirement Benefit Obligation	514,103
	9,615,826
Shareholders' Equity	
Share Capital	8,038,524
Retained Earnings	47,537
	8,086,062
	$ 32,320,815

UNAUDITED: FOR MANAGEMENT PURPOSES ONLY

ERIE THAMES POWERLINES CORPORATION
PROFORMA STATEMENT OF INCOME
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2012

	Current Period YTD ACTUAL 2011	%
Electricity Revenue	$ 50,501,860	100.0
Cost of Power	41,327,870	81.8
Gross Margin	9,173,990	18.2
Miscellaneous Revenues	933,058	1.8
Total Revenues from Operations	10,107,049	20.0
Expenses		
Billing and Collecting	1,129,747	2.2
Community Relations	148,783	0.3
Regulatory and Professional	180,378	0.4
Office and Administration	3,166,381	6.3
Direct Operation	975,948	1.9
	5,601,237	11.1
Net Income from Operations Before Taxes, Interest & Amortization	4,505,811	
Amortization	1,930,321	3.8
Shareholder Interest	893,778	1.8
Other Interest	-	0.0
Interest income on regulatory assets	-	0.0
Net Income from Operations Before Tax	1,681,712	3.3
Current Taxes		
PILS	517,163	1.0
Net Income (Loss)	1,164,549	2.3
Retained Earnings (deficit) Beginning of Period	47,537	
Less Dividends to Holding Corp		
Retained Earnings (deficit) End of Period	$ 1,212,086	

PROPOSED ACCOUNTING TREATMENT

Erie Thames does not have any projects with a life cycle of greater than one year in this Application that require specific treatment. Erie Thames does have certain capital projects that will be done in phases over multiple years.

Reconciliations

Not included as trial balance information used for historical purposes tie into audited financial statements and RRR filings.

ERIE THAMES POWERLINES CORPORATION

FINANCIAL STATEMENTS

DECEMBER 31, 2011

ERIE THAMES POWERLINES CORPORATION
INDEX TO AUDITED FINANCIAL STATEMENTS
DECEMBER 31, 2011

ERIE THAMES POWERLINES CORPORATION
BALANCE SHEET
AS AT DECEMBER 31, 2011

ASSETS

	2011	2010
Current Assets		
Cash	$ 302,726	$ 714,843
Accounts receivable (note 4)	9,780,559	10,253,466
Inventory	96,433	144,107
Prepaid expenses	67,571	74,173
Payment in lieu of income taxes recoverable	147,115	-
Due from related parties (note 11)	-	30,436
	10,394,404	11,217,025
Investments (note 5)	11,677	11,677
Property, Plant and Equipment (note 6)	23,513,122	22,118,110
Future Payment in Lieu of Income Tax Asset (note 19)	1,408,000	1,408,000
Regulatory Assets (note 7)	2,718,766	3,715,305
Goodwill (note 8)	76,667	76,667
	$38,122,636	$38,546,784

LIABILITIES AND SHAREHOLDER'S EQUITY

	2011	2010
Current Liabilities		
Demand operating loan (note 9)	$ 1,453,564	$ 998,056
Accounts payable and accrued liabilities	7,051,952	7,127,606
Customer deposits (note 10)	1,442,624	1,115,637
Payments in lieu of income taxes payable	-	210,123
Due to related parties (note 11)	4,796,635	5,847,777
Related party notes payable (note 12)	2,083,391	2,083,391
Current portion of long-term debt (note 14)	165,195	208,591
	16,993,361	17,591,181
Related Party Long-term Debt (note 13)	8,038,524	8,038,524
Long-term Debt (note 14)	305,403	368,693
Regulatory Liabilities (note 7)	(7,891)	71,059
Future Regulatory Taxes Payable (note 7)	1,408,000	1,408,000
Post-Retirement Benefit Obligation (note 15)	551,600	514,103
Shareholder's Equity		
Share capital (note 16)	10,855,585	10,855,585
Deficit	(21,946)	(300,361)
	10,833,639	10,555,224
	$38,122,636	$38,546,784

Contingent Liabilities (notes 17 and 18)
Commitments (note 20)

APPROVED ON BEHALF OF THE BOARD:

______________________________ Director ______________________________ Director

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION
STATEMENT OF RETAINED EARNINGS(DEFICIT)
FOR THE YEAR ENDED DECEMBER 31, 2011

	2011	2010
Balance, Beginning of Year	$ (300,361)	$ (161,311)
Assumption of Employee Future Benefit Obligation	-	(250,474)
Net Income	278,415	111,424
Balance, End of Year	$ (21,946)	$ (300,361)

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION
STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2011

	2011	%	2010	%
Electricity Revenue	$50,424,672		$47,795,312	
Cost of Power	42,724,654		40,241,517	
Distribution Revenue	7,700,018	100.00	7,553,795	100.00
Expenses				
Billing and collecting	1,039,317	13.50	1,060,995	14.06
Community relations	241,904	3.14	261,334	3.46
Direct operation	3,700,869	48.06	3,116,695	41.26
Office and administration	862,937	11.21	825,313	10.93
Regulatory and professional	236,613	3.07	685,774	9.08
	6,081,640	78.98	5,950,111	78.79
Income from Operations Before the Following	1,618,378	21.02	1,603,684	21.21
Amortization	1,456,074	18.91	1,477,987	19.57
Interest income on regulatory assets	(319,938)	(4.16)	(37,184)	(0.49)
Interest	1,101,090	14.30	965,077	12.78
Income from Operations Before Other Income and Tax	(618,848)	(8.03)	(802,196)	(10.65)
Other Income				
Interest income	40,191	0.52	31,636	0.42
Service revenue	857,072	11.13	1,068,984	14.14
	897,263	11.65	1,100,620	14.56
Income Before Income Tax	278,415	3.62	298,424	3.91
Payments in Lieu of Income Taxes (note 19)				
Current	-	-	187,000	2.48
Net Income	$ 278,415	3.62	$ 111,424	1.43

The attached Auditors' Report and notes form an integral part of these audited financial statements.

ERIE THAMES POWERLINES CORPORATION
STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2011

	2011	2010
Cash Flows from Operating Activities		
Net income	$ 278,415	$ 111,424
Items not requiring an outlay of cash:		
Amortization	1,456,074	1,477,987
Post retirement benefit obligation	37,497	8,402
	1,771,986	1,597,813
Changes in non-cash working capital balances:		
Accounts receivable	472,908	(851,362)
Inventory	47,674	12,123
Prepaid expenses	6,602	90,238
Payment in lieu of income taxes	(357,118)	291,690
Regulatory assets	996,539	(1,552,747)
Accounts payable and accrued liabilities	(75,654)	(821,799)
Regulatory liabilities	(78,950)	-
Customer deposits	326,988	202,957
Due to related parties	(1,020,706)	581,432
Net Cash Provided by (Used in) Operating Activities	2,090,269	(449,655)
Cash Flows from Financing Activities		
(Decrease) increase in long-term debt	(106,686)	511,429
Cash Flows from Investing Activities		
Additions to property, plant and equipment	(2,731,209)	(2,302,420)
Net Decrease in Cash	(747,626)	(2,240,646)
Cash (Bank Indebtedness), Beginning of Year	(283,213)	1,957,433
Cash (Bank Indebtedness), End of Year	$ (1,030,839)	$ (283,213)
Supplemental Cash Flow Information		
Interest paid	$ 1,246,796	$ 1,175,090
Payment in lieu of income taxes	$ 357,238	$ (210,123)
Represented By:		
Cash	$ 302,726	$ 714,843
Demand Operating Loan	(1,453,564)	(998,056)
	$ (1,150,838)	$ (283,213)

The attached Auditors' Report and notes form an integral part of these audited financial statements.

1. Description of Business

During the year, Erie Thames Powerlines Corporation, West Perth Power Inc., and Clinton Power Corporation were amalgamated and became Erie Thames Powerlines Corporation ("the Company").

2. Nature of Operations

The Ontario Government enacted the Energy Competition Act, 1998 to introduce competition to the Ontario electricity market by the year 2000. Under the terms of this legislation, the Ontario Energy Board (the "OEB") regulates industry participants by issuing licences for the right to generate, transmit, distribute or retail electricity. These licences require compliance with established market rules and codes. The Ontario Government opened the Ontario electricity market to competition on May 1, 2002.

The Company is wholly owned by ERTH Corporation who is in turn owned by the following nine municipalities, each of whom has one voting common share: Aylmer, Central Elgin, East-Zorra Tavistock, Ingersoll, Norwich, South-West Oxford, Zorra, West Perth and Central Huron.

The Company carries on the business of distributing electricity to the following communities: Aylmer, Beachville, Belmont, Burgessville, Embro, Ingersoll, Norwich, Otterville, Port Stanley, Tavistock, Thamesford, Mitchell, Dublin and the town of Clinton.

3. Significant Accounting Policies

The financial statements of the Company have been prepared by management in accordance with Canadian generally accepted accounting principles, as modified by regulations and policies set forth in the Ontario Energy Board Accounting Procedures Handbook. Those policies that are considered to be particularly significant are outlined below:

(a) Property, Plant and Equipment

Property, plant and equipment are recorded at the fair market value of the assets transferred from the Municipal Hydro Electric Commissions to the Company on August 31, 2000, and subsequent to August 31, 2000, at cost on the date of purchase. Property, plant and equipment are amortized over their useful lives using the straight-line method over the following periods:

Buildings	25 years
Plant and equipment	
Automotive equipment	8 years
Computer equipment	5 - 15 years
Service, office and other equipment	10 years
Transmission and distribution system	25 years

Construction work in progress are recorded at cost until such time that the asset is completed and available for use at which point it is amortized over its useful life.

3. Significant Accounting Policies (cont.)

(b) Contributions to Property, Plant and Equipment

Contributions are received from developers and contractors for capital costs incurred by the Company. These contributions are included as a reduction to the cost of the related Property, Plant or Equipment when those assets are placed in service.

(c) Revenue Recognition

(i) Electricity Sales

The Company follows the practice of cycle billing of customer's accounts and revenue is recognized in the period consumed. Estimated customer usage from the last billing date to the year end (unbilled revenue) is included in revenue.

(ii) Interest Income

Interest income on outstanding customer accounts is recognized on a time proportion basis, taking account of the principal outstanding and the effective rate over the period to maturity, when it is determined that such income will accrue to the Company.

(iii) Service Revenue

Service revenue is recognized as service is performed.

(d) Pension and Other Retirement Benefit Plans

(i) The actuarial determination of the accrued benefit obligations for other retirement benefits uses the projected benefit method prorated on service, which incorporates management's best estimate of cost escalation, retirement ages of employees and actuarial factors.

(ii) Past service costs arising from plan amendments are deferred and amortized on a straight-line basis using the corridor method over the average remaining service period of employees active at the date of amendment.

(iii) When the restructuring of a benefit plan gives rise to both a curtailment and a settlement of obligations, the curtailment is accounted for prior to the settlement.

3. Significant Accounting Policies (cont.)

(e) Financial Instruments

The Company's financial assets and financial liabilities are classified and measured as follows:

- Cash is classified as held for trading and is measured at fair value. Gains and losses related to periodical revaluation are recorded in net income.
- Accounts receivable, due from related parties and regulatory assets are classified as loans and receivables and are initially measured at fair value and, subsequently, at amortized cost using the effective interest rate method.
- Investments are recorded using the cost method of accounting and adjusted to fair market value.
- Accounts payable and accrued liabilities, regulatory liabilities, customer deposits, due to related party and long-term debt are classified as other liabilities and are initially measured at fair value and, subsequently, at amortized cost using the effective interest rate method.

(f) Financial Effects of Distribution Rate Regulation

The financial results presented are in accordance with generally accepted accounting principles and within that framework the Company accounts for the impact of regulatory actions in the following manner:

(i) Regulatory Decisions to Adjust Distribution Rates

In the event that a regulatory decision is rendered, providing regulatory approval and certainty to the recognition of an asset or creation of a liability and culminating in an adjustment to the Company's distribution rates, such occurrences are immediately reflected in the Company's accounts.

(ii) Regulatory Direction and Practice

In the absence of regulatory decision impacting rates, and where the Company is required by regulatory accounting practice or direction to accumulate balances for future rate recovery or create liabilities for future discharge, those amounts are recorded in accordance with that regulatory direction. Management assesses the future uncertainty with respect to the final regulatory disposition of those amounts and to the extent required, makes accounting provisions to reduce the deferred balances accumulated or to increase the recorded liabilities. Upon rendering of the final regulatory decisions adjusting distribution rates, the provisions are adjusted to reflect the final impact of that decision, and such adjustment is reflected in net earnings for the period.

Amounts currently confirmed by final regulatory decision, and amounts currently accounted for in the absence of final regulatory decision together with related provisions for future uncertainty, are more fully described in note 7 to the financial statements.

3. Significant Accounting Policies (cont.)

(iii) Regulatory balances

Effective January 1, 2009, the Company adopted the changes to CICA Handbook Section 1100 - *Generally Accepted Accounting Principles*. The amendment to this section removed the temporary exemption pertaining to the application of the section to the recognition and measurement of assets and liabilities arising from rate regulation. In response to the removal of the exemption, the Company established accounting policies for the recognition and measurement of assets and liabilities arising from rate regulation. In accordance with the Canadian GAAP hierarchy guidance framework outlined in CICA Handbook Section 1100, the company has determined that its assets and liabilities arising from rate regulation qualify for recognition under Canadian GAAP and this recognition is constant with U.S. Statement of Financial Accounting Standards No. 71, *Accounting for Effects of Certain Types of Regulations* ("FAS71"). The company concluded that its policies for assets and liabilities arising from rate regulation were consistent with the primary sources of Canadian GAAP and were developed through the exercise of professional judgment.

(iv) Income tax expense

Effective January 1, 2009, the Company adopted the changes to CICA Handbook Section 3465 - *Income Taxes*, which states that, as a rate regulated entity, future income tax assets will be returned to customers as they are recovered. As a result, all increases or decreases in future income tax assets are offset by a regulatory liability. As at December 31, 2011 the Company has recorded a future income tax assets of $1,408,000 and a corresponding regulatory liability of $1,408,000 (note 7).

(v) Rate Setting

The distribution rates of the Company are based on a revenue requirement that provides a regulated Maximum Allowable Return on Equity ("MARE") on the amount of shareholders' equity supporting the business of electricity distribution, which is also determined by regulation. The Company files a rate application with the OEB annually. Rates are typically effective May 1 to April 30 of the following year. Accordingly, for the first four months of 2011, distribution revenue is based on the rates approved for 2010. Once every four years, the Company files an Electricity Distribution Rate application ("EDR") where rates are rebased through a cost of service review. In the intervening years an Incentive Rate Mechanism application ("IRM") is filed. A cost of service EDR application is based upon a forecast of the amount of operating and capital expenses, debt and shareholder's equity required to support the Company's business. An IRM application results in a formulaic adjustment to distribution rates to increase distribution rates for the annual change in the GDP IPI-FDD net of a productivity factor and a "Stretch Factor" determined by the relative efficiency of an electricity distributor.

3. Significant Accounting Policies (cont.)

The Company's last cost of service EDR application was made in 2008 and approved on October 27, 2009 with rates effective December 1, 2008. Such decision provided for 2008 service distribution revenue requirement and rate base of $6,578,355 and $22,246,774 respectively. Such amounts do not include provision for the investment of the Company in the Smart Meter Initiative, further elaborated below.
The Company has filed IRM applications to adjust its Erie Thames Powerlines Corporation ("Powerlines") rates effective May 1st, 2011, West Perth Power Inc. ("West Perth") and Clinton Power Corporate ("Clinton Power") rates effective January 1st, 2011 through a settlement of a Cost of Service application. Accordingly, the Companys' Powerlines IRM rates were increased by 0.98% effective May 1, 2011. The Company's 2011 IRM application was approved on April 20th, 2011 with an increase in distribution rates for the annual change in the GDP IPI-FDD of 1.30% net of a productivity factor of 0.72% and a "Stretch Factor" of 0.60% determined by the relative efficiency of the Company. The Company's West Perth rates were agreed to in a settlement conference at a 10% increase over the existing rates and similarly Clinton Power's distribution rates were increased by 33% over the 2010 rates during the same process. The rates were approved on January 7th of 2011 and were effective January 1st 2011.

In December 2009, the OEB concluded a Cost of Capital proceeding with the issuance of a final report. The report principally dealt with the adequacy and determination of the Maximum Allowable Return on Equity ("MARE"). The Board has acknowledged that it needs to refine and reset its current formula for determining MARE to:

i) acknowledge and incorporate a utility spread off of Canada long-bonds within the Equity Risk Premium ("ERP") to better reflect utility borrowing costs (initially 141.5bps);
ii) to include a 50bps "transaction cost" component within the ERP to reflect estimated transaction costs related to utility borrowings; and
iii) reduce MARE volatility from annual changes in the Canada long-bond and i) by reducing the annual adjustment factor from 0.75 to 0.5; and
iv) reflect a more realistic and "fair" base risk premium for Local Distribution Companies.

The method of transition to the new MARE is through a Cost of Service Application similar to the 2006 EDR Application. The Corporation will file such an application in 2011 with an effective date of May 1, 2012.

(vi) Smart Meter Initiative

The Province of Ontario has committed to have "Smart Meter" electricity meters installed in all homes and small businesses throughout Ontario by the end of 2010. Smart Meters permit consumption to be recorded within specific time intervals and specific tariffs to be levied within such intervals.

In support of this initiative, the Company completed its deployment of Smart Meters throughout 2009, 2010 and early 2011, with 17,906 Smart Meters deployed by the end of 2011. Successful testing with the provincial Meter Data Management Repository ("MDMR") has been completed in 2011.

3. Significant Accounting Policies (cont.)

In December 2010, the Company submitted an application to the OEB for the consideration and approval of a Utility-Specific Smart Meter Funding Adder in accordance with the Smart Meter Funding and Cost Recovery Guideline of the OEB. On April 7, 2011, the Application was approved as filed. The Application provided for a new rate adder of $1.74 per metered customer per month, beginning May 1, 2011.

(vii) Green Energy and Green Economy Act

In early 2009, the government tabled the Green Energy and Green Economy Act ("GEGEA"). This new legislation makes fundamental changes to the roles and responsibilities of LDC's in the areas of renewable power generation, conservation and demand management delivery, and the development of smart distribution grids.

The Green Energy and Green Economy Act provides LDC's with the freedom to own and operate a portfolio of renewable power generation and will permit them to provide district heating services in their communities through co-generation. LDC's will also bear added responsibilities to assist and enable consumers to reduce their peak demand and conserve energy in an effort to meet provincial conservation targets. LDC's will also gain new responsibilities in transforming their local distribution networks into smart grids harnessing advanced technologies to facilitate the connection of small-scale generators and the two-way flow of information.

(viii) New LDC License Requirements - Conservation and Demand Management Targets

On November 12, 2010, the OEB amended LDC licenses to include requirements for achieving certain CDM targets over a four year period commencing January 1, 2011. The Company's CDM targets include a demand reduction target of 4.28MW and a consumption reduction target of 18,600MWh. LDC's must also comply with a new CDM Code of the OEB, which provides LDC requirements for the development and delivery of CDM Strategy to the OEB for the achievement of LDC-specific CDM targets, annual accounting and reporting to the OEB, and eligibility criteria for performance incentive payments. The Company has filed its CDM Strategy with the OEB.

(g) Payments in Lieu of Income Taxes (PILs)

The Company uses the liability method for accounting for PILs. Under this method, future payment in lieu of income tax assets and liabilities are recognized for differences between the carrying value of assets and liabilities for accounting purposes and their respective values for payment in lieu of income tax purposes. These differences are measured using substantively enacted tax rates applicable for the period in which those differences are expected to be recovered or settled. To the extent that there is uncertainty regarding the recovery of a future payment in lieu of income tax asset, a valuation allowance reducing the future payment in lieu of income tax asset is recorded.

3. Significant Accounting Policies (cont.)

(h) Goodwill and Intangible Assets

Goodwill and intangible assets acquired individually or as part of a group of other assets are initially recognized and measured at cost. The cost of a group of intangible assets acquired in a transaction, including those acquired in a business combination, are allocated to the individual assets based on their relative fair value. Intangible assets with finite lives are amortized on a straight-line basis over their estimated useful lives. Goodwill and intangible assets with indefinite useful lives are not amortized and are tested for impairment annually or more frequently if events and changes in circumstances indicate that an asset might be impaired.

(i) Inventory

Inventories consist primarily of materials and supplies. Items considered to be major future components of property, plant and equipment are transferred to property, plant and equipment. Inventories are carried at the lower of cost and net realizable value, with cost determined on an average cost basis net of a provision for obsolescence.

(j) Impairment of Long-lived Assets

Long-lived assets are tested for recoverability when events or changes in circumstances indicate that their carrying value may not be recoverable. An impairment loss is recognized when the carrying value exceeds the total undiscounted cash flow expected from their use and eventual disposition. The amount of the impairment loss is determined as the excess of the carrying value of the asset over its fair value.

(k) Use of Estimates

The preparation of the financial statements of the Company in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the balance sheet date and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates.

3. Significant Accounting Policies (cont.)

(l) Future Accounting Changes

(i) International Financial Reporting Standards ("IFRS")

On February 13, 2008, the Canadian Accounting Standards Board confirmed the publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. On September 10, 2010, the AcSB decided to permit rate-regulated entities to defer their IFRS implementation date to January 1, 2012.

The Company has an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its financial statements. Although the impact of the adoption to IFRS on the Company's Balance Sheet and Income Statement is not yet reasonably determinable or estimable, the company does expect a significant increase in financial statement disclosure requirements resulting from the adoption of IFRS, and is designing the systems and related process changes, which will be required in order to provide the additional information required to make these disclosures.

Given the continued uncertainty around the timing, scope and eventual adoption of a rate-regulated accounting standard under IFRS and the potential material impact of these standards on the Company's financial statements, the Company has decided to apply IFRS to its financial statements ending December 31, 2012 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011, for comparative purposes. The company continues to assess the impact of the conversion to IFRS on its results of operation. At this time, the impact on the Company's future financial statements cannot be determined.

4. Accounts Receivable

	2011	2010
Energy, water and sewer	$ 4,421,474	$ 4,964,402
Unbilled energy	4,179,730	4,946,758
Service revenues	1,179,355	342,306
	$ 9,780,559	$10,253,466

The amounts shown above are net of allowance for doubtful accounts of $556,000 (2010 - $471,353.

5. Investments

	2011	2010
386 Common shares in Sunlife Financial, at market value (cost - $1).	$ 11,677	$ 11,677

6. Property, Plant and Equipment

	Cost 2011	Accumulated Amortization	Net 2011	Net 2010
Land	$ 140,944	$ -	$ 140,944	$ 132,673
Buildings	156,690	52,427	104,263	89,140
Plant and equipment	2,671,258	1,145,082	1,526,176	1,003,699
Transmission and distribution system	32,691,136	11,898,528	20,792,608	20,618,601
Construction work in progress	433,461	-	433,461	-
Equipment under capital leases	844,111	328,441	515,670	273,997
	$36,937,600	$13,424,478	$23,513,122	$22,118,110

During the year, the Company recorded amortization of $1,456,074 (2010 - $1,477,987).

7. Regulatory Assets and Liabilities

Regulatory assets consist of the following:

	2011	2010
Retail settlement variances (a)	$ 1,752,165	$ 1,820,711
Special purpose charge variance (b)	1,411	63,471
Late payment penalties settlement (c)	71,323	65,125
Deferred charges	**(45,698)**	204,198
	1,779,201	2,088,380
Recovery of regulatory assets	939,565	1,561,800
	$ 2,718,766	$ 3,715,305

Regulatory liabilities consist of the following:

	2011	2010
Regulatory assets recovery account	**$ (7,891)**	$ 71,059
Future payment in lieu of income tax liability	1,408,000	1,408,000
	$ 1,400,109	$ 1,479,059

The OEB approved an Interim Rate Order for May 1, 2008, that effectively removed the recovery allocation of the regulatory assets amounts until the final Cost of Service Rate Application was approved. The new Cost of Service Rate Order approved by the OEB, effective December 1, 2008, includes an allocation of the recovery of the low voltage energy variances. The remainder of the regulatory assets will be recovered based on future rate orders.

7. Regulatory Assets and Liabilities (cont.)

(a) Retail settlement variances represent amounts accumulated since the opening of the electricity market on May 1, 2002. These variances are comprised of variances between amounts charged by the Independent Electricity Market Operator and amounts billed to customers plus variances from settlement and transmission charges. In the absence of rate regulations, these costs (revenues) would be charged to the period incurred.

(b) On April 9, 2010, the OEB informed electricity distributors of a Special Purpose Charge assessment under Section 26.1 of the Ontario Energy Board Act, 1998, for the Ministry of Energy and Infrastructure conservation and renewable energy program costs. The OEB assessed the Company $152,675 for their apportioned share of the total provincial amount of the Special Purpose Charge of $53,695,000 in accordance with the rules set out in Ontario Regulation 66/10. In accordance with Section 9 of the Special Purpose Charge Regulation, the Company is allowed to recover this balance. The recovery is expected to be achieved over a one-year period, which began on May 1, 2010.

(c) The late payment penalties settlement account relates to the settlement costs accrual associated with the late payment charges class action. All of the Municipal Electricity Utilities ("MEU") involved in the settlement, including the Company, have requested an order from the OEB allowing for the future recovery from customers of all costs related to the settlement.

8. Goodwill

	Cost 2011	Accumulated Amortization	Net 2011	Net 2010
Goodwill	$ 100,000	$ 23,333	$ 76,667	$ 76,667

At year end, management tested goodwill and determined that there was no impairment of goodwill.

9. Demand Operating Loan

Through a mirror banking agreement with its parent company the Company has available to its use a $6,000,000 revolving line of credit. The Company provides a guarantee on this facility, as outlined in note 17.

10. Customer Deposits

Customer deposits are obtained as security for energy consumption. On an annual basis, interest is calculated and credited to the customers' utility accounts. Also included are security deposits received for construction projects.

11. Related Parties

The Company has a contract with ERTH Corporation for management services and rental of facilities used by the Company.

The Company has contracted ERTH (Holdings Inc.) a company under common control, to provide the following services: maintenance and upgrades to the existing capital infrastructure of the Company and administrative services.

The contracts between the Company, ERTH (Holdings) Inc., ERTH Business Technologies Inc. and ERTH Corporation are measured at the exchange amount, which is the amount of consideration paid or received as established and agreed to by the related parties, unless noted otherwise.

During the year, ERTH (Holdings) Inc. transferred to the Company one bucket truck under capital lease at the carrying amount of the assets recorded in ERTH (Holdings) Inc. accounts (note 14(a)). In exchange, the Company agreed to assume the remaining lease obligations of the capital leases at the carrying amount of the liability.

The revenue reflected in the financial statements includes the electricity revenue for the sale of electricity to ERTH Corporation, ERTH (Holdings) Inc. and the municipal facilities located in the communities of Aylmer, Beachville, Belmont, Burgessville, Embro, Ingersoll, Norwich, Otterville, Port Stanley, Tavistock, Thamesford and the Municipalities of Central Huron and West Perth in the amount of $2,196,963 (2010 - $2,278,617). These transactions are in the normal course of operations at rates approved by the Ontario Energy Board. The Municipality of West Perth charges the Company for tree trimming and rent in the amount of $4,150 and $52,095 respectively.

11. Related Parties (cont.)

During the year, the Company purchased and sold the following services to and from related parties.

CRU Solutions Inc.	**2011**	**2010**
Purchase of capitalized items	$ -	$ 83,886
Sale of operations, maintenance and administrative services	-	(130,618)
Purchase of operations, maintenance and administrative services	-	163,851
	$ -	$ 117,119
ERTH360 Generation and Consulting Inc.		
Purchase of capitalized items	$ -	$ 554,188
Purchase of operations, maintenance and administrative services	-	62,693
	$ -	$ 616,881
ERTH Business Technologies Inc.		
Purchase of consulting services	$ 350,885	$ 30,632
ERTH Corporation		
Purchase of management services	$2,244,834	$1,493,777
Sale of operations and administrative services	(310,751)	-
Rent	240,543	267,433
	$2,174,626	$1,761,210
Ecaliber (Canada) Inc.		
Purchase of capitalized items	$ -	$ 12,050
Sale of operations and administrative services	-	(116,784)
Purchase of operations, maintenance and administrative services	-	1,088,385
	$ -	$ 983,651
Utilismart Corporation		
Purchase of capitalized items	$ -	$ 23,010
Purchase of consulting services	-	106,593
	$ -	$ 129,603
ERTH (Holdings) Inc.		
Purchase of operations, maintenance and administrative services	1,556,338	-
Sale of operations, maintenance and administrative service	$ (348,525)	$ -
Purchase of capitalized items	52,140	-
	$1,259,953	$ -

11. Related Parties (cont.)

At the end of the year, amounts due from related parties are as follows:

	2011	2010
Trade Receivables	$ -	$ -
CRU Solutions Inc.	-	28,218
Municipality of Central Huron	-	-
Coutler Water Meter Service Inc.	-	2,218
	$ -	$ 30,436

At the end of the year, amounts due to related parties are as follows:

	2011	2010
ERTH Corporation	$ 3,709,688	$ 4,902,602
ERTH (Holdings) Inc.	546,576	-
Ecaliber (Canada) Inc.	-	450,513
Utilismart Corporation	-	12,445
ERTH Business Technologies Inc.	418,024	656
ERTH360 Generation & Consulting Inc.	-	169,411
Municipality of Central Huron	68,041	67,449
Municipality of West Perth	47,415	110,432
Town of Aylmer	6,891	134,269
	$ 4,796,635	$ 5,847,777

The companies are related as follows:

ERTH Corporation owns 100% of the issued and outstanding shares of ERTH (Holdings) Inc. and ERTH Limited.

ERTH Business Technologies Inc. is a wholly-owned subsidiary of ERTH Limited.

The Town of Aylmer, the Municipality of Central Huron and Municipality of West Perth are shareholders of ERTH Corporation.

12. Shareholder Notes

	2011	2010
The demand promissory note is payable to the Municipality of West Perth and bears interest at 7%. Interest is payable in monthly interest installments of $5,250. This note is unsecured.	$ 900,000	$ 900,000
The demand note is payable to the Municipality of West Perth and bears interest at 7.25%. There are no fixed terms of repayment. This note is unsecured.	1,183,391	1,183,391
	$2,083,391	$2,083,391

The fair value of the shareholder notes payable is not readily determinable due to the related party nature of the instrument.

13. Related Party Long-Term Debt

The long-term debt represents amounts owing to the municipal shareholders of ERTH Corporation for purchase of the respective Municipality's Hydro Electric Commission's net assets. The rate of interest is currently 7.25% and is set by the Board of Directors, from time to time. There are no fixed repayment terms associated with the principle outstanding and no principal amounts are anticipated to be paid over the next twelve months. The loan is secured by a second position General Security Agreement covering accounts receivable, inventory and equipment, including motor vehicles.

13. Related Party Long-Term Debt (cont.)

The amounts owing to the municipalities are as follows:

	2011	2010
Aylmer	$ 1,694,863	$ 1,694,863
Central Elgin	806,436	806,436
East Zorra Tavistock	569,073	569,073
Ingersoll	3,402,080	3,402,080
Norwich	763,755	763,755
Southwest Oxford	192,062	192,062
Zorra	610,255	610,255
	$ 8,038,524	$ 8,038,524

During 2011, $582,793 was charged to interest expense for interest on related party long-term debt (2010 - $582,793).

14. Long Term Debt

	2011	2010
Capital lease obligation (a)	$ 437,120	$ 524,919
Bank loans (b)	33,478	52,365
	470,598	577,284
Less: current portion of long-term debt (c)	(165,195)	(208,591)
	$ 305,403	$ 368,693

a) Capital Lease Obligation

During the year, the Company transferred to ERTH (Holdings) Inc., a related party, one capital lease obligations of a bucket truck. The vehicles are being leased for a period of six to seven years on various contracts that began between 2005 to 2011. The interest rate imputed in these leases range from 6.3%-8.8%.

The following is a schedule of the future minimum lease payments of the capital leases, together with the balance of the obligation.

Year ending December 31,	2012	$ 182,088
	2013	118,922

2014	53,137
2015	53,137
2016	38,768
2017	38,768
2018	6,461
Total minimum lease payments	491,281
Less: amount representing interest	54,161
Balance of obligations	437,120
Less: current portion	(151,218)
	$ 285,902

14. Long Term Debt (cont.)

b) Bank Loans

	2011	2010
Financing Loan repayable in monthly instalments of $604, with a 0% interest rate maturing August 2014.	19,328	31,725
Financing Loan repayable in monthly instalments of $579, with a 1.9% interest rate maturing September 2014.	14,150	20,640
	33,478	52,365
Less: Current Portion	(13,977)	(13,850)
	$ 19,501	$ 38,515

c) Current Portion of Long-term Debt

	2011	2010
Capital lease obligation	$ 151,218	$ 194,741
Bank loans	13,977	13,850
	$ 165,195	$ 208,591

The aggregate principal portion of long-term debt and capital lease payments required in each of the next five years are as follows:

Year ending	December 31, 2012	$ 165,195
	December 31, 2013	113,847
	December 31, 2014	50,058
	December 31, 2015	46,930
	December 31, 2016	35,118
	December 31, 2017	37,214
	December 31, 2018	6,399
		$ 454,761

The attached Auditors' Report and notes form an integral part of these audited financial statements.

15. Post-Retirement Benefit Obligation

a) Pension Plan

The Company has a pension agreement with the Ontario Municipal Employees Retirement System Funds ("OMERS"), which is a multi-employer plan, on behalf of its employees.

The plan is a contributory, defined benefit plan which specifies the amount of retirement benefits to be received by the employees based on the length of service and rates of pay. As the plan is a multi-employer plan, it is accounted for as a defined contribution plan as allowed under Canadian Generally Accepted Accounting Principals. Contributions by the Company are 7.4% for employee earnings below the year's maximum personable earnings of $47,200 and 10.7% thereafter.

For the year ended December 31, 2011, the Company's OMERS current service pension costs were $**141,468** (2010 - $141,468).

b) Employee Future Benefits Other than Pension

The Company provides medical and life insurance benefit coverage to certain retirees of the Company. Eligible retirees are provided health coverage until the age of 65 and life insurance coverage is provided to retirees who have at least 10 years of eligible service. The obligation under these plans is funded by the Company and expensed in the year that it is paid. Benefits paid in 2011 amounted to $**17,876** (2010 - $17,876).

Post-retirement benefits, other than pensions, are accrued during the years which employees provide service to certain of the companies.

i) Total Cash Payments

Total cash payments for employee future benefits for 2011 consist of cash contributed by the Company to its funded pension plans, cash payments directly to beneficiaries for its unfunded other benefit plans, cash contributed to its defined contribution plans and cash contributed to its defined plan was **$159,344** (2010 - $159,344).

15. Post-retirement Benefit Obligation (cont.)

ii) Measurement Actuarial Valuations Dates

Plan assets and the accrued benefit obligation were measured based on the actuarial valuation completed as of December 31, 2011. The next required valuation will be as of December 31, 2012.

Accrued Benefit Obligation

	2011	2010
Assumption of benefit obligation	$ 584,565	$ 541,368
Service cost	7,200	7,200
Interest on projected plan benefits	18,700	18,700
Actuarial loss	35,173	35,173
Benefits paid	(17,876)	(17,876)
Benefit obligation at end of year	$ 627,762	$ 584,565

Reconciliation of the Accrued Benefit Obligation to the Balance Sheet Accrued Benefits Liability

	2011	2010
Accrued benefit obligation	$ 627,762	$ 584,565
Unrecognized net actuarial loss	(70,462)	(70,462)
Accrued benefits liability	$ 557,300	$ 514,103

Significant Assumptions

The significant assumptions used are as follows:

	2011	2010
Discount rates applicable to post-retirement benefits other than pensions and benefit costs	5.75%	5.75%
Rate of compensation increase	3.50%	3.50%
Ultimate dental care cost	4.00%	4.00%

For December 31, 2011, medical costs are assumed to increase at **10% reduced by 0.5% per year to 5% over 10 years.**

16. Share Capital

Authorized

Unlimited number of common shares

	2011	2010
Issued capital		
10,000 common shares	$10,855,585	$10,855,585

17. Guarantee

The Company has guaranteed the operating and term loans of its parent company ERTH Corporation up to 25% of the Company's equity or $2,708,410. The loans are secured by a General Security Agreement covering all assets of the Company and a pledge of the shares of the Company. As the Company does not expect to be in a position where it would need to honour this guarantee in the foreseeable future, no liability has been recorded in these financial statements.

18. Prudential Support Requirements

Erie Thames Powerlines Corporation, as a Local Distribution Company under the Energy Competition Act, 1998, R.S.O., posted prudential support obligations on market opening, May 1, 2002 with the Electric Independent Market Operator. The prudential support obligation as at June 24, 2008 was $1,586,703 and had not changed as at December 31, 2011. The prudential support requirement is honoured through a letter of credit.

19. Payments in Lieu of Income Taxes

The provision for payments in lieu ("PILs") of income taxes differs from amounts which would be calculated by applying the Company's combined statutory income tax rate as follows:

	2011	2010
Income from continuing operations before PILs	$ 278,415	$ 298,424
Statutory Canadian Federal and Provincial income tax rate	31.00 %	31.00 %
Basic rate applied to income before PILs	86,309	92,511
Other	(120,950)	94,489
Provision for payment in lieu of income tax	$ (34,641)	$ 187,000
Effective tax rate	(12.44)%	62.66 %

19. Payments in Lieu of Income Taxes (cont.)

The Company as of December 31, 2011 has recorded a future payment in lieu of income tax asset of $1,408,000 (2010 - $1,408,000) and future income tax regulatory liability of $1,408,000 (2010 - $1,408,000), based on substantively enacted income tax rates.

Significant components of the Company's future income tax assets and regulatory liability are as follows:

	2011	2010
Property, plant and equipment	$ 723,000	$ 723,000
Intangible assets	63,000	63,000
Regulatory adjustments	338,000	338,000
Post-retirement Benefits Obligation	71,000	71,000
Non-Capital loss carryforwards	213,000	213,000
	$ 1,408,000	$ 1,408,000

The Company has approximately $851,000 of non-capital loss carryforwards which may be applied to reduce taxable income of future years expiring as follows:

2015	$ 120,000
2028	11,000
2029	134,000
2030	586,000

20. Commitments

Lease commitments

The Company has entered into various operating lease agreements. The future minimum annual payments under operating leases are as follows:

Year ending	December 31, 2012	$ 50,313
	December 31, 2013	36,226
	December 31, 2014	36,716
	December 31, 2015	7,627
	December 30, 2016	2,358
		$ 133,240

21. Financial Instruments

As a rate-regulated entity, the nature of the Company's operations are defined and restricted by regulation. Financial operations and risks are also substantially influenced by regulation, limiting the necessity to engage in risk mitigation strategies involving the use of derivatives or hedges, and the Company did not engage in those activities during the fiscal year.

The company has adopted CICA Handbook Section 3861- *Financial Instruments* for disclosure purposes as the Company's financial instruments are not subject to disclosure requirements under Section 3862 or 3863 of the CICA Handbook

a) Credit Risk

By regulation, the Company is responsible for collecting both the distribution and energy portions of the electricity bill. On average, 16% of amounts billed to customers are for distribution charges and 84% of the bill is energy related. Unless the retailer elects to bill the customers directly for the energy portion of the bill, the Company is exposed to a credit risk substantially greater then their portion of the electricity bill.

Mitigation of substantial losses is provided through the opportunity to apply for recovery for those losses through distribution rate adjustments in future years, if approved by the regulator. Additionally, regulation provides for certain customers to provide security deposits for a prescribed period of period to mitigate collection loss.

The Company is not exposed to a significant concentration of credit risk within any customer segment or individual customer.

21. Financial Instruments (cont.)

b) Fair Values

The fair values of the Company's financial assets and liabilities approximate their book values unless otherwise disclosed.

c) Interest Rate Risk

The Company is subject to the risks associated with debt financing, including the risk that existing indebtedness secured by the property may not be refinanced or that the terms of such refinancing may not be as favourable as the terms of existing indebtedness. The Company is exposed to interest rate risk as its assets are held as security for the parent company's commercial loan facilities. The Company does not use any hedging instruments to mitigate its risk.

22. Capital Disclosures

The Company's main objective is to ensure ongoing access to funding to maintain and improve the electricity distribution system of the Company.

As at December 31, 2011 the Company's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2011, shareholders' equity amounts to $10,833,639 (2010 - $10,555,224) and long-term debt amounts to $10,592,513 (2010 - $10,699,199). The Company's structure as at December 31, 2011 is 49% debt and 51% equity (2010 - 50% debt and 50% equity). There have been no changes in the Company's approach to capital management during the year.

23. Comparative Figures

Certain comparative figures have been reclassified to conform with the financial statement presentation adopted in the current year.

RATE BASE

1.0 Introduction

This Exhibit provides Erie Thames' distribution rate base forecast for the 2012 Test Year and a discussion of the variances between 2008 Board Approved, 2008 to 2010 Actual and 2011/2012 forecast or budget rate bases. In accordance with the Board's Update to Chapter 2 of the *Filing Requirements for Transmission and Distribution Applications*, issued June 26th, 2011, the rate base used to determine the revenue requirement for the Test Year includes a forecast of net fixed assets, calculated on a mid-year average basis, plus a working capital requirement. Net fixed assets are gross assets in service minus accumulated amortization and contributed capital. Table 1 shows the calculation of the 2012 rate base. WCA has been developed using the Board default approach of 15% of the cost of power and controllable expenses.

Approach

The *Ontario Energy Board Act, 1998* and the *Electricity Act, 1998* establish certain purposes and objectives for the Ontario Energy Board in its decision-making and thereby provide goals and objectives for distributors and other industry participants. In order to pursue these objectives, Erie Thames is committed to building sustainable and reliable infrastructure assets to service the needs of its community, and to comply with regulatory obligations and license conditions. Erie Thames is also committed to improving the customer experience in dealing with the utility and has and continues to implement processes, system reviews and enhancements for service improvements and to gain further productivity and efficiencies in its work place. As such, Erie Thames has taken steps to ensure infrastructure investment decisions achieve the optimal balance between reliability and quality of service, and reasonable and fair cost of electricity delivery to its customers.

Erie Thames is committed to providing its customers with an economical, safe, reliable supply of electricity. Erie Thames Asset Management Plan has been completed and along with other reports and studies, provides a framework which is key to the Erie Thames operating and capital plan development. The estimated capital expenditures for the 2011 Bridge Year and 2012 Test Year are influenced by a number of factors including growth in the residential customer base, the conversion of aging infrastructure, ensuring power quality and Erie Thames' capacity to finance capital projects. Project cost estimates are provided for the project and broken down over the various applicable accounts.

The specific priority of identified projects are influenced by a number of factors, compliance, safety, obligations to third parties such as municipal reconstruction projects, subdivisions assumed or new generation projects. Capital Contributions have been shown in total as a separate line item. In addition, Erie Thames has ongoing capital programs – such as pole replacement - that necessitate annual spending. All proposed capital projects for the 2011 Bridge year and the 2012 Test Year are expected to be completed and in service in the year forecasted. Certain projects are multi-year projects and will continue through the IRM period.

In addition, Erie Thames would note that it is focussing more on capital spending to reduce future O&M costs. This should assist Erie Thames in improving its O&M efficiency rating.

Rate Base Summary Table:

RATE BASE SUMMARY	2008 Board Approved	2008 Actual	Variance from 2008 Board Approved	2008 Actual	2009 Actual	Variance from 2008 Actual	2009 Actual	2010 Actual	Variance from 2009 Actual	2010 Actual	2011 Bridge	Variance from 2010 Actual	2011 Bridge	2012 Test	Variance from 2011 Bridge
	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)		($'s)	($'s)
Gross Asset															
Asset Values at Cost	$21,923,880	$29,811,592	$7,887,712	$29,811,592	$31,753,827	$1,942,235	$31,753,827	$35,371,442	$3,617,615	$35,371,442	$37,805,360	$2,433,918	$37,805,360	$39,225,360	$1,420,000
Accumulated Depreciation															
Depreciation	-$5,366,284	-$9,029,842	-$3,663,558	-$9,029,842	-$10,330,451	-$1,300,609	-$10,330,451	-$11,847,726	-$1,517,275	-$11,847,726	-$13,680,808	-$1,833,082	-$13,680,808	-$14,687,643	-$1,006,835
Net Fixed Asset	**$16,557,596**	**$20,781,750**	**$4,224,154**	**$20,781,750**	**$21,423,376**	**$641,625**	**$21,423,376**	**$23,523,716**	**$2,100,340**	**$23,523,716**	**$24,124,551**	**$600,835**	**$24,124,551**	**$24,537,716**	**$413,165**
Allowance for Working Capital															
	$5,689,178	$5,985,951	$296,773	$5,985,951	$6,402,183	$416,232	$6,402,183	$6,892,145	$489,962	$6,892,145	$6,869,459	-$22,686	$6,869,459	$6,382,958	-$486,501
Utility Rate Base	**$22,246,774**	**$26,767,701**	**$4,520,927**	**$26,767,701**	**$27,825,558**	**$1,057,858**	**$27,825,558**	**$30,415,861**	**$2,590,302**	**$30,415,861**	**$30,994,011**	**$578,150**	**$30,994,011**	**$30,920,674**	**-$73,336**

Variance Analysis on Rate Base:

The following paragraphs provide a narrative on the changes that have driven the rate base changes/variances since the 2008 COS for Erie Thames.

2008 Board Approved compared to 2008 Actual:

The large variance between 2008 Board Approved and 2008 Actual is simply related to the fact that the Board Approved amounts represents the Erie Thames stand alone approved 2008 rate base calculation from the COS decision, while the 2008 actual amounts include the calculated rate base amounts of WPPI and CPC. WPPI and CPC did not rebase in 2008 but had previously rebased in 2006. As such, WPPI's calculated rate base for 2008 is $2,451,436 and $1,507,452 for CPC. Given that the 2008 Board approved is for stand-alone Erie Thames and the 2008 figures are combined for the three entities comparisons at this stage provide little value. However, it should be noted that capital spending for Erie Thames was as forecasted at the time of the 2008 COS proceeding.

2008 Actual Compared to 2009 Actual:

Prior to the re-organization, Erie Thames had 2 employees and relied upon affiliates service providers for capital and O&M spending. In 2009 the Erie Thames affiliate experienced an eighteen week work interruption from June to October with respect to its union staff, which led to a significant reduction in the amount of capital projects completed that year. The loss of the summer/fall construction season prevented the completion of several capital projects. This was the primary reason for the less than average increase in rate base of $640,000 year over year. The increase effectively is with respect to CPC and WPPI's capital spending for 2009 which were still standalone utilities at that point and unaffected by the work interruption.

Working capital increased by a total of $372,000 the driver of that increase was fully with respect to the increase in commodity cost – which drove a $440,000 increase in working capital while the remainder of the WCA, the controllable expenses, was actually reduced.

2009 Actual Compared to 2010 Actual:

Net fixed assets increased by $2,100,000 in 2010 over 2009. This change was predominantly the result of the re-organization of Erie Thames and the retrenching of staff and vehicles from Erie Thames' affiliate into the LDC. This resulted in the addition of $1,871,000 gross fleet costs into Erie Thames and the associated amortization of the fleet offset the capital spend for the year.

Again, the increase in working capital of $476,000 was driven by the increase in commodity cost by the amount of $490,000 increase in working capital allowance that is derived as a direct result.

2010 Actual Compared to 2011 Bridge:

The change in net fixed assets between 2010 to 2011 bridge of $600,000 is specifically related to the normal capital spending program of Erie Thames and the addition of two bucket trucks for approximately $600,000 and leasehold improvements of $150,000. The need for the bucket trucks was dealt with in the CPC and WPPI 2010 COS proceeding.

The change in working capital allowance for the bridge year is not related to the change in cost of power as was the case in previous years, the $23,000 decrease is directly related to the change in operating costs for 2011.

2011 Bridge Compared to 2012 Test:

The change in net fixed assets between the bridge and test year of $413,000 is directly attributable to the projected capital spending plan as discussed later in the asset management portion of this Application.

The decrease in working capital allowance is with respect to the decrease in cost of power amounts due to the significant change in load forecast as a result of the lost customer and decreased production of industry within Erie Thames's service territory.

2.0 Gross Assets – Property Plant and Equipment and Accumulated Depreciation

The following section details the impact of the application on Erie Thames asset base including consolidated historical Continuity statements, back to 2006, along with bridge and test year projections. Erie Thames has provided consolidated continuity statements for the years prior to the amalgamation of WPPI and CPC into Erie Thames. Similarly this section also reviews the change in gross asset base and an explanation of those changes and an analysis of Accumulated amortization and the associated annual amortization expense.

Fixed Asset Continuity Schedule

Year [1] **2006**

CCA Class	OEB	Description	Depreciation Rate	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
N/A	1805	Land		$ 150,429			$ 150,429	$ -			$ -	$ 150,429
47	1808	Buildings	4.00%	$ 121,536	$ 813		$ 122,349	-$ 23,136	-$ 4,573		-$ 27,709	$ 94,640
13	1810	Leasehold Improvements	10.00%		$ 7,040		$ 7,040	$ -	-$ 1,408		-$ 1,408	$ 5,632
47	1815	Transformer Station Equipment >50 kV					$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV	4.00%	$ 395,685	$ 78,984		$ 474,669	-$ 100,822	-$ 46,825		-$ 147,647	$ 327,022
47	1825	Storage Battery Equipment	4.00%				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 3,189,082	$ 349,231		$ 3,538,313	-$ 1,083,353	-$ 117,489		-$ 1,200,842	$ 2,337,471
47	1835	Overhead Conductors & Devices	4.00%	$ 6,795,864	$ 612,942	-$ 4,044	$ 7,404,762	-$ 1,149,135	-$ 290,660		-$ 1,439,795	$ 5,964,967
47	1840	Underground Conduit	4.00%	$ 1,930,233	$ 51,444	-$ 6,855	$ 1,974,822	-$ 597,018	-$ 69,439		-$ 666,457	$ 1,308,365
47	1845	Underground Conductors & Devices	4.00%	$ 2,891,471	$ 425,038		$ 3,316,509	-$ 511,734	-$ 117,419		-$ 629,153	$ 2,687,356
47	1850	Line Transformers	4.00%	$ 4,439,832	$ 476,201		$ 4,916,033	-$ 1,102,001	-$ 242,354		-$ 1,344,355	$ 3,571,678
47	1855	Services (Overhead & Underground)	4.00%	$ 1,512,414	$ 355,545		$ 1,867,959	-$ 305,087	-$ 73,166		-$ 378,253	$ 1,489,706
47	1860	Meters	4.00%	$ 2,048,408	$ 244,380		$ 2,292,788	-$ 453,628	-$ 82,400		-$ 536,028	$ 1,756,760
47	1860	Meters (Smart Meters)					$ -				$ -	$ -
N/A	1905	Land					$ -				$ -	$ -
CEC	1906	Land Rights					$ -				$ -	$ -
47	1908	Buildings & Fixtures					$ -				$ -	$ -
13	1910	Leasehold Improvements					$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 52,107	$ 3,173		$ 55,280	-$ 24,026	-$ 16,572		-$ 40,598	$ 14,682
8	1915	Office Furniture & Equipment (5 years)	20.00%				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	20.00%	$ 63,626	$ 5,727		$ 69,353	-$ 35,733	-$ 16,573		-$ 52,306	$ 17,047
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)					$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)					$ -				$ -	$ -
12	1925	Computer Software	20.00%	$ 306,988	$ 90,779		$ 397,767	-$ 105,892	-$ 113,347		-$ 219,239	$ 178,528
10	1930	Transportation Equipment	12.50%	$ 17,152			$ 17,152	-$ 9,677	-$ 1,873		-$ 11,550	$ 5,602
8	1935	Stores Equipment	20.00%	$ -	$ 458		$ 458	$ -	-$ 46		-$ 46	$ 412
8	1940	Tools, Shop & Garage Equipment	20.00%	$ 58,517	$ 23,613		$ 82,130	-$ 31,169	-$ 27,395		-$ 58,564	$ 23,566
8	1945	Measurement & Testing Equipment	20.00%	$ -	$ 11,007		$ 11,007	$ -	-$ 83		-$ 83	$ 10,924
8	1950	Power Operated Equipment	20.00%	$ 64,091			$ 64,091	$ -	-$ 468		-$ 468	$ 63,623
8	1955	Communications Equipment					$ -				$ -	$ -
8	1955	Communication Equipment (Smart Meters)					$ -				$ -	$ -
8	1960	Miscellaneous Equipment					$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises					$ -				$ -	$ -
47	1980	System Supervisor Equipment					$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets					$ -				$ -	$ -
47	1995	Contributions & Grants	4.00%	-$ 389,708	-$ 467,608		-$ 857,316	$ 24,866	$ 27,595		$ 52,461	-$ 804,855
	etc.						$ -				$ -	$ -
		Total		**$ 23,647,725**	**$ 2,268,767**	**-$ 10,899**	**$ 25,905,593**	**-$ 5,507,545**	**-$ 1,194,495**	**$ -**	**-$ 6,702,040**	**$ 19,203,553**

Fixed Asset Continuity Schedule

Year [1] **2007**

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land		$ 150,429	$ -		$ 150,429	$ -			$ -	$ 150,429
47	1808	Buildings	4.00%	$ 122,349	$ 3,500		$ 125,849	-$ 27,709	-$ 4,902		-$ 32,611	$ 93,238
13	1810	Leasehold Improvements	10.00%	$ 7,040			$ 7,040	-$ 1,408	-$ 1,408		-$ 2,816	$ 4,224
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	4.00%	$ 474,669			$ 474,669	-$ 147,647	-$ 16,005		-$ 163,652	$ 311,017
47	1825	Storage Battery Equipment	4.00%	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 3,538,313	$ 431,176		$ 3,969,489	-$ 1,200,842	-$ 176,240		-$ 1,377,082	$ 2,592,407
47	1835	Overhead Conductors & Devices	4.00%	$ 7,404,762	$ 748,345		$ 8,153,107	-$ 1,439,795	-$ 285,306		-$ 1,725,101	$ 6,428,006
47	1840	Underground Conduit	4.00%	$ 1,974,822	$ 67,666		$ 2,042,487	-$ 666,457	-$ 93,420		-$ 759,877	$ 1,282,611
47	1845	Underground Conductors & Devices	4.00%	$ 3,316,509	$ 309,552		$ 3,626,061	-$ 629,153	-$ 131,665		-$ 760,818	$ 2,865,243
47	1850	Line Transformers	4.00%	$ 4,916,033	$ 238,335		$ 5,154,368	-$ 1,344,355	-$ 208,227		-$ 1,552,582	$ 3,601,786
47	1855	Services (Overhead & Underground)	4.00%	$ 1,867,959	$ 310,317		$ 2,178,276	-$ 378,253	-$ 74,482		-$ 452,735	$ 1,725,541
47	1860	Meters	4.00%	$ 2,292,788	$ 145,477		$ 2,438,265	-$ 536,028	-$ 86,497		-$ 622,525	$ 1,815,740
47	1860	Meters (Smart Meters)		$ -			$ -	$ -			$ -	$ -
N/A	1905	Land		$ -			$ -	$ -			$ -	$ -
CEC	1906	Land Rights		$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures		$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 55,280	$ 1,270		$ 56,550	-$ 40,598	-$ 4,831		-$ 45,429	$ 11,121
8	1915	Office Furniture & Equipment (5 years)	20.00%	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	20.00%	$ 69,353	$ 1,691		$ 71,044	-$ 52,306	-$ 14,970		-$ 67,276	$ 3,768
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
12	1925	Computer Software	20.00%	$ 397,767	$ 24,405		$ 422,172	-$ 219,239	-$ 81,593		-$ 300,832	$ 121,340
10	1930	Transportation Equipment	12.50%	$ 17,152	$ 13,025		$ 30,177	-$ 11,550	-$ 4,478		-$ 16,028	$ 14,149
8	1935	Stores Equipment	20.00%	$ 458			$ 458	-$ 46	-$ 92		-$ 138	$ 320
8	1940	Tools, Shop & Garage Equipment	20.00%	$ 82,130	$ 1,007		$ 83,137	-$ 58,564	-$ 14,222		-$ 72,786	$ 10,351
8	1945	Measurement & Testing Equipment	20.00%	$ 11,007			$ 11,007	-$ 83			-$ 83	$ 10,924
8	1950	Power Operated Equipment	20.00%	$ 64,091			$ 64,091	-$ 468			-$ 468	$ 63,623
8	1955	Communications Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	4.00%	-$ 857,316	-$ 880,601		-$ 1,737,917	$ 52,461	$ 55,814		$ 108,275	-$ 1,629,643
	etc.						$ -	$ -			$ -	$ -
								$ -				
		Total		**$ 25,905,593**	**$ 1,415,166**	**$ -**	**$ 27,320,758**	**-$ 6,702,040**	**-$ 1,142,522**	**$ -**	**-$ 7,844,562**	**$ 19,476,196**

Fixed Asset Continuity Schedule

Year [1] **2008**

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land		$ 150,429			$ 150,429	$ -			$ -	$ 150,429
47	1808	Buildings	4.00%	$ 125,849	$ 10,160		$ 136,009	-$ 32,611	-$ 5,175		-$ 37,786	$ 98,223
13	1810	Leasehold Improvements	10.00%	$ 7,040			$ 7,040	-$ 2,816	-$ 1,408		-$ 4,224	$ 2,816
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	4.00%	$ 474,669	$ 24,560		$ 499,229	-$ 163,652	-$ 17,445		-$ 181,097	$ 318,132
47	1825	Storage Battery Equipment	4.00%	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 3,969,489	$ 367,223		$ 4,336,711	-$ 1,377,082	-$ 191,344		-$ 1,568,426	$ 2,768,286
47	1835	Overhead Conductors & Devices	4.00%	$ 8,153,107	$ 811,112		$ 8,964,219	-$ 1,725,101	-$ 315,099		-$ 2,040,199	$ 6,924,020
47	1840	Underground Conduit	4.00%	$ 2,042,487	$ 104,873		$ 2,147,360	-$ 759,877	-$ 96,671		-$ 856,548	$ 1,290,812
47	1845	Underground Conductors & Devices	4.00%	$ 3,626,061	$ 648,401		$ 4,274,462	-$ 760,818	-$ 156,743		-$ 917,561	$ 3,356,901
47	1850	Line Transformers	4.00%	$ 5,154,368	$ 544,806		$ 5,699,174	-$ 1,552,582	-$ 225,332		-$ 1,777,914	$ 3,921,260
47	1855	Services (Overhead & Underground)	4.00%	$ 2,178,276	$ 309,884		$ 2,488,160	-$ 452,735	-$ 85,883		-$ 538,618	$ 1,949,541
47	1860	Meters	4.00%	$ 2,438,265	$ 128,946		$ 2,567,211	-$ 622,525	-$ 91,150		-$ 713,675	$ 1,853,536
47	1860	Meters (Smart Meters)		$ -			$ -	$ -			$ -	$ -
N/A	1905	Land		$ -			$ -	$ -			$ -	$ -
CEC	1906	Land Rights		$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures		$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 56,550	$ 1,323		$ 57,873	-$ 45,429	-$ 2,809		-$ 48,238	$ 9,635
8	1915	Office Furniture & Equipment (5 years)	20.00%	$ -	$ 5,594		$ 5,594	$ -			$ -	$ 5,594
10	1920	Computer Equipment - Hardware	20.00%	$ 71,044	$ 4,869		$ 75,913	-$ 67,276	-$ 6,155		-$ 73,431	$ 2,482
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
12	1925	Computer Software	20.00%	$ 422,172	$ 143,626		$ 565,798	-$ 300,832	-$ 71,796		-$ 372,627	$ 193,171
10	1930	Transportation Equipment	12.50%	$ 30,177	$ 66,156		$ 96,333	-$ 16,028	-$ 10,277		-$ 26,304	$ 70,029
8	1935	Stores Equipment	20.00%	$ 458			$ 458	-$ 138	-$ 183		-$ 321	$ 137
8	1940	Tools, Shop & Garage Equipment	20.00%	$ 83,137	$ 7,497		$ 90,634	-$ 72,786	-$ 6,603		-$ 79,388	$ 11,246
8	1945	Measurement & Testing Equipment	20.00%	$ 11,007			$ 11,007	-$ 83			-$ 83	$ 10,924
8	1950	Power Operated Equipment	20.00%	$ 64,091			$ 64,091	-$ 468			-$ 468	$ 63,623
8	1955	Communications Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	4.00%	-$ 1,737,917	-$ 688,197		-$ 2,426,115	$ 108,275	$ 98,792		$ 207,067	-$ 2,219,047
	etc.						$ -	$ -			$ -	$ -
								$ -				
		Total		**$ 27,320,758**	**$ 2,490,833**	**$ -**	**$ 29,811,592**	**-$ 7,844,562**	**-$ 1,185,279**	**$ -**	**-$ 9,029,842**	**$ 20,781,750**

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Appendix 2-B
Fixed Asset Continuity Schedule

Year [1] **2009**

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land		$ 150,429			$ 150,429	$ -	$ -		$ -	$ 150,429
47	1808	Buildings	4.00%	$ 136,009	$ 12,254		$ 148,263	-$ 37,786	-$ 5,623		-$ 43,409	$ 104,854
13	1810	Leasehold Improvements	10.00%	$ 7,040			$ 7,040	-$ 4,224	-$ 1,408		-$ 5,632	$ 1,408
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -	$ -		$ -	$ -
47	1820	Distribution Station Equipment <50 kV	4.00%	$ 499,229			$ 499,229	-$ 181,097	-$ 17,937		-$ 199,034	$ 300,195
47	1825	Storage Battery Equipment	4.00%	$ -			$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 4,336,711	$ 324,127		$ 4,660,839	-$ 1,568,426	-$ 205,171		-$ 1,773,597	$ 2,887,242
47	1835	Overhead Conductors & Devices	4.00%	$ 8,964,219	$ 567,212		$ 9,531,432	-$ 2,040,199	-$ 342,665		-$ 2,382,864	$ 7,148,567
47	1840	Underground Conduit	4.00%	$ 2,147,360	$ 65,260		$ 2,212,620	-$ 856,548	-$ 100,074		-$ 956,622	$ 1,255,998
47	1845	Underground Conductors & Devices	4.00%	$ 4,274,462	$ 473,710		$ 4,748,172	-$ 917,561	-$ 179,186		-$ 1,096,747	$ 3,651,425
47	1850	Line Transformers	4.00%	$ 5,699,174	$ 276,411		$ 5,975,585	-$ 1,777,914	-$ 241,756		-$ 2,019,670	$ 3,955,915
47	1855	Services (Overhead & Underground)	4.00%	$ 2,488,160	$ 309,114		$ 2,797,274	-$ 538,618	-$ 98,263		-$ 636,881	$ 2,160,393
47	1860	Meters	4.00%	$ 2,567,211	$ 154,321		$ 2,721,532	-$ 713,675	-$ 96,815		-$ 810,490	$ 1,911,042
47	1860	Meters (Smart Meters)		$ -			$ -	$ -	$ -		$ -	$ -
N/A	1905	Land		$ -			$ -	$ -	$ -		$ -	$ -
CEC	1906	Land Rights		$ -			$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures		$ -			$ -	$ -	$ -		$ -	$ -
13	1910	Leasehold Improvements		$ -			$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 57,873	$ 593		$ 58,466	-$ 48,238	-$ 2,904		-$ 51,142	$ 7,324
8	1915	Office Furniture & Equipment (5 years)	20.00%	$ 5,594			$ 5,594	$ -	-$ 559		-$ 559	$ 5,035
10	1920	Computer Equipment - Hardware	20.00%	$ 75,913	$ 4,720		$ 80,633	-$ 73,431	-$ 7,114		-$ 80,545	$ 88
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -	$ -		$ -	$ -
12	1925	Computer Software	20.00%	$ 565,798	$ 44,890		$ 610,688	-$ 372,627	-$ 90,647		-$ 463,274	$ 147,414
10	1930	Transportation Equipment	12.50%	$ 96,333	$ 128,093		$ 224,426	-$ 26,304	-$ 22,417		-$ 48,722	$ 175,705
8	1935	Stores Equipment	20.00%	$ 458	$ 73		$ 531	-$ 321	-$ 190		-$ 511	$ 20
8	1940	Tools, Shop & Garage Equipment	20.00%	$ 90,634	$ 4,253		$ 94,887	-$ 79,388	-$ 7,778		-$ 87,166	$ 7,721
8	1945	Measurement & Testing Equipment	20.00%	$ 11,007	$ 3,399		$ 14,406	-$ 83	-$ 340		-$ 423	$ 13,983
8	1950	Power Operated Equipment	20.00%	$ 64,091			$ 64,091	-$ 468	$ -		-$ 468	$ 63,623
8	1955	Communications Equipment		$ -			$ -	$ -	$ -		$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment		$ -			$ -	$ -	$ -		$ -	$ -
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	4.00%	-$ 2,426,115	-$ 426,196		-$ 2,852,311	$ 207,067	$ 121,080		$ 328,148	-$ 2,524,163
	etc.						$ -	$ -			$ -	$ -
								$ -				
		Total		**$ 29,811,592**	**$ 1,942,235**	**$ -**	**$ 31,753,827**	**-$ 9,029,842**	**-$ 1,299,767**	**$ -**	**-$ 10,329,609**	**$ 21,424,218**

Appendix 2-B
Fixed Asset Continuity Schedule

Year [1] **2010**

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land		$ 150,429	$ 244		$ 150,673	$ -	$ -		$ -	$ 150,673
47	1808	Buildings	4.00%	$ 148,263	$ 6,292		$ 154,555	-$ 43,409	-$ 5,994		-$ 49,403	$ 105,152
13	1810	Leasehold Improvements	10.00%	$ 7,040			$ 7,040	-$ 5,632	-$ 1,408		-$ 7,040	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -	$ -		$ -	$ -
47	1820	Distribution Station Equipment <50 kV	4.00%	$ 499,229			$ 499,229	-$ 199,034	-$ 17,937		-$ 216,970	$ 282,258
47	1825	Storage Battery Equipment	4.00%	$ -			$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 4,660,839	$ 407,253		$ 5,068,092	-$ 1,773,597	-$ 219,799		-$ 1,993,395	$ 3,074,697
47	1835	Overhead Conductors & Devices	4.00%	$ 9,531,432	$ 624,038		$ 10,155,470	-$ 2,382,864	-$ 366,490		-$ 2,749,354	$ 7,406,115
47	1840	Underground Conduit	4.00%	$ 2,212,620	$ 70,161		$ 2,282,781	-$ 956,622	-$ 102,782		-$ 1,059,404	$ 1,223,377
47	1845	Underground Conductors & Devices	4.00%	$ 4,748,172	$ 163,646		$ 4,911,818	-$ 1,096,747	-$ 191,933		-$ 1,288,680	$ 3,623,138
47	1850	Line Transformers	4.00%	$ 5,975,585	$ 477,753		$ 6,453,338	-$ 2,019,670	-$ 256,839		-$ 2,276,510	$ 4,176,829
47	1855	Services (Overhead & Underground)	4.00%	$ 2,797,274	$ 239,939		$ 3,037,212	-$ 636,881	-$ 109,244		-$ 746,125	$ 2,291,087
47	1860	Meters	4.00%	$ 2,721,532	$ 103,209		$ 2,824,741	-$ 810,490	-$ 101,966		-$ 912,456	$ 1,912,285
47	1860	Meters (Smart Meters)		$ -			$ -	$ -	$ -		$ -	$ -
N/A	1905	Land		$ -			$ -	$ -	$ -		$ -	$ -
CEC	1906	Land Rights		$ -			$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures		$ -			$ -	$ -	$ -		$ -	$ -
13	1910	Leasehold Improvements		$ -			$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 58,466	$ 8,921		$ 67,387	-$ 51,142	-$ 3,380		-$ 54,522	$ 12,865
8	1915	Office Furniture & Equipment (5 years)	20.00%	$ 5,594			$ 5,594	-$ 559	-$ 559		-$ 1,119	$ 4,476
10	1920	Computer Equipment - Hardware	20.00%	$ 80,633	$ 2,564		$ 83,197	-$ 80,545	-$ 7,842		-$ 88,387	-$ 5,190
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -	$ -		$ -	$ -
12	1925	Computer Software	20.00%	$ 610,688	$ 61,396		$ 672,084	-$ 463,274	-$ 101,276		-$ 564,550	$ 107,534
10	1930	Transportation Equipment	12.50%	$ 224,426	$ 1,871,335		$ 2,095,762	-$ 48,722	-$ 147,381		-$ 196,103	$ 1,899,659
8	1935	Stores Equipment	20.00%	$ 531	$ 723		$ 1,254	-$ 511	-$ 270		-$ 781	$ 473
8	1940	Tools, Shop & Garage Equipment	20.00%	$ 94,887	$ 23,622		$ 118,508	-$ 87,166	-$ 10,565		-$ 97,731	$ 20,777
8	1945	Measurement & Testing Equipment	20.00%	$ 14,406			$ 14,406	-$ 423	-$ 680		-$ 1,103	$ 13,304
8	1950	Power Operated Equipment	20.00%	$ 64,091			$ 64,091	-$ 468	$ -		-$ 468	$ 63,623
8	1955	Communications Equipment		$ -			$ -	$ -	$ -		$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment		$ -			$ -	$ -	$ -		$ -	$ -
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	4.00%	-$ 2,852,311	-$ 443,482		-$ 3,295,793	$ 328,148	$ 138,474		$ 466,621	-$ 2,829,171
	etc.						$ -	$ -			$ -	$ -
		Total		**$ 31,753,827**	**$ 3,617,615**	**$ -**	**$ 35,371,442**	**-$ 10,329,609**	**-$ 1,507,872**	**$ -**	**-$ 11,837,481**	**$ 23,533,961**

Appendix 2-B
Fixed Asset Continuity Schedule

Year [1] **2011**

			Cost				Accumulated Depreciation				
OEB	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land		$ 150,673	$ 8,271		$ 158,944	$ -	$ -		$ -	$ 158,944
1808	Buildings	4.00%	$ 154,555	$ 20,327		$ 174,882	-$ 49,403	-$ 6,527		-$ 55,930	$ 118,952
1810	Leasehold Improvements	10.00%	$ 7,040	$ -		$ 7,040	-$ 7,040	-$ 1,408		-$ 8,448	-$ 1,408
1815	Transformer Station Equipment >50 kV		$ -	$ -		$ -	$ -	$ -		$ -	$ -
1820	Distribution Station Equipment <50 kV	4.00%	$ 499,229			$ 499,229	-$ 216,970	-$ 17,937		-$ 234,907	$ 264,322
1825	Storage Battery Equipment	4.00%	$ -			$ -	$ -	$ -		$ -	$ -
1830	Poles, Towers & Fixtures	4.00%	$ 5,068,092	$ 350,281		$ 5,418,373	-$ 1,993,395	-$ 234,949		-$ 2,228,345	$ 3,190,029
1835	Overhead Conductors & Devices	4.00%	$ 10,155,470	$ 335,000		$ 10,490,470	-$ 2,749,354	-$ 385,671		-$ 3,135,025	$ 7,355,445
1840	Underground Conduit	4.00%	$ 2,282,781	$ 50,267		$ 2,333,048	-$ 1,059,404	-$ 105,191		-$ 1,164,595	$ 1,168,453
1845	Underground Conductors & Devices	4.00%	$ 4,911,818	$ 256,072		$ 5,167,890	-$ 1,288,680	-$ 200,327		-$ 1,489,007	$ 3,678,883
1850	Line Transformers	4.00%	$ 6,453,338	$ 693,252		$ 7,146,590	-$ 2,276,510	-$ 280,259		-$ 2,556,769	$ 4,589,821
1855	Services (Overhead & Underground)	4.00%	$ 3,037,212	$ 267,698		$ 3,304,910	-$ 746,125	-$ 119,397		-$ 865,522	$ 2,439,388
1860	Meters	4.00%	$ 2,824,741	$ 78,815		$ 2,903,557	-$ 912,456	-$ 105,606		-$ 1,018,063	$ 1,885,494
1860	Meters (Smart Meters)		$ -			$ -	$ -	$ -		$ -	$ -
1905	Land		$ -			$ -	$ -	$ -		$ -	$ -
1906	Land Rights		$ -			$ -	$ -	$ -		$ -	$ -
1908	Buildings & Fixtures		$ -			$ -	$ -	$ -		$ -	$ -
1910	Leasehold Improvements	10.00%	$ -	$ 154,461		$ 154,461	$ -	-$ 7,723		-$ 7,723	$ 146,738
1915	Office Furniture & Equipment (10 years)	10.00%	$ 67,387	$ 2,404		$ 69,792	-$ 54,522	-$ 3,946		-$ 58,469	$ 11,323
1915	Office Furniture & Equipment (5 years)	20.00%	$ 5,594			$ 5,594	-$ 1,119	-$ 559		-$ 1,678	$ 3,916
1920	Computer Equipment - Hardware	20.00%	$ 83,197	$ 10,807		$ 94,005	-$ 88,387	-$ 9,180		-$ 97,567	-$ 3,562
1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -	$ -		$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -	$ -		$ -	$ -
1925	Computer Software	20.00%	$ 672,084	$ 19,607		$ 691,691	-$ 564,550	-$ 109,376		-$ 673,926	$ 17,765
1930	Transportation Equipment	12.50%	$ 2,095,762	$ 596,685		$ 2,692,447	-$ 196,103	-$ 301,633		-$ 497,736	$ 2,194,711
1935	Stores Equipment	20.00%	$ 1,254			$ 1,254	-$ 781	-$ 342		-$ 1,124	$ 131
1940	Tools, Shop & Garage Equipment	20.00%	$ 118,508	$ 35,356		$ 153,865	-$ 97,731	-$ 16,463		-$ 114,194	$ 39,671
1945	Measurement & Testing Equipment	20.00%	$ 14,406	$ 56		$ 14,462	-$ 1,103	-$ 685		-$ 1,788	$ 12,674
1950	Power Operated Equipment	20.00%	$ 64,091			$ 64,091	-$ 468	$ -		-$ 468	$ 63,623
1955	Communications Equipment		$ -			$ -	$ -	$ -		$ -	$ -
1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -	$ -		$ -	$ -
1960	Miscellaneous Equipment		$ -			$ -	$ -	$ -		$ -	$ -
1975	Load Management Controls Utility Premises		$ -			$ -	$ -	$ -		$ -	$ -
1980	System Supervisor Equipment		$ -			$ -	$ -	$ -		$ -	$ -
1985	Miscellaneous Fixed Assets		$ -			$ -	$ -	$ -		$ -	$ -
1995	Contributions & Grants	4.00%	-$ 3,295,793	-$ 445,443		-$ 3,741,235	$ 466,621	$ 156,252		$ 622,874	-$ 3,118,362
etc.						$ -	$ -			$ -	$ -
	Total		**$ 35,371,442**	**$ 2,433,918**	**$ -**	**$ 37,805,360**	**-$ 11,837,481**	**-$ 1,750,927**	**$ -**	**-$ 13,588,408**	**$ 24,216,951**

Appendix 2-B
Fixed Asset Continuity Schedule

Year [1] **2012**

			Cost				Accumulated Depreciation				
OEB	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land		$ 158,944			$ 158,944	$ -	$ -		$ -	$ 158,944
1808	Buildings	4.00%	$ 174,882			$ 174,882	-$ 55,930	-$ 6,933		-$ 62,863	$ 112,019
1810	Leasehold Improvements	10.00%	$ 7,040			$ 7,040	-$ 8,448	-$ 1,408		-$ 9,856	-$ 2,816
1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -	$ -		$ -	$ -
1820	Distribution Station Equipment <50 kV	4.00%	$ 499,229	$ -		$ 499,229	-$ 234,907	-$ 17,937		-$ 252,843	$ 246,385
1825	Storage Battery Equipment	4.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
1830	Poles, Towers & Fixtures	4.00%	$ 5,418,373	$ 733,000		$ 6,151,373	-$ 2,228,345	-$ 256,615		-$ 2,484,960	$ 3,666,414
1835	Overhead Conductors & Devices	4.00%	$ 10,490,470	$ 505,000		$ 10,995,470	-$ 3,135,025	-$ 402,471		-$ 3,537,496	$ 7,457,974
1840	Underground Conduit	4.00%	$ 2,333,048	$ 281,000		$ 2,614,048	-$ 1,164,595	-$ 111,816		-$ 1,276,411	$ 1,337,637
1845	Underground Conductors & Devices	4.00%	$ 5,167,890	$ 180,000		$ 5,347,890	-$ 1,489,007	-$ 209,049		-$ 1,698,055	$ 3,649,834
1850	Line Transformers	4.00%	$ 7,146,590	$ 482,000		$ 7,628,590	-$ 2,556,769	-$ 303,765		-$ 2,860,534	$ 4,768,057
1855	Services (Overhead & Underground)	4.00%	$ 3,304,910	$ 374,000		$ 3,678,910	-$ 865,522	-$ 132,231		-$ 997,753	$ 2,681,157
1860	Meters	4.00%	$ 2,903,557	$ 70,000		$ 2,973,557	-$ 1,018,063	-$ 108,583		-$ 1,126,645	$ 1,846,911
1860	Meters (Smart Meters)		$ -			$ -	$ -	$ -		$ -	$ -
1905	Land		$ -			$ -	$ -	$ -		$ -	$ -
1906	Land Rights		$ -			$ -	$ -	$ -		$ -	$ -
1908	Buildings & Fixtures		$ -			$ -	$ -	$ -		$ -	$ -
1910	Leasehold Improvements	10.00%	$ 154,461	$ 60,000		$ 214,461	-$ 7,723	-$ 18,446		-$ 26,169	$ 188,292
1915	Office Furniture & Equipment (10 years)	10.00%	$ 69,792			$ 69,792	-$ 58,469	-$ 4,067		-$ 62,535	$ 7,256
1915	Office Furniture & Equipment (5 years)	20.00%	$ 5,594			$ 5,594	-$ 1,678	-$ 559		-$ 2,238	$ 3,357
1920	Computer Equipment - Hardware	20.00%	$ 94,005	$ 25,000		$ 119,005	-$ 97,567	-$ 12,760		-$ 110,327	$ 8,678
1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -	$ -		$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -	$ -		$ -	$ -
1925	Computer Software	20.00%	$ 691,691	$ -		$ 691,691	-$ 673,926	-$ 111,337		-$ 785,263	-$ 93,572
1930	Transportation Equipment	12.50%	$ 2,692,447	$ 380,000		$ 3,072,447	-$ 497,736	-$ 362,675		-$ 860,411	$ 2,212,036
1935	Stores Equipment	20.00%	$ 1,254			$ 1,254	-$ 1,124	-$ 342		-$ 1,466	-$ 211
1940	Tools, Shop & Garage Equipment	20.00%	$ 153,865	$ 35,000		$ 188,865	-$ 114,194	-$ 23,499		-$ 137,693	$ 51,172
1945	Measurement & Testing Equipment	20.00%	$ 14,462			$ 14,462	-$ 1,788	-$ 691		-$ 2,479	$ 11,983
1950	Power Operated Equipment	20.00%	$ 64,091			$ 64,091	-$ 468	$ -		-$ 468	$ 63,623
1955	Communications Equipment		$ -			$ -	$ -	$ -		$ -	$ -
1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -	$ -		$ -	$ -
1960	Miscellaneous Equipment		$ -			$ -	$ -	$ -		$ -	$ -
1975	Load Management Controls Utility Premises		$ -			$ -	$ -	$ -		$ -	$ -
1980	System Supervisor Equipment	20.00%	$ -	$ 200,000		$ 200,000	$ -	-$ 20,000		-$ 20,000	$ 180,000
1985	Miscellaneous Fixed Assets		$ -			$ -	$ -	$ -		$ -	$ -
1995	Contributions & Grants	4.00%	-$ 3,741,235	-$ 485,000		-$ 4,226,235	$ 622,874	$ 174,861		$ 797,735	-$ 3,428,500
etc.						$ -	$ -	$ -		$ -	$ -
	Total		**$ 37,805,360**	**$ 2,840,000**	**$ -**	**$ 40,645,360**	**-$ 13,588,408**	**-$ 1,930,321**	**$ -**	**-$ 15,518,730**	**$ 25,126,630**

Gross Asset Table

GROSS ASSET	2008 Board Approved ($'s)	2008 Actual ($'s)	Variance from 2008 Board Approved	2008 Actual ($'s)	2009 Actual ($'s)	Variance from 2008 Actual
Land and Buildings						
1805-Land	$120,344	$150,429	$30,085	$150,429	$150,429	$0
1806-Land Rights	$26,340	$0	-$26,340	$0	$0	$0
1808-Buildings and Fixtures	$155,349	$136,009	-$19,340	$136,009	$148,263	$12,254
1905-Land	$0	$0	$0	$0	$0	$0
1906-Land Rights	$0	$0	$0	$0	$0	$0
1810-Leasehold Improvements	$0	$7,040	$7,040	$7,040	$7,040	$0
Sub-Total-Land and Buildings	$302,033	$293,478	-$8,555	$293,478	$305,732	$12,254
TS Primary Above 50						
1815-Transfromer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0
Sub-Total-TS Primary Above 50	$0	$0	$0	$0	$0	$0
DS						
1820-Distribution Station Equipment - Normally Primary below 50 kV	$283,529	$499,229	$215,700	$499,229	$499,229	$0
Sub-Total-DS	$283,529	$499,229	$215,700	$499,229	$499,229	$0
Poles and Wires						
1830-Poles, Towers and Fixtures	$2,249,627	$4,336,711	$2,087,084	$4,336,711	$4,660,839	$324,127
1835-Overhead Conductors and Devices	$8,398,500	$8,964,219	$565,719	$8,964,219	$9,531,432	$567,212
1840-Underground Conduit	$912,671	$2,147,360	$1,234,689	$2,147,360	$2,212,620	$65,260
1845-Underground Conductors and Devices	$3,397,383	$4,274,462	$877,079	$4,274,462	$4,748,172	$473,710
Sub-Total-Poles and Wires	$14,958,181	$19,722,753	$4,764,572	$19,722,753	$21,153,062	$1,430,309
Line Transfromers						
1850-Line Transfromers	$4,259,046	$5,699,174	$1,440,128	$5,699,174	$5,975,585	$276,411
Sub-Total-Line Transfromers	$4,259,046	$5,699,174	$1,440,128	$5,699,174	$5,975,585	$276,411
Services and Meters						
1855-Services	$2,070,505	$2,488,160	$417,655	$2,488,160	$2,797,274	$309,114
1860-Meters	$1,926,294	$2,567,211	$640,917	$2,567,211	$2,721,532	$154,321
Sub-Total-Services and Meters	$3,996,799	$5,055,371	$1,058,572	$5,055,371	$5,518,806	$463,435
General Plant						
1908-Buildings and Fixtures	$0	$0	$0	$0	$0	$0
1910-Leasehold Improvements	$0	$0	$0	$0	$0	$0
Sub-Total-General Plant	$0	$0	$0	$0	$0	$0
IT Assets						
1920-Computer Equipment - Hardware	$13,419	$75,913	$62,494	$75,913	$80,633	$4,720
1925-Computer Software	$364,107	$565,798	$201,691	$565,798	$610,688	$44,890
Sub-Total-IT Assets	$377,526	$641,711	$264,185	$641,711	$691,321	$49,610
Equipment						
1915-Office Furniture and Equipment	$14,438	$63,467	$49,029	$63,467	$64,060	$593
1930-Transportation Equipment	$14,983	$96,333	$81,350	$96,333	$224,426	$128,093
1935-Stores Equipment	$0	$458	$458	$458	$531	$73
1940-Tools, Shop and Garage Equipment	$0	$90,634	$90,634	$90,634	$94,887	$4,253
1945-Measurement and Testing Equipment	$11,007	$11,007	$0	$11,007	$14,406	$3,399
1950-Power Operated Equipment	$64,091	$64,091	$0	$64,091	$64,091	$0
1955-Communication Equipment	$0	$0	$0	$0	$0	$0
1960-Miscellaneous Equipment	$0	$0	$0	$0	$0	$0
Sub-Total-Equipment	$104,519	$325,991	$221,472	$325,991	$462,402	$136,411
Other Distribution Assets						
1825-Storage Battery Equipment	$0	$0	$0	$0	$0	$0
1970-Load Management Controls - Customer Premises	$0	$0	$0	$0	$0	$0
1975-Load Management Controls - Utility Premises	$0	$0	$0	$0	$0	$0
1980-System Supervisory Equipment	$0	$0	$0	$0	$0	$0
1985-Sentinel Lighting Rental Units	$0	$0	$0	$0	$0	$0
1990-Other Tangible Property	$0	$0	$0	$0	$0	$0
1995-Contributions and Grants - Credit	-$1,796,263	-$2,426,115	-$629,852	-$2,426,115	-$2,852,311	-$426,196
Sub-Total-Other Distribution Assets	-$1,796,263	-$2,426,115	-$629,852	-$2,426,115	-$2,852,311	-$426,196
GROSS ASSET TOTAL	$22,485,370	$29,811,591	$7,326,221	$29,811,591	$31,753,826	$1,942,235

Gross Asset Table

GROSS ASSET	2009 Actual ($'s)	2010 Actual ($'s)	Variance from 2009 Actual	2010 Actual ($'s)	2011 Bridge ($'s)	Variance from 2010 Actual
Land and Buildings						
1805-Land	$150,429	$150,673	$244	$150,673	$158,944	$8,271
1806-Land Rights	$0	$0	$0	$0	$0	$0
1808-Buildings and Fixtures	$148,263	$154,555	$6,292	$154,555	$174,882	$20,327
1905-Land	$0	$0	$0	$0	$0	$0
1906-Land Rights	$0	$0	$0	$0	$0	$0
1810-Leasehold Improvements	$7,040	$7,040	$0	$7,040	$7,040	$0
Sub-Total-Land and Buildings	$305,732	$312,268	$6,536	$312,268	$340,866	$28,597
TS Primary Above 50						
1815-Transfromer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0
Sub-Total-TS Primary Above 50	$0	$0	$0	$0	$0	$0
DS						
1820-Distribution Station Equipment - Normally Primary below 50 kV	$499,229	$499,229	$0	$499,229	$499,229	$0
Sub-Total-DS	$499,229	$499,229	$0	$499,229	$499,229	$0
Poles and Wires						
1830-Poles, Towers and Fixtures	$4,660,839	$5,068,092	$407,253	$5,068,092	$5,418,373	$350,281
1835-Overhead Conductors and Devices	$9,531,432	$10,155,470	$624,038	$10,155,470	$10,490,470	$335,000
1840-Underground Conduit	$2,212,620	$2,282,781	$70,161	$2,282,781	$2,333,048	$50,267
1845-Underground Conductors and Devices	$4,748,172	$4,911,818	$163,646	$4,911,818	$5,167,890	$256,072
Sub-Total-Poles and Wires	$21,153,062	$22,418,161	$1,265,098	$22,418,161	$23,409,781	$991,621
Line Transfromers						
1850-Line Transfromers	$5,975,585	$6,453,338	$477,753	$6,453,338	$7,146,590	$693,252
Sub-Total-Line Transfromers	$5,975,585	$6,453,338	$477,753	$6,453,338	$7,146,590	$693,252
Services and Meters						
1855-Services	$2,797,274	$3,037,212	$239,939	$3,037,212	$3,304,910	$267,698
1860-Meters	$2,721,532	$2,824,741	$103,209	$2,824,741	$2,903,557	$78,815
Sub-Total-Services and Meters	$5,518,806	$5,861,954	$343,148	$5,861,954	$6,208,467	$346,513
General Plant						
1908-Buildings and Fixtures	$0	$0	$0	$0	$0	$0
1910-Leasehold Improvements	$0	$0	$0	$0	$154,461	$154,461
Sub-Total-General Plant	$0	$0	$0	$0	$154,461	$154,461
IT Assets						
1920-Computer Equipment - Hardware	$80,633	$83,197	$2,564	$83,197	$94,005	$10,807
1925-Computer Software	$610,688	$672,084	$61,396	$672,084	$691,691	$19,607
Sub-Total-IT Assets	$691,321	$755,281	$63,961	$755,281	$785,696	$30,414
Equipment						
1915-Office Furniture and Equipment	$64,060	$72,981	$8,921	$72,981	$75,386	$2,404
1930-Transportation Equipment	$224,426	$2,095,762	$1,871,335	$2,095,762	$2,692,447	$596,685
1935-Stores Equipment	$531	$1,254	$723	$1,254	$1,254	$0
1940-Tools, Shop and Garage Equipment	$94,887	$118,508	$23,622	$118,508	$153,865	$35,356
1945-Measurement and Testing Equipment	$14,406	$14,406	$0	$14,406	$14,462	$56
1950-Power Operated Equipment	$64,091	$64,091	$0	$64,091	$64,091	$0
1955-Communication Equipment	$0	$0	$0	$0	$0	$0
1960-Miscellaneous Equipment	$0	$0	$0	$0	$0	$0
Sub-Total-Equipment	$462,402	$2,367,003	$1,904,601	$2,367,003	$3,001,505	$634,502
Other Distribution Assets						
1825-Storage Battery Equipment	$0	$0	$0	$0	$0	$0
1970-Load Management Controls - Customer Premises	$0	$0	$0	$0	$0	$0
1975-Load Management Controls - Utility Premises	$0	$0	$0	$0	$0	$0
1980-System Supervisory Equipment	$0	$0	$0	$0	$0	$0
1985-Sentinel Lighting Rental Units	$0	$0	$0	$0	$0	$0
1990-Other Tangible Property	$0	$0	$0	$0	$0	$0
1995-Contributions and Grants - Credit	-$2,852,311	-$3,295,793	-$443,482	-$3,295,793	-$3,741,235	-$445,443
Sub-Total-Other Distribution Assets	-$2,852,311	-$3,295,793	-$443,482	-$3,295,793	-$3,741,235	-$445,443
GROSS ASSET TOTAL	$31,753,826	$35,371,441	$3,617,615	$35,371,441	$37,805,359	$2,433,918

Gross Asset Table

GROSS ASSET	2011 Bridge ($'s)	2012 Test ($'s)	Variance from 2011 Bridge
Land and Buildings			
1805-Land	$158,944	$158,944	$0
1806-Land Rights	$0	$0	$0
1808-Buildings and Fixtures	$174,882	$174,882	$0
1905-Land	$0	$0	$0
1906-Land Rights	$0	$0	$0
1810-Leasehold Improvements	$7,040	$7,040	$0
Sub-Total-Land and Buildings	$340,866	$340,866	$0
TS Primary Above 50			
1815-Transfromer Station Equipment - Normally Primary above 50 kV	$0	$0	$0
Sub-Total-TS Primary Above 50	$0	$0	$0
DS			
1820-Distribution Station Equipment - Normally Primary below 50 kV	$499,229	$499,229	$0
Sub-Total-DS	$499,229	$499,229	$0
Poles and Wires			
1830-Poles, Towers and Fixtures	$5,418,373	$6,151,373	$733,000
1835-Overhead Conductors and Devices	$10,490,470	$10,995,470	$505,000
1840-Underground Conduit	$2,333,048	$2,614,048	$281,000
1845-Underground Conductors and Devices	$5,167,890	$5,347,890	$180,000
Sub-Total-Poles and Wires	$23,409,781	$25,108,781	$1,699,000
Line Transfromers			
1850-Line Transfromers	$7,146,590	$7,628,590	$482,000
Sub-Total-Line Transfromers	$7,146,590	$7,628,590	$482,000
Services and Meters			
1855-Services	$3,304,910	$3,678,910	$374,000
1860-Meters	$2,903,557	$2,973,557	$70,000
Sub-Total-Services and Meters	$6,208,467	$6,652,467	$444,000
General Plant			
1908-Buildings and Fixtures	$0	$0	$0
1910-Leasehold Improvements	$154,461	$214,461	$60,000
Sub-Total-General Plant	$154,461	$214,461	$60,000
IT Assets			
1920-Computer Equipment - Hardware	$94,005	$119,005	$25,000
1925-Computer Software	$691,691	$691,691	$0
Sub-Total-IT Assets	$785,696	$810,696	$25,000
Equipment			
1915-Office Furniture and Equipment	$75,386	$75,386	$0
1930-Transportation Equipment	$2,692,447	$3,072,447	$380,000
1935-Stores Equipment	$1,254	$1,254	$0
1940-Tools, Shop and Garage Equipment	$153,865	$188,865	$35,000
1945-Measurement and Testing Equipment	$14,462	$14,462	$0
1950-Power Operated Equipment	$64,091	$64,091	$0
1955-Communication Equipment	$0	$0	$0
1960-Miscellaneous Equipment	$0	$0	$0
Sub-Total-Equipment	$3,001,505	$3,416,505	$415,000
Other Distribution Assets			
1825-Storage Battery Equipment	$0	$0	$0
1970-Load Management Controls - Customer Premises	$0	$0	$0
1975-Load Management Controls - Utility Premises	$0	$0	$0
1980-System Supervisory Equipment	$0	$200,000	$200,000
1985-Sentinel Lighting Rental Units	$0	$0	$0
1990-Other Tangible Property	$0	$0	$0
1995-Contributions and Grants - Credit	-$3,741,235	-$4,226,235	-$485,000
Sub-Total-Other Distribution Assets	-$3,741,235	-$4,026,235	-$285,000
GROSS ASSET TOTAL	$37,805,359	$40,645,359	$2,840,000

Materiality Analysis of Gross Assets

2008 Board Approved compared to 2008 Actual:

The large variance between 2008 Board Approved and 2008 Actual is simply related to the fact that the Board Approved amounts represents Erie Thames stand alone approved 2008 gross assets, while the 2008 actual amounts include the gross assets of West Perth Power Corporation and Clinton Power Corporation. When you remove the Gross Asset cost of WPPI of $5,193,244 and $1,593,049 for CPC the remaining total change for Erie Thames is $539,938 which is related to (i) $215,000 for the capitalization of transformers in inventory at year end for financial statement purposes which was not included as part of the 2008 Cost of Service application; and (ii) the remainder is attributable to spending for each entity not included in rate base during the Cost of Service process.

2008 Actual compared to 2009 Actual:

The change in gross assets from 2008 to 2009 of $1,942,235 is comprised of Erie Thames's capital spend for the year of $816,000 (low capital spend given the 2009 work interruption), WPPI's capital spend of $726,000 and CPC's capital spend of $400,000. The amounts for WPPI and CPC are not outside the normal spend for a year while the spend for Erie Thames was abnormally small.

2009 Actual compared to 2010 Actual:

The large change in gross assets in 2010 versus 2009 of $3,617,000. In 2010 the line staff were brought within the utility from the affiliate along with all of the required vehicles. The addition of $1,871,000 in vehicles was a transfer of assets only and reduces the change in fixed assets to $1,750,000. This capital spend is low compared to a normal spending year, however significant resources were used to implement the smart meter programs of both WPPI and Erie Thames in 2010. But for the mandated installation of smart meters and the diversion of resources to the smart meter program, Erie Thames would have pursued additional capital projects.

2010 Actual compared to 2011 Bridge:

The change in net fixed assets from 2010 to 2011 of $2,400,000 represents the first year of merged spending for the new combined LDC and included the addition of two large vehicles to the fleet to replace two vehicles that had been in service well beyond the end of useful life.

2011 Bridge compared to 2012 Actual:

The change in net fixed assets in the Test year of $2,840,000 represents spending that is in line with the sustainment spend as detailed later in this section of the application.

3.0 Capital Budget – General

Erie Thames is an infrastructure-based business with its distribution system assets the key element in the delivery of electricity to its existing and new customers. Erie Thames distribution assets range in age from new to over 60 years old.

Asset management is the professional management of physical infrastructure with systematic methodology integrating best practices in all aspects of selection, design, construction, operation, maintenance, replacement and disposition. The goal is to use an Asset Management Plan to optimize the whole life business impact of costs, performance and risk exposures of Erie Thames' physical assets. Performance of the assets is directly related to reliability of the distribution system which is another key regulatory and customer satisfaction measure second only to rates. Accompanying this Schedule is Erie Thames Asset Condition Assessment and Asset Management Plan prepared by Metsco Energy Solutions and Erie Thames. The Asset Management Report represents the most recent document containing a high level description of Erie Thames's assets, their condition, the criteria used to determine when replacement should occur, and a five to ten year financial forecast for the necessary capital and maintenance required to meet Erie Thames' objectives. The reliability of the distribution system is the major driver of the Asset Management Plan, and maintaining or improving the level of reliability is of primary importance to Erie Thames.

The annual replacement costs, found in the Asset Management Plan, are engineering estimates only and the actual expenditure levels in the capital budgets for each year will vary somewhat based on project scope, prevailing construction costs and other outside influences (e.g. relocation requests, system expansions, etc.). The Asset Management system "Optimizer" utilized by Erie Thames has been in use for approximately ten years, and has been an effective tool for prioritizing projects. However, the "Optimizer" did not go the next step to assess what is required for a sustainable capital spend. The Asset Condition Assessment performed by Metsco, an independent consultant provides an accurate forecast on capital investments costs required to sustain Erie Thames distribution assets over the next rolling five to ten year horizon. The Asset Condition Assessment and Management Plan supports an Optimal annual expenditure of $2.7 million for **sustainment** of Erie Thames fixed distribution assets which is a significant increase.

Erie Thames has reviewed in detail the plan and feels a two-stepped approach would be a more prudent approach to effectively manage the significant expenditure increase for sustainment of distribution fixed assets. A two-stepped approach will mitigate Erie Thames customer and business impacts. The detailed Capital Project Description puts forward $3,325,000 in expenditures in 2012 which will continue for the next few years for the necessary sustainment and expansion of Erie Thames assets.

3.1 Asset Management Sustainment/Enhancements

Asset management sustainment/enhancements projects are identified and then critically assessed and prioritized based on the following factors:

- Safety related to both the public or employees;
- System reliability – customer outages or system performance related to feeder outages or worst performing feeders, aging assets or equipment/plant failure, or outdated standards;
- Power Quality;
- Environmental impacts;
- Investment effectiveness;
- Capacity requirements; and
- Total Cost of the Project.

These projects are driven by the condition of the asset and the need to replace or enhance the distribution plant to improve or sustain system and or customer reliability, address safety related issues or upgrade old plant to meet new standards due to materials/equipment being obsolete.

Identification of the projects is through annual maintenance and inspections programs and reviews of records of outage frequency and duration/severity. The recent installation of Smart Meters will enhance our ability to identify issues and prioritize projects.

Load growth caused by new customer connections and increased demand of existing customers over time can result in a need for capacity improvement on the system. Projects can take the form of new or upgraded feeders and transformers. These projects are not customer-specific, but rather, benefit many customers.

3.2 Municipal Reconstruction

These capital projects are driven by requests from by the municipal governments based on their work program (for example, road widening or street extension/closure). Typically, Erie Thames performs the work before or contemporaneously with the municipal work and the work is generally completed in the year that the municipal work is done. These projects may be partially funded through capital contributions which are generally calculated as 50% of labour and vehicle costs, in accordance with the *Public Service Works on Highways Act*.

3.3 Regulatory Requirements

Erie Thames is a licensed distributor and required to comply with regulatory requirements. Projects of this nature are driven by regulatory bodies such as the OEB, IESO, ESA, Ministry of Energy & Infrastructure (“MEI”) or the Ministry of the Environment.

3.4 Substations

Substation investments include work related to power transformers, switchgear, breakers, relays, buss refurbishment, and station facilities, which are undertaken to improve or maintain reliability to Erie Thames customers along with maintaining the security of the grid and safety of Erie Thames employees and the public.

Erie Thames in its review of its asset condition, will undertake the replacement and upgrade of existing aged power substation transformers that are at or are reaching their end of useful life (>40yrs) and are operating at rated capacity such that they run the risk of being overloaded. This is to prevent high risk in–service life failures to improve system and customer reliability, along with providing increased capacity to the grid to accommodate future load increases. The condition of these critical substation transformers are confirmed by the company's asset condition assessment prepared by Metsco Energy Solutions.

3.5 Ongoing Asset Replacements

Erie Thames completes visual inspections of its plant, performs predictive testing on certain assets where such testing is available, and replaces assets based on inspection and testing results as warranted. Erie Thames would note the asset condition of the CPC system requires significant investment in assets and in substations. New assets require less maintenance, deliver better reliability and reduce safety risks to the general public. Erie Thames has taken a more proactive approach in this matter to reduce the future O&M costs associated with maintaining aging infrastructure.

3.6 Development/ Subdivision Expansion Capital

These projects are driven by the development of subdivisions and/or construction of new customer facilities. The capital spend of Erie Thames, and the third party, is determined by using the OEB's Distribution System Code ("DSC") and Erie Thames Conditions of Service.

3.7 Customer Connections

These projects are driven by individual customer requests for new or upgraded residential, commercial or industrial services. This spending is based upon historical averages. Erie Thames is obligated to connect and service these customers in accordance with the DSC and Erie Thames Conditions of Service.

3.8 Fleet

New fleet investments are required to replace vehicles that have reached their useful life and/or are demonstrating excessive maintenance costs, experience frequent breakdowns or are ergonomically unsuitable to the employees using the vehicles. Replacing old vehicles which are having frequent break downs and high maintenance costs will improve utilization and efficiency. Fleet replacements are included in Erie Thames 2011-2015 capital plan.

3.9 General Plant

These investments include:

- Building Facilities capital which is driven as part of the overall improvements in work place conditions, to maintain employee safety and efficiency.
- IT systems (software or hardware) enhancements for improved business and operational needs.
- Tools/Equipment – replacements are for tools and equipment that have come to the end of their useful life or become a health and safety risk to the user.
- Meter Purchases
- SCADA and Smart Grid

3.10 Capitalization Policy

Erie Thames has followed Generally Accepted Accounting Principles, in particular the CICA Handbook Section 3060, Capital Assets as well as the guidelines as set out in the OEB Accounting Procedure handbook for financial reporting periods to December 31, 2011. Property, plant and equipment purchased or constructed by Erie Thames are stated at historic costs and include contracted services, material, labour, engineering and overhead costs. Furthermore, constructed property, plant and equipment include ascribed interest during the period of construction.

When identifiable capital assets are retired or otherwise disposed of, their original cost and accumulated depreciation are removed from the accounts and the related gain or loss is included in the determination of income for the year. Repairs and maintenance expenditures are charged to operations as incurred.

Construction-in-progress comprises capital assets under construction, capital assets not yet placed into service and pre-construction activities related to specific projects expected to be constructed. These assets are not depreciated until place into service.

4.0 Net Fixed Assets

Erie Thames experienced continued growth in the net fixed assets resulting from normal capital investments, the acquisition of assets associated with CPC and WPPI and the Fixed Asset Continuity Schedules for 2008, 2009, 2010, 2011 Bridge Year and 2012 Test Year may be found at Exhibit <>, Tab <>, Schedule < >.

The below average spending in 2009 is primarily a result of the strike that lasted for 18 weeks during the prime construction period. Following the strike, efforts were directed toward operation and maintenance that was required to be completed and non-discretionary capital spending. As such discretionary capital spending was reduced.

The 2010 above average spending is primarily a result of the merger of Erie Thames with CPC and WPPI and the transfer of certain assets into Erie Thames from the former service affiliate. The transactions that occurred were recorded at Net Book Value.

Table 2-xx Summary of Additions to Net Fixed Assets

Year	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 Test Year	Ave. 2008 to 2011
Amount	**$ 2,490,833**	**$ 1,942,235**	**$ 3,617,615**	**$ 2,433,918**	**$ 2,840,000**	**$2,621,150**

5.0 Working Capital Allowance

The OEB in <> prescribes two acceptable approaches to calculating an appropriate Working Capital Allowance (“**WCA**”): (i) a utility specific lead/lag study; or (ii) the default value of 15% of controllable expenses and the cost of power. Erie Thames has chosen to use the 15% default methodology. Given the size of utility, and recent changes, such as the Clean Energy Benefit, that would tend to increase the WCA.

This Exhibit provides a schedule of the Working Capital Requirement for the bridge year (2011) and the Test year (2012). For comparison purposes, the approved and actual Working Capital Requirement for the base year (2008) is also shown. WCA will be recalculated at the time a decision is rendered using the most up-to-date information available.

Table <> - Working Capital Summary

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Test
Cost of Power	$ 34,025,046.44	$ 37,011,377.99	$ 40,082,660.19	$ 39,963,276.17	$ 36,951,816.67
OM&A Expenses					
Operations	$ 275,864.41	$ 262,099.83	$ 284,838.15	$ 274,004.39	$ 282,214.51
Maintenance	$ 1,951,406.27	$ 629,843.33	$ 768,547.66	$ 693,542.86	$ 724,349.14
Billing and Collecting	$ 971,450.24	$ 1,219,844.92	$ 1,356,295.64	$ 1,178,679.81	$ 1,247,914.04
Administration	$ 2,682,569.92	$ 3,558,052.42	$ 3,455,290.39	$ 3,686,890.87	$ 3,346,759.37
Working Capital	$ 39,906,337.28	$ 42,681,218.49	$ 45,947,632.03	$ 45,796,394.10	$ 42,553,053.73
WCA 15%	***$ 5,985,950.59***	***$ 6,402,182.77***	***$ 6,892,144.80***	***$ 6,869,459.11***	***$ 6,382,958.06***

6.0 <u>2012 Test Year Capital Program</u>

6.1 Capital Project Description

Erie Thames has been, and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers through effective capital spending. The capital spending by account is broken down by project in the table below. As projects can be charged to different OEB capital accounts, additional accounts have been identified where required.

				2012 Capital Assets by Project		Uniform System of Accounts #									
Project Name	Poles & Fixtures	OH Conductor	UG Conduit	UG Conductor	Transformers	Services	Meters	Building/Fixture	Hardware	Software	Tansportation	Tools	SCADA	Contributed Cap	TOTAL
	1830	1835	1840	1845	1850	1855	1860	1908	1920	1925	1930	1940	1980	1995	
Pole Replacement Program	$ 150,000														$ 150,000
New Service Connections & Upgrades						$ 285,000									$ 285,000
Aylmer, Park Street Ph2	$ 60,000	$ 20,000	$ 40,000	$ 20,000	$ 15,000		$ 25,000								$ 180,000
Belmont Hazelwood Crescent - Underground	$ 15,000		$ 30,000	$ 25,000	$ 45,000										$ 115,000
Clinton MS#2 Conversion	$ 111,000	$ 164,000	$ 5,000	$ 5,000	$ 65,000	$ 5,000									$ 355,000
Tavistock, William St	$ 45,000	$ 35,000													$ 80,000
Tavistock, Maria, Adam and Area	$ 83,000	$ 102,000			$ 65,000										$ 250,000
Municipal Road Reconstruction	$ 50,000														$ 50,000
Ingersoll, Ingersoll Street re-insulate	$ 55,000														$ 55,000
Ingersoll, Melita, Wohnam Street		$ 10,000	$ 75,000	$ 35,000	$ 60,000										$ 180,000
Otterville, Dover St 27kv Ext	$ 84,000	$ 128,000			$ 63,000										$ 275,000
Port Stanley Main St S: Jameson - Cornel			$ 112,000	$ 74,000	$ 135,000	$ 84,000									$ 405,000
Mitchell Conversion, Pond St and Thames	$ 57,000	$ 36,000			$ 12,000										$ 105,000
Mitchell Conversion, St George St	$ 10,000	$ 8,000			$ 22,000										$ 40,000
Clinton Town Hall UG Upgrade	$ 13,000	$ 2,000	$ 19,000	$ 21,000											$ 55,000
Substaions Upgrades								$ 20,000							$ 20,000
Fleet											$ 340,000				$ 340,000
Tools & Equipment												$ 35,000			$ 35,000
Meter Purchases							$ 45,000								$ 45,000
Computers, Monitors, Phones and Equipment									$ 25,000						$ 25,000
Pole Trailer/Fork Lift											$ 40,000				$ 40,000
Building Leasehold Improvements								$ 40,000							$ 40,000
SCADA and Automation													$ 200,000		$ 200,000
Total by Account GL	**$ 733,000**	**$ 505,000**	**$ 281,000**	**$ 180,000**	**$ 482,000**	**$ 374,000**	**$ 70,000**	**$ 60,000**	**$ 25,000**	**$ -**	**$ 380,000**	**$ 35,000**	**$ 200,000**	**$ -**	**$3,325,000**

6.2 Specific Capital Projects/Programs

6.2.1 Pole Replacement Program

Each year Erie Thames budgets for pole testing on a 10 year rolling cycle. The pole replacement program is designed to address necessary high and medium priority pole replacements. Identified rotten poles pose a public and employee risk which needs to be addressed in appropriate time frames. The project is designed to mitigate the safety risks along with reliability risks as a result of the poor condition of the asset. Typically the poles being replaced are at their end of useful life. If specific poles have been identified as being subject to premature failures, Erie Thames will target the particular poles for testing. Erie Thames has budgeted $150,000 based on previous years replacements, the project is an ongoing project that typically gets completed in the first quarter of every year.

6.2.2. New Service Connections and Upgrades

This line item represents all new services and service upgrades completed during the year due to customer requests. The scope of this project is typically half of these requests are associated with new residential subdivisions that fill in over a two to three year period. The remaining requests are split between commercial service upgrades and various residential service upgrades. The estimated cost for 2012 is $285,000 based on previous years' experience. If these projects are not completed, Erie Thames would be in violation of the Distribution System Code by failing to connect customers in a reasonable amount of time.

6.2.3. Aylmer, Park Street Ph2 Overhead Upgrade

This particular project is addressing rear lot poles that have been identified as being danger poles through Erie Thames's testing program and therefore in need of replacement. The existing poles and overhead lines are not accessible and have various barriers to access including trees, poles and sheds. Erie Thames will be relocating the overhead line to front yard overhead construction on Park Street and removing the existing rear lot overhead lines. Erie Thames estimates the cost of the line relocation to be $180,000.

6.2.4 Belmont, Hazelwood Crescent Underground Upgrade

The scope of this project is to address underground 8kv distribution primary cables in poor condition. The subject area has primary cable that is >40 years old and has reached its end of useful life. The Crescent is currently fed by a radial feed from the overhead 8kv distribution system supplying approximately 60 homes in the area. Erie Thames plans to upgrade the underground cable and transformers and convert them to a 27.6kv supply giving the area a loop feed on the underground system. Currently with no loop feed if there was to be a primary cable failure customers would be without power for a prolonged period of time. The project is estimated to cost $115,000 and will be completed in the 3rd quarter.

6.2.5 Clinton MS#2 Conversion

This municipal substation was built in 1949 utilizing used 1928 vintage transformers to supply the local area with 4 kV distribution. The station has exceeded end of life expectations, and the majority of the 4 kV distribution system is also nearing end of life. Therefore, rather than replace both the station and distribution with 4 kV equipment, it was decided to convert the area to 27.6kV to eliminate the need for the station and reduce system losses. This project will span several USofA accounts, and will be completed over a four year period from 2012 to 2016. As each street is converted to 27.6 kV, it will be immediately put into service. The scope of this year's portion of the project is on James Steet, Gordon Street, Matilda and a small section on east street, upgrading and converting the overhead 4kv system to 27.6kv overhead allowing for further expansion of the 27.6kv system to eventually eliminate MS#2 by 2016.

The purpose of this project is to replace distribution infrastructure that is at end of life, convert the 4 kV load to 27.6 kV supply, and allow the Station to be decommissioned in 2016. The cost of this portion of the project is estimated at $355,000. If this project is not completed, the 4 kV equipment (transformers and cables) will need to be replaced with 4 kV equipment at a cost of $255,000 and the Station will need to be replaced in 2013 at a cost of approximately $1,000,000.

6.2.6. Clinton Town Hall UG Upgrade

Install New Three Phase Underground Primary cables to the transformer For the Town Hall - Install a new dip pole at William and Princess and then install three runs of 285m of 2/0 al. u/g primary. This job is recommended because presently the transformer is fed radially from Rattenbury Street with #6 u/g 5kv direct buried primary cable that is >40 years old and end of life in very poor condition. With a radial supply the Town Hall and it municipal operations is at great risk of a very long outage if a fault were to occur. The project will also help remove load to eliminate the MS#2 substation in Clinton described above.

6.2.7. Tavistock, William Street Extension

The scope of this project is to extend the existing 27.6kv distribution system on William Street 9 pole spans and create a loop feed to the towns sewage lagoon system, arena and public school located in the area. Currently the load is served by a radial feed that transition from overhead to underground back up to overhead 27.6kv. Currently when a fault occurs there is no way to restore power quickly to these significant loads. The present situation presents a risk for a prolonged outage if a fault were to occur which would not be ideal for the sewage lagoon which is an essential service for the town. The project is expected to cost $80,000 and will be completed in the 4th quarter.

6.2.8 Municipal Road Reconstruction

The scope of this project includes line relocations (requested by MTO or City), single pole relocations (to accommodate new or expanded driveways), and make-ready work for third party attachments. In some cases, portions of the project cost are recoverable as a connection fee or capital contribution as determined by the Net Present Value calculation (as per the DSC). The estimated cost for 2012 is $50,000, based on previous years' experience. The average cost of these projects is expected to be $10,000 and the largest project is expected to be $75,000 to which the customer may contribute all or a portion of the actual costs.

6.2.9. Ingersoll – Reinsulate Poles – 38M51 Feeder

This project is to upgrade the porcelain insulators on the Ingersoll M51 feeder which supplies GM CAMI Assembly Plant. Analysis of outage causes indicates that a particular porcelain insulator has been subject to flashover failures due to broken skirts on the insulators. The insulators have been in service for approximately 30 years. GM represents a significant load to Erie Thames and intermittent power quality issues are not acceptable to the plant. The project is a proactive measure to help reduce power quality issues to GM. The project is estimated to cost $55,000

6.2.10 Ingersoll, Melita and Wohnam Street

The scope of this project includes the upgrade of existing underground 4kv primary distribution including submersible transformers and converting the primary underground distribution to 27.6kv utilizing pad mounted transformers. This project will result in the elimination of submersible transformers in the area which have caused approximately 3-4 outages per year effecting more than 60 customers in the area. Outage stats have shown this area to be one of Erie Thames worst performing feeder as a result of the issues. The existing underground system is 35 to 45 years old approaching end of life and in poor condition. The submersible transformers and vaults are subject to high water table levels in early spring which has impacted and deteriorated the overall condition of the assets. Phase one of the project was completed in 2011 at a cost of approximately $260,000. Phase 2 would be completed in the 3rd quarter at a cost of $180,000.

6.2.11 Otterville, Dover Street Conversion

This project will replace aging infrastructure that has been identified as a potential risk for failure in the near future. The scope of this project is an overhead 3 phase line conversion and upgrade on Dover Street with single phase lateral runs off to Wellington, Norfolk and William Streets on the F2 8kv feeder that has reached end of life. Poles, wooden crossarms, porcelain insulators, and transformers are 45 to 55 years old and in relatively poor condition. The existing overhead primary conductors are #4 and #6 AWG copper which poses risk to the public and employees safety. The project is estimated to cost $275,000.

6.2.12 Port Stanley, Main Street South and Jameson OH to UG Conversion

This project will replace aging infrastructure that has been identified as a potential risk for failure in the near future. The scope of this project is to convert an overhead 3 phase 4kv distribution line to underground 27.6kv on the main street in Port Stanley. The existing overhead system has reached end of life. Poles, wooden crossarms, porcelain insulators, and transformers are 45 to 55 years old and in very poor condition. The existing overhead primary conductors are #6 AWG copper which poses risk to the public and employees safety. The area is a high traffic area given the nature of the summer time tourist attraction with this beach front community posing even higher risk. The project will utilize an already installed underground primary network to pick of the servicing of approximately 50 homes and businesses in the area. The project is estimated to cost $405,000 and is expected to be completed before the long weekend in May.

6.2.13 Mitchell Conversion, Pond Street, Thames Ave – St George Street

The 2 projects are designed to deal with Mitchell's municipal substation #2 that was built in 1968 to supply the local area with 4 kV distribution. The station has exceeded end of life expectations, and the majority of the 4 kV distribution system is also nearing end of life. Therefore, rather than replace both the station and distribution with 4 kVequipment, it was decided to convert the last few remaining areas to 27.6kV to eliminate the need for the station and reduce system losses. This project will be completed over the next 3 year period from 2012 to 2015. As each street is converted to 27.6 kV, it will be immediately put into service. The purpose of this project is to replace distribution infrastructure that is at end of life

- Convert Pond Street and Thames Avenue – This job involves the replacement of two padmounts, three poletrans 345m of 28KV u/g primary cable, bore 1-3" pipe 175m, and install single phase KABAR. This will also eliminate some old 5 KV u/g cable.
- St. George Street polemount transformer conversions. This job will allow Erie Thames to remove the underbuild (4KV) from Frances Street to Henry Street along St. George Street with our goal to work our way back to the substation removing the existing 4kv circuit and converting out the station.

The projects will allow the MS#2 substation to be decommissioned in 2015. The cost of these two projects is estimated at $145,000. If this project is not completed, the 4 kV equipment (transformers and cables) will need to be replaced with 4 kV equipment at a cost of $125,000 and the Station will need to be replaced in 2015 at a cost of approximately $600,000.

6.2.14 Substation Upgrades

$20,000 represents the costs to make necessary upgrades to substation fences and grounding that is deteriorating with the aging stations. Even though a few substations have been identified for decommissioning over the next few years it is imperative to keep the stations in good safe working condition. Fence repairs will help to reduce the risk till such time the stations are taken completely out of service.

6.2.15 Fleet

The scope of this project includes the replacement of a bucket truck (# 11-92, 1992 vintage), a 4X4 pickup (#01-02 is 2002 vintage). These two vehicles are deemed to be at end of life based on physical condition, cost to maintain, in-field failure frequency, and maintainability along with a utilization factor. For the bucket truck, it is in very poor condition having body frame issues (repairs done in the past).

Pickup #01-02 is a highly utilized pickup now with over 200,000km on the vehicle and is becoming more costly to maintain. The estimated cost for replacements is $340,000. If these vehicles are not replaced, they are expected to fail in use and require extensive repairs to keep them roadworthy. If the bucket truck fails in-service, it could be a safety hazard to the workers, cause damage to the system, and create an inefficiency (vehicle unavailable for use until repaired).

6.2.16 Tools and Equipment

This line item represents various tools and equipment purchased during the year, primarily to replace existing devices that have reached end of life or failed beyond repair. The estimated cost for this project is $35,000 based on previous years' experience. If this project is not completed, workers will not be able to fulfill their duties or work safely.

6.2.17 Meter Purchases

This line item represents the purchase and installation of new meters for inventory necessary to backfill the requirement for Measurements Canada Compliance Sampling. The scope of this project includes the replacement of meters that are at end of life, meters that have reached seal expiry, upgraded meters triggered by customer demand, or new connections. The estimated cost for 2012 is $40,000 based on previous years' experience. If these projects are not completed, Erie Thames will be in violation with Measurement Canada for using meters that do meet requirements, and in violation of the Distribution System Code by failing to connect customers in a reasonable amount of time.

6.2.18 Computers, Monitors, Phones and Associated Equipment

This line item represents various computer, monitors, phones and associated equipment upgrades required during the year to be replaced and existing units at end of life or that have failed beyond repair. The estimated cost for replacements is $25,000, based on previous years' experience.

6.2.19 Pole Trailer and Forklift

Hwy 8 service centres (CPC and WPP) currently have two pole trailers both of which are not able to leave the town because of their road worthiness. This line item represents $15,000 of the budgeted $40,000 to purchase a new pole trailer for the safe transportation of pole up and down the highway between service centres. Failure to purchase the pole trailer will create a safety risk for staff as well as put them in violation of trailer safety MTO requirements.

A new forklift represents the increase in material handling required to run a larger utility with the volumes of materials going in and out on a regular basis. This item represents $25,000 of the budgeted $40,000. Failure to purchase the forklift significantly impedes the stores keeper to manage inventories at our service centres requiring an inefficient use of line staff and large utility equipment to unload materials.

6.2.20 Lands and Buildings/Leasehold Improvements

This line item represents several small projects to maintain and upgrade the Operations and Administration Hub Building in Ingersoll. The scope of the project includes furniture upgrades, minor office renovations, and replacements of failed components such as plumbing fixtures and the planned renovation of the stores warehouse to create a new office and storage space. Erie Thames growth through the merger of Erie Thames, CPC and WPP has created a strain on space due to staffing level increase and the requirement for space to run effective operations. If these projects are not completed, facility operations will suffer creating inefficiencies the building will continue to deteriorate to the point where additional damage occurs requiring a much larger capital investment. The renovations to the stores warehouse will make more effective use of the warehouse space and create one new office making the workflow and utilization of space more efficient. The additional warehouse storage utilization will allow more inventories to be stored indoors, protecting them from the elements and making them easier to access during the winter as well as reducing theft risks.

This line item also represents several small projects to maintain and upgrade the Service Centres. The scope of the project includes furniture upgrades, minor renovations, and replacements of failed components such as plumbing fixtures. The estimated cost for this project is $40,000 based on past experiences.

6.2.21 SCADA and Smart Grid

This project is to upgrade various hardware and software components associated with the SCADA system to improve reliability, security, and visibility to the Distribution System in real time, and adding new data points for functionality. The scope of phase 1 for this project in 2012, this includes the role out of a SCADA system that has been estimated to cost $200,000 for hardware and software components along with consultants support to implement. Data points will begin by getting access to Hydro One’s breaker status then moving downstream to Erie Thames’s wholesale meter points embedded with Hydro One Distribution System. Phase 2 will lead to a pilot utilizing automated switches to the SCADA system (so they could be remotely monitored and controlled) were appropriate and expanding the roll out of the switch's in subsequent years. The project is expected to be completed by the end of the 3rd quarter. If this project is not completed smart grid advancements will stall and reliability as the system ages will suffer.

7.0 <u>2013, 2014 and 2015 Capital Programs</u>

In the years of IRM Erie Thames anticipates its capital spending requirements will be similar to that during the Test Year. As such, the majority of capital spending will be targeted towards assets that are at end of life. Programs and specific projects identified to continue beyond 2012 are summarized in the Table below. The METSCO Report identifies an annual sustainment of fixed distribution assets of $2,300,000 and total annual capital spending of $3,725,000. Of this, $1,025,000 is capital spending on programs which is based upon historical spending patterns and the recommendations of METSCO for appropriate spending levels. Erie Thames has only included $3,325,000 in the capital spend in order to mitigate the rate impact for the customer. Erie Thames has also estimated contribution at $485,000 which is higher than the historical average.

The METSCO Report identified $2,300,000 as the appropriate annual level of sustainment funding for <u>fixed distribution</u> assets. Of this, $500,000 per year for 2013 and 2104 are the continuation of projects currently underway and $170,000 represents capital spending on pole replacements and station upgrades. Other specific projects will be identified for each year based upon the condition of the assets and coordination with other activities (such as new construction or municipal reconstruction) in order to ensure orderly capital program.

The METSCO Report identified 6 Distribution Substations that would need replacing over the next decade. The 2012 spending will deal with 1 (Clinton, $355,000) of the 6 and 5 will remain.

It is likely that at least 2 of the remaining 5 will be replaced prior to the next rebasing at a cost similar to the Clinton Project.

Table <>. Capital Spending

Program and Project	2013	2014	2015
New Service Connections and Upgrades	$285,000	$285,000	$285,000
Municipal Road Reconstruction	$50,000	$50,000	$50,000
Meters	$45,000	$45,000	$45,000
Tools & Equipment	$35,000	$40,000	$40,000
Computers, Phones, etc.	$25,000	$25,000	$25,000
Lands, Buildings & Leasehold Improvements	$40,000	$40,000	$40,000
Fleet	$340,000	$340,000	$340,000
SCADA & Smart Grid	$200,000	$200,000	$200,000
Sub-total	**$1,025,000**	**$1,025,000**	**$1,025,000**
Pole Replacement[1]	$150,000	$150,000	$150,000
Clinton MS#2 Conversion[1]	$355,000	$355,000	$355,000
Mitchell Conversion[1]	$145,000	$145,000	-
Station Upgrades[1]	$20,000	$20,000	$20,000

WORKING CAPITAL ALLOWANCE CALCULATION BY ACCOUNT	2008 Actual	15%	Allowance for Working Capital	2009 Actual	15%	Allowance for Working Capital
Operation (Working Capital)						
5005-Operation Supervision and Engineering	$44,233.50	15%	$6,635.03	$70,139.13	15%	$10,520.87
5010-Load Dispatching	$0.00	15%	$0.00	$54.84	15%	$8.23
5012-Station Buildings and Fixtures Expense	$36.03	15%	$5.40	$0.00	15%	$0.00
5014-Transformer Station Equipment - Operation Labour	$0.00	15%	$0.00	$0.00	15%	$0.00
5015-Transformer Station Equipment - Operation Supplies and Expenses	$620.24	15%	$93.04	$0.00	15%	$0.00
5016-Distribution Station Equipment - Operation Labour	$0.00	15%	$0.00	$0.00	15%	$0.00
5017-Distribution Station Equipment - Operation Supplies and Expenses	$39,666.09	15%	$5,949.91	$21,832.31	15%	$3,274.85
5020-Overhead Distribution Lines and Feeders - Operation Labour	$6,703.41	15%	$1,005.51	$5,771.04	15%	$865.66
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$2,194.49	15%	$329.17	$10,321.90	15%	$1,548.29
5030-Overhead Sub transmission Feeders - Operation	$0.00	15%	$0.00	$0.00	15%	$0.00
5035-Overhead Distribution Transformers- Operation	$253.67	15%	$38.05	$555.59	15%	$83.34
5040-Underground Distribution Lines and Feeders - Operation Labour	$964.41	15%	$144.66	$686.59	15%	$102.99
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$501.98	15%	$75.30	$322.19	15%	$48.33
5050-Underground Sub transmission Feeders - Operation	$0.00	15%	$0.00	$0.00	15%	$0.00
5055-Underground Distribution Transformers - Operation	$742.11	15%	$111.32	$277.76	15%	$41.66
5060-Street Lighting and Signal System Expense	$1,204.16	15%	$180.62	$0.00	15%	$0.00
5065-Meter Expense	-$6,328.60	15%	-$949.29	$51,512.89	15%	$7,726.93
5070-Customer Premises - Operation Labour	$0.00	15%	$0.00	$512.04	15%	$76.81
5075-Customer Premises - Materials and Expenses	$0.00	15%	$0.00	$5,960.96	15%	$894.14
5085-Miscellaneous Distribution Expense	$135,788.55	15%	$20,368.28	$92,685.12	15%	$13,902.77
5090-Underground Distribution Lines and Feeders - Rental Paid	$1,049.99	15%	$157.50	$245.44	15%	$36.82
5095-Overhead Distribution Lines and Feeders - Rental Paid	$3,028.50	15%	$454.28	$587.50	15%	$88.13
5096-Other Rent	$45,205.88	15%	$6,780.88	$634.53	15%	$95.18
Sub-Total	$275,864.41		$41,379.66	$262,099.83		$39,314.97
Maintenance (Working Capital)						
5105-Maintenance Supervision and Engineering	$0.00	15%	$0.00	$3,283.78	15%	$492.57
5110-Maintenance of Buildings and Fixtures - Distribution Stations	$1,402,006.53	15%	$210,300.98	$66,239.74	15%	$9,935.96
5112-Maintenance of Transformer Station Equipment	$0.00	15%	$0.00	-$7.99	15%	-$1.20
5114-Maintenance of Distribution Station Equipment	$32,579.11	15%	$4,886.87	$38,614.04	15%	$5,792.11
5120-Maintenance of Poles, Towers and Fixtures	$129,504.18	15%	$19,425.63	$91,570.62	15%	$13,735.59
5125-Maintenance of Overhead Conductors and Devices	$31,685.27	15%	$4,752.79	$20,010.91	15%	$3,001.64
5130-Maintenance of Overhead Services	$48,481.44	15%	$7,272.22	$87,437.81	15%	$13,115.67
5135-Overhead Distribution Lines and Feeders - Right of Way	$39,535.69	15%	$5,930.35	$71,115.75	15%	$10,667.36
5145-Maintenance of Underground Conduit	$228.99	15%	$34.35	$576.36	15%	$86.45
5150-Maintenance of Underground Conductors and Devices	$32,933.36	15%	$4,940.00	$63,120.88	15%	$9,468.13
5155-Maintenance of Underground Services	$63,438.46	15%	$9,515.77	$49,537.28	15%	$7,430.59
5160-Maintenance of Line Transformers	$89,285.86	15%	$13,392.88	$61,108.86	15%	$9,166.33
5165-Maintenance of Street Lighting and Signal Systems	$17.82	15%	$2.67	$0.00	15%	$0.00
5170-Sentinel Lights - Labour	$0.00	15%	$0.00	$0.00	15%	$0.00
5172-Sentinel Lights - Materials and Expenses	$7.26	15%	$1.09	$0.00	15%	$0.00
5175-Maintenance of Meters	$81,702.30	15%	$12,255.35	$77,235.29	15%	$11,585.29
5178-Customer Installations Expenses- Leased Property	$0.00	15%	$0.00	$0.00	15%	$0.00
5185-Water Heater Rentals - Labour	$0.00	15%	$0.00	$0.00	15%	$0.00
5186-Water Heater Rentals - Materials and Expenses	$0.00	15%	$0.00	$0.00	15%	$0.00
5190-Water Heater Controls - Labour	$0.00	15%	$0.00	$0.00	15%	$0.00
5192-Water Heater Controls - Materials and Expenses	$0.00	15%	$0.00	$0.00	15%	$0.00
5195-Maintenance of Other Installations on Customer Premises	$0.00	15%	$0.00	$0.00	15%	$0.00
Sub-Total	$1,951,406.27		$292,710.94	$629,843.33		$94,476.50

Billing and Collections						
5305-Supervision	$802.00	15%	$120.30	$0.00	15%	$0.00
5310-Meter Reading Expense	$63,178.25	15%	$9,476.74	$49,052.72	15%	$7,357.91
5315-Customer Billing	$750,077.19	15%	$112,511.58	$636,816.18	15%	$95,522.43
5320-Collecting	$83,881.44	15%	$12,582.22	$48,189.31	15%	$7,228.40
5325-Collecting- Cash Over and Short	-$100.06	15%	-$15.01	$21.07	15%	$3.16
5330-Collection Charges	-$17,988.01	15%	-$2,698.20	$246,554.41	15%	$36,983.16
5335-Bad Debt Expense	$15,892.27	15%	$2,383.84	-$9,273.92	15%	-$1,391.09
5340-Miscellaneous Customer Accounts Expenses	$27,649.72	15%	$4,147.46	-$9.02	15%	-$1.35
Sub-Total	$923,392.80		$138,508.92	$971,350.75		$145,702.61
Community Relations						
5405-Supervision	$38,658.82	15%	$5,798.82	$2,429.63	15%	$364.44
5410-Community Relations - Sundry	$413.72	15%	$62.06	$46,717.06	15%	$7,007.56
5415-Energy Conservation	$0.00	15%	$0.00	$77,260.87	15%	$11,589.13
5420-Community Safety Program	$0.00	15%	$0.00	$1,321.33	15%	$198.20
5425-Miscellaneous Customer Service and Informational Expenses	$0.00	15%	$0.00	$107,157.70	15%	$16,073.66
5505-Supervision	$0.00	15%	$0.00	$0.00	15%	$0.00
5510-Demonstrating and Selling Expense	$0.00	15%	$0.00	$0.00	15%	$0.00
5515-Advertising Expense	$8,984.90	15%	$1,347.74	$13,607.58	15%	$2,041.14
5520-Miscellaneous Sales Expense	$0.00	15%	$0.00	$0.00	15%	$0.00
Sub-Total	$48,057.44		$7,208.62	$248,494.17		$37,274.13
Administrative and General Expenses						
5605-Executive Salaries and Expenses	$237,336.93	15%	$35,600.54	$226,657.86	15%	$33,998.68
5610-Management Salaries and Expenses	$971,561.91	15%	$145,734.29	$1,011,873.65	15%	$151,781.05
5615-General Administrative Salaries and Expenses	$459,385.88	15%	$68,907.88	$192,595.37	15%	$28,889.31
5620-Office Supplies and Expenses	$150,618.86	15%	$22,592.83	$236,875.92	15%	$35,531.39
5625-Administrative Expense Transferred Credit	$0.00	15%	$0.00	$0.00	15%	$0.00
5630-Outside Services Employed	$336,183.79	15%	$50,427.57	$772,533.10	15%	$115,879.97
5635-Property Insurance	$75,834.30	15%	$11,375.15	$55,967.38	15%	$8,395.11
5640-Injuries and Damages	$0.00	15%	$0.00	$0.00	15%	$0.00
5645-Employee Pensions and Benefits	$12,610.68	15%	$1,891.60	$191,713.47	15%	$28,757.02
5650-Franchise Requirements	$0.00	15%	$0.00	$0.00	15%	$0.00
5655-Regulatory Expenses	$158,966.57	15%	$23,844.99	$221,070.12	15%	$33,160.52
5660-General Advertising Expenses	$0.00	15%	$0.00	$40.52	15%	$6.08
5665-Miscellaneous General Expenses	$110,448.51	15%	$16,567.28	$440,685.35	15%	$66,102.80
5670-Rent	$99,009.40	15%	$14,851.41	$172,364.58	15%	$25,854.69
5675-Maintenance of General Plant	$67,934.52	15%	$10,190.18	$33,473.72	15%	$5,021.06
5680-Electrical Safety Authority Fees	$2,678.57	15%	$401.79	$2,201.38	15%	$330.21
5685-Independent Market Operator Fees and Penalties	$0.00	15%	$0.00	$0.00	15%	$0.00
Sub-Total	$2,682,569.92		$402,385.49	$3,558,052.42		$533,707.86

Amortization Expenses						
5705-Amortization Expense - Property, Plant, and Equipment	$949,932.13	0%	$0.00	$1,017,710.59	0%	$0.00
5710-Amortization of Limited Term Electric Plant	$0.00	0%	$0.00	$0.00	0%	$0.00
5715-Amortization of Intangibles and Other Electric Plant	$0.00	0%	$0.00	$0.00	0%	$0.00
5720-Amortization of Electric Plant Acquisition Adjustments	$0.00	0%	$0.00	$0.00	0%	$0.00
5725-Miscellaneous Amortization	$0.00	0%	$0.00	$0.00	0%	$0.00
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	$0.00	0%	$0.00	$0.00	0%	$0.00
5735-Amortization of Deferred Development Costs	$0.00	0%	$0.00	$0.00	0%	$0.00
5740-Amortization of Deferred Charges	$0.00	0%	$0.00	$0.00	0%	$0.00
Sub-Total	$949,932.13		$0.00	$1,017,710.59		$0.00
Cost of Power						
4705	$25,854,812.64	15%	$3,878,221.90	$29,406,629.34	15%	$4,410,994.40
4708	$3,022,927.13	15%	$453,439.07	$3,022,326.61	15%	$453,348.99
4710	$0.00	15%	$0.00	$0.00	15%	$0.00
4712	$15,466.29	15%	$2,319.94	$18,436.95	15%	$2,765.54
4714	$2,397,911.17	15%	$359,686.67	$2,053,581.00	15%	$308,037.15
4715	$0.00	15%	$0.00	$0.00	15%	$0.00
4716	$2,257,994.05	15%	$338,699.11	$1,929,090.78	15%	$289,363.62
4720	$0.00	15%	$0.00	$0.00	15%	$0.00
4725	$0.00	15%	$0.00	$0.00	15%	$0.00
4730	$0.00	15%	$0.00	$0.00	15%	$0.00
4750	$475,935.16	15%	$71,390.27	$581,313.31	15%	$87,197.00
5205	$0.00	15%	$0.00	$0.00	15%	$0.00
5210	$0.00	15%	$0.00	$0.00	15%	$0.00
5215	$0.00	15%	$0.00	$0.00	15%	$0.00
5685	$0.00	15%	$0.00	$0.00	15%	$0.00
Sub-Total	$34,025,046.44		$5,103,756.97	$37,011,377.99		$5,551,706.70
WORKING CAPITAL ALLOWANCE TOTAL			**$5,985,950.59**			**$6,402,182.77**

WORKING CAPITAL ALLOWANCE CALCULATION BY ACCOUNT	2010 Actual	15%	Allowance for Working Capital	2011 Bridge	15%	Allowance for Working Capital
Operation (Working Capital)						
5005-Operation Supervision and Engineering	$185,439.22	15%	$27,815.88	$187,413.29	15%	$28,111.99
5010-Load Dispatching	$837.20	15%	$125.58	$0.00	15%	$0.00
5012-Station Buildings and Fixtures Expense	$0.00	15%	$0.00	$0.00	15%	$0.00
5014-Transformer Station Equipment - Operation Labour	$0.00	15%	$0.00	$0.00	15%	$0.00
5015-Transformer Station Equipment - Operation Supplies and Expenses	$0.00	15%	$0.00	$0.00	15%	$0.00
5016-Distribution Station Equipment - Operation Labour	$0.00	15%	$0.00	$0.00	15%	$0.00
5017-Distribution Station Equipment - Operation Supplies and Expenses	$28,246.94	15%	$4,237.04	$3,416.28	15%	$512.44
5020-Overhead Distribution Lines and Feeders - Operation Labour	$17,774.24	15%	$2,666.14	$3,576.10	15%	$536.42
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$2,385.01	15%	$357.75	$1,398.84	15%	$209.83
5030-Overhead Sub transmission Feeders - Operation	$0.00	15%	$0.00	$0.00	15%	$0.00
5035-Overhead Distribution Transformers- Operation	$1,022.04	15%	$153.31	$0.00	15%	$0.00
5040-Underground Distribution Lines and Feeders - Operation Labour	$2,519.90	15%	$377.99	$372.63	15%	$55.89
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$7.88	15%	$1.18	$27.07	15%	$4.06
5050-Underground Sub transmission Feeders - Operation	$0.00	15%	$0.00	$0.00	15%	$0.00
5055-Underground Distribution Transformers - Operation	$100.32	15%	$15.05	$0.00	15%	$0.00
5060-Street Lighting and Signal System Expense	$0.00	15%	$0.00	$0.00	15%	$0.00
5065-Meter Expense	-$14,781.69	15%	-$2,217.25	$5,970.53	15%	$895.58
5070-Customer Premises - Operation Labour	$0.00	15%	$0.00	$190.13	15%	$28.52
5075-Customer Premises - Materials and Expenses	$4,104.34	15%	$615.65	$18.31	15%	$2.75
5085-Miscellaneous Distribution Expense	$56,835.67	15%	$8,525.35	$71,621.21	15%	$10,743.18
5090-Underground Distribution Lines and Feeders - Rental Paid	$0.00	15%	$0.00	$0.00	15%	$0.00
5095-Overhead Distribution Lines and Feeders - Rental Paid	$0.00	15%	$0.00	$0.00	15%	$0.00
5096-Other Rent	$347.08	15%	$52.06	$0.00	15%	$0.00
Sub-Total	$284,838.15		$42,725.72	$274,004.39		$41,100.66
Maintenance (Working Capital)						
5105-Maintenance Supervision and Engineering	$636.41	15%	$95.46	$0.00	15%	$0.00
5110-Maintenance of Buildings and Fixtures - Distribution Stations	$117,200.84	15%	$17,580.13	$93,146.33	15%	$13,971.95
5112-Maintenance of Transformer Station Equipment	$89.15	15%	$13.37	$0.00	15%	$0.00
5114-Maintenance of Distribution Station Equipment	$13,741.80	15%	$2,061.27	$3,286.92	15%	$493.04
5120-Maintenance of Poles, Towers and Fixtures	$44,471.00	15%	$6,670.65	$28,922.80	15%	$4,338.42
5125-Maintenance of Overhead Conductors and Devices	$9,225.28	15%	$1,383.79	$5,675.64	15%	$851.35
5130-Maintenance of Overhead Services	$97,358.49	15%	$14,603.77	$73,848.45	15%	$11,077.27
5135-Overhead Distribution Lines and Feeders - Right of Way	$74,467.36	15%	$11,170.10	$111,568.14	15%	$16,735.22
5145-Maintenance of Underground Conduit	$150,430.97	15%	$22,564.65	$140,828.06	15%	$21,124.21
5150-Maintenance of Underground Conductors and Devices	$71,584.22	15%	$10,737.63	$52,885.52	15%	$7,932.83
5155-Maintenance of Underground Services	$52,231.00	15%	$7,834.65	$53,555.41	15%	$8,033.31
5160-Maintenance of Line Transformers	$65,975.22	15%	$9,896.28	$100,101.65	15%	$15,015.25
5165-Maintenance of Street Lighting and Signal Systems	$0.00	15%	$0.00	$0.00	15%	$0.00
5170-Sentinel Lights - Labour	$0.00	15%	$0.00	$0.00	15%	$0.00
5172-Sentinel Lights - Materials and Expenses	$0.00	15%	$0.00	$0.00	15%	$0.00
5175-Maintenance of Meters	$71,135.92	15%	$10,670.39	$29,723.94	15%	$4,458.59
5178-Customer Installations Expenses- Leased Property	$0.00	15%	$0.00	$0.00	15%	$0.00
5185-Water Heater Rentals - Labour	$0.00	15%	$0.00	$0.00	15%	$0.00
5186-Water Heater Rentals - Materials and Expenses	$0.00	15%	$0.00	$0.00	15%	$0.00
5190-Water Heater Controls - Labour	$0.00	15%	$0.00	$0.00	15%	$0.00
5192-Water Heater Controls - Materials and Expenses	$0.00	15%	$0.00	$0.00	15%	$0.00
5195-Maintenance of Other Installations on Customer Premises	$0.00	15%	$0.00	$0.00	15%	$0.00
Sub-Total	$768,547.66		$115,282.15	$693,542.86		$104,031.43

Billing and Collections						
5305-Supervision	$0.00	15%	$0.00	$18,088.24	15%	$2,713.24
5310-Meter Reading Expense	$111,444.19	15%	$16,716.63	$33,212.93	15%	$4,981.94
5315-Customer Billing	$835,310.33	15%	$125,296.55	$846,846.16	15%	$127,026.92
5320-Collecting	$30,175.35	15%	$4,526.30	$21,186.98	15%	$3,178.05
5325-Collecting- Cash Over and Short	-$11,160.00	15%	-$1,674.00	$0.00	15%	$0.00
5330-Collection Charges	$184,211.57	15%	$27,631.74	$114,870.26	15%	$17,230.54
5335-Bad Debt Expense	$20,635.01	15%	$3,095.25	$0.00	15%	$0.00
5340-Miscellaneous Customer Accounts Expenses	$1,822.81	15%	$273.42	$25.97	15%	$3.90
Sub-Total	$1,172,439.26		$175,865.89	$1,034,230.54		$155,134.58
Community Relations						
5405-Supervision	$38,165.93	15%	$5,724.89	$2,097.05	15%	$314.56
5410-Community Relations - Sundry	$21,781.79	15%	$3,267.27	$18,620.19	15%	$2,793.03
5415-Energy Conservation	$0.00	15%	$0.00	$0.00	15%	$0.00
5420-Community Safety Program	$0.00	15%	$0.00	$0.00	15%	$0.00
5425-Miscellaneous Customer Service and Informational Expenses	$112,725.50	15%	$16,908.83	$116,532.91	15%	$17,479.94
5505-Supervision	$0.00	15%	$0.00	$0.00	15%	$0.00
5510-Demonstrating and Selling Expense	$0.00	15%	$0.00	$0.00	15%	$0.00
5515-Advertising Expense	$11,183.16	15%	$1,677.47	$7,199.12	15%	$1,079.87
5520-Miscellaneous Sales Expense	$0.00	15%	$0.00	$0.00	15%	$0.00
Sub-Total	$183,856.38		$27,578.46	$144,449.27		$21,667.39
Administrative and General Expenses						
5605-Executive Salaries and Expenses	$804,878.29	15%	$120,731.74	$212,029.45	15%	$31,804.42
5610-Management Salaries and Expenses	$698,031.80	15%	$104,704.77	$1,316,529.96	15%	$197,479.49
5615-General Administrative Salaries and Expenses	$249,762.37	15%	$37,464.36	$351,093.45	15%	$52,664.02
5620-Office Supplies and Expenses	$207,523.99	15%	$31,128.60	$139,536.22	15%	$20,930.43
5625-Administrative Expense Transferred Credit	$0.00	15%	$0.00	$0.00	15%	$0.00
5630-Outside Services Employed	$423,980.44	15%	$63,597.07	$353,514.27	15%	$53,027.14
5635-Property Insurance	$51,089.18	15%	$7,663.38	$0.00	15%	$0.00
5640-Injuries and Damages	$0.00	15%	$0.00	$13,046.68	15%	$1,957.00
5645-Employee Pensions and Benefits	$271,144.62	15%	$40,671.69	$463,625.12	15%	$69,543.77
5650-Franchise Requirements	$0.00	15%	$0.00	$0.00	15%	$0.00
5655-Regulatory Expenses	$157,539.54	15%	$23,630.93	$104,232.30	15%	$15,634.85
5660-General Advertising Expenses	$2,167.21	15%	$325.08	$0.00	15%	$0.00
5665-Miscellaneous General Expenses	$290,173.66	15%	$43,526.05	$325,378.10	15%	$48,806.72
5670-Rent	$282,922.71	15%	$42,438.41	$322,400.90	15%	$48,360.14
5675-Maintenance of General Plant	$15,759.34	15%	$2,363.90	$77,868.44	15%	$11,680.27
5680-Electrical Safety Authority Fees	$317.24	15%	$47.59	$7,635.98	15%	$1,145.40
5685-Independent Market Operator Fees and Penalties	$0.00	15%	$0.00	$0.00	15%	$0.00
Sub-Total	$3,455,290.39		$518,293.56	$3,686,890.87		$553,033.63
Amortization Expenses						
5705-Amortization Expense - Property, Plant, and Equipment	$1,177,337.74	0%	$0.00	$1,810,506.30	0%	$0.00
5710-Amortization of Limited Term Electric Plant	$0.00	0%	$0.00	$0.00	0%	$0.00
5715-Amortization of Intangibles and Other Electric Plant	$0.00	0%	$0.00	$0.00	0%	$0.00
5720-Amortization of Electric Plant Acquisition Adjustments	$0.00	0%	$0.00	$0.00	0%	$0.00
5725-Miscellaneous Amortization	$0.00	0%	$0.00	$0.00	0%	$0.00
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	$0.00	0%	$0.00	$0.00	0%	$0.00
5735-Amortization of Deferred Development Costs	$0.00	0%	$0.00	$0.00	0%	$0.00
5740-Amortization of Deferred Charges	$0.00	0%	$0.00	$0.00	0%	$0.00
Sub-Total	$1,177,337.74		$0.00	$1,810,506.30		$0.00
Cost of Power						
4705	$31,981,792.21	15%	$4,797,268.83	$32,504,777.54	15%	$4,875,716.63
4708	$2,904,538.93	15%	$435,680.84	$2,581,914.24	15%	$387,287.14
4710	$0.00	15%	$0.00	$0.00	15%	$0.00
4712	$22,327.63	15%	$3,349.14	$24,207.33	15%	$3,631.10
4714	$2,485,444.81	15%	$372,816.72	$2,264,938.50	15%	$339,740.78
4715	$0.00	15%	$0.00	$0.00	15%	$0.00
4716	$2,295,401.30	15%	$344,310.19	$2,091,755.47	15%	$313,763.32
4720	$0.00	15%	$0.00	$0.00	15%	$0.00
4725	$0.00	15%	$0.00	$0.00	15%	$0.00
4730	$0.00	15%	$0.00	$0.00	15%	$0.00
4750	$393,155.31	15%	$58,973.30	$495,683.09	15%	$74,352.46
5205	$0.00	15%	$0.00	$0.00	15%	$0.00
5210	$0.00	15%	$0.00	$0.00	15%	$0.00
5215	$0.00	15%	$0.00	$0.00	15%	$0.00
5685	$0.00	15%	$0.00	$0.00	15%	$0.00
Sub-Total	$40,082,660.19		$6,012,399.03	$39,963,276.17		$5,994,491.42
WORKING CAPITAL ALLOWANCE TOTAL			**$6,892,144.80**			**$6,869,459.11**

WORKING CAPITAL ALLOWANCE CALCULATION BY ACCOUNT	2012 Test	15%	Allowance for Working Capital
Operation (Working Capital)			
5005-Operation Supervision and Engineering	$193,035.69	15%	$28,955.35
5010-Load Dispatching	$0.00	15%	$0.00
5012-Station Buildings and Fixtures Expense	$0.00	15%	$0.00
5014-Transformer Station Equipment - Operation Labour	$0.00	15%	$0.00
5015-Transformer Station Equipment - Operation Supplies and Expenses	$0.00	15%	$0.00
5016-Distribution Station Equipment - Operation Labour	$0.00	15%	$0.00
5017-Distribution Station Equipment - Operation Supplies and Expenses	$3,518.76	15%	$527.81
5020-Overhead Distribution Lines and Feeders - Operation Labour	$3,683.39	15%	$552.51
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$1,440.80	15%	$216.12
5030-Overhead Sub transmission Feeders - Operation	$0.00	15%	$0.00
5035-Overhead Distribution Transformers- Operation	$0.00	15%	$0.00
5040-Underground Distribution Lines and Feeders - Operation Labour	$383.81	15%	$57.57
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$27.88	15%	$4.18
5050-Underground Sub transmission Feeders - Operation	$0.00	15%	$0.00
5055-Underground Distribution Transformers - Operation	$0.00	15%	$0.00
5060-Street Lighting and Signal System Expense	$0.00	15%	$0.00
5065-Meter Expense	$6,149.65	15%	$922.45
5070-Customer Premises - Operation Labour	$195.83	15%	$29.37
5075-Customer Premises - Materials and Expenses	$8.86	15%	$1.33
5085-Miscellaneous Distribution Expense	$73,769.84	15%	$11,065.48
5090-Underground Distribution Lines and Feeders - Rental Paid	$0.00	15%	$0.00
5095-Overhead Distribution Lines and Feeders - Rental Paid	$0.00	15%	$0.00
5096-Other Rent	$0.00	15%	$0.00
Sub-Total	$282,214.51		$42,332.18
Maintenance (Working Capital)			
5105-Maintenance Supervision and Engineering	$0.00	15%	$0.00
5110-Maintenance of Buildings and Fixtures - Distribution Stations	$95,940.72	15%	$14,391.11
5112-Maintenance of Transformer Station Equipment	$0.00	15%	$0.00
5114-Maintenance of Distribution Station Equipment	$3,385.53	15%	$507.83
5120-Maintenance of Poles, Tow ers and Fixtures	$39,790.48	15%	$5,968.57
5125-Maintenance of Overhead Conductors and Devices	$5,845.91	15%	$876.89
5130-Maintenance of Overhead Services	$76,063.90	15%	$11,409.59
5135-Overhead Distribution Lines and Feeders - Right of Way	$114,915.18	15%	$17,237.28
5145-Maintenance of Underground Conduit	$145,052.90	15%	$21,757.94
5150-Maintenance of Underground Conductors and Devices	$54,472.09	15%	$8,170.81
5155-Maintenance of Underground Services	$55,162.07	15%	$8,274.31
5160-Maintenance of Line Transformers	$103,104.70	15%	$15,465.71
5165-Maintenance of Street Lighting and Signal Systems	$0.00	15%	$0.00
5170-Sentinel Lights - Labour	$0.00	15%	$0.00
5172-Sentinel Lights - Materials and Expenses	$0.00	15%	$0.00
5175-Maintenance of Meters	$30,615.66	15%	$4,592.35
5178-Customer Installations Expenses- Leased Property	$0.00	15%	$0.00
5185-Water Heater Rentals - Labour	$0.00	15%	$0.00
5186-Water Heater Rentals - Materials and Expenses	$0.00	15%	$0.00
5190-Water Heater Controls - Labour	$0.00	15%	$0.00
5192-Water Heater Controls - Materials and Expenses	$0.00	15%	$0.00
5195-Maintenance of Other Installations on Customer Premises	$0.00	15%	$0.00
Sub-Total	$724,349.14		$108,652.37

Billing and Collections			
5305-Supervision	$18,630.88	15%	$2,794.63
5310-Meter Reading Expense	$34,209.32	15%	$5,131.40
5315-Customer Billing	$906,125.39	15%	$135,918.81
5320-Collecting	$21,822.59	15%	$3,273.39
5325-Collecting- Cash Over and Short	$0.00	15%	$0.00
5330-Collection Charges	$118,316.37	15%	$17,747.46
5335-Bad Debt Expense	$0.00	15%	$0.00
5340-Miscellaneous Customer Accounts Expenses	$26.75	15%	$4.01
Sub-Total	$1,099,131.30		$164,869.70
Community Relations			
5405-Supervision	$2,159.96	15%	$323.99
5410-Community Relations - Sundry	$19,178.79	15%	$2,876.82
5415-Energy Conservation	$0.00	15%	$0.00
5420-Community Safety Program	$0.00	15%	$0.00
5425-Miscellaneous Customer Service and Informational Expenses	$120,028.90	15%	$18,004.34
5505-Supervision	$0.00	15%	$0.00
5510-Demonstrating and Selling Expense	$0.00	15%	$0.00
5515-Advertising Expense	$7,415.09	15%	$1,112.26
5520-Miscellaneous Sales Expense	$0.00	15%	$0.00
Sub-Total	$148,782.74		$22,317.41
Administrative and General Expenses			
5605-Executive Salaries and Expenses	$218,390.34	15%	$32,758.55
5610-Management Salaries and Expenses	$1,194,775.86	15%	$179,216.38
5615-General Administrative Salaries and Expenses	$361,626.25	15%	$54,243.94
5620-Office Supplies and Expenses	$143,722.31	15%	$21,558.35
5625-Administrative Expense Transferred Credit	$0.00	15%	$0.00
5630-Outside Services Employed	$180,378.46	15%	$27,056.77
5635-Property Insurance	$0.00	15%	$0.00
5640-Injuries and Damages	$13,438.08	15%	$2,015.71
5645-Employee Pensions and Benefits	$413,501.80	15%	$62,025.27
5650-Franchise Requirements	$0.00	15%	$0.00
5655-Regulatory Expenses	$115,000.00	15%	$17,250.00
5660-General Advertising Expenses	$0.00	15%	$0.00
5665-Miscellaneous General Expenses	$295,455.82	15%	$44,318.37
5670-Rent	$322,400.90	15%	$48,360.14
5675-Maintenance of General Plant	$80,204.49	15%	$12,030.67
5680-Electrical Safety Authority Fees	$7,865.06	15%	$1,179.76
5685-Independent Market Operator Fees and Penalties	$0.00	15%	$0.00
Sub-Total	$3,346,759.37		$502,013.90

Amortization Expenses			
5705-Amortization Expense - Property, Plant, and Equipment	$1,930,321.46	0%	$0.00
5710-Amortization of Limited Term Electric Plant	$0.00	0%	$0.00
5715-Amortization of Intangibles and Other Electric Plant	$0.00	0%	$0.00
5720-Amortization of Electric Plant Acquisition Adjustments	$0.00	0%	$0.00
5725-Miscellaneous Amortization	$0.00	0%	$0.00
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	$0.00	0%	$0.00
5735-Amortization of Deferred Development Costs	$0.00	0%	$0.00
5740-Amortization of Deferred Charges	$0.00	0%	$0.00
Sub-Total	$1,930,321.46		$0.00
Cost of Power			
4705	$28,937,364.51	15%	$4,340,604.68
4708	$2,326,408.06	15%	$348,961.21
4710	$0.00	15%	$0.00
4712	$0.00	15%	$0.00
4714	$2,705,002.92	15%	$405,750.44
4715	$0.00	15%	$0.00
4716	$2,401,439.16	15%	$360,215.87
4720	$0.00	15%	$0.00
4725	$0.00	15%	$0.00
4730	$581,602.02	15%	$87,240.30
4750	$0.00	15%	$0.00
5205	$0.00	15%	$0.00
5210	$0.00	15%	$0.00
5215	$0.00	15%	$0.00
5685	$0.00	15%	$0.00
Sub-Total	$36,951,816.67		$5,542,772.50
WORKING CAPITAL ALLOWANCE TOTAL			**$6,382,958.06**

ERIE THAMES POWERLINES

Asset Condition Assessment

&

Asset Management Plan

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METSCO
Energy Solutions

November, 2011

Contents

Table of Exhibits

Executive Summary

This report summarizes (a) the results of an asset condition assessment study carried out with the objective of establishing the health and condition of fixed assets employed on Erie Thames Power Lines' (ETPL)'s distribution system and (b) provides an asset management plan, covering capital and preventative maintenance investments in distribution system fixed assets for the next 10 years.

The recommendations in the report are based on a risk based asset management strategy, described in the Asset Management Standard PAS-55, a specification developed by British Standards Institute (BSI) and commonly employed by progressive electric utilities. A risk based asset management strategy determines the timing and scope of investments into asset renewal, based on the risk of an asset's failure determined by the condition of the asset.

A comprehensive methodology has been developed and documented in Section 3 of the report, to conduct condition assessment of all fixed assets employed on ETPL's distribution network, including the assets employed in substations, overhead lines and underground distribution system. By applying this methodology, condition assessment of the assets has been completed and is documented in Section 4. Estimates of capital investment required for asset sustainment have been developed by evaluating the risk of in-service asset failures, based on assets' age profiles and anticipated life expectancy of assets. Estimates of capital expenditure required for new services and road widening programs have been prepared by taking into account typical historic costs. Similarly estimates of capital expenditure for revenue metering equipment, motor vehicles, IT equipment, building upgrades and office furniture have been prepared through consultations with the ETPL's staff, based on the identified needs.

Overall capital investments required during the next 10 years for asset sustainment in **optimal** condition are summarized below:

	Annual CAPEX
Annual capital expenditure for sustainment of fixed distribution assets	2 723 581
Annual capital expenditure to permit new connections and service upgrades	285 000
Annual capital expenditure to permit municipal road upgrades	50 000
Annual capital expenditure in revenue metering and equipment	45 000
Annual capital expenditure tools equipment	35 000
Annual capital expenditure IT equipment	25 000
Annual capital expenditure on building improvements, office equip & furniture	40 000
Annual capital expenditure on motor vehicle fleet	340 000
Total annual capital expenditure requirement	3 543 581

1 INTRODUCTION

This report summarizes the results of an asset condition assessment study carried out by METSCO Inc. on behalf of ETPL's, with the objective of establishing the health and condition of fixed assets employed on ETPL' distribution system. The report also provides an asset management plan, covering capital and preventative maintenance investments in fixed assets for the 10 years.

The fixed assets covered by the report include:

a) Wood, steel and concrete poles;
b) 3-ph and 1-ph overhead distribution lines, including medium voltage and low voltage circuits;
c) 3-ph and 1-ph underground cables, including medium voltage and low voltage circuits;
d) Distribution transformers, typically installed in pole-mounted and pad-mounted configurations;
e) Distribution substations and related substation equipment, including power transformers, 27.6 kV switchgear and fused disconnects, 4 kV switchgear, protection and controls, and substation buildings.

The report is organized into five sections including this introductory section. Section 2 describes the principles of a risk based asset management strategy to achieve optimal operation of the distribution grid. Section 3 provides the methodology for implementation of the recommended asset management strategy. Section 4 summarizes the results of asset condition assessment exercise and Section 5 summarizes the asset management plan and provides the scope of capital and maintenance investments required for asset sustainment.

2 STRATEGIC MANAGEMENT OF DISTRIBUTION FIXED ASSETS

Decisions involving investment into fixed assets play a major role in determining the optimal performance of distribution system fixed assets. A majority of the investments in fixed assets are triggered by either declining performance in the areas of supply system reliability, power quality or safety; or increasing operating and maintenance costs associated with aging assets; or anticipated growth in demand requiring capacity upgrades. In either case, investments that are either oversized or made too far in advance of the actual system need may result in non-optimal operation. On the other hand, investment not made on time when warranted by the system needs raise the risk of performance targets not being achieved and would also result in non-optimal operation. Optimal operation of distribution system is achieved when “right sized” investments into renewal and replacement (capital investments) and into asset repair, rehabilitation and preventative maintenance are planned and implemented based on a “just-in-time” approach. In summary, the overarching objective of the asset management strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of the asset is minimized.

A risk based asset management strategy, therefore, determines the risk of asset failure based on the condition of the asset, which is commonly measured with the help of a yard stick of “Asset health indices”, and computes the valuation of the risk based on consequences of asset failure and identifies the optimal risk mitigation alternative through an evaluation of all available options. Asset management covers the full life cycle of a fixed asset, from preparation of the asset specification and installation standards - to the scope and frequency of preventative maintenance during the assets service life – and finally to the determination of the assets end-of- life and retirement from service. At each stage of an asset’s life cycle, decisions are made to achieve the right balance between achieving maximum life expectancy, highest operating performance, lowest initial investment (capital costs) and lowest operating costs. The best-in-class asset management strategies employ integrated processes that allow optimal levels of financial and operating performance to be achieved, using transparent and objective criteria that can easily be audited and inspected by regulators.

PAS-55, a specification for asset management, was developed by British Standards Institute (BSI) and offers one of the best in class strategies for risk management associated with fixed assets of electricity distribution systems. To be compliant with PAS-55 asset management standard, the asset management approach must contain the essential elements documented in Exhibit 2.1.

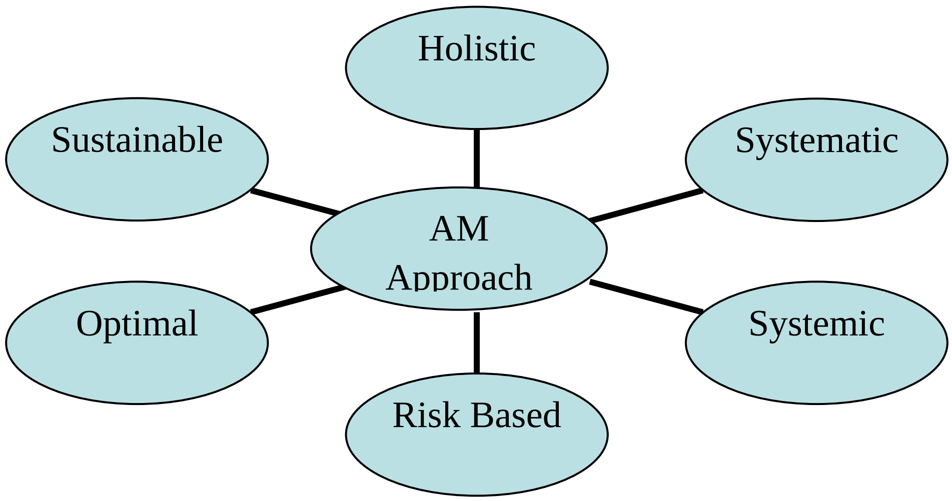


Exhibit 2-1: Essentials of PAS-55 Compliant Asset Management Strategy

The overarching objective is to develop capital and preventative maintenance investment plans, which could be implemented over a period of five to ten years to achieve optimal system performance by placing appropriate weights on corporate objectives and performance criteria, as shown in Exhibit 2.2.

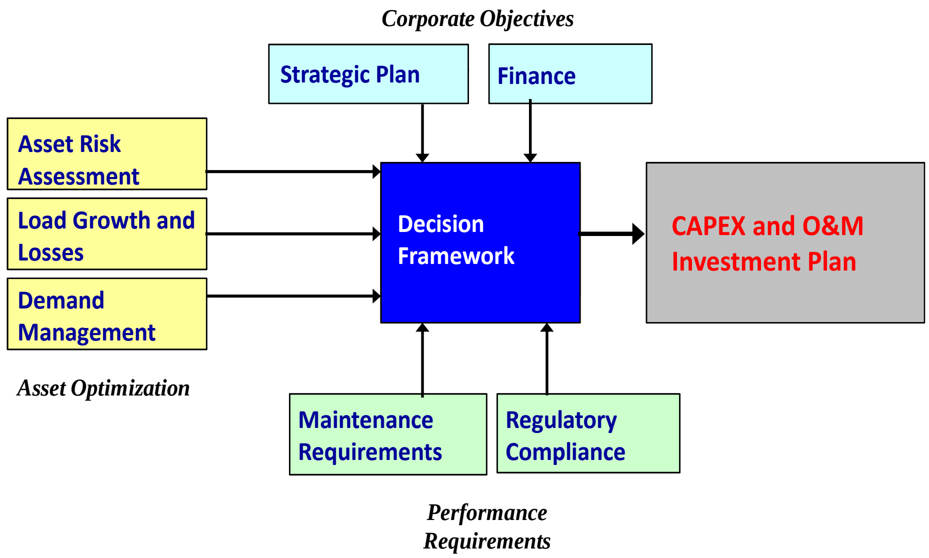


Exhibit 2-2: Multi-Prong Decision Framework

For regulated transmission and distribution businesses, the key considerations in development of a strategic asset management plan include:

a) Regulatory Compliance
b) Public and Employee Safety
c) Protecting Brand Name and Image
d) Operating Efficiency
e) Reliability and Supply System Security
f) Customer Service Quality

g) Getting Full Life out of Assets
h) Return on investment
i) Risk Based Maintenance Strategy
j) Minimizing Asset Life Cycle Costs
k) Minimizing Risk of Premature Failures
l) Minimizing Environmental Risks

Exhibit 2.3 shows the basic decision support model employed under a risk based strategy. The timing and size of investments is selected to minimize the "Total Cost" of risk and risk mitigation initiatives.

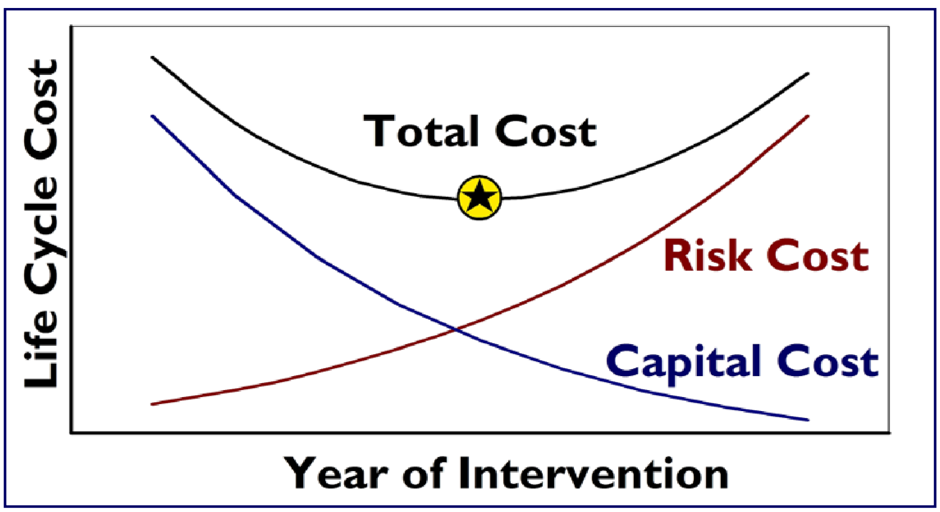


Exhibit 2-3: Risk Based Decision Support System

Exhibit 2.4 summarizes a practical matrix to sift through a large number of assets, typically employed on T&D systems to objectively identify assets that present the highest risk of in-service failures so that the investments could be targeted into assets that present the highest risk. Numeric health indices, typically normalized to a scale of 100, are commonly used to express the health and condition of assets, as shown in Exhibit 2.5 and this allows separation of the assets in good condition that require minimal risk mitigation from those in poor condition, requiring a higher level of investments. This exercise allows development of an investment plan as shown in Exhibit 2.6 that could be implemented over a 5-10 year period.

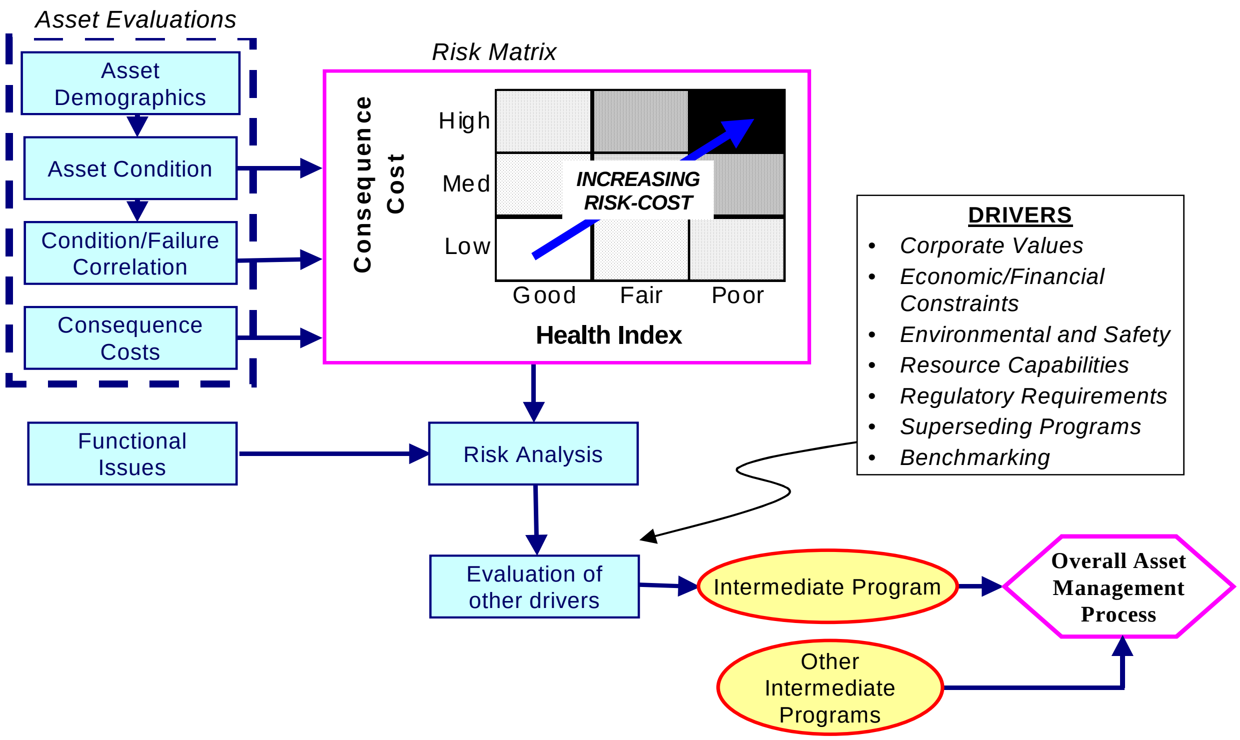
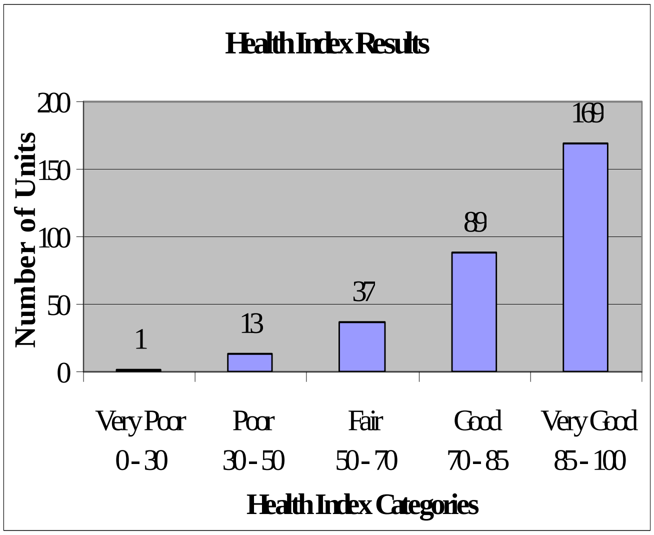


Exhibit 2-4: Model to Identify Assets with Highest Risks



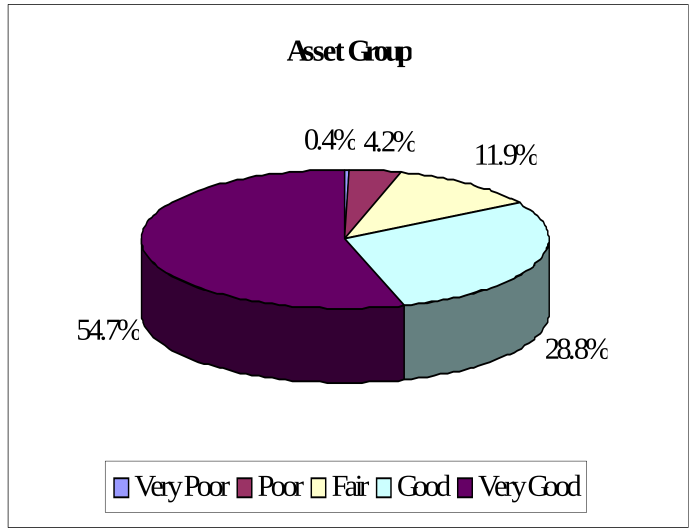


Exhibit 2-5: Model to Identify Assets with Highest Risks

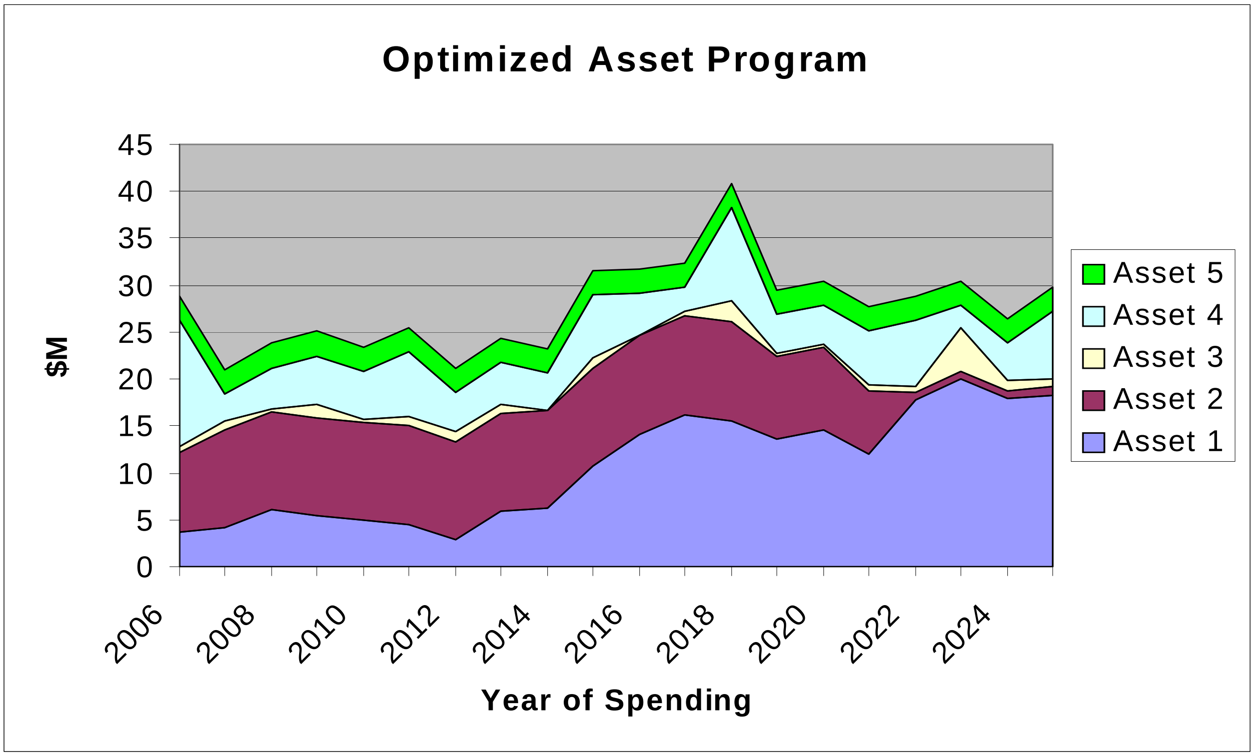


Exhibit 2-6: Investment Plan

3 Asset Condition Assessment Methodology

This section describes in detail an asset condition assessment methodology for different categories of fixed assets employed on ETPL's distribution system. Adoption of this methodology would require periodic asset inspections and recording of their condition to identify the assets most at risk, requiring focussed investments into risk mitigation.

Asset condition assessment methodologies are described below for the following distribution system asset categories:

a) Overhead Lines
b) Underground Lines
c) Substations
d) Distribution Transformers (Pole mounted, pad mounted and vault mounted)
e) Distribution Switches and Fused Cut-outs (Pole mounted, pad mounted and vault mounted)

3.1 Overhead Lines

Condition assessment methodologies for the following components employed on overhead lines are discussed below:

- ✓ Poles
- ✓ Insulators
- ✓ Hardware
- ✓ Conductors and splices

3.1.1 Condition Assessment Criteria for Poles:

Because wood is a natural material, its degradation processes are different from other assets on distribution systems. The most critical degradation process for wood poles involves biological and environmental mechanisms such as fungal decay, wildlife damage and effects of weather. Fungi attack both external surfaces and the internal heartwood of wood poles. The process of fungal decay requires the presence of fungus spores in the presence of water and oxygen. For this reason, the area of the pole most susceptible to fungal decay is at and around the ground line, although pole rot is also known to begin at the top of the pole. To prevent the decay of wood poles, utilities treat them with preservatives before installation. Wood preservatives have two basic functions:

- keep out moisture that supports fungi by sealing the surfaces, and
- kill off the fungal spores.

Most power companies install only fully treated wood poles these days, however this was not always the case and the lines constructed 40 years ago or earlier may not have been constructed with fully treated poles but only butt treated poles may have been used. Typically, fully treated poles are expected to provide a longer service life in relation to butt treated poles.

The following factors represent some of the more critical factors affecting wood pole strength as poles age:

- Original type and class of wood pole;
- Original defects in wood (e.g. knots, cracks or rot);
- Rate of decay in service life which depends on type of treatment and environmental conditions;
- Pole damage by woodpeckers, insects, and other wildlife; and
- Wood burns.

Several types of damage can also deform bolt holes in poles. Generally, such deformities do not present immediate problems. However, in some cases deformed holes can result in both failure of the structure and failure of other components attached to the pole. Bolts also can become loose, elongated, bent, cracked, sheared/broken and lost.

Visual inspection can detect the following types of wood pole damage readily:

- Fiber damage that may occur when wind hits a wood pole with force beyond the pole's bearing capacity;

- Partial damage that may result when objects hit wood poles and reduce effective pole circumference. If the damage affects only part of a pole's cross-section the utility may keep the pole in service with a reduced factor of safety.
- Wood splits from various causes that may accelerate the end of a pole's life, depending upon the extent of the split damage;
- Mis-orientation from excessive transverse forces that may result in pole tilting as well as "stretching" (i.e., loosening) and breaking of guys and guying systems;
- Burning from conductor faults and insulator flashovers that may damage wood poles, wooden support cross-braces and timber, reducing the ability of these structures to withstand mechanical stress changes or causing their complete loss through fire; and
- Wood cracks or checks that may hold moisture and cause decay or weaken the structures through freeze/thaw forces during winter.

Utilities have sought objective and accurate means to assess pole condition and remaining life, as a result of which, a wide range of wood pole assessment and diagnostic tools and techniques has developed. These include techniques designed to apply traditional probing and hammer tests in more controlled, repeatable and objective ways. Indirect and non-destructive techniques such as ultrasonics, X-rays, and electrical resistance have received widespread testing.

Concrete poles also undergo whether related degradation which may manifest itself in form of concrete spalling, exposure of steel rebar and rusting of steel rebar, which reduces the pole strength with age.

3.1.2 Condition Assessment Criteria for Insulators:

The types of insulators and configurations typically used in Distribution systems include dead-end, suspension, post and pin types. The insulating portion may consist of porcelain or polymer. The metallic parts usually are made from zinc coated ductile or malleable iron. Both electrical and mechanical stresses may affect insulators. Degradation and eventual failure generally result from the loss of either dielectric or mechanical strength. Mechanical loading on suspension and line post insulators consists of a combination of tensile, torsional, cantilever, vibration and compression forces resulting from factors such as conductor vibration and galloping, accumulation of high density snow or ice, and sudden ice shedding. Line post, strut and pin type insulators are unique since they may experience a combination of cantilever, transverse and tensile forces simultaneously. Impact or contact induced damage also may occur.

Contamination of insulator surface with road salt, freezing rain, and snow accumulation may induce flashovers resulting in dielectric failure of insulators. Electrical flashovers can cause both external and internal damage to porcelain and composite insulators. Visual inspection can detect the following external insulator damage readily:

- Broken porcelain from the shell caused by a flashover (lightning) or impact damage (vandalism);
- Flashover burn markings on the porcelain shell resulting from burns/arching damage/galvanizing;

Latent damages, typically internal to the porcelain shell, metal fitting and hardware include:

- Internal cracks under the metal cap or inside the porcelain head from lightning flashovers or line galloping, which in essence cause electrical shorts in the insulator that can distort the insulator string's voltage profile;
- Radial cracks (come from cement growth) through the porcelain shell;

Composite insulators consist of a glass fibre reinforced rod covered in either EPDM or silicone rubber weather sheds with appropriate end fittings. While the composite insulators offer a great range of mechanical strengths and much lower weight than other types of insulators, the EPDM silicone rubber material also is soft and easily cut, ripped or punctured by sharp objects. The integrity of the sheath and weather sheds is critical. Failure commonly occurs when moisture enters into the glass fibre rod area.

Noticeable damage to insulator includes cuts, splits, holes, erosion, tracking, or burning of the rubber shed and sheath material, plus separation or degradation of the rubber sheath material where it meets the metal end fittings. Any signs of power arc, lightning damage, or corrosion on the metal end fittings also indicate deterioration of the component.

3.1.3 Condition Assessment Criteria for Metal Cross arms or Hardware

Degradation or reduction in strength of insulator hardware may occur due to the following:

- Loss of galvanization and corrosion of steel members;
- Loss in strength due to fatigue;
- Loosening of hardware due to conductor vibrations; or
- Hardware failure during major storm events.

Close-up visual inspections generally can determine the extent of degradation. Laboratory testing can further corroborate results of visual investigations.

3.1.4 Ranking Condition of Poles and Accessories through Multiple Criteria

The condition assessment process includes scoring based on multiple parameter criteria as described below:

(a) Age Related Score:

Since the service age provides a reasonably good measure of the remaining strength of wood poles, cross arms, hardware and insulators, it is employed as an assessment parameter, with the following scores:

Line Age	Assigned Score
0 to 10 years	5
10 to 20 years	4
20 to 30 years	3
30 to 40 years	2
40 to 50 years or older	1

Exhibit 3-1: Overhead Lines – Age Related Health Score

(b) Preservative Treatment Based Scoring for Wood Poles

Since the rate of pole degradation is affected by the effectiveness of the preservative treatment, wood pole treatment is employed in health index formation of line sections, as indicated in the table below:

Type of Pole Treatment	Assigned Score
Fully Treated	5
Butt Treated	3
No Treatment	1

Exhibit 3-2: Overhead Lines – Pole Treatment Based Health Score

(c) Condition Rating Based on Visual Examinations of Pole Line Components:

Different components of the pole line, including wood poles, cross-arms, hardware, insulators and pole grounding are visually inspected by qualified staff during line patrols. By taking into account the results of these inspections, the health and condition of each component is scored in accordance with the following table:

Component Condition	Assigned Score
Component is in “as new” condition	5
Component has normal wear expected with age	4
Component has many minor problems or a major problem that requires close attention and monitoring;	3
Component has many problems and the potential for its failure would rapidly escalate unless preventative maintenance is performed	2
Component has damaged/degraded beyond repair and will require replacement	1

Exhibit 3-3: Overhead Lines - Visual Inspections Based Health Score

3.1.5 Condition Assessment Criteria for Conductors

Conductors allow flow of current through them facilitating the movement of power from substations to customers’ premises. Overhead line conductors are typically supported on wood pole structures to which they are attached by insulators suitable for the voltage at which the lines operate. The conductors on a line are sized by taking into account the amount of current to be carried. The maximum current carrying capacity of conductors is determined by their thermal rating. However distribution line conductors are commonly sized to provide the right balance between energy loss in conductors (copper loss) and the capital cost of conductors. As a result the distribution lines often operate under loads significantly below the thermal rating of the conductors.

Overhead line conductors must have adequate tensile strength, enabling them to be stretched between poles. Distribution lines typically have span length of 40 m to 60 m. Three different types of conductors are commonly used on distribution lines:

- Aluminum Conductors Steel Reinforced (ACSR),
- Aluminum Stranded Conductors (ASC),
- Aluminum Alloy Conductors (AAC).

Steel reinforced aluminum conductors have galvanized steel core strands that supply most of their tensile strength. The steel core has both tensile and ductile properties, allowing the core to withstand both longitudinal forces and bending movements without failure. AAC conductors cost less in relation to ACSR conductors, but their tensile strength is significantly lower than those of the ACSR conductors. Both the price and tensile strength of AAC conductors lie in between those of ASC and ACSR conductors.

Because of the relatively short span lengths employed on distribution lines in relation to transmission lines, the tensile strength of conductors on distribution lines is not as critical as it is on transmission lines. Most distribution utilities these days, therefore, employ all aluminum conductors on distribution lines. Aluminium alloy conductors are sometimes used on distribution lines with longer span lengths.

As current passes through the conductors, the resistance causes its temperature to rise, the temperature change is proportional to the square of the load current passing through the conductor. The rise in temperature causes the conductor to lengthen and sag between points of support, reducing the height of the conductor above ground. Although it seldom happens on distribution lines, line operation at loads beyond conductors' thermal rating of approximately 90° C may lead to annealing of conductors, resulting in permanent loss of its tensile strength.

Distribution systems of older vintage employ copper conductors of #4 or #6 AWG. The small conductor sizes often break in service making the live line to come down and pose a serious safety risk to public.

To provide their intended functions on distribution lines, conductors must retain both their conductive properties and mechanical (i.e., tensile) strength. Aluminium 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.

Generally, corrosion represents the most critical life-limiting factor for ACSR conductors. Environmental conditions affect degradation rates from corrosion. Both aluminium and zinc-coated steel core conductors are susceptible to corrosion from chlorine-based pollutants, even in low concentrations, but the rate of corrosion of steel core is significantly greater than that of aluminum. While fatigue degradation is a serious concern for transmission lines that are strung with significantly higher tension, it is commonly not a serious issue for distribution lines.

Overloading lines operating beyond their thermal capacity can suffer from a loss of tensile strength due to annealing at elevated operating temperatures. Each elevated temperature event adds cumulative damage to the conductors. After loss of 10% of a conductor's rated tensile strength, significant sag occurs, requiring either resagging or replacement of the conductor. ACSR conductors can withstand greater annealing degradation compared to ASC.

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 aluminium strands, reducing strength at those sites and potentially leading to conductor failures.

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.

Although laboratory tests are available to determine the degree of corrosion and assess the tensile strength and remaining useful life of conductors, distribution line conductors rarely require testing. Conductors on distribution lines often outlive the poles and are not usually on the critical path to determine end of life for a line section.

The only exception to the above rule might be where small copper conductors susceptible to frequent breakdowns are in use or where line conductors are too small for line loads resulting in sub optimal system operation due to high line loss.

3.1.6 Condition Assessment Criteria for Splices

Conductor splices generally have a larger cross-sectional area than the conductor itself. When properly installed, splices should outlast the conductor. However, when improperly installed, splices can reduce a conductor’s life. Improperly crimped splices represent the weakest link in conductors under tension.

In extreme cases, splice failures lead to excessive conductor annealing that may cause the conductor’s strands to be pulled from the compression splice. Any strand damage that occurs during splice installation may lead to localized weakening of the conductor and premature splice failure. Failure to use non-oxidizing grease in splices also may lead to the development of hot spots and splice failure.

3.1.7 Ranking Condition of Conductors and Splices through Multiple Criteria

Computing the Health Index for overhead line conductors and splices requires developing end-of-life criteria for conductors. The condition assessment process includes scoring based on the following parameters:

(a) Age Related Scoring

Since the service age provides a reasonably good measure of the remaining strength of conductors and all the defects are not easily detected through visual inspections, an age based criteria is proposed as indicted below:

Line Age	Assigned Score
0 to 10 years	5
10 to 20 years	4
20 to 30 years (or	3
30 to 40 years	2

40 to 50 years or older	1

Exhibit 3-4: Conductors and Splices – Age Related Health Score

(b) Small Conductor Risk

Since small sized conductors pose a serious safety risk, the value of this risk is scored separately with help of the table below:

Type of Pole Treatment	Assigned Score
Presence of small sized conductors (#4 to #6 copper)	1
Absence of small sized conductors	5

Exhibit 3-5: Overhead Lines - Small Conductor Related Health Score

(c) Valuation of System losses

In addition to the above criteria, % losses on the feeder will be calculated and when significantly greater than the average distribution system losses on ETPL' system, will be included in valuation as indicated below:

Line Loss	Assigned Score
Less than or Equal to Average system loss	5
5% higher from the average system loss	4
10% higher from the average system loss	3
20% higher from the average system loss	2
30% higher from the average system loss	1

Exhibit 3-6: Overhead Lines – System Losses Related Score

3.1.8 Health Index Formulation for Overhead Lines

Health indexing quantifies equipment conditions relative to long-term degradation factors that cumulatively lead to an asset's end-of-life. Health indexing differs from maintenance testing, which emphasizes finding defects and deficiencies that need correction or remediation to keep the asset operating during some time period.

For purposes of formulating the Health Index for overhead line sections, it is proposed to assign the following weights to various health index criteria described in Section 3.1.1 and 3.1.7.

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum weighted Score
1	Age of pole line	1 - 5	5	3	15
2	Pole treatment	1 - 5	5	1	5
3	Visual inspection of poles	1 - 5	5	1	5
4	Pole testing	1 - 5	5	4	20
5	Visual inspection of insulators	1 - 5	5	1	5
6	Visual inspection of hardware	1 - 5	5	1	5
7	Age of conductors	1 - 5	5	1	5
8	Small conductor risk	1 - 5	5	5	25
9	Energy loss in conductors	1 - 5	5	3	15
	Total				100

Exhibit 3-7: Overhead Lines – Health Index Calculation

3.2 Underground Distribution System

The major assets employed on underground distribution systems can be grouped into the following categories:

- Cables, splices and terminations
- Manholes and vaults

3.2.1 Condition Assessment Criteria for Cables, Splices and Terminations

Safety, reliability, aesthetics and operating costs govern the design and construction standards for underground distribution lines. Underground cables can be constructed in a number of configurations, including direct buried cables, cables installed in direct buried conduits and cables installed in a concrete encased duct manhole system. Medium voltage underground cables have the following key components:

- Cables
- Cable Splices
- Cable Terminations

Medium voltage cables may employ either copper or aluminium conductors. They may be constructed in either single phase or three phase configurations. Two major types of cables are in common use in Ontario: paper insulated lead covered (PILC) and cross linked polyethylene (XLPE). The Distribution Standards Manual used by ETPL's contains information on design and construction standards employed.

The original designs of medium voltage cables were constructed out of oil impregnated layers of paper covered with a lead jacket and these cables are commonly referred to as paper insulated lead covered (PILC) cables. For these 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.

Polymer insulations for cables were introduced as an economic alternative to PILC cables in 1970's. The insulation system in these cables consists of a semi-conducting sheath over the conductor, the insulation, another semi-conducting layer over the insulation, a metallic shield tape or concentric neutral and a jacket. For the early generation of these cables, manufactured in the 1970's, two unexpected factors entered into the failure mechanism: presence of impurities in the insulation system and ingress of moisture that made these cables susceptible to premature failures due to water treeing. Water treeing in XLPE cables of 1970's vintage are the major cause of excessive cable failures on EPC's distribution system. Corrosion of concentric neutral conductors is another potential mode of failure.

Water treeing is the most significant degradation process for polymeric cables. The original design of cables with polymeric sheaths allowed water to penetrate and come into contact with the insulation. In the presence of electric fields water migration can result in treeing and ultimately breakdown. The rate of growth of water trees is dependent on the quality of the polymeric insulation and the manufacturing process. Any contamination voids or discontinuities will accelerate degradation. This has been the reason for poor reliability and relatively short lifetimes of early polymeric cables. As manufacturing processes have improved the performance and ultimate life of this type of cable has also improved. In addition to manufacturing improvements, development of tree retardant XLPE cables and designs to incorporate metal foil barriers and water migration control have further reduced the rate of deterioration due to treeing.

Distribution underground cables are one of the more challenging assets on electricity systems from a condition assessment and asset management viewpoint. Underground cables are relatively expensive and have long effective lifetimes. However, it is very difficult and therefore very expensive to obtain meaningful condition information for buried cables. Furthermore, cable systems have a good reliability record and when failures do occur they can be repaired at much lower cost than replacement. For all these reasons, the standard approach to managing cable systems has been monitoring of cable failure rates and the impacts of in service failures on reliability and operating costs.

3.2.2 Condition Assessment Criteria for Cable Splices and Terminations

Cable splices and terminations are subject to the same type of insulation degradation and aging as the cables themselves. But improperly made splices may be susceptible to moisture ingress and as a result may experience higher failure rates compared to cables. Compound filled cable pot terminations employed on PILC cable laterals are particularly vulnerable to failure from moisture ingress.

3.2.3 Ranking Condition of Cables and Splices through Multiple Criteria

Computing the Health Index for an underground cable section requires developing end-of-life criteria for its various components. The condition assessment process includes scoring based on multiple parameter criteria as described below:

(a) Age Related Scoring

Since the service age provides a reasonably good measure of the remaining useful life of cables, splices and terminations, it can be employed as an assessment parameter, with the following scores:

Line Age	Assigned Score
0 to 10 years	5
10 to 20 years	4
20 to 30 years	3
30 to 40 years	2
40 to 50 years or older	1

Exhibit 3-8: Underground Cables: Age Related Score

(b) **Cable Design and Construction**

Since PILC cable designs are known to provide significantly longer service life compared to XLPE cables and earlier vintages of XLPE cables that did not employ tree retardant designs are subject to premature failures, design of cable is employed in health index formation, as indicated in the table below:

Type of Pole Treatment	Assigned Score
PILC Cables	5
Tree Retardant XLPE	4
Earlier vintages of XLPE	1

Exhibit 3-9: Underground Cables Design Related Health Score

(c) Circuit Loading

The rate of insulation degradation is directly related to the operating temperature. Assuming similar types of backfills result in uniform rates of heat dissipation for all circuits, current loading of circuits measured as % of circuit's rated current carrying capacity, can be employed as an indicator of cable health as indicated below:

Component Condition	Assigned Score
Circuit loaded less than 25% of its rating	5
Circuit loading of 25% to 50% of its rating	4
Circuit loading of 50% to 75% of its rating	3
Circuit loading of 75% to 100% of its rating	2
Circuit loading of greater than 100% of its rating	1

Exhibit 3-10: Underground Cables – Loading Related Score

(d) Historic Rates of Circuit Failures

Historic failure rates on a cable circuit are an excellent indicator of the cable health and condition and its useful remaining life and therefore employed in cable health index formulation as indicated below:

Component Condition	Assigned Score

No Failures in the last 10 years	5
1 Failure in the last 10 years	4
2 Failure in the last 10 years	2
3 or more Failures in the last 10 years	1

Exhibit 3-11: Underground Cables – Failure Related Score

(e) **Condition of Cable Terminator**

Physical condition of cable terminators can be employed in assessing overall condition of the cable circuit:

Component Condition	Assigned Score
Terminator appears in good condition, no indication of moisture ingress	5
Normal wear, no apparent damage or compound leak, no evidence of moisture ingress	3
Poor condition, leaking compound indicates potential moisture ingress or IR indicates hot spot	1

Exhibit 3-12: Underground Cables: Terminator Related Health Score

3.2.4 Condition Assessment Criteria for Manholes and Vaults

Manholes provide the junction point on underground ducts to facilitate cable pulling and provide access for inspection of cable splices. Vaults provide below grade space of installation of electrical equipment such as submersible transformers or switches. In the case of both manholes and vaults, steel reinforced concrete is used for walls, roofs and floors. In locations subject to flooding floor drains and sump pumps are provided. Vaults where heat generating equipment such as distribution transformers are installed are also equipped with ventilation grates. Man access is provided through the top. When vaults and manholes are located in road ways, parking lots or other areas open to vehicular traffic, the structures must be designed by a structural engineer. Since manholes and vaults are confined spaces, they must be adequately sized to rescue trapped workers during a fire or explosion inside the vault or manhole.

The common degradation mode for manholes and vaults is the deterioration of concrete structures due to concrete spalling and corrosion of rebar, sinking of the roof top surfaces allowing rain water to collect and flood the manhole and vaults. Functional obsolescence, where the size of the manhole or vault no longer meets the space requirements can also lead to end of life of a structure.

3.2.5 Ranking Condition of Manholes and Vaults through Multiple Criteria

The health and condition of manhole and vaults can be measured through visual inspections, looking for:

- Structural damage to concrete walls or roof
- Frequent flooding incidents of the vaults or manholes
- Non functioning drains or sump pumps
- Inadequate space

(a) Structural Condition:

Inspections	Assigned Score
No deficiencies in the vault or manhole	5
Only minor deficiencies	3
Major deficiencies requiring immediate repairs/replacement	1

Exhibit 3-13: Manhole and Vaults Structural Health Score

(b) Flooding Incidents, Drains, Sump pumps

Inspections	Assigned Score

No incidents of Flooding at this location	5
Occasional Flooding, working sump pumps and drains	3
Frequent Flooding, No sump pumps or drains	1

Exhibit 3-14: Manhole and Vaults: Flooding Related Health Score

(c) Vault Size and Access

Inspections	Assigned Score
Adequate ergonomic size and safe access to vault	5
Vault size slightly smaller than ideal, but adequate for safe working and reasonable access to vault	3
Vault size or access inadequate for safe working or worker rescue during an accident immediate repairs/replacement	1

Exhibit 3-15: Manholes and Vaults Size Related Health Score

3.2.6 Health Index Formulation for Underground Cables, manholes and vaults

Health indexing quantifies equipment conditions relative to long-term degradation factors that cumulatively lead to an asset's end-of-life. Health indexing differs from maintenance testing, which emphasizes finding defects and deficiencies that need correction or remediation to keep the asset operating during some time period.

For purposes of formulating the Health Index for underground cables and manholes/vaults, it is proposed to assign the following weights to various health index criteria:

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum weighted Score
1	Age of Cable Circuit	1 – 5	5	3	15
2	Type/Design of Cable	1 – 5	5	3	15
3	Loading of Cable Circuit	1 – 5	5	5	25
4	Historic Failure rates	1 – 5	5	8	40
5	Visual inspection of terminators	1 – 5	5	1	5
	Total				100

Exhibit 3-16: Cables, Splices and Terminators Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum weighted Score
1	Structural Integrity	1 – 5	5	8	40
2	Flooding and Its mitigation	1 – 5	5	4	20
3	Size and Access	1 – 5	5	8	40
	Total				100

Exhibit 3-17: Manholes and Vaults Health Index

3.3 Substations

The major assets employed in substations include:

- Power Transformers
- Circuit Breakers or Reclosers
- Controls and Protective Relays
- Control Battery and Chargers
- Condition of Ground Grid
- Fences
- Buildings

3.3.1 Condition Assessment of Power Transformers

The key role of the power transformers is to step down transmission or sub-transmission voltage to distribution voltage. In case of ETPL, power transformers step down from 27.6 kV sub-transmission voltages to 4.16kv. Power transformers are virtually always pad mounted. The key components of a power transformer are:

- primary and secondary coils, made of copper of aluminium conductors
- magnetic core made of iron laminations
- insulation system, commonly consisting of paper and mineral oil
- transformer tank, either sealed or breather type, and
- primary and secondary bushings.
- Auxiliary devices

The most critical component in transformer aging consideration is the insulation system, consisting of mineral oil and paper. Transformer oil consists of hydrocarbon compounds that degrade with time due to oxidation, resulting in formation of moisture, organic acids and sludge. The oil oxidation rate is a function of operating temperature. Increased acidity and moisture content in insulating oil causes accelerated degradation of insulation paper. Formation of sludge adversely impacts the cooling efficiency of transformer, resulting in higher operating temperatures and further increasing the rate of oxidation of both the oil and the paper. Condition assessment of transformer oil, therefore, provides extremely useful information in assessing the health and condition of a transformer.

The paper insulation consists of long cellulose chains, that break as the paper ages (oxidizes). Tensile strength and ductility of insulation paper are important properties that are determined by the average length of the cellulose chains. As the paper oxidizes, its mechanical strength is gradually reduced, making it weak and brittle. This can lead to insulation failure if the transformer is subjected to mechanical shocks that are common in normal operating conditions. Insulation degradation and failure can also result from electrical activity inside insulation, such as partial discharge activity, which is initiated if the level of moisture in oil builds up or if other minor defects develop within the insulation. Partial discharge and other electrical and thermal faults in the transformer can be detected and monitored by measurement of hydrocarbon gases in the oil through Dissolved Gas Analysis (DGA).

Oil analysis provides information on three critical factors:

- condition of the oil from moisture, acidity and breakdown strength measurements,
- condition of the paper insulation from Furan, carbon dioxide, carbon monoxide and moisture measurements, and,
- presence of any incipient electrical or thermal faults within the transformer from the DGA results.

Some other tests that can be applied to oil samples such as interfacial tension, power factor etc.

3.3.2 Ranking Condition of Power Transformers through Multiple Criteria

Computing the Health Index for a transformer requires developing end-of-life criteria for its various components. Each criterion represents a factor critical in determining the component's condition relative to potential failure. The condition assessment process includes scoring based on multiple parameter criteria as described below:

(a) **Age Related Scoring**

Since the service age provides a reasonably good measure of the remaining life of transformers, it is employed as an assessment parameter, with the following scores:

Power Transformer Age	Assigned Score
0 to 10 years	5

10 to 20 years	4
20 to 30 years	3
30 to 50 years	2
50 years or older	1

Exhibit 3-18: Power Transformers Age Related Health Score

(b) Condition Assessment Based on Loading Level

The rate of insulation degradation is directly related to the operating temperature and operating temperature is directly related to loading levels. Peak loading level of the transformers expressed in % of nameplate rating can therefore be employed as an indicator of transformer health:

Component Condition	Assigned Score
Peak load less than 50% of its rating	5
Peak load of 50% to 75% of its rating	4
Peak load of 75% to 100% of its rating	3
Circuit loading of 100% to 125% of its rating	2
Circuit loading of greater than 125% of its rating	1

Exhibit 3-19: Power Transformers – Load Related Health Score

(c) Visual Inspections

Visual inspections can provide a good indication of the physical condition of transformers, which can be ranked as indicated below:

Visual Inspections	Assigned Score

No rust on tank/radiator, no damage to bushings, no sign of oil leaks, forced air cooling fully functional	5
Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leak	4
Two or more of the above indicated defects present but do not impact safe operation	3
Tank/radiator badly rusted or major damage to bushing or major oil leak	2
Two or more of the above indicated defects or the cooling fans do not work	1

Exhibit 3-20: Power Transformers Health Score Based On Visual Inspections

(d) Condition Rating Based on Evaluation of the oil tests

Various insulation tests can be interpreted by an expert to rank the overall condition of transformer insulation system:

Test Results	Assigned Score
Test results indicate excellent insulation condition, no indication of moisture, arcing, overheating or degradation of paper	5
Tests indicate normal aging, no concerns about insulation health	4
Tests indicate slightly above average but stable moisture content or presence of arcing overheating related gases	3
Some of the tests indicates significant concerns about insulation condition	2
Two or more of the tests indicate rapidly deteriorating insulation condition	1

Exhibit 3-21: Power Transformers – Health Score Based on Oil Tests

3.3.3 Condition Assessment Criteria for Circuit Breakers and Reclosers

Medium voltage circuit breakers provide local or remote control for closing and opening of power supply circuits and in conjunction with protective relays provide an important safety function to automatically detect and isolate faulty circuits in order to provide safe, stable and reliable operation with desired selectivity. A pole mounted recloser virtually provides the same functions as a circuit breaker. While its design is significantly different, the recloser employs the same operating principle as a circuit breaker.

When a circuit breaker interrupts current, an electrical arc is produced in the ionized insulation medium. In order for the circuit breaker action to succeed, the large amount of energy contained in the arc must be successfully extinguished by the breaker's interrupting medium. Depending on the type of arc interrupting medium employed, circuit breakers (or reclosers) are classified as oil circuit breakers, magnetic air circuit breakers, SF-6 circuit breakers or Vacuum circuit breakers. In order to deliver the desired functions, circuit breakers and reclosers are required to possess the following properties and characteristics:

- highly conductive contact material, capable of withstanding repeated arcs;
- High quality of contact make with extremely low resistance;
- High quality contact mating, capable of retaining high conductivity over time
- Adequate contacts parting distance in open position for the rated voltage;
- Adequate line to ground insulation for the rated voltage;
- Stable insulating medium, capable of withstanding repeated arcs;
- Fast speed during opening and closing of contacts;
- Appropriate arc blowing techniques to extinguish arcs;
- Adequate energy imparting mechanisms for making or breaking of short circuit currents.

Different types of circuit breakers employed on ETPL' distribution system are described below:

(a) Oil Circuit Breakers (OCB)

In minimum oil circuit breakers, insulating oil provides the role of arc quenching only, but in bulk oil circuit breakers, the insulating oil provides both the arc quenching and the insulation functions. OCBs generally perform well at low ambient temperatures. They also provide long and reliable service life when the number of loading switching or fault interruption operations is infrequent. However, frequent switching fault interruption applications must be accompanied by frequent preventative maintenance. OCBs do not perform well in switching capacitive loads, during switching operations of which high peak recovery voltages are produced. Generally, after 4 to 8 fully rated interruptions, OCB's require preventative maintenance, during which excessive contact erosion, carbonisation of oil, and maintenance of operating mechanism may need to be attended to. The manufacture of new OCBs has been discontinued for at least 25 years now. The original equipment manufacturers (OEMs) provided service support and spares for these OCBs until the late 1990s. Many utilities in North America continue to successfully employ older vintages of OCBs on their systems.

(b) Air Magnetic Circuit Breakers (Air Magnetic Breakers)

Air magnetic breakers employ the magnetic effect of the current in their design, by forcing the electric arc produced during opening on the contacts into an arc chute. The arc chute causes elongation of the arc path and allows cooling, splitting and eventual extinction of the arc. In some designs, an auxiliary puffer is employed to blast air into the arc, which allows successful interruption of low-level currents with weaker magnetic fields. Air magnetic breakers represent the second oldest technology in circuit breaker design, next to OCBs. They are also no longer in manufacture and have been superseded by SF6 and vacuum technologies since the late 1970s.

(c) Vacuum Circuit Breakers

In a Vacuum circuit breaker, vacuum interrupters are employed to make or break load or fault current. Upon separation of the contacts, the current initiates a metal vapour arc discharge and flows through the plasma until the next current zero. The arc is extinguished at current zero and the conductive metal vapour condenses on the metal surfaces during a very short time internal measured in micro seconds. Therefore, the dielectric strength in the breaker builds up very rapidly. The effectiveness of vacuum interrupter depends largely on the material and form of the contacts. In modern designs, oxygen free copper chromium alloy is commonly employed as it is believed to be the best material for the application. This material combines good arc extinguishing characteristic with a reduced tendency to contact welding.

The operating mechanism of circuit breakers and reclosers consists of numerous moving parts that are subject to wear and tear during breaker operation. Because circuit breakers are required to frequently "make" and "break" heavy currents, the contacts are subjected to arcing that accompanies such operations. Each time a circuit breaker opens or closes, the contact surfaces undergo some degradation and degraded contacts produced higher degree of arcing in subsequent operations. Heat produced during contact arcing also decomposes metal surface from the contacts as well as the insulation medium and the by-products so decomposed are deposited in surrounding insulation materials. The mechanical energy required to generate high contact velocities also results in wear and tear of the mechanical parts in operating mechanism.

A number of factors influence the overall rate of wear and severity of degradation of circuit breakers, including type of the insulating medium, design of the contacts, operating environment, and the duty cycle of the circuit breaker. Load current switching or fault current interruption seldom lead to sudden failure of circuit breakers, but repeated operations result in overall wear and tear which lead to eventual end of life.

Circuit breakers mounted outdoors may experience adverse environmental conditions that may further contribute to the rate and severity of degradation. The following factors represent environmental degradation of outdoor mounted circuit breakers:

- Corrosion of enclosures and metal parts;
- Potential ingress of moisture into operating parts and insulating system;
- Bushing/insulator deterioration under the influence of moisture, fog, ice; and
- Deterioration of mechanical parts;

OCBs typically have longer current interruption duration compared with other types of designs. Contacts and the insulation medium are therefore subjected to severe arcing, resulting in deterioration of the contact surface as well as insulation. Thus, both contacts and oil degrade more rapidly in case of OCBs than they do in either SF6 or vacuum designs, especially when the OCB undergoes frequent switching operations. Generally, 4 to 8 interruptions under fault or heavy load will cause contact erosion and oil carbonisation, requiring contact maintenance and possibly oil filtration. OCBs have therefore higher operating costs compared to other designs.

3.3.4 Ranking Condition of Circuit Breakers and Reclosers through Multiple Criteria

Computing the Health Index for circuit breakers requires collection of data on a number of condition indicators:

(a) Age Related Scoring

Service age provides a reasonably good measure of the remaining life of circuit breakers and reclosers. Since the outdoor mounted reclosers, exposed to the weather elements experience a faster rate of aging, two separate sets of criteria are provided for outdoor and indoor mounted circuit breakers / reclosers:

Age	Assigned Score
0 to 7 years	5
8 to 15 years	4
16 to 24 years (or	3
25 to 32 years	2
33 years or older	1

Exhibit 3-22: Outdoor Circuit Breakers – Age Related Health Score

Age	Assigned Score
0 to 10 years	5
11 to 20 years	4
21 to 30 years (or	3
31 to 40 years	2
41 years or older	1

Exhibit 3-23: Indoor Circuit Breakers – Age Related health Score

(b) Visual Inspections

Visual inspections can provide a good indication of the physical condition of circuit breakers, which can be ranked as indicated below:

Visual Inspection Indicators	Assigned Score
No rust on tank/enclosure, no damage to bushings, no leaks, controls and wiring in excellent condition	5
Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leak	4
Two or more of the above indicated defects present but do not impact safe operation	3
Tank/enclosure badly rusted or major damage to bushing or major oil leak	2
Two or more of the above indicated defects or the cooling fans do not work	1

Exhibit 3-24: Circuit Breakers – Visual Inspections Based Health Score

(c) **Condition Rating Based on Evaluation of the test tests**

Various interruption chamber tests can be interpreted by an expert to rank the overall condition of transformer insulation system:

Test Results	Assigned Score
Test results indicate excellent condition of contacts, operating mechanism, insulation condition and protection relays	5
Normal aging, each of the four indicators within specified limits	4

One of the above four indicators is slightly beyond the specified limits	3
Two or more of the above four indicators beyond the specified limits	2
Two or more of the indicators beyond specifications and cannot be brought to comply with the specifications	1

Exhibit 3-25: Circuit Breakers – Testing Based Health Score

3.3.5 Condition Assessment Criteria for Protection Relays and Remote Terminal Units

The function of protection relays on distribution systems is to detect and annunciate abnormal operating conditions and initiate circuit breaker or recloser trip to isolate faulty circuits from healthy. Protection relays obtain their input from instrument transformers, process the information and automatically take corrective action with adequate speed and selectivity. There is currently no SCADA link to substations and no remote terminal units (RTUs) are employed at ETPL substations.

Electro-mechanical designs of protection relays have been in use in the industry for several decades, but the industry best practice has been to replace these relays with solid state and microprocessor relays. Electro-mechanical relays have many moving parts and require calibration at regularly scheduled intervals to assure accurate operation. Modern micro-processor relays have no moving parts and can provide much more accurate operation without requiring frequent calibration.

The electro-mechanical relays with many moving parts lose their operating accuracy due to the moving parts developing friction or the springs becoming weak with passage of time and need to be readjusted from time to time. Voltage and current surges can also harm electrical components of relays. The micro-processor and the solid state relays do not require frequent calibrations, but they are vulnerable to voltage and current surges.

3.3.6 Ranking of Protection Relays Condition through Multiple Criteria

(a) Age Related Scoring

Service age provides a reasonably good measure of the remaining life of protection relays. Since the relays are either installed indoors or in weatherproof cabinets, they are protected from the weather elements.

Age	Assigned Score
0 to 10 years	5
11 to 20 years	4
21 to 30 years (or	3
31 to 40 years	2
41 years or older	1

Exhibit 3-26: Protection Relays Age Based Health Score

(b) Condition Rating Based on Evaluation of the test tests:

Calibration tests can be interpreted by an expert to rank the overall condition of protection relays:

Test Results	Assigned Score
Excellent operating condition, calibration well within specified limits	5
Normal aging, calibration within the specified limits	4
Frequent calibration required, but it is possible to meet specified limits	3
Not possible to calibrate the relays to bring settings to specified limits	1

Exhibit 3-27: Protection Relays Testing Based Health Score

3.3.7 Control Battery and Chargers

The purpose of substation control batteries is to provide power for critical control functions such as trip coils of circuit breakers. Two types of batteries are commonly used: lead acid batteries and nickel cadmium batteries. Batteries are carefully sized to store adequate energy for system operation during an AC power failure.

The key parts of a control battery include two electrodes immersed in an electrolyte inside a jar. The battery terminals are brought out for cable connections. While the earlier vintages of control batteries required frequent maintenance and monitoring of electrolyte, modern batteries employ sealed design and are virtually maintenance free for the service life.

Battery chargers employ solid state rectifiers and are equipped with normal slow charge or fast charge functions.

Both the electrodes and electrolyte in control batteries undergo aging with repeated charge and discharge cycles, which result in gradual reduction of battery storage capacity. The end of life is reached when the battery is no longer able to retain adequate charge for required functions.

Battery chargers can experience component failures, but these can be easily replaced and as a result the charger often outlasts the battery.

3.3.8 Ranking Condition Control Batteries through Multiple Criteria

(a) Age Related Scoring

Since different types of batteries can have significantly different life expectancy, age related scoring needs to be measured in terms of manufacturer recommended life expectancy:

Actual Battery Age	Assigned Score
Less than 25% of manufacturer recommended age	5
Less than 50% of manufacturer recommended age	4
Less than 75% of manufacturer recommended age	3
Less than manufacturer recommended age	2
More than manufacturer recommended age	1

Exhibit 3-28: Control Batteries and Chargers Age Related Health Score

(b) Condition Rating Based on Evaluation of the test tests:

Test Results	Assigned Score
Battery capable of storing full rated energy	5
Battery stores marginally less than full rated energy, but still adequate for required functions	3
Battery stores significantly less than the full rated energy, inadequate for required functions	1

Exhibit 3-29: Control Batteries and Chargers Test Based Health Score

3.3.9 Substation Ground Grids

The purpose of substation ground grid is to provide a low resistance ground electrode for system neutral, for equipment case grounding and to maintain safe potential gradients within the station yards during abnormal operating conditions, i.e. line-to-ground faults.

The station ground electrode consist of multiple ground rods driven into the ground and located strategically and connected with underground copper conductors to make a mesh of sufficiently low resistance. All feeder neutrals are connected to the electrode. Cases of each piece of power equipment are also bonded to the ground electrode. All fences and gates are bonded to the perimeter ground grid.

Where the ground potential rise (GPR) exceeds safe limits, surface stone of high resistivity is used in the substation yard to maintain step potential within safe limits.

Buried ground rods, conductors and connectors are subject to corrosion, which reduces the effectiveness of the ground electrode with passage of time. Above ground components of the electrode and copper conductors are subject to vandalism and damage. The surface stone can degrade in quality due to growth of weeds.

3.3.10 Ranking Condition of Ground Grids through Multiple Criteria

The health and condition of ground grid can be verified though ground grid resistance measurements and integrity tests.

(a) Age Related Scoring

Actual Battery Age	Assigned Score
Ground Electrode less than 10 years old	5
Ground Electrode Between 10 and 20 years Old	4
Ground Electrode Between 20 and 30 years Old	3
Ground Electrode Between 30 and 40 years Old	2
Ground Electrode More than 40 years Old	1

Exhibit 3-30: Ground Grid Age Related Score

(b) **Condition Rating Based on Evaluation of the test tests**:

Test Results	Assigned Score
Ground electrode resistance and GPR within safe limits, all electrode components pass integrity test	5
Ground electrode resistance and GPR within safe limits but a few electrode components do not pass integrity test	3
Ground electrode resistance or GPR not within safe limits or many electrode components pass integrity test	1

Exhibit 3-31: Ground Grid Testing Related Health Score

(c) **Rating Based on Condition of Surface Stone**

Test/Inspection Results	Assigned Score
Resistivity of Surface Stone >3000 Ohm-m, no sign of vegetation growth	5
Resistivity of Surface Stone marginally less than <3000 Ohm-m, but no sign of vegetation growth	3
Resistivity of Surface Stone significantly less than <3000 Ohm-m, and signs of vegetation growth	1

Exhibit 3-32: Ground Grid Testing Related Health Score

3.3.11 Substation Fences

The purpose of substation fences is to provide security for substation assets by not allowing entry into the yard to unauthorized people or wild life.

To achieve this objective the fence has to be of a minimum height of 6’ to comply with the electrical safety act and topped three rungs of barbed wire covering a height of 12”. The fence must be secured with posts of adequate strength and should limit the crawl space between the fence and ground to 4” or less. Where a fence connects into another steel fence, an insulated section should be added to prevent transfer of harmful potential to remote locations.

The fence should be grounded and bonded throughout. The gates should be lockable and locked and warning signs should be provided.

The common degradation mode for station fences are rusting and corrosion, damage to fence posts and gates, soil erosion increasing the crawl space under the fence and vandalism to damage and deface warning signs.

3.3.12 Ranking Condition of Fences through Multiple Criteria

(a) Condition Rating Based on Evaluation of the test tests:

Inspections	Assigned Score
No deficiencies in the fence	5

Only minor deficiencies	3
Major deficiencies requiring immediate attention	1

Exhibit 3-33: Fences Health Score based on Visual Inspections

3.3.13 Substation Buildings

Substation buildings provide protection to critical substation assets, i.e. circuit breakers and protection relays against weather elements. While the switchgear is commonly located on the main floor, the basements serve as an oversized manhole to provide exit for feeder cables.

The common degradation mode for substation buildings is deterioration of roofs, sidings, doors and windows. A small leak in the roof can cause a lot of harm to electrical equipment and defeat the very purpose of the substation building.

3.3.14 Ranking Condition of Substation Buildings through Multiple Criteria:

The health and condition of substation building can be measured through visual inspections:

Inspections	Assigned Score
No deficiencies in the building	5
Only minor deficiencies	3
Major deficiencies requiring immediate attention	1

Exhibit 3-34: Substation Buildings Health Score

3.3.15 Health Index Formulation for Substation Equipment

Since each piece of substation equipment can be independently replaced or rehabilitated, rather than developing an overall health index for substations, methodology for developing health indices for key substation assets is provided below:

For purposes of formulating the Health Index for major substation assets, it is proposed to assign the following weights to various health index criteria described in the previous sections:

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum weighted Score
1	Age of transformer	1 - 5	5	6	30
2	Peak loading	1 - 5	5	4	20
3	Visual inspection	1 - 5	5	2	10
4	Testing	1 - 5	5	8	40
	Total				100

Exhibit 3-35: Power Transformers – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum weighted Score
1	Age	1 - 5	5	8	40

2	Visual inspection	1 - 5	5	4	20
3	Testing	1 - 5	5	8	40
	Total				100

Exhibit 3-36: Circuit Breakers – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum weighted Score
1	Age	1 - 5	5	10	50
2	Testing	1 - 5	5	10	50
	Total				100

Exhibit 3-37: Protection Relays and RTUs – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum weighted Score
1	Age	1 – 5	5	10	50
2	Testing	1 – 5	5	10	50
	Total				100

Exhibit 3-38: Substation Control Batteries and Chargers Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum weighted Score

1	Age	1 - 5	5	8	35
2	Testing	1 - 5	5	8	35
3	Condition of Surface Stone	1 - 5	5	4	30
	Total				100

Exhibit 3-39: Substation Ground Grid Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum weighted Score
1	Visual Inspection	1 – 5	5	20	100
	Total				100

Exhibit 3-40: Substation Fences Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum weighted Score
1	Visual Inspection	1 – 5	5	20	100
	Total				100

Exhibit 3-41: Substation Buildings Health Index

3.4 Distribution Transformers

Four main types of distribution transformers are employed on ETPL]'s distribution system:

- Pole mounted transformer
- Pad mounted transformer
- Poles Trans
- Submersibles

Aside from the different design and construction standards employed in their manufacture and installation, each type of transformers serve the same functions and the same asset management strategy can be employed for both of these assets as described below:

Distribution transformers step down to the medium voltage distribution power to final utilization voltage of either 120/240V, or 120/208V or 347/600 V. Both single phase and three phase transformers are in use. In pole top applications, three single phase transformers are commonly employed to create a three phase bank, however for pad mounted applications, three phase transformers are used for three phase applications.

The key components of a distribution transformer are

- primary and secondary coils, made of copper of aluminium conductors
- magnetic core made of iron laminations
- insulation system, commonly consisting of paper and mineral oil
- sealed transformer tank,
- primary and secondary bushings or bushing wells to accommodate elbows.
- Auxiliary devices

The most critical component in transformer aging consideration is the insulation system, consisting of mineral oil and paper. Transformer oil consists of hydrocarbon compounds that degrade with time due to oxidation, resulting in formation of moisture, organic acids and sludge. The oil oxidation rate is a function of operating temperature. Increased acidity and moisture content in insulating oil causes accelerated degradation of insulation paper. Formation of sludge adversely impacts the cooling efficiency of transformer, resulting in higher operating temperatures and further increasing the rate of oxidation of both the oil and the paper. Distribution transformers commonly fail when the age weakened insulation system is subjected to a voltage surge during lightening.

Most utilities run the distribution transformers to failure, i.e. replace them only after they fail. With the exception of rust proofing and painting of the tanks, replacing a damaged bushing or repairing a leaky gasket, very little invasive preventative maintenance or testing is carried out on distribution transformers.

3.4.1 Ranking the Condition of Distribution Transformers through Multiple Criteria

Computing the Health Index for a distribution transformer requires developing end-of-life criteria for its various components. Each criterion represents a factor critical in determining the component's condition relative to potential failure. The condition assessment process includes scoring based on multiple parameter criteria as described below:

(a) **Age Related Scoring**

Since the service age provides a reasonably good measure of the remaining life of transformers, it is employed as an assessment parameter, with the following scores:

Distribution Transformer Age	Assigned Score
0 to 10 years	5
10 to 20 years	4
20 to 30 years	3
30 to 40 years	2
40 years or older	1

Exhibit 3-42: Distribution Transformers Age Based Health Scoring

(b) **Condition Assessment Based on Loading Level**

The rate of insulation degradation is directly related to the operating temperature and operating temperature is directly related to loading levels. Peak loading level of the transformers expressed in % of nameplate rating can therefore be employed as an indicator of transformer health:

Component Condition	Assigned Score
Peak load less than 50% of its rating	5
Peak load of 50% to 75% of its rating	4
Peak load of 75% to 100% of its rating	3
Circuit loading of 100% to 125% of its rating	2
Circuit loading of greater than 125% of its rating	1

Exhibit 3-43: Distribution Transformers – Load Based Health Scoring

(c) Visual Inspections

Visual inspections can provide a good indication of the physical condition of transformers, which can be ranked as indicated below:

Visual Inspections	Assigned Score
No rust on tank/enclosure, no damage to bushings, no sign of oil leaks, padlocks in good condition on pad mounted transformers	5
Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leak	4
Two or more of the above indicated defects present but do not impact safe operation	3
Tank/radiator badly rusted or major damage to bushing	2

or major oil leak	
Two or more of the above indicated defects	1

Exhibit 3-44: Distribution Transformers – Inspections Based Health Scoring

3.4.2 Health Index Formulation for Distribution Transformers

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum weighted Score
1	Age of transformer	1 – 5	5	6	30
2	Peak loading	1 – 5	5	6	30
3	Visual inspection	1 – 5	5	8	10
	Total				100

Exhibit 3-45: Distribution Transformers Health Index

3.5 Disconnect Switches and Cut-outs

This asset class include pad and vault mounted medium voltage switchgear as well as pole mounted ganged disconnect switches and single phase solid blade or cutouts. Disconnect switches provide means of load disconnect and isolation for equipment, such as underground laterals or distribution transformers.

The key components of a distribution switch are

- Switch blades
- Operating handle and mechanism
- Insulator bushings
- Grounding and bonding conductors

In case of pad mounted disconnects, it has following additional components:

- Pad or Vault mounted metal enclosure
- Inter-phase glass polyester barriers
- Padlocks

The most critical components in the disconnect switch are the switch blades and operating mechanism. Misaligned or poorly surfaced contacts can result in excessive arcing during switch opening or closing, resulting in further deterioration of the blades. Corrosion may cause rusting of the links and pins in operating mechanism reducing the blade movement speed. Broken grounds or damaged insulators are some other defects that may appear with age.

Pad or vault mounted disconnect switch enclosures are vulnerable to corrosion due to road salt spray. Non functioning padlocks or broken inter phase barriers are other serious defects that may develop with aging.

3.5.1 Ranking Condition of Disconnect Switches through Multiple Criteria

(a) Age Related Scoring

Since the service age provides a reasonably good measure of the remaining life of disconnect switches, it is employed as an assessment parameter, with the following scores:

Disconnect Switch Age	Assigned Score
0 to 10 years	5
10 to 20 years	4
20 to 30 years	3
30 to 40 years	2

40 years or older	1

Exhibit 3-46: Disconnect Switches and Cutouts Age Based Health Scoring

(b) Visual Inspections

Visual inspections can provide a good indication of the physical condition disconnect switches. IR scan can provide indication of hot spots resulting from misaligned blades.

Visual Inspections	Assigned Score
No rust on tank/enclosure, no damage to bushings, padlocks in good condition on pad mounted switchgear, operating mechanism and blades in excellent condition.	5
Only minor wear, no defects.	4
No more than one of the above indicated defects present but does not impact safe operation	3
Two or more of above indicated defects, but they can be repaired	2
Two or more of the above indicated defects, but they cannot be repaired	1

Exhibit 3-47: Disconnect Switches and Cutouts Inspections Based Scoring

3.5.2 Health Index Formulation for Disconnect Switches

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum weighted

					Score
1	Age of disconnect	1 - 5	5	10	50
2	Visual inspections and IR Scan	1 - 5	5	10	50
	Total				100

Exhibit 3-48: Distribution Switches and Cutouts – Health Index

4 Asset Demographics and Condition Assessment

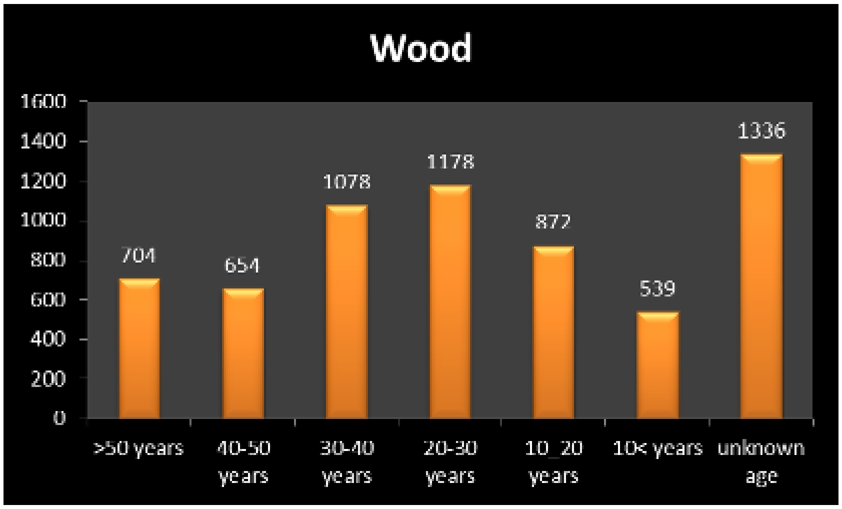
The methodology described in detail in section 3 provides means of accurate and comprehensive condition assessment of all major assets employed on ETPL's distribution network. However, complete data required for condition assessment thorough this methodology is not presently available and would require some time for collection from the field.

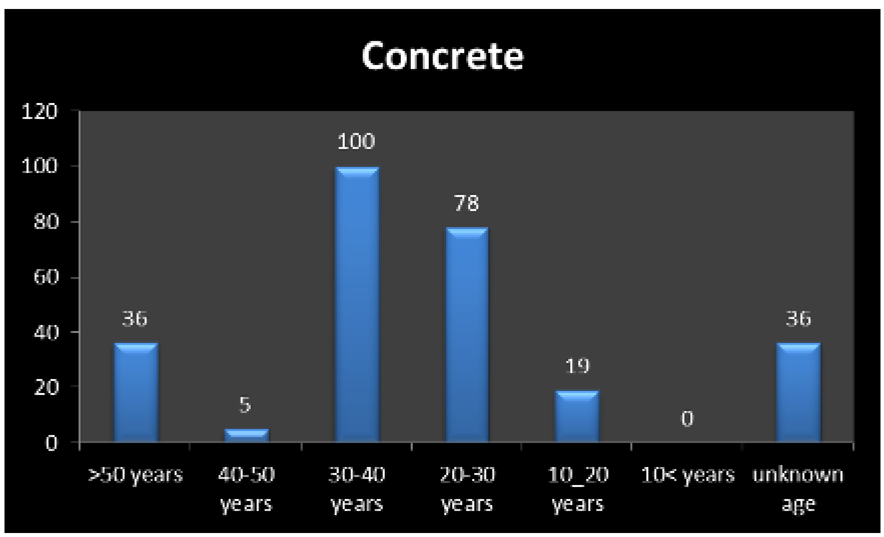
In this section we have completed the condition assessment of the assets by taking into account all of the available information and asset condition specific data. We have developed estimates of the overall investment requirement by evaluating the risk of in-service asset failures, based on assets' age profiles and mean life expectancy of assets. It is recommended that data required for condition assessment of the assets, described in Section 3 be collected and analyzed for targeting investments into those assets that are at the highest risk of in-service failures.

This section of the report, essentially, provides a snap shot into the general condition of the assets employed on ETPL' distribution network, based on the demographic information retrieved from the GIS system and physical inspections of a representative sample of assets.

4.1 Overhead Line Support Poles:

There are approximately 8,617 poles employed on ETPL' distribution network. Approximately 1890 of these poles (22% of the total) are employed in the newly acquired region of Mitchell, Dublin and Clinton (North Region) and the remaining78% are employed in the southern service territory (South Region). Demographic information on distribution poles is presented in Exhibits 4.1 and 4.2, respectively for South Region and North Region. As indicated a vast majority of the poles employed on ETPL distribution system are wood poles and more than 20% of these poles have been in service for over 40 years and are approaching the end of the their useful service life.


Wood
1600
1400
1200
1000
800
600
400
200
0
704
654
1078
1178
872
539
1336
>50 years
40-50 years
30-40 years
20-30 years
10_20 years
10< years
unknown age


Concrete
120
100
80
60
40
20
0
36
5
100
78
19
0
36
>50 years
40-50 years
30-40 years
20-30 years
10_20 years
10< years
unknown age

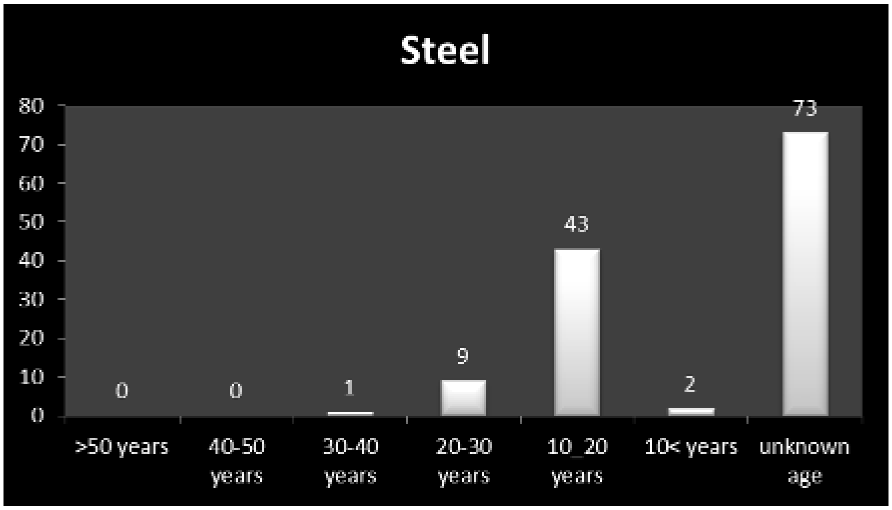
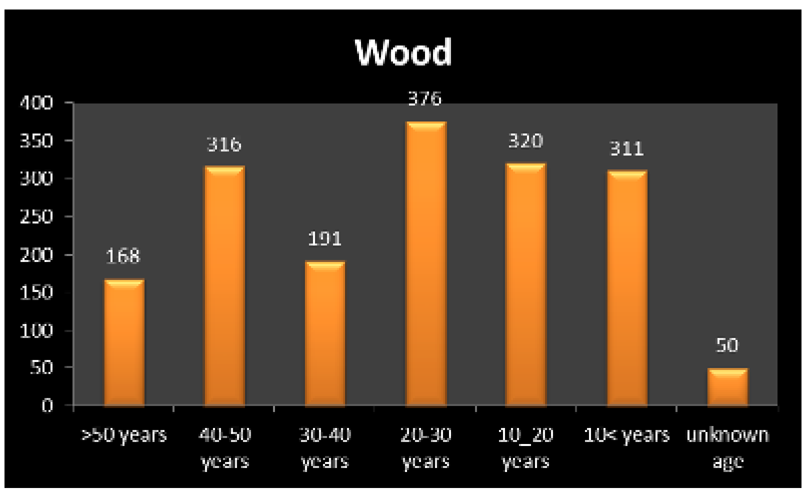
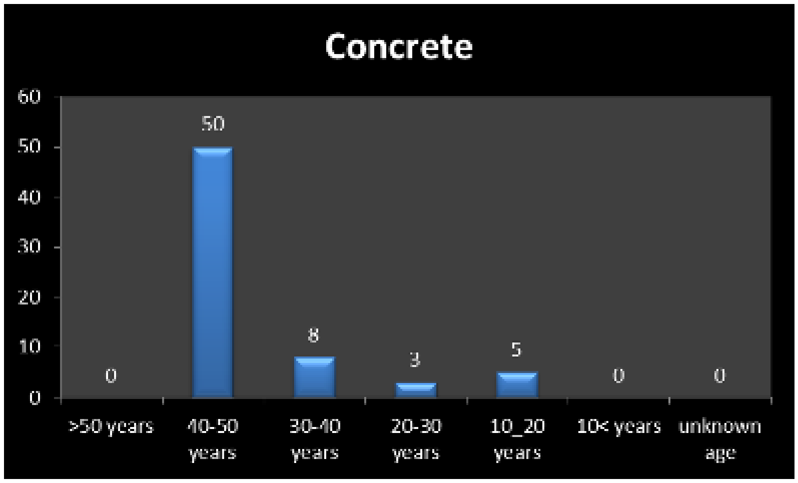


Exhibit 4-1: Pole Demographics (South Region)





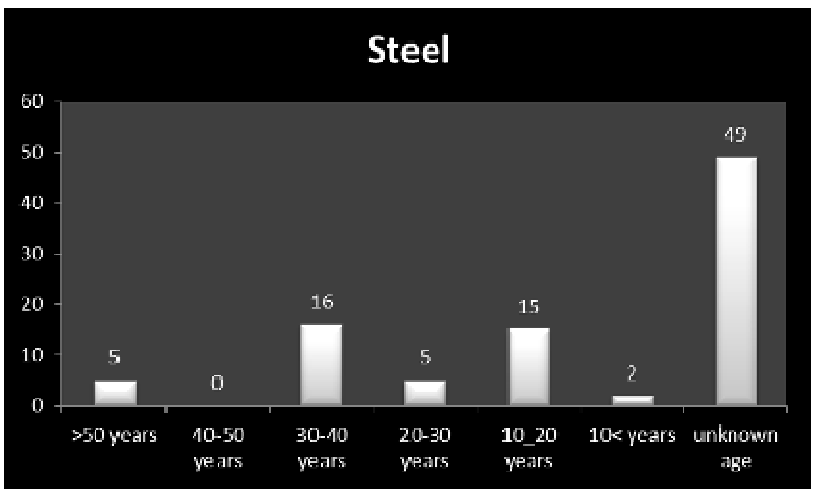


Exhibit 4-2: Pole Demographics (North Region)

Poles are employed in different configurations on overhead lines, some support only low voltage circuits, while others may support multiple circuits of different voltage lines, requiring taller poles. Exhibit 4-3 shows the number of poles of different heights employed on ETPL distribution system.

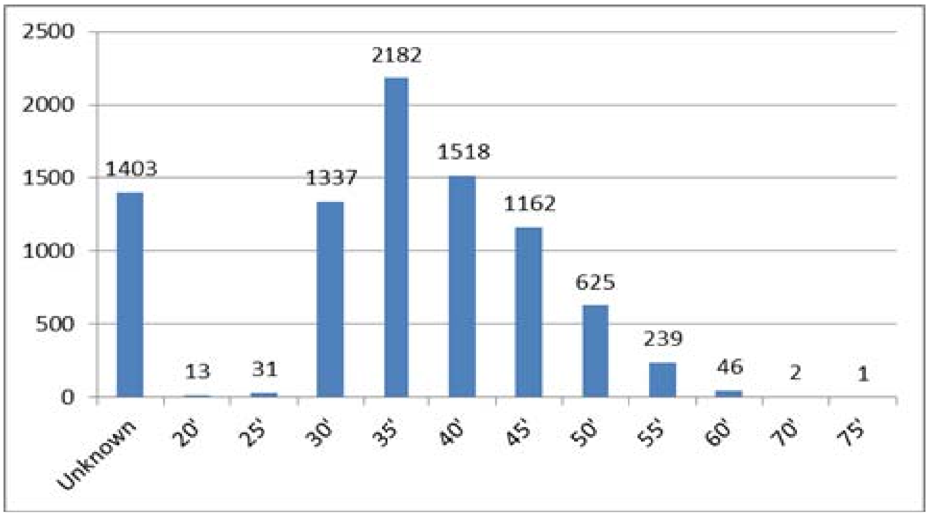


Exhibit 4-3: Pole Heights

A sample of approximately 1000 wood poles in Embro, Thamesford and Tavistock districts (all in South Region) have been tested recently and we have reviewed the test report. Approximately 3% of the poles were found to be in poor condition and in need of immediate replacement. It is noteworthy that the pole conditions deviate significantly from one district to another. For example, approximately 7% of the poles tested in Tavistock were found to be in poor condition, but only 1% of the poles tested in Embro district were determined to be in poor condition.

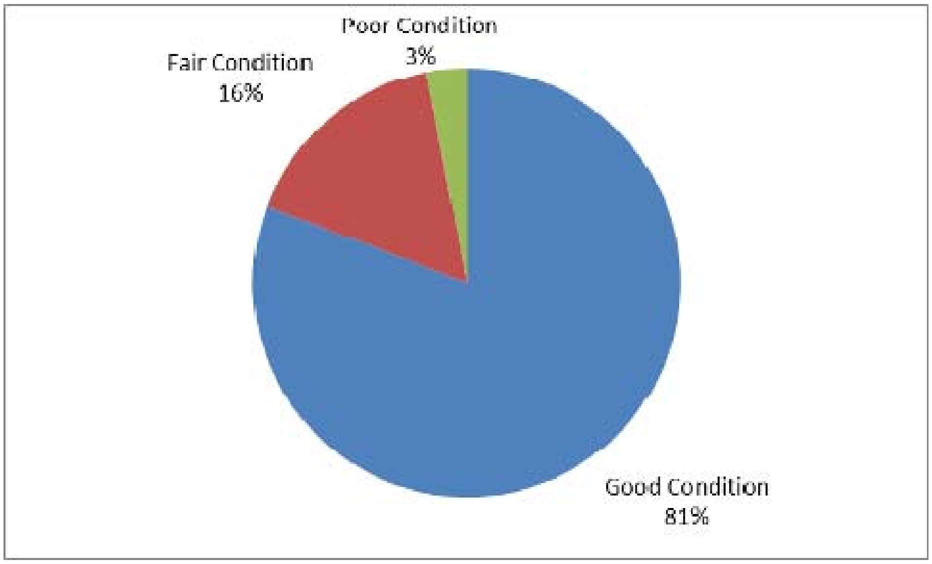


Exhibit 4-4: Pole Conditions (Based on Test Results

4.2 Medium Voltage Overhead Line Circuits

The overhead distribution network at ETPL employs 27 kV, 8 kV and 4 kV medium voltage lines. Total circuit lengths employed on 3-phase and 1-phase lines at different voltages are indicated in Exhibit 4.5.

Since no records are available to indicate the original installation dates for various lines, we have estimated ages for various overhead lines using the pole age as a proxy for the lines and the age profile for distribution lines presented in Exhibit 4-5 has been developed in this manner. Exhibit 4-6 displays the overhead line age profile in form of a pie chart. The overhead distribution lines in North Region are generally older in age, in relation to the overhead lines in South Region.

		Installed Quantity	0-10 yrs	11-20 yrs	21-30 yrs	31-40 yrs	41-50 yrs	>50 yrs
		km						
Overhead Lines	Overhead lines 3 ph 27.6 kV	78.8	16.5	26.8	23.6	11.8	-	-
	Overhead lines 3 ph 8.32 kV	8.4	-	-	1.7	3.8	2.9	-
	Overhead lines 3 ph 4.16 kV	41.8	-	-	4.2	8.4	9.6	19.6
	Overhead lines 1 ph 16 kV	14.8	3.4	4.9	4.4	2.1	-	-
	Overhead lines 1 ph 4.8 kV	23	-	-	4.1	10.7	8.1	-
	Overhead lines 1 ph 2.4 kV	31.8	-	-	3.2	6.4	7.3	14.9
	Total of overhead Lines	198.6	20.0	31.7	41.3	43.1	28.0	34.6

(a) Overhead Lines (South Region)

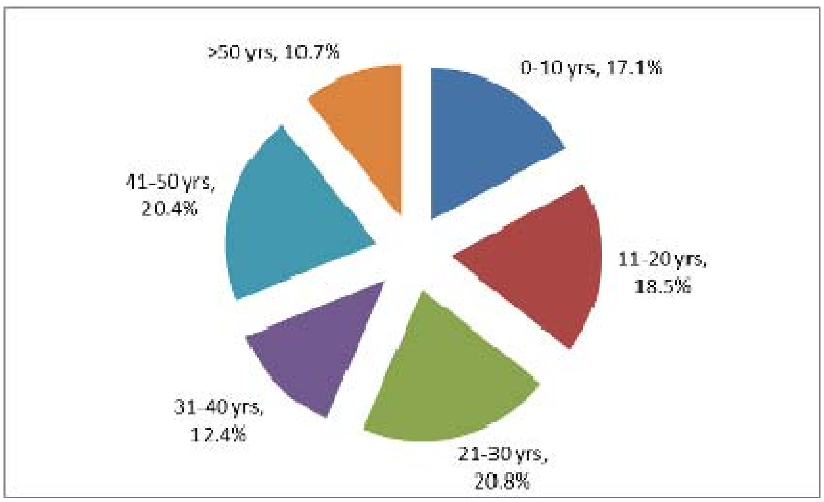
		Installed Quantity	0-10 yrs	11-20 yrs	21-30 yrs	31-40 yrs	41-50 yrs	>50 yrs
		km						
Overhead Lines	Overhead lines 3 ph 27.6 kV	42.3	9.7	18.2	8.5	5.9	-	-
	Overhead lines 3 ph 8.32 kV	3.9	-	-	0.6	1.8	1.4	-
	Overhead lines 3 ph 4.16 kV	39.3	-	-	2.0	7.9	9.0	18.5
	Overhead lines 1 ph 16 kV	6	1.3	2.8	1.2	0.8	-	-
	Overhead lines 1 ph 4.8 kV	1.4	-	-	0.1	0.7	0.5	-
	Overhead lines 1 ph 2.4 kV	9.8	-	-	0.5	2.0	2.3	4.6
	Total of overhead Lines	102.7	11.0	20.9	12.8	18.9	13.2	23.1

(b) Overhead Lines (North Region)

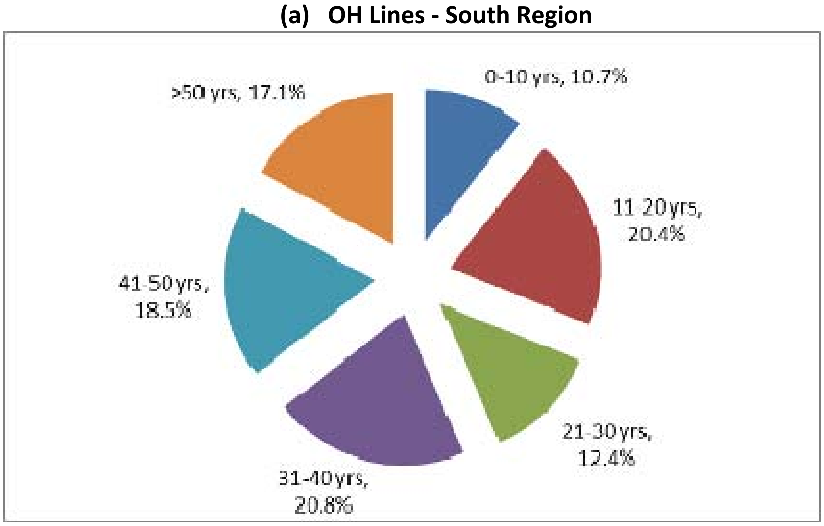
		Installed Quantity	0-10 yrs	11-20 yrs	21-30 yrs	31-40 yrs	41-50 yrs	>50 yrs
Overhead Lines		km	km	km	km	km	km	km
	Overhead lines 3 ph 27.6 kV	121.1	26.3	45.0	32.1	17.7	0.0	0.0
	Overhead lines 3 ph 8.32 kV	12.3	0.0	0.0	2.3	5.5	4.3	0.0
	Overhead lines 3 ph 4.16 kV	81.1	0.0	0.0	6.1	16.2	18.7	38.1
	Overhead lines 1 ph 16 kV	20.8	4.7	7.6	5.6	2.9	0.0	0.0
	Overhead lines 1 ph 4.8 kV	24.4	0.0	0.0	4.2	11.4	8.6	0.0
	Overhead lines 1 ph 2.4 kV	41.6	0.0	0.0	3.7	8.3	9.6	19.6
	Total of overhead Lines	301.3	30.9	52.6	54.0	62.0	41.2	57.7

(c) Overhead Lines (Total)

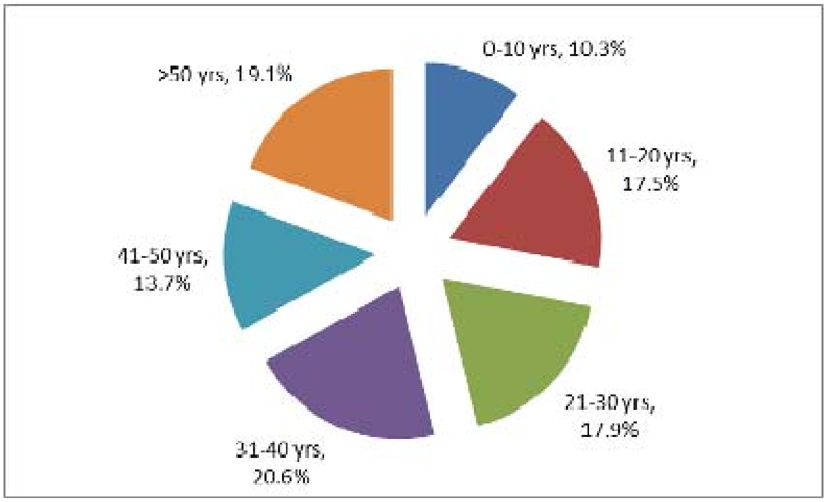
Exhibit 4-5: Overhead Line Demographic Information



(a) OH Lines - South Region



(b) OH Lines – North Region



(c) OH Lines – Total

Exhibit 4-6: Overhead Line Age Profiles

Under normal service conditions, overhead lines are expected to provide a mean service life of approximately 50 years. Exhibit 4.7 indicates the extent of lines that are currently of 40 years or older vintage and will therefore reach the end of their useful service life during the next 10 years.

		41-50 yrs	>50 yrs
Overhead Lines			
	Overhead lines 3 ph 27.6 kV	-	-
	Overhead lines 3 ph 8.32 kV	2.9	-
	Overhead lines 3 ph 4.16 kV	9.6	19.6
	Overhead lines 1 ph 16 kV	-	-
	Overhead lines 1 ph 4.8 kV	8.1	-
	Overhead lines 1 ph 2.4 kV	7.3	14.9
	Total of overhead Lines	28.0	34.6

South Region

		41-50 yrs	>50 yrs
Overhead Lines			
	Overhead lines 3 ph 27.6 kV	-	-
	Overhead lines 3 ph 8.32 kV	1.4	-
	Overhead lines 3 ph 4.16 kV	9.0	18.5
	Overhead lines 1 ph 16 kV	-	-
	Overhead lines 1 ph 4.8 kV	0.5	-
	Overhead lines 1 ph 2.4 kV	2.3	4.6
	Total of overhead Lines	13.2	23.1

North Region

		41-50 yrs	>50 yrs
Overhead Lines		km	km
	Overhead lines 3 ph 27.6 kV	0.0	0.0
	Overhead lines 3 ph 8.32 kV	4.3	0.0
	Overhead lines 3 ph 4.16 kV	18.7	38.1
	Overhead lines 1 ph 16 kV	0.0	0.0
	Overhead lines 1 ph 4.8 kV	8.6	0.0
	Overhead lines 1 ph 2.4 kV	9.6	19.6
	Total of overhead Lines	41.2	57.7

Total

Exhibit 4-7: Overhead Lines Requiring Replacement during Next 10 years

4.3 Medium Voltage Underground Circuits

Exhibit 4-8 indicates the circuit lengths of underground medium voltage cables employed on ETPL distribution system. There are no records of cable age or cable type available. In consultation with Erie Thames Power Line's operating staff, we have assigned the age profile indicated in Exhibit 4-8 to underground circuits. Exhibit 4-9 displays the underground cable circuit age profile in form of a pie chart. As indicated, the underground distribution cables in North Region are generally older in age, in relation to the cables in South Region.

		Installed Quantity	0-10 yrs	11-20 yrs	21-30 yrs	31-40 yrs	41-50 yrs	>50 yrs
Undrground Cicuits		km						
	Underground 3 ph cables 27.6 kV	6.8	2.0	2.0	2.0	0.7	-	-
	Underground 3 ph cables 8.32 kV	0.2	-	-	0.1	0.1	-	-
	Underground 3 ph cables 4.16 kV	2.6	-	-	0.7	0.7	0.7	0.7
	Underground 1 ph cables 16 kV	35.6	10.7	10.7	10.7	3.6	-	-
	Underground 1 ph cables 4.8 kV	3.4	-	-	1.7	1.7	-	-
	Underground 1 ph cables 2.4 kV	15.2	-	-	3.8	3.8	3.8	3.8
	Total of UG Cables	63.8	12.7	12.7	19.0	10.5	4.5	4.5

(a) Underground Lines (South Region)

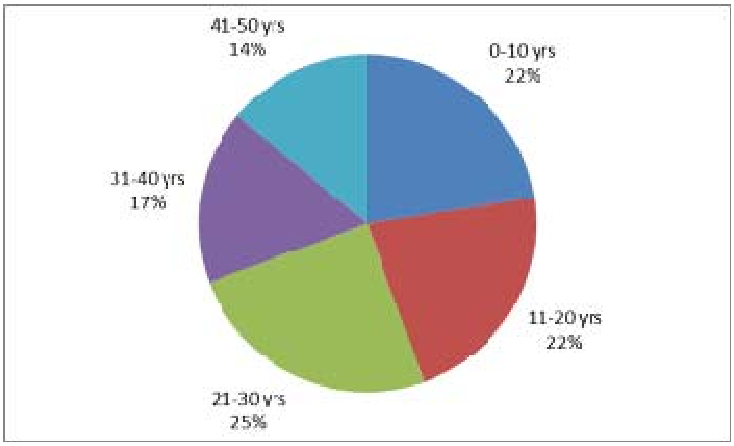
		Installed Quantity	0-10 yrs	11-20 yrs	21-30 yrs	31-40 yrs	41-50 yrs	>50 yrs
Underground Cables	Underground 3 ph cables 27.6 kV	0	-	-	-	-	-	-
	Underground 3 ph cables 8.32 kV	0	-	-	-	-	-	-
	Underground 3 ph cables 4.16 kV	4.5	-	-	1.1	1.1	1.1	1.1
	Underground 1 ph cables 16 kV	0	-	-	-	-	-	-
	Underground 1 ph cables 4.8 kV	0.1	-	-	0.1	0.1	-	-
	Underground 1 ph cables 2.4 kV	3.2	-	-	0.8	0.8	0.8	0.8
	Total of UG Cables	7.8	-	-	2.0	2.0	1.9	1.9

(b) Underground Lines (North Region)

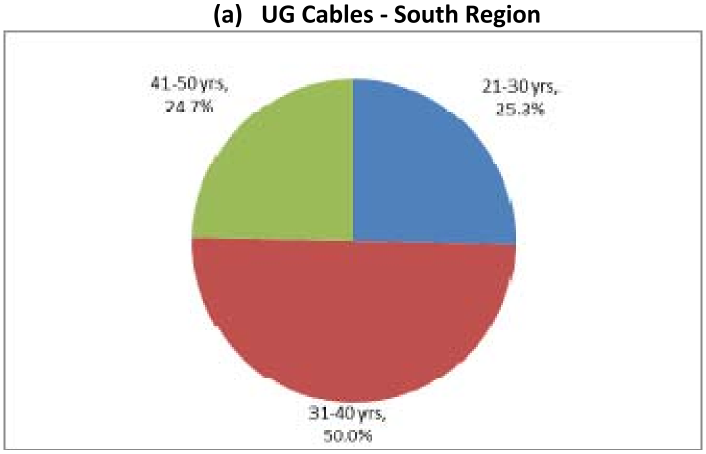
Undrground Cicuits		km						
	Underground 3 ph cables 27.6 kV	6.8	2.0	2.0	2.0	0.7	0.0	0.0
	Underground 3 ph cables 8.32 kV	0.2	0.0	0.0	0.1	0.1	0.0	0.0
	Underground 3 ph cables 4.16 kV	7.1	0.0	0.0	1.8	1.8	1.8	1.8
	Underground 1 ph cables 16 kV	35.6	10.7	10.7	10.7	3.6	0.0	0.0
	Underground 1 ph cables 4.8 kV	3.5	0.0	0.0	1.8	1.8	0.0	0.0
	Underground 1 ph cables 2.4 kV	18.4	0.0	0.0	4.6	4.6	4.6	4.6
	Total of UG Cables	71.6	12.7	12.7	20.9	12.5	6.4	6.4

(c) Underground Lines (Total)

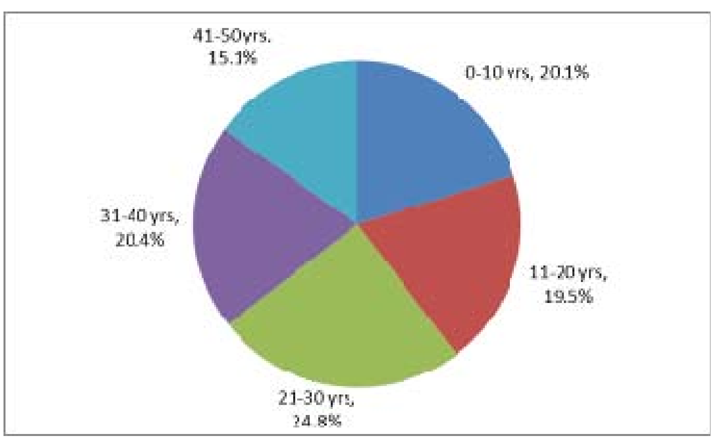
Exhibit 4-8: Underground Line Demographic Information



(a) UG Cables - South Region



(b) UG Cables – North Region



(c) UG Cables Total

Exhibit 4-9: Underground Cables

Age Profiles

Under normal service conditions, underground cables, particularly the TR XLPE insulated cables employed on 27.6 kV system and the older vintage XLPE cables employed on 4 kV system are expected to provide a mean service life of approximately 40 years. Exhibit 4.10 indicates the extent of underground cables that are currently of 30 years or older vintage and will therefore reach the end of their useful service life during the next 10 years.

		31-40 yrs	41-50 yrs
Undrground Cicuits	Underground 3 ph cables 27.6 kV	-	-
	Underground 3 ph cables 8.32 kV	0.1	-
	Underground 3 ph cables 4.16 kV	1.3	1.3
	Underground 1 ph cables 16 kV	-	-
	Underground 1 ph cables 4.8 kV	1.7	-
	Underground 1 ph cables 2.4 kV	7.6	7.6
	Total of UG Cables	10.7	8.9

South Region

		31-40 yrs	41-50 yrs
Underground Cables	Underground 3 ph cables 27.6 kV	-	-
	Underground 3 ph cables 8.32 kV	-	-
	Underground 3 ph cables 4.16 kV	2.3	1.1
	Underground 1 ph cables 16 kV	-	-
	Underground 1 ph cables 4.8 kV	0.1	-
	Underground 1 ph cables 2.4 kV	1.6	0.8
	Total of UG Cables	3.9	1.9

North Region

		31-40 yrs	41-50 yrs
Undrground Cicuits			
	Underground 3 ph cables 27.6 kV	0.0	0.0
	Underground 3 ph cables 8.32 kV	0.1	0.0
	Underground 3 ph cables 4.16 kV	3.6	2.4
	Underground 1 ph cables 16 kV	0.0	0.0
	Underground 1 ph cables 4.8 kV	1.8	0.0
	Underground 1 ph cables 2.4 kV	9.2	8.4
	Total of UG Cables	14.6	10.8

Total

Exhibit 4-10: UG Cables Requiring Replacement During the Next 10 Years

4.4 Distribution Transformers

Like most other LDCs, ETPL employs the strategy to run the distribution transformers to failure, i.e. replace them only after they fail and we recommend this practice to continue. However, when older vintage distribution transformers are replaced prior to their failure during voltage upgrade programs, reduction in distribution transformer losses and avoided cost of emergency repairs upon in-service failures provides additional financial incentives in support of early replacement of old vintage distribution transformers.

Energy loss in distribution transformers takes place in two forms: (a) iron loss consisting of eddy current and hysteresis loss, which represents the energy loss in conversion of electric energy into magnetic energy and from magnetic energy back into electric energy in a transformer and (b) copper loss which represents the I^2R loss due to current flow in transformer windings.

Over the years with technological advancements energy losses in transformers have been decreasing with energy efficient designs and improvement in designs and materials. Exhibit 4-25 illustrates the typical energy efficiency of distribution transformers built over different time periods during the last 50 years.[2] The slope of the chart in Exhibit 4-25 indicates that the energy efficiency of distribution transformers has been improving at the rate of approximately 0.025% per year; or in other words by

[2] U.S. Department of Energy (DOE), Annual Energy Outlook, 1994, DOE/EIA-0383(93)

replacing a 40 year old distribution transformer with a modern transformer, energy efficiency of the transformer could be improved by about 1%.

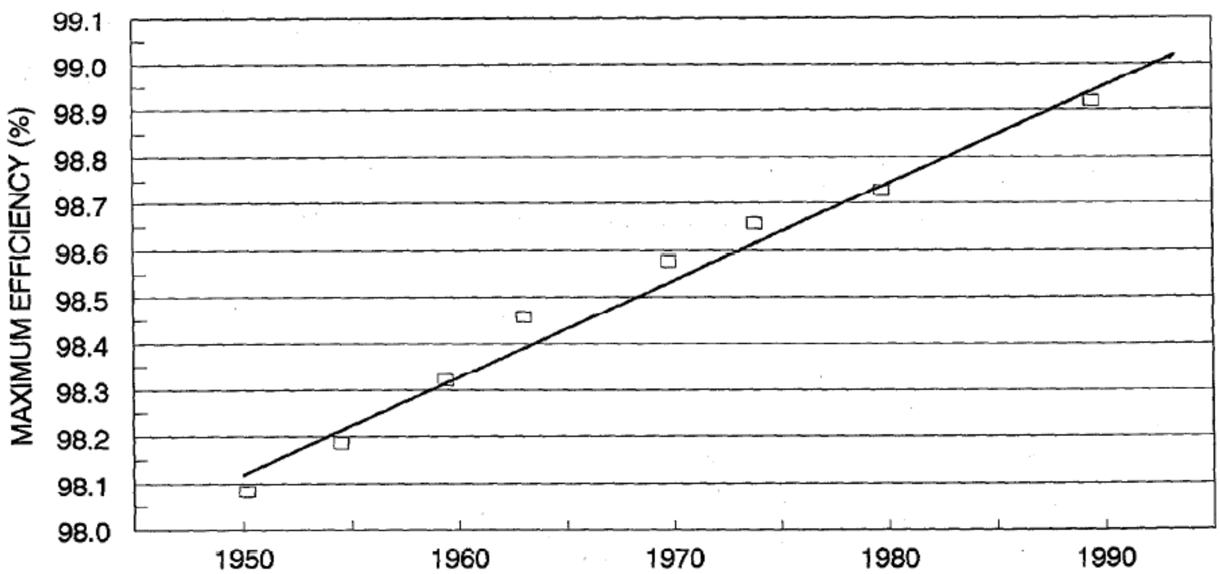


Exhibit 4-11: Energy Efficiency of Distribution Transformers Built at Different Times during the Last 50 years

The second direct financial benefit from proactive replacement of distribution transformer occurs in form of avoided emergency repair costs. Proactive and planned replacement of distribution transformers reduces the labor costs by almost 75% from those incurred in emergency repairs upon in-service failure of a distribution transformer. Proactive replacement of distribution transformers also results in non-tangible benefits in form of improved reliability and reduced risk of tank rupture or oil spill during an eventful failure of an old transformer.

In the absence of nameplate data for distribution transformers, we have assumed a uniformly distributed age profile for different age groups of distribution transformers, as shown in Exhibit 4-12. The single phase transformers listed in Exhibit 4-12 also include those employed on pole mounted three phase transformer banks. Assuming an average life expectancy of 40 years for distribution transformers, Exhibit 4-13 shows the indicative number of distribution transformers that would require replacement (upon failure), during the next 10 years.

		Installed Quantity	0-10 yrs	11-20 yrs	21-30 yrs	31-40 yrs	41-50 yrs	>50 yrs
Overhead Dist Transformers	Pole mounted 5 kVA, 1-ph	11	2	2	2	2	0	0
	Pole mounted 10 kVA, 1-ph	61	12	12	12	9	3	0
	Pole mounted 15 kVA, 1-ph	62	12	12	12	9	3	0
	Pole mounted 25 kVA, 1-ph	466	93	93	93	70	23	0
	Pole mounted 37 kVA, 1-ph	205	41	41	41	31	11	0
	Pole mounted 50 kVA, 1-ph	780	156	156	156	117	39	0
	Pole mounted 75 kVA, 1-ph	404	81	81	81	61	20	0
	Pole mounted 100 kVA, 1-ph	182	36	36	36	27	9	0
	Pole mounted 167 kVA, 1-ph	67	14	14	14	10	3	0
	Total of OH transformers	2238	447	447	447	336	111	0
Underground Transformers	Padmount 25 kVA, 1-ph	2	0	0	0	0	0	0
	Padmount 50 kVA, 1-ph	303	61	61	61	46	28	0
	Padmount 75kVA, 1-ph	194	39	39	39	16	10	0
	Padmount 100 kVA, 1-ph	41	8	8	8	6	2	0
	Padmount 167 kVA, 1-ph	5	1	1	2	1	0	0
	Padmount 45 kVA, 3-ph	2	0	0	2	0	0	0
	Padmount 75 kVA, 3-ph	5	1	1	1	0	0	0
	Padmount 150 kVA, 3-ph	12	2	2	2	2	4	0
	Padmount 225 kVA, 3-ph	20	4	4	4	3	1	0
	Padmount 300 kVA, 3-ph	38	8	8	8	5	6	0
	Padmount 500 kVA, 3-ph	17	3	3	3	2	1	0
	Padmount 750 kVA, 3-ph	15	3	3	3	2	2	0
	Total of Pad mounted Transformers	654	130	130	133	83	54	0

Exhibit 4-12: Pole-mounted and Pad-mounted Distribution Transformers

		31-40 yrs	41-50 yrs
Overhead Dist Transformers	Pole mounted 5 kVA, 1-ph	2	0
	Pole mounted 10 kVA, 1-ph	9	3
	Pole mounted 15 kVA, 1-ph	9	3
	Pole mounted 25 kVA, 1-ph	70	23
	Pole mounted 37 kVA, 1-ph	31	11
	Pole mounted 50 kVA, 1-ph	117	39
	Pole mounted 75 kVA, 1-ph	61	20
	Pole mounted 100 kVA, 1-ph	27	9
	Pole mounted 167 kVA, 1-ph	10	3
	Total of OH transformers	336	111
Underground Transformers	Padmount 25 kVA, 1-ph	0	0
	Padmount 50 kVA, 1-ph	46	28
	Padmount 75kVA, 1-ph	16	10
	Padmount 100 kVA, 1-ph	6	2
	Padmount 167 kVA, 1-ph	1	0
	Padmount 45 kVA, 3-ph	0	0
	Padmount 75 kVA, 3-ph	0	0
	Padmount 150 kVA, 3-ph	2	4
	Padmount 225 kVA, 3-ph	3	1
	Padmount 300 kVA, 3-ph	5	6
	Padmount 500 kVA, 3-ph	2	1
	Padmount 750 kVA, 3-ph	2	2
	Total of Pad mounted Transformers	83	54

Exhibit 4-13: Pole-mounted and Pad-mounted Distribution Transformers Requiring Replacement During Next 10 Years

4.5 Other Line Assets

Other distribution line assets include low voltage customer service drops. The expected service life of LV service lines is substantially longer than the medium voltage lines and they should not require significant investment for sustainment, during the next 10 years.

4.6 Distribution Substations

Distribution Substations on ETPL' system step down power from 27.6 kV to 4.16 kV. There are a total of 10 distribution stations owned and operated by ETPL'. The main components of the substations include:

(a) 27.6 kV fused disconnect
(b) Power Transformers
(c) 4 kV Switchgear or recloser
(d) Substation Buildings and yards

Based on visual inspections of the substations equipment and service age, the relative ranking of the health and condition of stations is summarized in Exhibit 4.14.

All of the distribution stations are expected to reach the end of their useful service life within the next 15 years. Based on the condition of the major power equipment employed at the stations, the following stations will need to be either rebuilt/replaced or retired, with conversion of the 4 kV distribution systems to 27.6 kV, during the next 10 years:

(a) Clinton MS 2
(b) Aylmer Forest DS
(c) Mitchell DS
(d) Ingersoll MS#3
(e) Clinton MS1
(f) Tavistock DS

The equipment employed at Clinton MS #2 and Aylmer Forest, is particularly old and obsolete and these two stations are virtually at the end of their economic service life now.

						Condiition Assessment					
	Station Rating	No. of 4 kV feeders	27 kV Switchgear	4 kV switchgear	Estimated Xformer Age (Yrs)	Results of Xformer Oil	Xformer Visual Inspection	27 kV Switchgear	4 kV Switchgear	Overall Score (Out of 45)	Priority for Conversion and Station Retirement
Clinton MS 2	3 x 1 MVA	3	Fused Disconnect	Reclosers mounted	80	2	3	2	2	6	1
Aylmer Forest	1 X 3.6 MVA	2	Pole mounted	Pole mounted	55	2	3	3	3	10.5	2
Mitchel	1 x 3 MVA	2	Pole mounted	S&C Outdoor	43	3	3	4	4	14.7	3
Ingersol MS#3	1 x 5 MVA	3	S&C Padmounted	ITE magnetic	45	3	4	4	4	15.5	4
Clinton MS1	1 X 5 MVA	4	Pole mounted	Indoor metal clad	40	3	4	4	4	16	5
Tavistock DS	1 x 5 MVA	3	Pole mounted	ITE magnetic	40	3	4	4	4	16	6
Beachville DS	1 x 3 MVA	2	S&C Padmounted	Pole mounted	35	3	5	4	3	16.5	7
Aylmer BcBrien	2 x 3 MVA	4	Pole mounted	Pad mounted	31	3	4	4	4	16.9	8
Port Stanley	1 x 5 MVA	3	S&C Padmounted	Indoor switchgear	32	3	5	4	4	17.8	9
Ingersol MS #1	1 x 5 MVA	3	S&C Padmounted	CGE metal clad	25	3	6	4	4	19.5	10

Exhibit 4-14: Distribution Station Condition Assessment Summary

4.7 Smart Grid Initiative:

Ontario Energy Board has mandated the local distribution companies (LDCs) to develop and implement smart grid initiative within their jurisdictions to improve reliability and operating efficiency of the distribution grid and to increase its capacity to accept connection of distributed generation from environmentally friendly initiatives. A significant part of ETPL distribution systems currently operates at 4 kV, which is planned to be upgraded to 27.6 kV operating voltage.

There is virtually no automation currently in existence at the 27.6/4.16 kV distribution substations. But because the aging distribution stations are fast approaching the end of their service life and will be all retired from service during the next 15 years, we are not recommending any investments for automation in these substations.

Voltage upgrade initiatives provide a number of benefits, including reduce system losses, lower operating costs and increased capacity for small scale generation from renewable resources. However, because 27.6 kV feeders are significantly longer in relation to 4 kV feeders, in the absence of automated sectionalizing, they can result in degradation of reliability. We are therefore proposing a pilot project involving use of fully automated switching to reconfigure the overhead radial circuits into a loop and to isolate faulted lines to improve supply system reliability of distribution system serving commercial customers in Ingersoll. The conceptual design of the recommended smart grid initiative is shown in Exhibit 4.15.

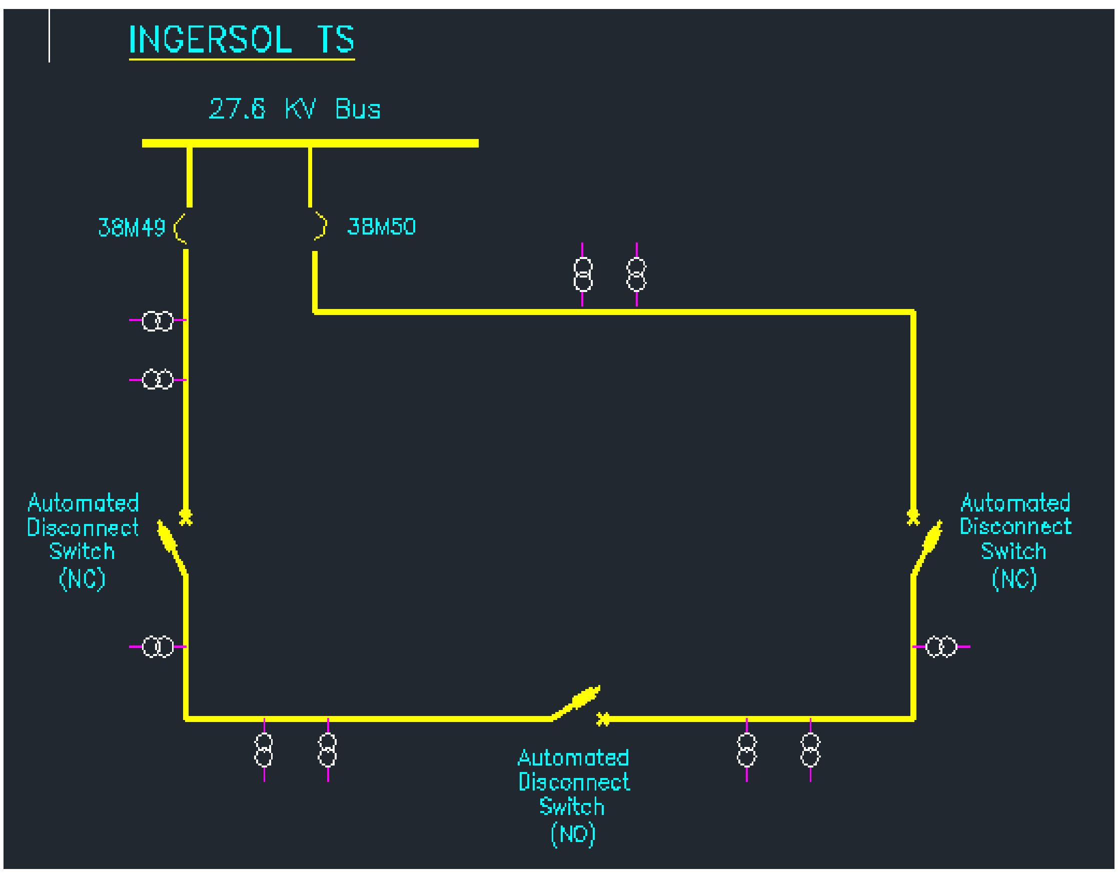


Exhibit 4-15: Smart Grid Pilot Project Initiative

No micro-FIT applications have been refused to date due to lack of adequacy of distribution system capacity. Aside from the system capacity increase which would result from planned voltage conversions, no additional reinforcements are required to facilitate implementation of the small scale green energy generation within ETPL's service territory.

4.8 Preventative Maintenance:

We have reviewed the fixed asset preventative maintenance program currently in use at ETPL and determined that it is in line with the best utility practices. The reliability performance over the recent years, indicted in Exhibit 4-16, provide evidence that the current preventative maintenance strategy is working well. Therefore, no changes are recommended in the preventative maintenance program, which is briefly described below:

(a) Critical assets installed in substations are inspected monthly. Major maintenance on substation equipment is carried out on a 5-year cycle, but the scope of the maintenance is determined based on the asset needs by taking into account asset condition.

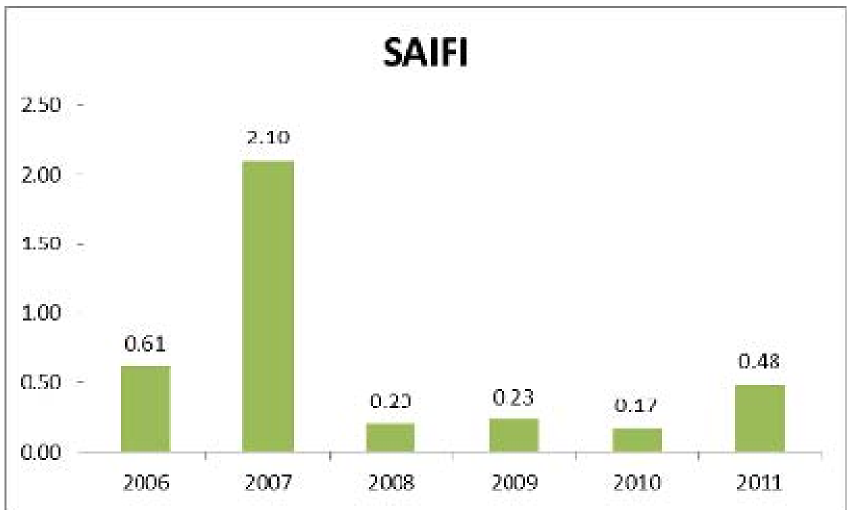
(b) Overhead lines and underground pads are inspected on a 3-year cycle, to comply with Electrical Safety Authority's regulations.

(c) Load Break Switch Maintenance has been carried out on a 5-year cycle in the past, which has been considered to be satisfactory.

(d) Tree trimming has been carried out on a 3–year cycle in the past, which we consider to be satisfactory.

(e) In accordance with the best utility practices, thermograph inspections of distribution assets are carried out with infra-red cameras and any hot spots are promptly attended. From our review of the test results for the past year, the thermograph inspections appear to be extremely effective in detecting incipient faults and we recommend these should be continued as part of the maintenance program.

(f) Due to the advanced age of distribution stations, power transformer oil samples are obtained and tested annually. The results of previous years oil testing have been used in assessing and ranking the condition of power transformers employed at distribution stations.



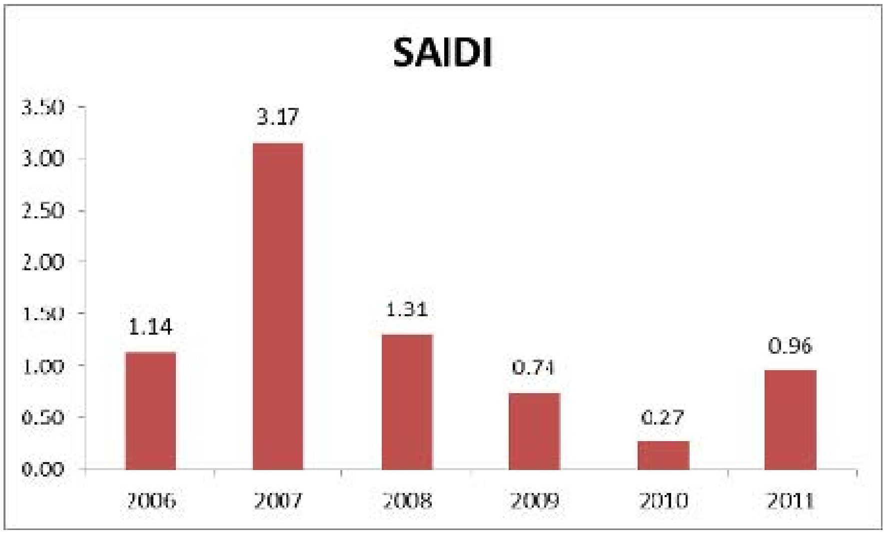


EXHIBIT 4-16: RELIABILITY PERFORMANCE

5 Asset Management Plan - Capital and Maintenance Investments

Based on the condition assessment of major assets employed in substations, overhead lines and underground distribution system, this section provides the budgetary estimates of capital investments required during the next ten years to keep the system operating at optimal levels. Recommendations for a preventative maintenance program are also provided.

5.1 Overall Long Term Capital Expenditure Requirements

Based on the 2011 replacement cost estimate of assets, under assumptions detailed in Exhibit 5.1, average capital expenditure of approximately $1,960,000 would be required annually to sustain the assets presently employed on overhead and underground distribution system. This cost estimate does not include capital expenditure into substations. It also does not include investments needed for system expansions and extensions required to serve new loads.

In line with the established best utility practices, we have assumed that the 4 kV distribution lines will be rebuilt and upgraded to 27.6 kV when they reach the end of their service life, thus eliminating the need for 27.6 to 4 kV step-down substations. This approach will result in avoidance of substation rebuild costs detailed in Exhibit 5.2.

However owing to inadequate level of investment during the past years, investment levels over the next 10 years will need to be higher than the above indicated annual average investment level. The following sections describe in detail the level of capital investments needed.to sustain distribution assets in safe and reliable condition.

		Installed Quantity	Estimated Replacement Unit Cost	Estimated Replacement Total Cost	Annual Sustainment Cost
Overhead Lines		km	$	$	
	Overhead lines 3 ph 27.6 kV	121.1	200	24 220 000	
	Overhead lines 3 ph 8.32 kV	12.3	200	2 460 000	
	Overhead lines 3 ph 4.16 kV	81.1	200	16 220 000	
	Overhead lines 1 ph 16 kV	20.8	100	2 080 000	
	Overhead lines 1 ph 4.8 kV	24.4	100	2 440 000	
	Overhead lines 1 ph 2.4 kV	41.6	100	4 160 000	
	Total of overhead Lines	301.3		51 580 000	1 031 600
Overhead Dist Transformers		#	$		
	Pole mounted 5 kVA, 1-ph	11	3000	33 000	
	Pole mounted 10 kVA, 1-ph	61	3500	213 500	
	Pole mounted 15 kVA, 1-ph	62	4000	248 000	
	Pole mounted 25 kVA, 1-ph	466	4500	2 097 000	
	Pole mounted 37 kVA, 1-ph	205	5500	1 127 500	
	Pole mounted 50 kVA, 1-ph	780	6000	4 680 000	
	Pole mounted 75 kVA, 1-ph	404	7000	2 828 000	
	Pole mounted 100 kVA, 1-ph	182	8500	1 547 000	
	Pole mounted 167 kVA, 1-ph	67	10500	703 500	
	Total of OH transformers	2238		13 477 500	336 938
Disconne	27.6 kV 3 ph load break switches	71	4500	319 500	
	4.16 kV 3 ph load break switches	30	2500	75 000	
	Total of Disconnect Switches	101		394 500	
Undrground Cicuits		km			
	Underground 3 ph cables 27.6 kV	6.8	350	2 380 000	
	Underground 3 ph cables 8.32 kV	0.2	350	70 000	
	Underground 3 ph cables 4.16 kV	7.1	350	2 485 000	
	Underground 1 ph cables 16 kV	35.6	150	5 340 000	
	Underground 1 ph cables 4.8 kV	3.5	150	525 000	
	Underground 1 ph cables 2.4 kV	18.4	150	2 760 000	
	Total of UG Cables	71.6		13 560 000	339 000
Underground Transformers		#			
	Padmount 25 kVA, 1-ph	2	8800	17 600	
	Padmount 50 kVA, 1-ph	303	10200	3 090 600	
	Padmount 75kVA, 1-ph	194	11600	2 250 400	
	Padmount 100 kVA, 1-ph	41	13200	541 200	
	Padmount 167 kVA, 1-ph	5	16800	84 000	
	Padmount 45 kVA, 3-ph	2	15500	31 000	
	Padmount 75 kVA, 3-ph	5	22600	113 000	
	Padmount 150 kVA, 3-ph	12	25500	306 000	
	Padmount 225 kVA, 3-ph	20	28500	570 000	
	Padmount 300 kVA, 3-ph	38	34400	1 307 200	
	Padmount 500 kVA, 3-ph	17	46700	793 900	
	Padmount 750 kVA, 3-ph	15	61500	922 500	
	Total of Pad mounted Transformers	654		10 027 400	250 685
	Total Annual sustainment Cost				1 958 223

Exhibit 5-1: Estimate of Annual Capital Investment to Sustain Existing Asset Base

	Station Rating	No. of 4 kV feeders	27 kV Switchgear	4 kV switchgear	Estimated Replacement
Clinton MS 2	3 x 1 MVA	3	Fused Disconnect	Reclosers mounted on OH structure	$ 600 000
Elmer Forest	1 X 3.6 MVA	2	Pole mounted Fused Disconnect	Pole mounted Fused	$ 660 000
Mitchel	1 x 3 MVA	2	Pole mounted Fused Disconnect	S&C Outdoor Switchgear metal enclosed	$ 600 000
Ingersol MS#3	1 x 5 MVA	3	S&C Padmounted Fused Disconnect	ITE magnetic air breakers	$ 800 000
Clinton MS1	1 X 5 MVA	4	Pole mounted Fused Disconnect	Indoor metal clad switchgear	$ 800 000
Beachville DS	1 x 3 MVA	2	S&C Padmounted Fused Disconnect	Pole mounted Reclosers	$ 600 000
Elmer BcBrien	2 x 3 MVA	4	Pole mounted Fused Disconnect	Pad mounted S&C Switchgear	$ 900 000
Tavistock DS	1 x 5 MVA	3	Pole mounted Fused Disconnect	ITE magnetic air breakers	$ 800 000
Port Stanley	1 x 5 MVA	3	S&C Padmounted Fused Disconnect	Indoor switchgear with breakers	$ 800 000
Ingersol MS #1	1 x 5 MVA	3	S&C Padmounted Fused Disconnect	CGE metal clad breakers	$ 800 000
Total Estimated Replacement Cost of All Stations					$ 7 360 000

Exhibit 5-2: Estimate of Substation Rebuild Cost (Avoided with Voltage Upgrade)

5.2 Overhead Lines

Based on the condition of existing overhead lines described in Section 4, Exhibit 5.3 indicates the approximate circuit length of 4 kV lines that would reach a service life of 50 years or greater over the next 10 years. In order to keep the risk of in-service equipment failures at acceptable level and to prevent deterioration in supply system reliability and safety, budgetary estimates for replacement of 1-ph and 3-ph 4 kV overhead lines and upgrade to 27.6 kV during the next 10 years are provided in Exhibit 5-3.

A number of the 4 kV to 27 kV voltage upgrade initiatives carried out during previous decades, have been completed using inadequate pole heights and pole top extensions that no longer meet the current construction standards. These lines require replacement of some poles with taller poles to conform to current standards. It is estimated that approximately 5% of the existing overhead lines would require upgrades during the next 10 years.

Exhibit 5-3 indicates estimates of capital investments required into overhead lines for voltage upgrade of 4 kV lines, as well as for replacement of sub-standard poles on 27 kV lines during the next 10 years.

	Installed Quantity	Replacement /Rebuild Required Over 10 years	CAPEX Required Over 10 Years	Annual CAPEX
	km	km	$	$
Overhead lines 3 ph 27.6 kV	121.1	6.1	1 211 000	
Overhead lines 3 ph 8.32 kV	12.3	4.3	861 000	
Overhead lines 3 ph 4.16 kV	81.1	56.8	11 354 000	
Overhead lines 1 ph 16 kV	20.8	1.0	104 000	
Overhead lines 1 ph 4.8 kV	24.4	8.6	863 760	
Overhead lines 1 ph 2.4 kV	41.6	29.1	2 912 000	
Total of overhead Lines	301.3		17 305 760	1 730 576

Exhibit 5-3: Capital Investment Needs – OH Lines

5.3 Underground Cable System

Based on the condition of existing underground cables described in Section 4, Exhibit 5-4 shows the circuit length of cables that will reach the end of economic service life of 40 years, during the next 10 years. In order to prevent deterioration in supply system reliability due to excessive cable failures, Exhibit 5-4 provides budgetary estimates for replacement of 1-ph and 3-ph cables during the next 10 years.

		Installed Quantity	Replacement /Rebuild Required Over 10 years	CAPEX Required Over 10 Years	Annual CAPEX
Undrground Cicuits	Underground 3 ph cables 27.6 kV	6.8	0.0	-	
	Underground 3 ph cables 8.32 kV	0.2	0.1	35 000	
	Underground 3 ph cables 4.16 kV	7.1	6.0	2 091 250	
	Underground 1 ph cables 16 kV	35.6	0.0	-	
	Underground 1 ph cables 4.8 kV	3.5	1.8	262 500	
	Underground 1 ph cables 2.4 kV	18.4	17.6	2 640 000	
	Total of UG Cables	71.6		5 028 750	502 875

Exhibit 5-4: Capital Investment Needs - U/G Cables

5.4 Distribution Transformers:

Exhibits 5-5 and 5-6, respectively, provide budgetary estimates for replacement of pole and pad mounted transformers that are expected to fail during the next 10 years.

		Installed Quantity	Replacement /Rebuild Required Over 10 years	CAPEX Required Over 10 Years	Annual CAPEX
Overhead Dist Transformers		#			
	Pole mounted 5 kVA, 1-ph	11	2	6 000	
	Pole mounted 10 kVA, 1-ph	61	12	42 000	
	Pole mounted 15 kVA, 1-ph	62	12	48 000	
	Pole mounted 25 kVA, 1-ph	466	93	418 500	
	Pole mounted 37 kVA, 1-ph	205	42	231 000	
	Pole mounted 50 kVA, 1-ph	780	156	936 000	
	Pole mounted 75 kVA, 1-ph	404	81	567 000	
	Pole mounted 100 kVA, 1-ph	182	36	306 000	
	Pole mounted 167 kVA, 1-ph	67	13	136 500	
	Total of OH transformers	2238		2 691 000	269 100

Exhibit 5-5: Capital Investment Needs – Pole-mounted Transformers

		Installed Quantity	Replacement /Rebuild Required Over 10 years	CAPEX Required Over 10 Years	Annual CAPEX
Underground Transformers	Padmount 25 kVA, 1-ph	2	0	-	
	Padmount 50 kVA, 1-ph	303	74	754 800	
	Padmount 75kVA, 1-ph	194	26	301 600	
	Padmount 100 kVA, 1-ph	41	8	105 600	
	Padmount 167 kVA, 1-ph	5	1	16 800	
	Padmount 45 kVA, 3-ph	2	0	-	
	Padmount 75 kVA, 3-ph	5	0	-	
	Padmount 150 kVA, 3-ph	12	6	153 000	
	Padmount 225 kVA, 3-ph	20	4	114 000	
	Padmount 300 kVA, 3-ph	38	11	378 400	
	Padmount 500 kVA, 3-ph	17	3	140 100	
	Padmount 750 kVA, 3-ph	15	4	246 000	
	Total of Pad mounted Transformers	654		2 210 300	221 030

Exhibit 5-6: Capital Investment Needs – Pad-mounted Transformers

5.5 Recommended CAPEX Investments into Asset Sustainment:

Exhibit 5-7 provides a summary of the overall annual capital expenditure required during the next 10 years for asset sustainment.

	CAPEX Required Over 10 Years	Annual CAPEX
	$	$
Total of overhead Lines	17 305 760	1 730 576
Total of OH transformers	2 691 000	269 100
Total of UG Cables	5 028 750	502 875
Total of Pad mounted Transformers	2 210 300	221 030
Total Annual sustainment Cost	27 235 810	2 723 581

Exhibit 5-7: Overall Capital Investment Needs – Asset Sustainment

5.6 Recommended CAPEX Investments into Smart Grid:

In addition to the capital investments proposed in Exhibit 5-7, capital budget of approximately $200,000 year over year will be required to procure equipment and implement the proposed smart grid pilot project,. Phase 1, ETPL is budgeting in 2012 the introduction of a SCADA system that will provide real time data on the distribution systems throughout our service territory. The system will requires annual upgrades to either hardware or software to improve system security, as well as the integration of new devices (automated switch's) to enhance smart grid automation going forward. ETPL will be installing automated switches on the distribution system to help improve system performance and monitoring. These switches are able to determine where a fault has occurred on the distribution system, and reconfigure the system to minimize the number of affected customers. ETPL will initially conduct a small pilot project in 2013, described in Section 4-7, with three of these switches, and when the project is deemed successful, a plan will be created for additional switches to be added over the next several years as required. The location and quantity of switches will be studied, optimized and finalized during the Annual Capital Budget preparation, based on performance history (feeder reliability statistics – targeting the worst performing feeders) and future use (load growth considerations). Ongoing maintenance costs to the SCADA system will be a low cost item set in the Annual

Maintenance Budget.

5.7 Non-Discretionary CAPEX Investments Requirements:

ETPL is required to invest into distribution system extensions and expansions to meet its regulatory obligations to serve new residential and commercial customers within its service territory. Based on prior years' experience an annual investment of $285,000 is required to cover such capital expenditures.

Similarly, the LDC is required to relocate its lines installed in the public right of ways when requested by the local municipalities in conjunction with their road widening projects. Historically, ETPL have incurred approximately $50,000 capital cost, annually to cover such expenditure, which is expected to continue.

5.8 Revenue Metering Investments:

ETPL's Revenue metering requirements have been reviewed and approximately $45,000 in capital investment is needed annually to purchase approximately 40 C&I meters at $400/meter and approximately 200 residential meters at $100/meter plus test blocks and miscellaneous items. During 2012 an additional investment of $10,000 is required to build up the necessary inventory of revenue meters to satisfy the measurement Canada requirement for compliance sampling.

5.9 Information Technology (IT) System Investments:

Based on the historical capital expenditures, approximately $25,000 of annual investment is needed for IT systems sustainment to replace/upgrade approximately 10 computers, printers and monitors. An additional $40,000 of capital investments is needed, annually for building/leasehold improvements, upgrades and office furniture and equipment.

5.10 Buildings and Fixtures

These include two main buildings (Ingersoll Business Administration and Operations Service Centre Hub along with Aylmer Service Centre) as well as two distribution substation buildings, a storage switch gear substation building, and a leased service depot in the town of Mitchelll as well as in Clinton. These assets are inspected monthly by staff, and major components (such as HVAC units) are inspected by external contractors annually. Major upgrades such as HVAC replacements and roof replacements are included as part of the Annual Capital Budget submission. In most cases, replacements or upgrades are determined based on physical condition, maintainability, and safety impacts, but where possible, upgrades that improve energy efficiency (such as occupancy sensors) and security enhancements are also considered. The Ingersoll Operations building had a new roof installed in 2008Repairs or replacements that do not meet the capitalization policy are put into the Annual Maintenance Budget for this category (which also includes tasks such as snow removal, lawn care, etc).

ETPL is not expected to incur any major capital investments to the existing building over the next 5 years and therefore is budgeting $40,000 per year for general improvements based on past years of experience.

5.11 Tools and Equipment

Tools and miscellaneous equipment includes devices used to assist in various aspects of the operation. Purchases that exceed $1000 are generally capitalized, with the remainder being charged to maintenance. During the Annual Capital Budget preparation, tools and other equipment are identified for replacement or purchase, primarily based on physical condition. Typically, these tend to be several relatively low cost items that are replacing existing units that have reached the end of their useful life. Most of these items are inspected routinely as well as being inspected prior to use by the worker. When the item requires a significant repair that approaches half the cost of replacement, the item is then replaced. Due to the unpredictable nature of these types of equipment failures, specific items are not always identified in the Budget, but may be grouped into categories such as replacement of safety equipment, replacement of operations tools, etc. The Annual Maintenance Budget for this category is normally based on prior years' experience. Erie Thames is budgeting $35,000 year over year for tools and equipment based on past years expenditures. In 2012 ETPL will be required to spend an additional onetime spend of $40,000 for a new pole trailer and fork lift for the Hwy 8 operations.

5.12 Motor Vehicle Fleet

Exhibit 5-8 summarizes all operating motor vehicle owed by ETPL and the replacement timeframe, inclusive of the HWY 8 operations vehicles, Clinton Power (CPC) and West Perth Power (WPP). A report covering a five year motor vehicle investment plan was reviewed and approved by the ETPL board in 2010 prior to the merge of the three LDC's.

The report recommends replacing one - large bucket truck or RBD at a cost of $300,000 each and one pickup truck or van at a cost of $40,000 each year, for a total annual investment of $340,000 over the next 5 years, beginning in 2011. ETPL's vehicle spend in 2011 was $390,000 inclusive of Hwy 8 North Operations, CPC and WPP. ETPL anticipates through the merge of the three LDC's one RBD will be deemed surplus to the overall operations. The RBD being surplus has reached its end of useful life allowing $300,000 in cost avoidance and allowing ETPL to stick with the 5 year plan with very little change.

The fleet assets consist of the large construction vehicles (such bucket trucks and radial boom derricks), passenger vehicles, and trailers. The upgrading or replacement of these assets is based on the physical condition, performance history, maintenance records, and maintainability. The physical condition is monitored by employees (workers and fleet mechanic) and annual independent testing and inspections. The performance history and maintenance records are tracked and kept on file and the status is reviewed annually to set priorities and a five year replacement schedule. Maintainability is assessed annually by the operations manager to ensure parts are readily available. Each asset has a set maintenance schedule based on either manufacturer recommendations or good utility practice. During the Annual Capital Budget preparation, all the criteria are reviewed to set priorities and determine the replacement schedule. This review is summarized in exhibit 5-8. Due to the long lead time required for the larger construction vehicles, replacements are ordered approximately 12 months before they are expected to be required. A vehicle is scheduled for replacement when the physical condition is rated as “fair” or “poor”, the performance history indicates issues experienced in the past, and the maintenance records show a trend to increasing repair costs (above the average for that type of asset), along with excessive mileage, end of useful life expectancies and applied utilization factor for the vehicle. The Annual Maintenance Budget for this category is based on the average costs for replacements based on the assessed needs plus any known major repairs that are expected.

TRUCK	Description	Location	MODEL	YEAR	Maint $	ODOMETER	MAINT $	Utilization	Condition	Recommend
					2009	2010 KM	2010			
01-02	1500 Ing Foreman	Ing	DODGE	2002	$ 1,464.13	177107	$ 1,937.17	5	Poor	replace in 2012
03-02	1500 Yard Truck	Ing	DODGE	2002	$ 2,269.44	164265	$ 580.86	2	Fair	replace in 2015
05-07	47' single bucket mat.	Ayl	FRHT	2007	$ 7,810.48	52337	$ 3,463.69	5	Good	
06-11	CHEV SIVERADO PICKUP	Ayl	CHEV	2011		n/a		4	Very Good	pickup replacement
07-02	50' single bucket mat.	Ayl	FRHT	2002	$ 4,532.76	121843	$ 3,775.42	3	Fair	replace in 2016
08-07	RBD Ayl single axel	Ayl	INTL	2007	$ 5,786.46	17912	$ 3,107.80	3	Very Good	
10-11	GMC SIERRA PICKUP	HWY 8	GMC	2011		n/a		4	Very Good	pickup replacement
11-92	42' Amador Single Bucket	HWY 8	INTL	1992		56785	>$6000	4	Very Poor	replace in 2012
12-92	RBD King K14	HWY 8	GMC	1992		46886	<$5000	3	Poor	surplus 2013
13-08	Dodge Ram 4X4	HWY 8	DODGE	2008		42877	<$2000	5	Good	
14-10	Ford Pickup	HWY 8	Ford	2009		32380	<$2000	4	Good	
15-09	50' Double Buck Posi	HWY 8	FRHT	2010		2387	<$3000	5	Very Good	
16-09	Terex 40-47 RBD	HWY 8	INTL	2009		14300		3	Very Good	demo bought in 2011
20-02	50' single bucket mat.	Ing	FRHT	2002	$ 7,216.39	120334	$ 7,981.22	5	Fair	replace in 2014
21-97	50' double bucket mat.	Ing	FRHT	1997	$ 4,986.45	10601	$ 7,825.47	3	Poor	replace in 2013
22-06	RBD Ing tandem axel	Ing	INTL	2005	$ 3,549.66	40856	$ 3,073.88	3	Good	
23-05	42' single bucket	Ing	FRHT	2005	$ 9,763.44	128314	$ 5,758.20	5	Fair	replace in 2015
24-07	Caravan	Ing	DODGE	2007	$ 500.09	59602	$ 1,050.61	4	Fair	replace in 2015
25-07	Caravan	Ing	DODGE	2007	$ 772.53	102319	$ 606.57	4	Fair	replace in 2014
29-11	GMC SIERRA PICKUP	Ing	GMC	2011		n/a		4	Very Good	pickup replacement
30-02	1500 4x4	Ing	DODGE	2002	$ 3,315.30	113051	$ 1,595.49	4	Fair	
31-11	GMC Terrain	HWY 8	GMC	2011		n/a		4	Very Good	pickup replacement
34-06	Caravan	Ing	DODGE	2006	$ 93.81	41329		5	Fair	replace in 2014
36-08	2500 4X4 (stores)	Ing	DODGE	2008	$ 412.09	45562	$ 1,020.02	3	Good	
40-08	CHEV 4X4	Ing	CHEV	2008	$ 8,218.52	22000	$ 621.84	2	Good	
41-09	VUE Hybrid (Engineering)	Ing	SATURN	2009	$ 1,884.34	53323	$ 68.25	3	Good	
42-09	NISSAN	Ing	NISSAN	2009		71300		3	Good	
02-12	Ford Escape Hybrid	Ing	FORD	2012		n/a		3	Very Good	van replacement

Exhibit 5-8: Motor Vehicle Inventory

5.13 Estimate of Annual Capital Expenditure:

Based on the various capital expenditure requirements itemized in Sections 5.1 to 5.13 Exhibit 5-9 represents a prudent and optimal estimate of total capital investments, required annually.

	Annual CAPEX
Annual capital expenditure for sustainment of fixed distribution assets	2 300 000
Annual capital expenditure to permit new connections and service upgrades	285 000
Annual capital expenditure to permit municipal road upgrades	50 000
Annual capital expenditure in revenue metering and equipment	45 000
Annual capital expenditure in tools and equipment	35 000
Annual capital expenditure IT equipment	25 000
Annual capital expenditure on building improvements, office equip & furniture	40 000
Annual capital expenditure on motor vehicle fleet-$340k, trailer & forklift-$40k	380 000
Total annual capital expenditure requirement	3 325 000

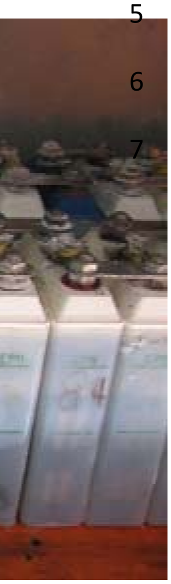
Exhibit 5-9: Overall Annual Capital Investment Requirements

Appendix A

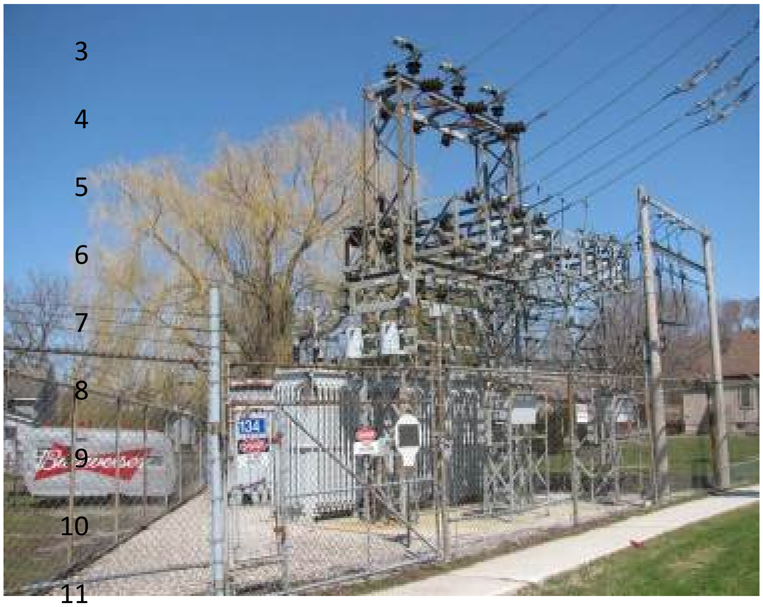
Distribution Station Photographs

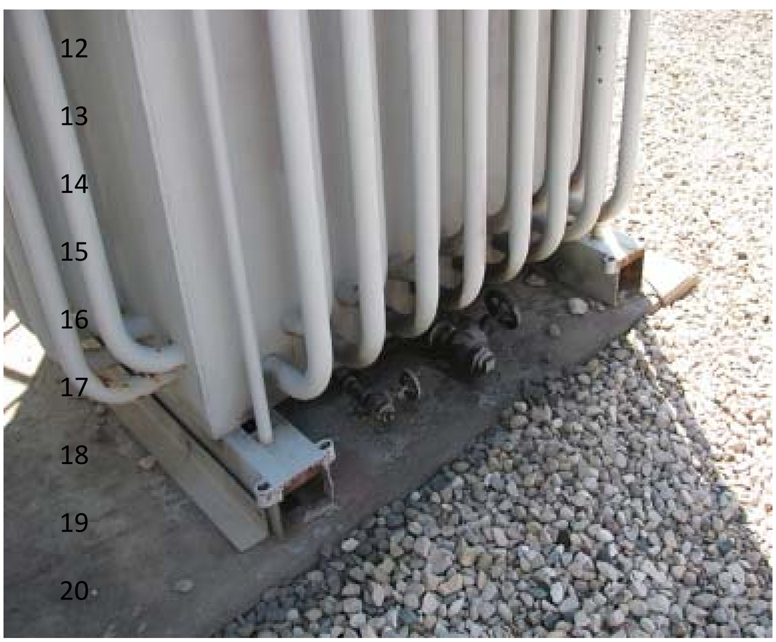
A1-Beachville DS

A2-Clinton DS#1



A3-Clinton DS#2





A4-Aylmer Forest DS

A5-Aylmer Mcbrien DS

A6-Ingersoll MS #1

A7-Ingersoll MS#3

A8-Mitchelll DS

A9-Pt Stanley DS

A10-Tavistock DS

OVERVIEW OF OPERATING REVENUE

This exhibit provides the details on Erie Thames Power's operating revenue for Historical, Board Approved, Bridge and Test years. This exhibit also provides a detailed variance analysis by rate class of the Operating Revenue components.

Distribution Revenues have been calculated using the most recently approved rates. In particular, delivery rates are based on the Erie Thames Rate Order EB-2010-0080, dated April 7th, 2011, and Clinton and West Perth Power's Rate Orders EB-2009-0262 and EB-2010-0121. Distribution Revenue does not include Regulatory Asset Recovery and Deferred Revenue Recovery Rate Rider revenues. Distribution Revenues do, however, include Low Voltage Wheeling revenues. A summary of normalized operating revenues is presented in Exhibit 3, Tab 3, and Schedule 4.

<u>Throughput Revenue</u>
Information related to the utility's throughput revenue include details such as weather normalized forecasting methodology, normalized volume and customer counts forecast tables. Detailed variance analysis on the forecast information is also provided.

<u>Other Revenue</u>
Other revenues include revenues such as Late Payment Charges, Miscellaneous Service Revenues and Retail Services Revenues. A summary of these operating revenues is presented in Exhibit 3, Tab 3, and Schedule 1.

<u>Revenue Sharing</u>
Erie Thames Power and its employees do not participate in revenue sharing.

SUMMARY OF OPERATING REVENUE TABLE

SUMMARY OF OPERATING REVENUE	2008 Board Approved	2008 Actual	Variance from 2008 Board Approved	2008 Actual	2009 Actual	Variance from 2008 Actual	2009 Actual	2010 Actual	Variance from 2009 Actual	2010 Actual	2011 Bridge	Variance from 2010 Actual	2011 Bridge	2012 Test	Variance from 2011 Bridge
	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)
Distribution Revenues															
Residential	$3,913,662	$3,585,527	-$328,135	$3,585,527	$3,780,878	$195,352	$3,780,878	$3,746,942	-$33,936	$3,746,942	$4,831,071	$1,084,129	$4,831,071	$5,176,750	$345,679
GS<50	$754,516	$983,548	$229,032	$983,548	$819,593	-$163,955	$819,593	$670,004	-$149,589	$670,004	$1,168,144	$498,140	$1,168,144	$1,244,340	$76,196
GS>50 to 999 kW	$1,002,726	$1,072,236	$69,509	$1,072,236	$1,002,045	-$70,190	$1,002,045	$467,222	-$534,824	$467,222	$865,766	$398,544	$865,766	$1,276,274	$410,507
Greater than 1,000 to 2,999 kW	$649,464	$852,138	$202,674	$852,138	$664,676	-$187,462	$664,676	$1,093,200	$428,524	$1,093,200	$554,874	-$538,326	$554,874	$522,514	-$32,359
Greater than 3,000 to 4,999 kW	$166,568	$177,972	$11,404	$177,972	$148,796	-$29,176	$148,796	$57,037	-$91,760	$57,037	$63,027	$5,991	$63,027	$0	-$63,027
Large Use	$455,028	$536,279	$81,250	$536,279	$742,353	$206,074	$742,353	$571,733	-$170,619	$571,733	$510,381	-$61,353	$510,381	$401,551	-$108,829
Unmetered Scattered Load	$11,236	$28,327	$17,091	$28,327	$12,418	-$15,909	$12,418	$9,707	-$2,711	$9,707	$14,437	$4,730	$14,437	$88,716	$74,279
Sentinel Lighting	$29,230	$15,505	-$13,724	$15,505	$36,012	$20,507	$36,012	$27,701	-$8,312	$27,701	$30,055	$2,355	$30,055	$32,568	$2,513
Street Lighting	$235,761	$44,897	-$190,864	$44,897	$439,079	$394,182	$439,079	$331,300	-$107,779	$331,300	$314,766	-$16,534	$314,766	$399,745	$84,979
Embedded Distributor	$219,224	$11,087	-$208,137	$11,087	$144,455	$133,368	$144,455	$142,471	-$1,984	$142,471	$166,268	$23,797	$166,268	$182,106	$15,837
	$7,437,415	**$7,307,516**	**-$129,900**	**$7,307,516**	**$7,790,306**	**$482,790**	**$7,790,306**	**$7,117,316**	**-$672,989**	**$7,117,316**	**$8,518,788**	**$1,401,472**	**$8,518,788**	**$9,324,564**	**$805,776**
Other Distribution Revenue															
Late Payment Charges	$92,667	$73,786	-$18,881	$73,786	$88,295	$14,509	$88,295	$84,480	-$3,815	$84,480	$139,262	$54,782	$139,262	$143,440	$4,178
Specific Service Charges	$253,659	$333,012	$79,353	$333,012	$287,538	-$45,475	$287,538	$334,970	$47,432	$334,970	$500,455	$165,485	$500,455	$595,805	$95,351
Other Distribution Revenue	$182,596	$6,238	-$176,358	$6,238	$71,098	$64,860	$71,098	$104,362	$33,265	$104,362	$153,538	$49,176	$153,538	$156,609	$3,071
RCVA Revenue	$2,780	$133,207	$130,427	$133,207	$30,703	-$102,505	$30,703	$31,449	$746	$10,854	$36,120	$25,266	$36,120	$37,204	$1,084
	$531,702	**$546,244**	**$14,542**	**$546,244**	**$477,633**	**-$68,611**	**$477,633**	**$555,261**	**$77,628**	**$534,666**	**$829,375**	**$294,709**	**$829,375**	**$933,058**	**$103,683**
Total Operating revenue	**$7,969,117**	**$7,853,760**	**-$115,358**	**$7,853,760**	**$8,267,939**	**$414,179**	**$8,267,939**	**$7,672,577**	**-$595,362**	**$7,651,983**	**$9,348,163**	**$1,696,181**	**$9,348,163**	**$10,257,622**	**$909,459**

VARIANCE ANALYSIS ON OPERATING REVENUE

Erie Thames Power's distribution revenue has been calculated using the most recently approved rates. In particular, delivery rates are based on the EB-2010-0080 Rate Order, dated April 7, 2011. Distribution revenue does not include commodity related revenue.

2012 Test Year

Erie Thames Power's operating revenue is forecast to be $10,075,517 in Fiscal 2012, as shown in Exhibit 3, Tab 1, and Schedule 2. Distribution revenue totals $9,1324,564 or 91% of total revenues. Other operating revenue (net) accounts for the remaining revenue of $933,058.

Comparison to 2011 Bridge Year
As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue is expected to be $909,459 above the bridge year level in fiscal 2012, $103,683 is related to changes in Misc. Service Revenue and the remaining $805,776 is the change in distribution revenue charges. The 2011 fiscal revenue is based on current rates multiplied by projected consumption while 2012 is based on rebased revenue. The major contributors to the distribution revenue difference is the fact that the 2008 COS application utilized load forecast amounts that were in excess of the actuals since the application's approval. Erie Thames filed its first COS application in 2007 for 2008 approval and at this same time the economy began its downturn. Erie Thames lost load over this time frame and this coupled with the normal inflation of costs over time has resulted in the change reported for distribution revenue year over year.

2011 Bridge Year

Comparison to Fiscal 2010 Actual
As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue is expected to be $1,696,181 greater than the 2010 Actual level in fiscal 2011. This is a resulting from the inclusion of Clinton Power Corporation and West Perth Power Corporation's billing statistics for the fiscal year in 2011. The 2010 amount represents only Erie Thames figures since at that time the entities were separate and distinct.

2010 Actual

Comparison to 2009 Actual
As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue was $595,362 lower in 2010 vs. 2009 Actual. This difference is directly attributable to differences in 2010 and 2009 approved rates. Erie Thames's rates were reduced in 2010 versus 2009 for the stretch factor and this is coupled with the fact that the 2009 rates are inclusive of Low Voltage rates and the low voltage amount is excluded from the 2010 rate 2010 low voltage revenue amounts to approximately $522,000 which is almost 100% of the difference detailed here.

2009 Actual

Comparison to 2008 Actual
As shown in Exhibit 3, Tab 1, Schedule 2, total operating revenue increased $414,179 from 2009 actual to 2008 actual. The timing of Erie Thames's 2008 rate approval being delayed until December of 2008 is the reason for the difference in the distribution revenue collected year over year.

2008 Actual

Comparison to 2008 Approved
As shown in Exhibit 3, Tab 1, Schedule 2, total operating revenue decreased $115,358 from 2008 approved to 2008 actual. The timing of Erie Thames's 2008 rate approval being delayed until December of 2008 is the reason for the difference in the distribution revenue collected year over year.

Erie Thames Powerlines Corporation

2012 Load Forecasting

Stratadyne Group Inc.

11/22/2011

Table of Contents

1. Introduction

This report was created on November 22, 2011 and was updated on April 11, 2012 to reflect on the changes in some customer class allocations.

On December 24, 2010, Erie Thames Powerlines Corporation (“Erie Thames”) filed an application with the Ontario Energy Board to amalgamate with West Perth Power Inc. (“West Perth”) and Clinton Power Corporation (“Clinton”). On March 24, 2011, Erie Thames is granted leave to amalgamate with West Perth and Clinton by the Ontario Energy Board.

This report covers the 2012 load forecast for the following classes of customers of the amalgamated Erie Thames Powerlines Corporation.

Table 1 – Classes of Customers of the Amalgameted Erie Thames Powerlines Corporation

Rate Group	Rate Classes	Fixed Metric	Vol Metric
RES	Residential	Customer – 12 per year	kWh
GS LT50	General Service Less Than 50 kW	Customer – 12 per year	kWh
GSGT50	General Service 50 to 4,999 kW	Customer – 12 per year	kW
LU	Large Use Service Equal or greater than 5,000 kW	Customer – 12 per year	kW
USL	Unmetered Scattered Load	Connection -12 per year	kWh
Sen	Sentinel Lighting	Connection -12 per year	kW
SL	Street Lighting	Connection -12 per year	kW
E	Embedded Distributor	Customer -12 per year	kW

2. 2012 Load Forecast Summary

The 2012 Load Forecasting for the amalgamated Erie Thames Powerlines Corporation is shown in table below. The 2010 values were actual demand (kW) and energy (kWh) without loss adjustment. The 2012 values are the forecast demand (kW) and energy (kWh) without loss adjustment.

Table 2 – 2012 Load Forecast Summary

Consumption	**2012**	**2012**	**2010**	**2010**
	KW	**KWH**	**KW**	**KWH**
Residential		147,767,075		148,114,381
General Service <50		50,460,667		50,456,016
GS > 50	143,211	44,453,178	139,928	43,335,594
GI > 50	84,710	33,395,845	82,948	32,698,642
General Service 1000-2999	96,900	59,000,000	93,487	57,741,953
General Service 3000-4999	26,704	10,200,000	29,135	11,691,664
Large user	160,146	97,146,783	152,704	92,434,594
Unmetered scattered load		618,341		605,495
Sentinel	772	284,787	772	284,787
Streetlights	13,507	4,979,730	10,754	3,964,612
Embedded Distributors	39,284	17,350,000	39,665	17,518,323
Total	**565,234**	**465,656,406**	**549,394**	**458,846,062**
Changes from 2010	2.9%	1.5%		

3. Residential Customers

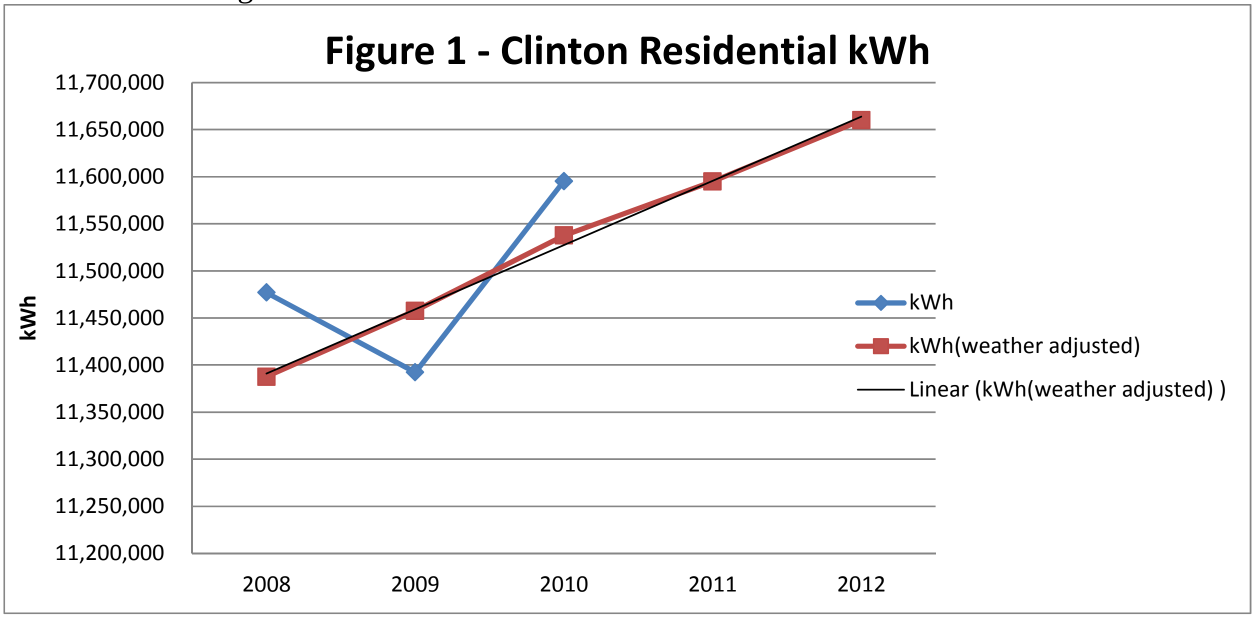
Clinton

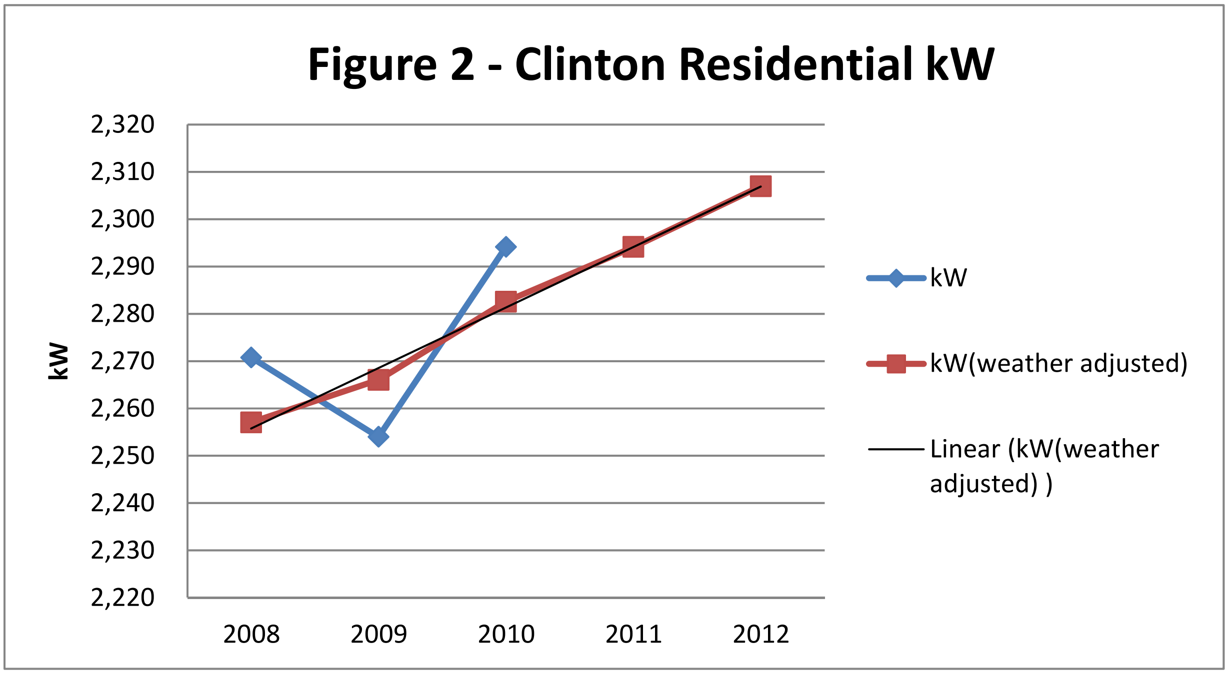
The historical residential load of Clinton from 2007 to 2010 are shown in Table 3 below. The 2011 and 2012 values are the forecast figures. Both actual and weather adjusted values are shown.

Table 3 - Annual Clinton Residential Load in kWh and Annual Peak Demand in kW

	2007	2008	2009	2010	2011	2012
Actual kWh	12,523,015	11,477,044	11,392,233	11,595,218		
Weather adjusted kWh	12,487,198	11,407,595	11,453,131	11,536,648	11,595,000	11,660,000
change from previous yr		-8.65%	0.40%	0.73%	0.51%	0.56%
	2007	2008	2009	2010	2011	2012
Actual kW	2,478	2,271	2,254	2,294		
Peak Demand kW weather adjusted	2,471	2,257	2,266	2,283	2,294	2,307
	2007	2008	2009	2010		
# of Customers	1,764	1,769	1,786	1,797		
kWh/customer/month	590	537	534	535		

Figure 1 shows the Clinton residential load in kWh from 2008 to 2012. The 2011 and 2012 values are forecast values. Figure 2 shows the residential demand in kW from 2008 to 2012.





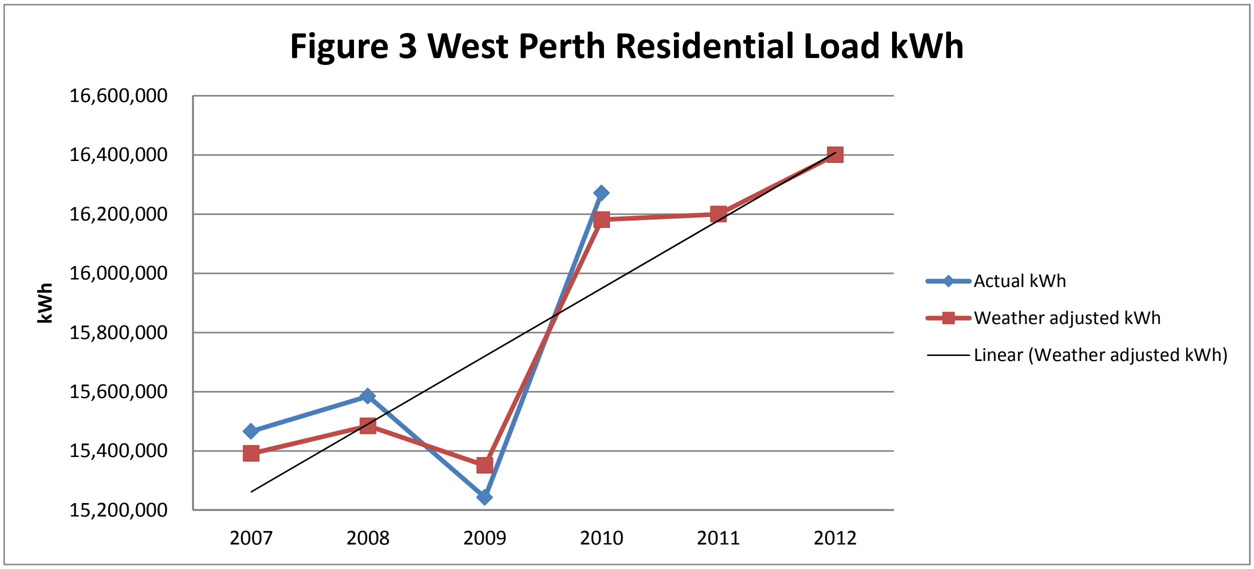
West Perth

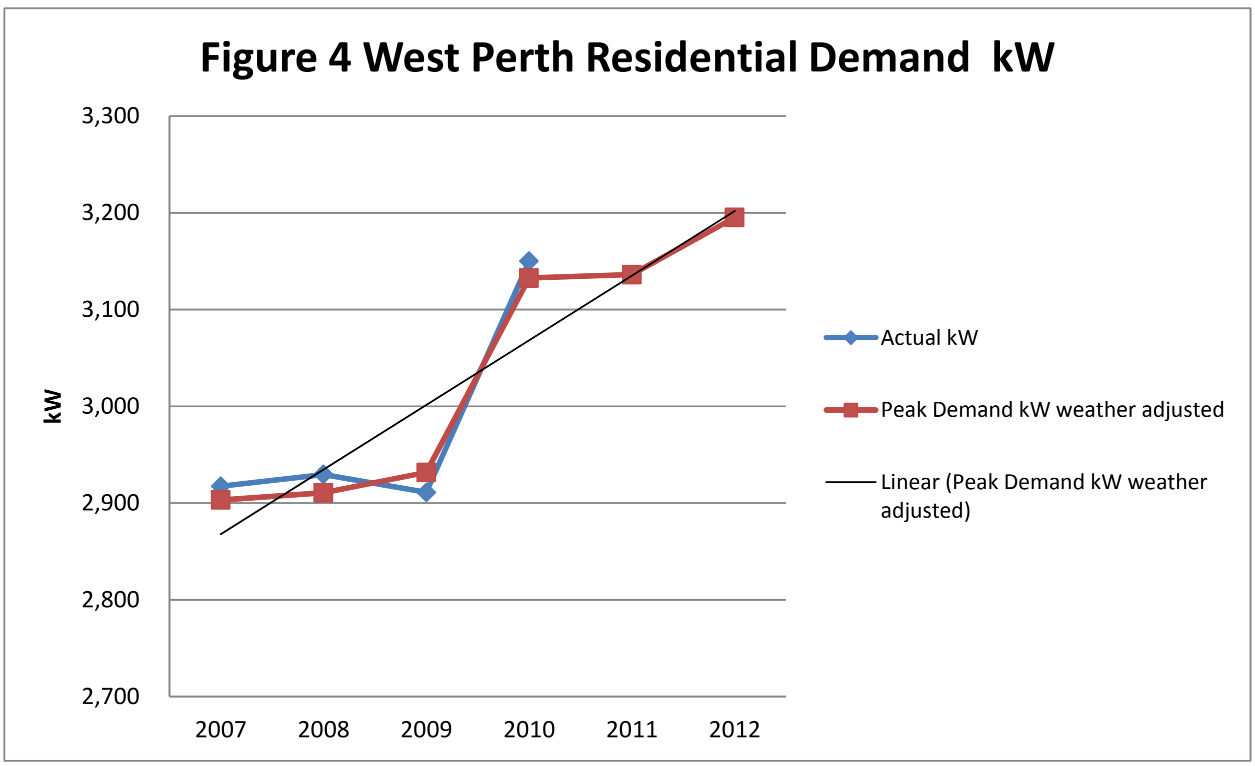
The historical residential load of West Perth from 2007 to 2010 are shown in Table 4 below. The 2011 and 2012 values are the forecast values. Both actual and weather adjusted values are shown.

Table 4 - Annual West Perth Residential Load in kWh and Annual Peak Demand in kW

	2007	2008	2009	2010	2011	2012
Actual kWh	15,466,784	15,585,731	15,243,552	16,271,614		
Weather adjusted kWh	15,391,783	15,485,313	15,351,455	16,181,193	16,200,000	16,400,000
change from previous yr		0.61%	-0.86%	5.40%	0.12%	1.23%
Actual kW	2,917	2,930	2,911	3,150		
Peak Demand kW weather adjusted	2,903	2,911	2,932	3,133	3,136	3,195
Annual LF	61%	61%	60%	59%	59%	59%
# of Customers	1,764	1,769	1,786	1,797	1,828	1,845
kWh/customer/month (Weather Adjusted)	727	729	716	750	739	741

Figure 3 shows the West Perth residential load in kWh from 2007 to 2012. The 2011 and 2012 values are forecast values. Figure 4 shows the residential demand in kW from 2007 to 2012.





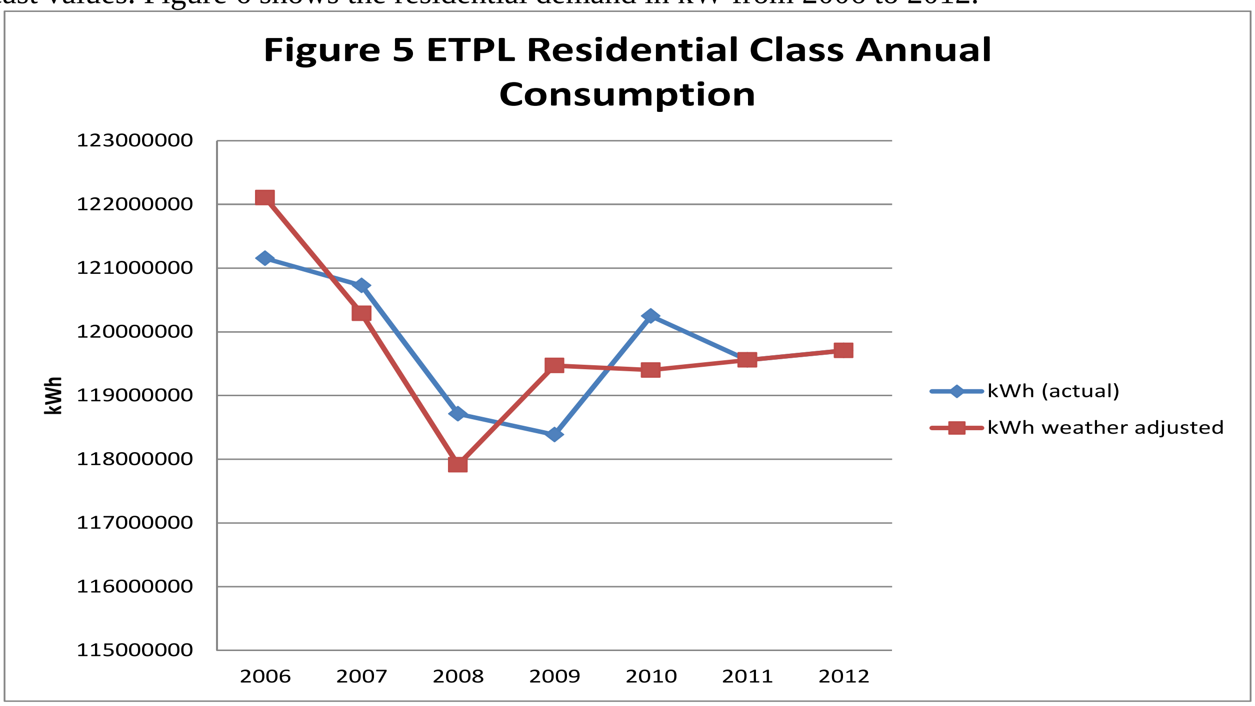
Erie Thames

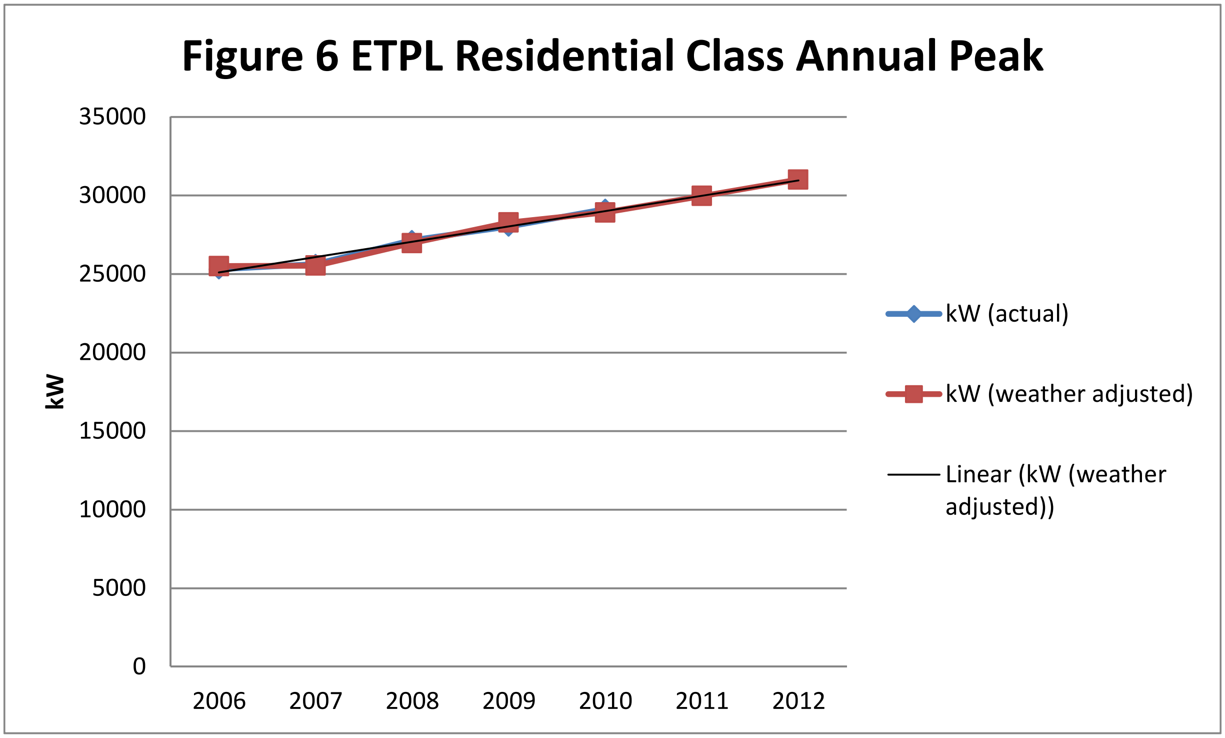
The historical residential load of Erie Thames before amalgamation from 2006 to 2012 are shown in Table 5 below. The 2011 and 2012 values are the forecast values. Both actual and weather adjusted values are shown.

Table 5- Annual Erie Thames Powerlines Corporation
Residential Load in kWh and Annual Peak Demand in kW

Residential						Forecast	
	2006	2007	2008	2009	2010	2011	2012
Customer Counts	12206	12328	12451	12116	12847	12864	12880
% change		1.0%	1.0%	-2.7%	6.0%	0.1%	0.1%
	2006	2007	2008	2009	2010	2011	2012
kWh (actual)	121,153,509	120,726,508	118,713,119	118,385,417	120,247,549	119,558,371	119,707,075
kWh weather adjusted	122,104,570	120,288,713	117,912,670	119,471,078	119,400,372	119,558,371	119,707,075
	2006	2007	2008	2009	2010	2011	2012
kWh/customer/month (actual)	827	816	795	814	780	775	775
kWh/customer/month (weather adj.)	834	813	789	822	775	775	775

Figure 5 shows the Erie Thames residential load in kWh from 2006 to 2012. The 2011 and 2012 values are forecast values. Figure 6 shows the residential demand in kW from 2006 to 2012.





2010 Consolidated Residential Class
The cosolidated load of the residential class was calculated by summing the residential loads of Clinton, West Perth and Erie Thames together. Table 6 shows the 2010 consolidated residential load. The annual kWh was 148,114,381. The non-coincident peak was 34,153 kW. The coincident peak in December was 34,066 kW. The Total Erie Thames System Peak occurred in December 2010.

Table 6 - 2010 Consolidated Residential Class

2010	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	14,511,182	19,504	26,354	74%	1/4/2010	18	26,336	99.9%
Feb	12,694,205	18,890	24,491	77%	2/9/2010	19	23,983	97.9%
Mar	12,117,674	16,287	23,950	68%	3/26/2010	8	23,673	98.8%
Apr	10,183,201	14,143	21,541	66%	4/9/2010	9	18,574	86.2%
May	10,922,333	14,681	25,011	59%	5/31/2010	13	22,980	91.9%
Jun	11,349,635	15,763	30,832	51%	6/23/2010	17	30,712	99.6%
Jul	13,614,622	18,299	30,226	61%	7/28/2010	14	24,861	82.2%
Aug	13,243,194	17,800	29,281	61%	8/12/2010	14	27,126	92.6%
Sep	10,405,622	14,452	28,935	50%	9/1/2010	16	28,552	98.7%
Oct	10,997,346	14,781	23,461	63%	10/13/2010	19	23,135	98.6%
Nov	12,039,576	16,722	28,655	58%	11/29/2010	18	28,317	98.8%
Dec	16,035,793	21,553	34,153	63%	12/13/2010	18	34,066	99.7%
Annual	148,114,381		326,890		12/13/2010	18	34,066	99.7%

2012 Consolidated Residential Class Forecast

The 2012 forecast of the consolidated residential class is shown in Table 7 below. The forecast annual kWh is 147,767,075. The forecast non-coincident peak is 36,069 kW. The forecast coincident peak is 35,979 kW.

Table 7 - 2012 Consolidated Residential Class

2012	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of Syst	Hr	Coincident Peak kW	Coincident Factor
Jan	14,477,676	19,459	27,772		1/4/2010	18	27,753	99.9%
Feb	12,665,035	18,847	25,802		2/9/2010	19	25,277	98.0%
Mar	12,090,399	16,251	25,247		3/26/2010	8	24,968	98.9%
Apr	10,160,669	14,112	22,700		4/9/2010	9	19,545	86.1%
May	10,897,167	14,647	26,366		5/31/2010	13	24,212	91.8%
Jun	11,322,787	15,726	32,569		6/23/2010	17	32,449	99.6%
Jul	13,581,096	18,254	31,872		7/28/2010	14	26,221	82.3%
Aug	13,211,132	17,757	30,866		8/12/2010	14	28,599	92.7%
Sep	10,382,520	14,420	30,496		9/1/2010	16	30,088	98.7%
Oct	10,972,536	14,748	24,751		10/13/2010	19	24,422	98.7%
Nov	12,011,535	16,683	30,259		11/29/2010	18	29,899	98.8%
Dec	15,994,523	21,498	36,069		12/13/2010	18	35,979	99.8%
Annual	147,767,075		344,769		12/13/2010	18	35,979	99.8%

4. General Service less than 50 kW

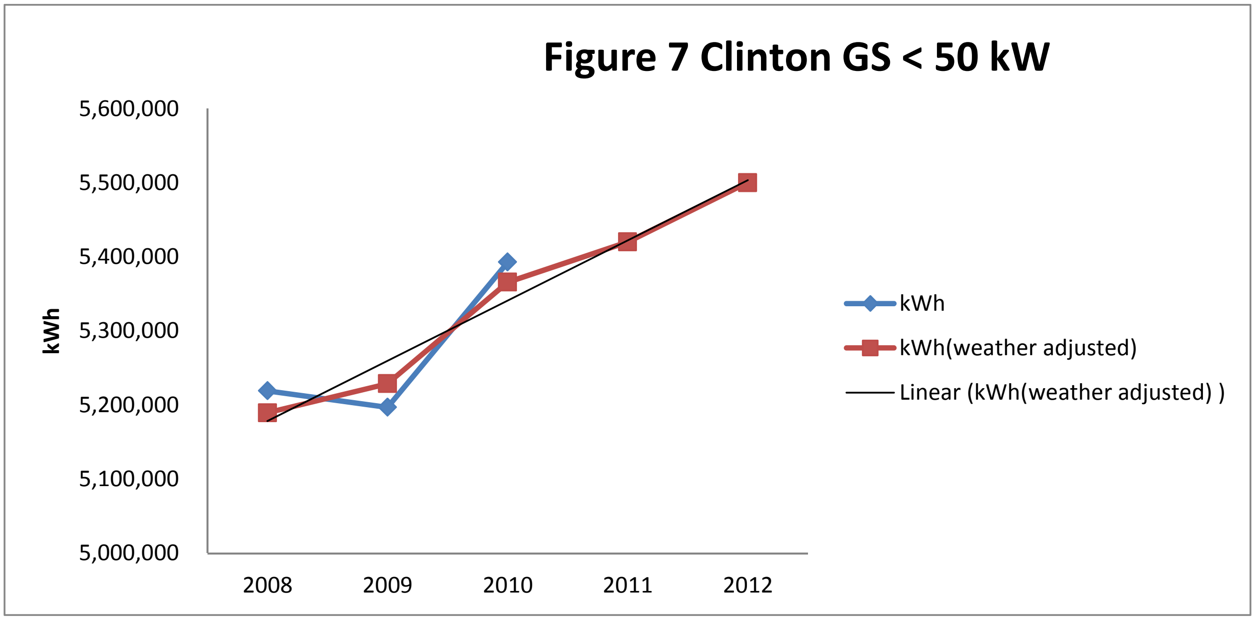
Clinton

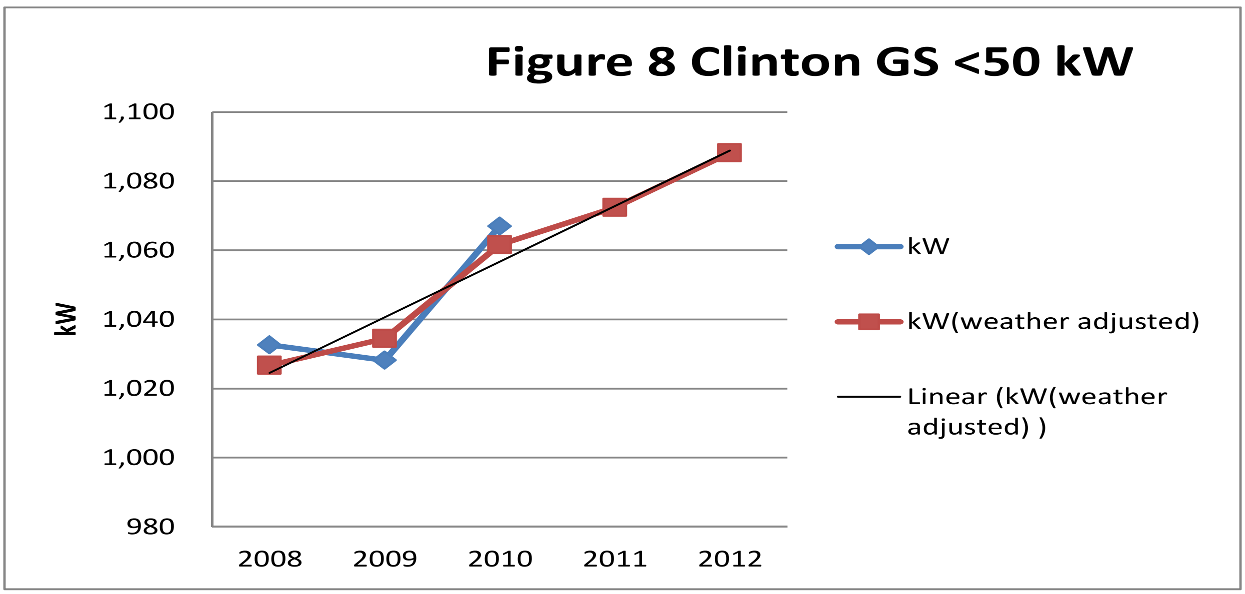
The historical load from 2007 to 2012 are shown in Table 8 below. The 2011 and 2012 values are forecast numbers. Both actual and weather adjusted values are shown.

Table 8 - Annual Clinton General Services < 50 kW Load in kWh and Annual Peak Demand in kW

	2007	2008	2009	2010	2011	2012
Actual kWh	6,002,124	5,219,160	5,196,841	5,392,837		
Weather adjusted kWh	5,984,939	5,189,387	5,228,685	5,365,596	5,420,000	5,500,000
change from previous yr		-13.29%	0.76%	2.62%	1.01%	1.48%
	2007	2008	2009	2010	2011	2012
Actual kW	1,188	1,033	1,028	1,067		
Peak Demand kW weather adjusted	1,184	1,027	1,035	1,062	1,072	1,088

Figure 7 shows the annual consumption in kWh. Figure 8 shows the peak demand in kW.





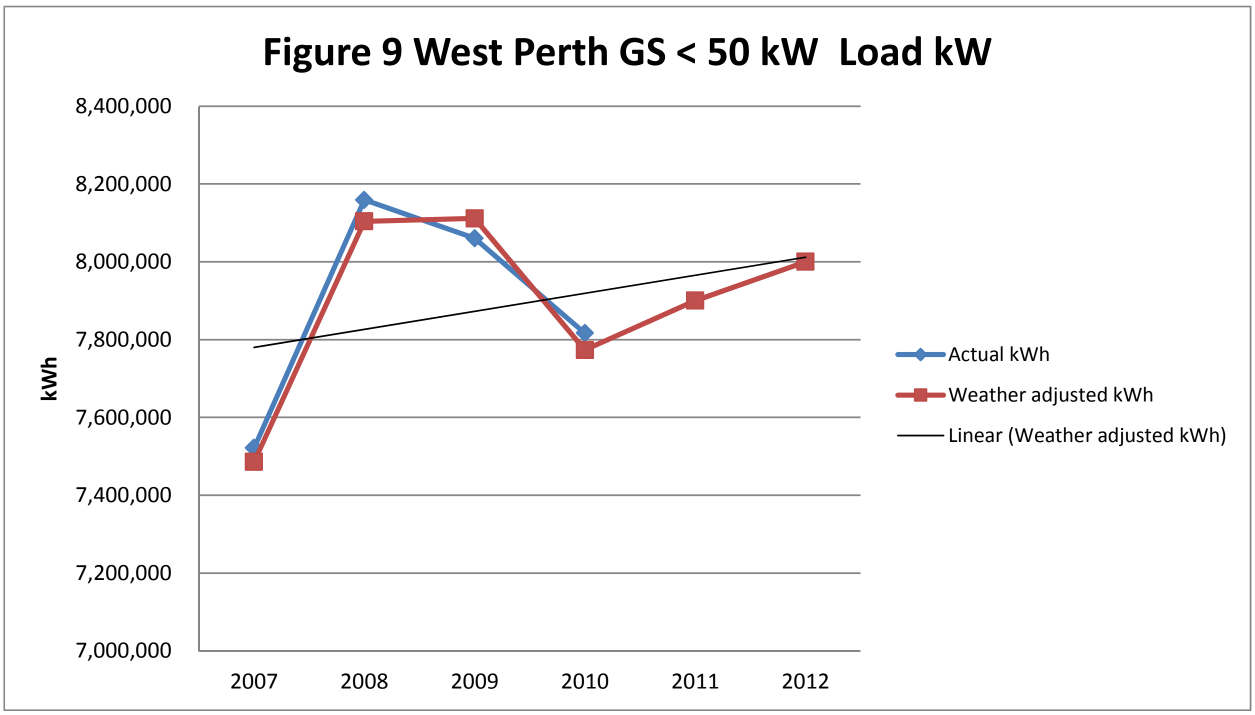
West Perth

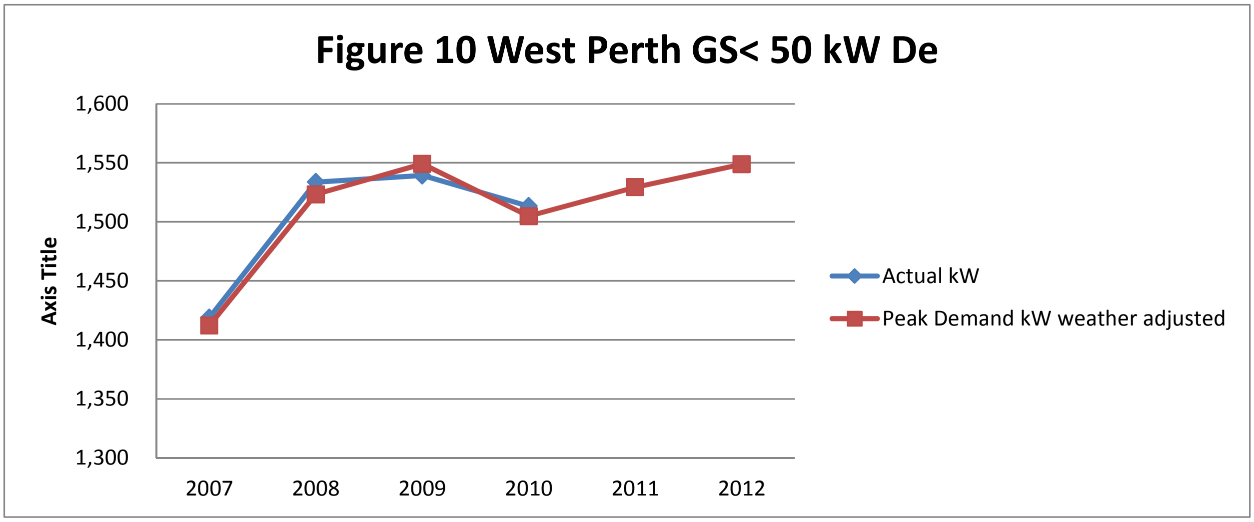
The historical load from 2007 to 2012 are shown in Table 9 below. The 2011 and 2012 values are forecast numbers. Both actual and weather adjusted values are shown.

Table 9 - Annual West Perth General Services < 50 kW Load in kWh and Annual Peak Demand in kW

	2007	2008	2009	2010	2011	2012
Actual kWh	7,521,417	8,159,292	8,060,447	7,816,746		
Weather adjusted kWh	7,485,674	8,104,001	8,111,473	7,773,309	7,900,000	8,000,000
change from previous yr		8.3%	0.1%	-4.2%	1.6%	1.3%
Actual kW	1,419	1,534	1,539	1,513		
Peak Demand kW weather adjusted	1,412	1,523	1,549	1,505	1,529	1,549
Annual LF	61%	61%	60%	59%	59%	59%
# of Customers	235	239	241	243	245	247
kWh/customer/month (Weather Adjusted)	2,654	2,826	2,805	2,666	2,687	2,699

Figure 9 shows the annual consumption in kWh. Figure 10 shows the peak demand in kW.





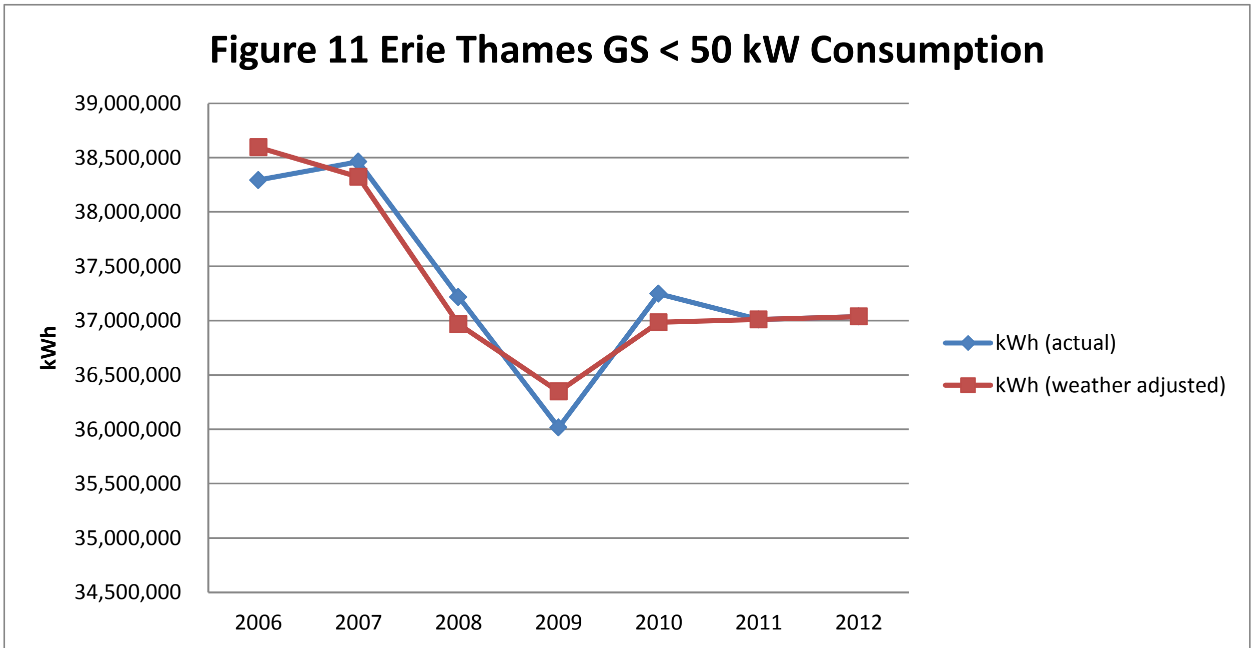
Erie Thames

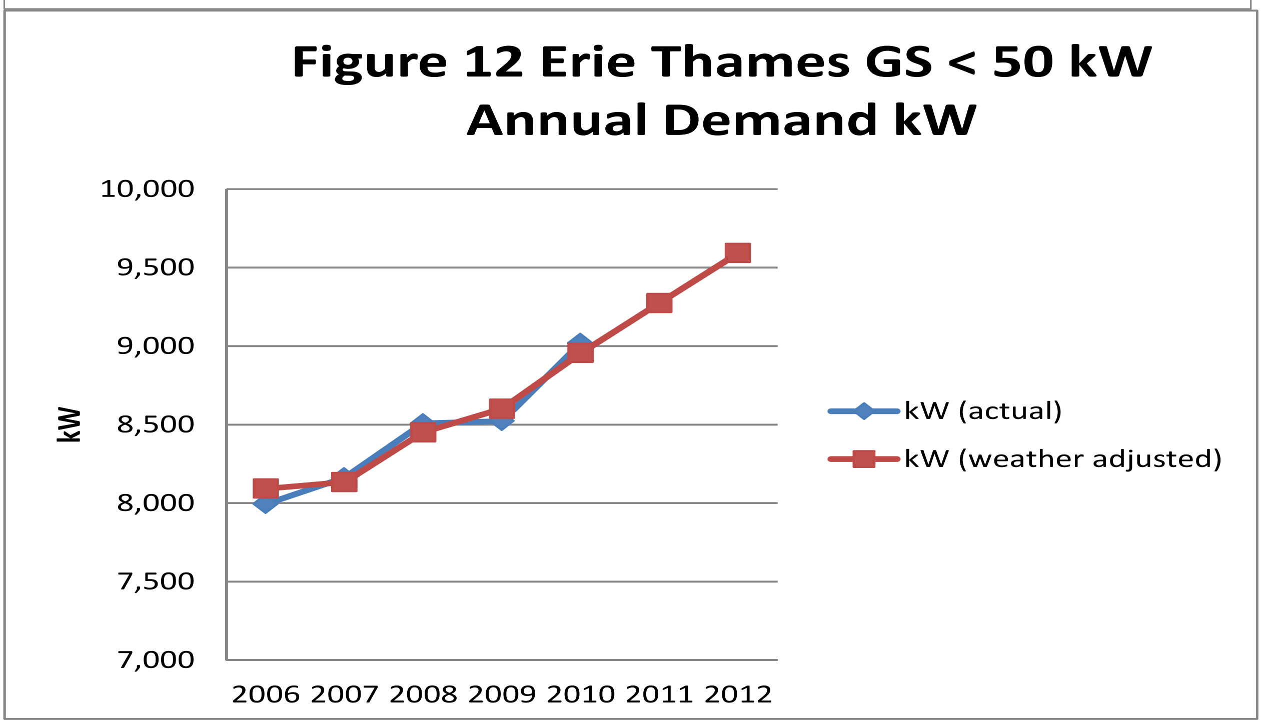
The historical load from 2006 to 2012 are shown in Table 10 below. The 2011 and 2012 values are forecast numbers. Both actual and weather adjusted values are shown.

Table 10 - Annual Erie Thames General Services < 50 kW Load in kWh and Annual Peak Demand in kW

	2006	2007	2008	2009	2010	2011	2012
Customer Counts	1375	1375	1388	1234	1378	1379	1380
% change		0.0%	0.9%	-11.1%	11.7%	0.1%	0.1%
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
kWh (actual)	38,293,129	38,462,309	37,217,234	36,016,683	37,246,433	37,010,861	37,037,700
kWh (weather adjusted)	38,593,732	38,322,832	36,966,289	36,346,976	36,984,022	37,010,861	37,037,700
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
kWh/customer/month (actual)	2,321	2,331	2,234	2,433	2,252	2,237	2,237
kWh/customer/month (weather adjusted)	2,339	2,323	2,219	2,455	2,237	2,237	2,237

Figure 11 shows the annual consumption in kWh. Figure 12 shows the peak demand in kW.





Consolidated General Service < 50 kW

The 2010 cosolidated load of the General Services < 50 kW class was calculated by summing the General Services < 50 kW loads of Clinton, West Perth and Erie Thames together. Table 11 shows the 2010 consolidated load. The 2010 annual kWh for this class was 50,456,016. The non-coincident peak was 11,407 kW. The annual coincident peak was 11,373 kW.

Table 11 - 2010 Consolidated Load of the General Service < 50 kW Class

2010	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincide Peak kW	Coincident Factor
Jan	4,951,812	6,655	8,998	74%	1/4/2010	18	8,955	99.5%
Feb	4,333,274	6,448	8,358	77%	2/9/2010	19	8,155	97.6%
Mar	4,144,572	5,571	8,130	69%	3/26/2010	9	7,995	98.4%
Apr	3,498,404	4,849	7,338	66%	4/9/2010	9	8,408	97.5%
May	3,727,050	5,010	8,460	59%	5/31/2010	13	7,837	92.3%
Jun	3,862,595	5,365	10,274	52%	6/23/2010	17	10,215	99.5%
Jul	4,614,756	6,203	10,239	61%	7/26/2010	14	9,432	92.1%
Aug	4,496,909	6,044	9,942	61%	8/12/2010	14	9,199	92.5%
Sep	3,563,497	4,949	8,639	58%	9/1/2010	16	8,728	95.6%
Oct	3,758,953	5,054	7,913	64%	10/13/2010	19	7,767	98.1%
Nov	4,103,952	5,700	9,595	59%	11/23/2010	18	9,473	98.9%
Dec	5,409,695	7,271	11,407	64%	12/13/2010	18	11,373	99.7%
Annual	50,456,016		110,457		12/13/2010	18	11,373	99.7%

The 2012 forecast of the consolidated General Service < 50 kW class is shown in Table 12 below. The forecast annual kWh is 50,460,667. The forecast non-coincident peak is 12,018 kW. The forecast coincident peak is 11,983 kW.

Table 12 2012 Forecast Consolidated Load of the General Service < 50 kW Class

2012	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	4,951,814	6,656	9,435	71%	1/4/2010	18	9,426	99.9%
Feb	4,334,030	6,449	8,783	73%	2/9/2010	19	8,573	97.6%
Mar	4,145,797	5,572	8,548	65%	3/26/2010	8	8,415	98.4%
Apr	3,489,850	4,847	7,711	63%	4/9/2010	9	6,723	87.2%
May	3,727,817	5,011	8,927	56%	5/31/2010	13	8,236	92.3%
Jun	3,863,023	5,365	10,827	50%	6/23/2010	17	10,770	99.5%
Jul	4,613,909	6,201	10,769	58%	7/28/2010	14	8,840	82.1%
Aug	4,496,484	6,044	10,454	58%	8/12/2010	14	9,674	92.5%
Sep	3,564,850	4,951	10,343	48%	9/1/2010	16	10,217	98.8%
Oct	3,761,274	5,055	8,328	61%	10/13/2010	19	8,172	98.1%
Nov	4,104,535	5,701	10,095	56%	11/29/2010	18	9,983	98.9%
Dec	5,407,282	7,268	12,018	60%	12/13/2010	18	11,983	99.7%
Annual	50,460,667		116,237		12/13/2010	18	11,983	99.7%

5. General Service Greater than 50 kW

The forecast for this class is further divided into the group without interval meters (G > 50 kW) and the group with interval meters (GI>50 kW).

5.1 G > 50 kW

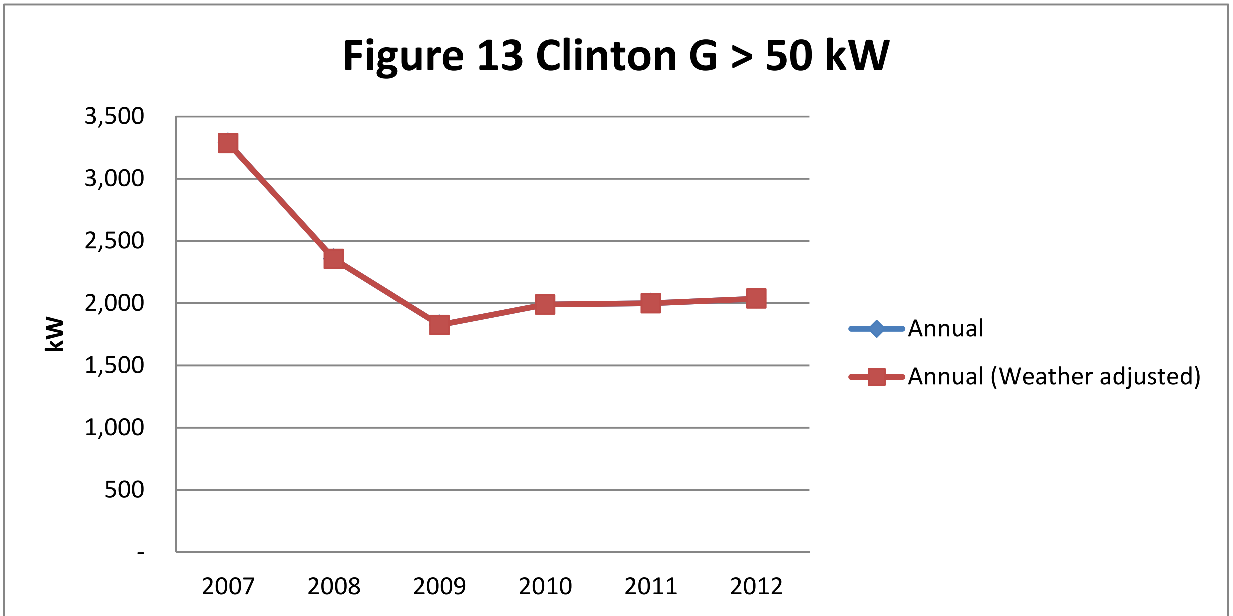
Clinton

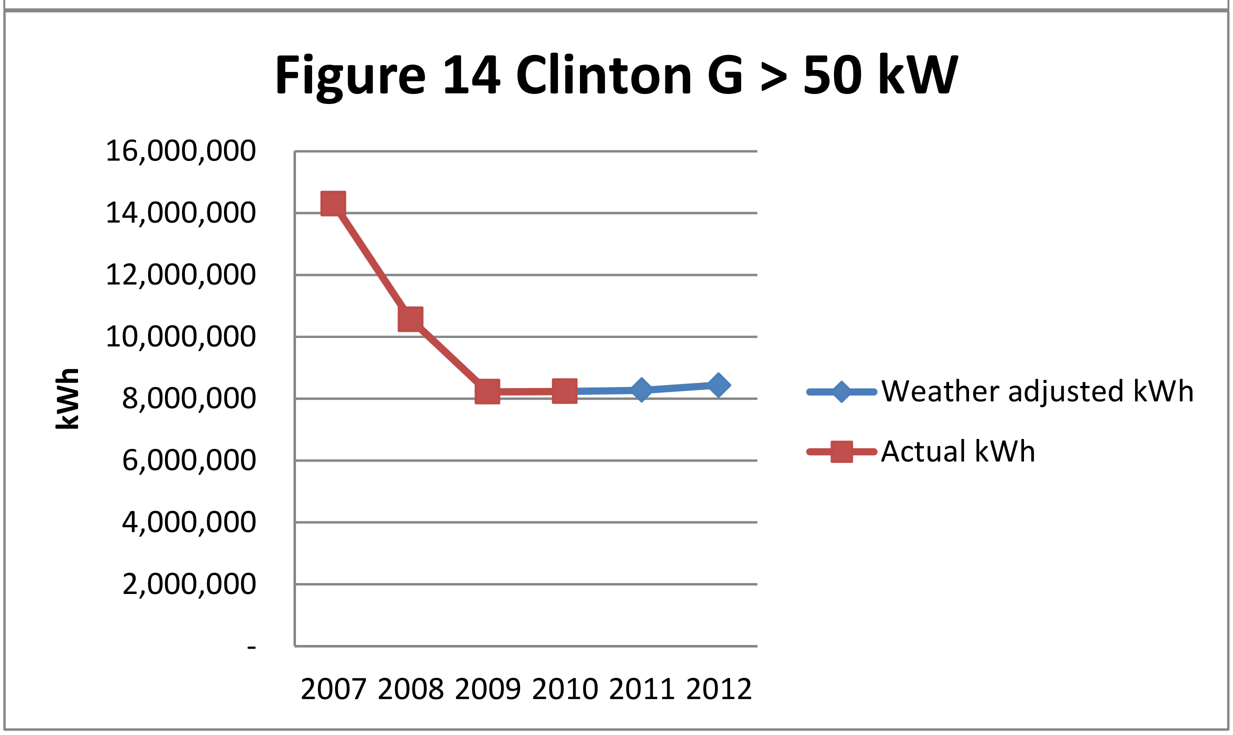
The historical load from 2007 to 2012 are shown in Table 13 below. The 2011 and 2012 values are forecast numbers. Both actual and weather adjusted values are shown.

Table 13 – Clinton General Services > 50 kW Load in kWh

	2007	2008	2009	2010	2011	2012
Weather adjusted kWh	14,299,976	10,564,172	8,220,540	8,234,516	8,275,689	8,432,927
Actual kWh	14,299,976	10,564,172	8,220,540	8,234,516		
# of GS>50kW customers	20	20	20	20	20	20
kWh/customer/month	59,583	44,017	34,252	34,310	34,482	35,137
kWh/customer/month growth		-26.1%	-22.2%	0.2%	0.5%	1.9%
IESO 18 month outlook (May 24 2011) Ontario Energy Growth					0.50%	1.90%

Figure 13 shows the peak demand in kW. Figure 14 shows the annual consumption in kWh.





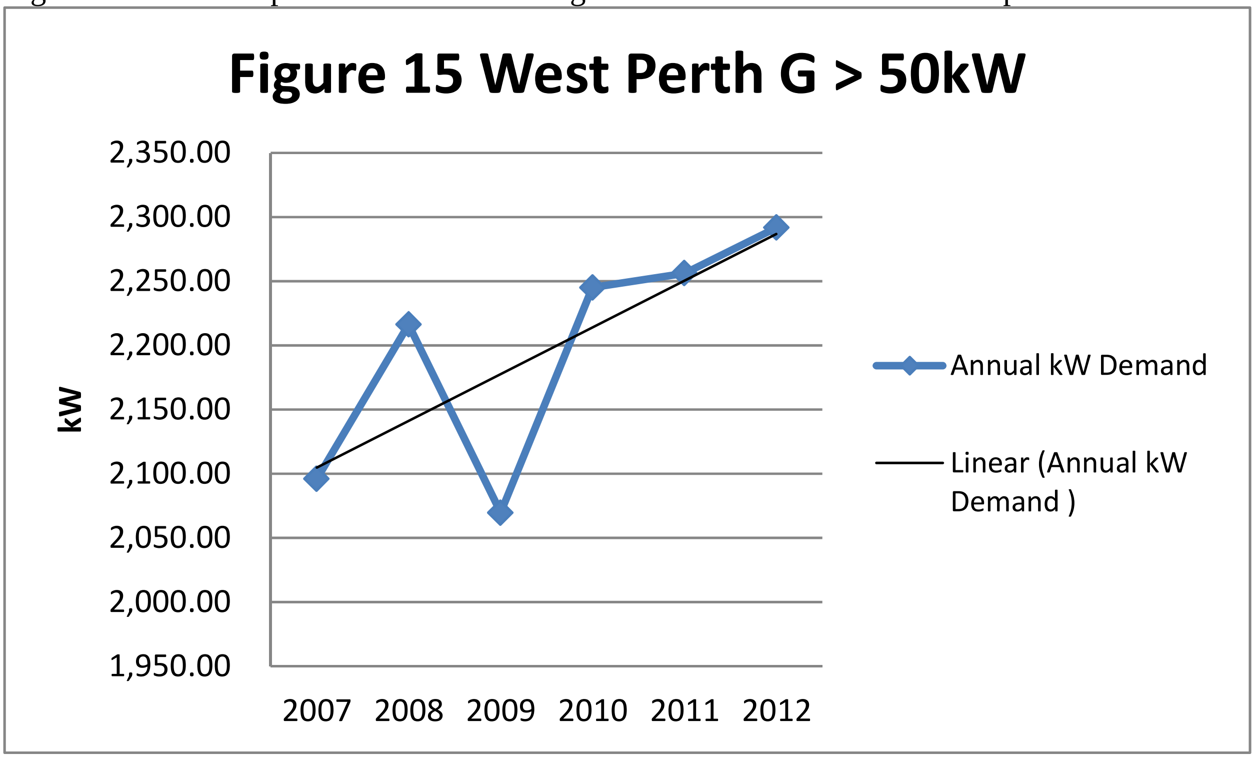
West Perth

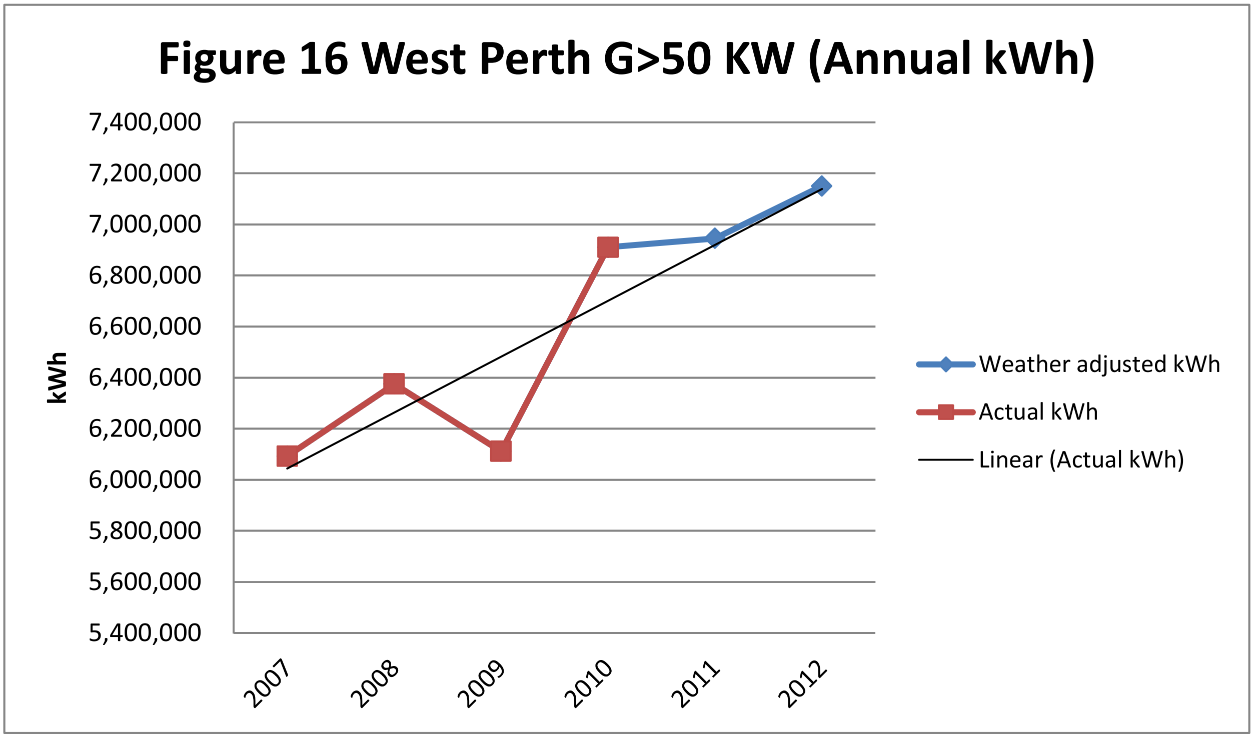
The historical load from 2007 to 2012 are shown in Table 14 below. The 2011 and 2012 values are forecast numbers. Both actual and weather adjusted values are shown.

Table 14 – West Perth General Services > 50 kW Annual Load in kWh

	2007	2008	2009	2010	2011	2012
Weather adjusted kWh	6,092,680	6,374,610	6,111,750	6,910,240	6,944,791	7,150,000
Actual kWh	6,092,680	6,374,610	6,111,750	6,910,240		
# of GS>50kW customers	14	15	15	15	15	15
kWh/customer/month	36,266	35,415	33,954	38,390	38,582	39,722

Figure 15 shows the peak demand in kW. Figure 16 shows the annual consumption in kWh.





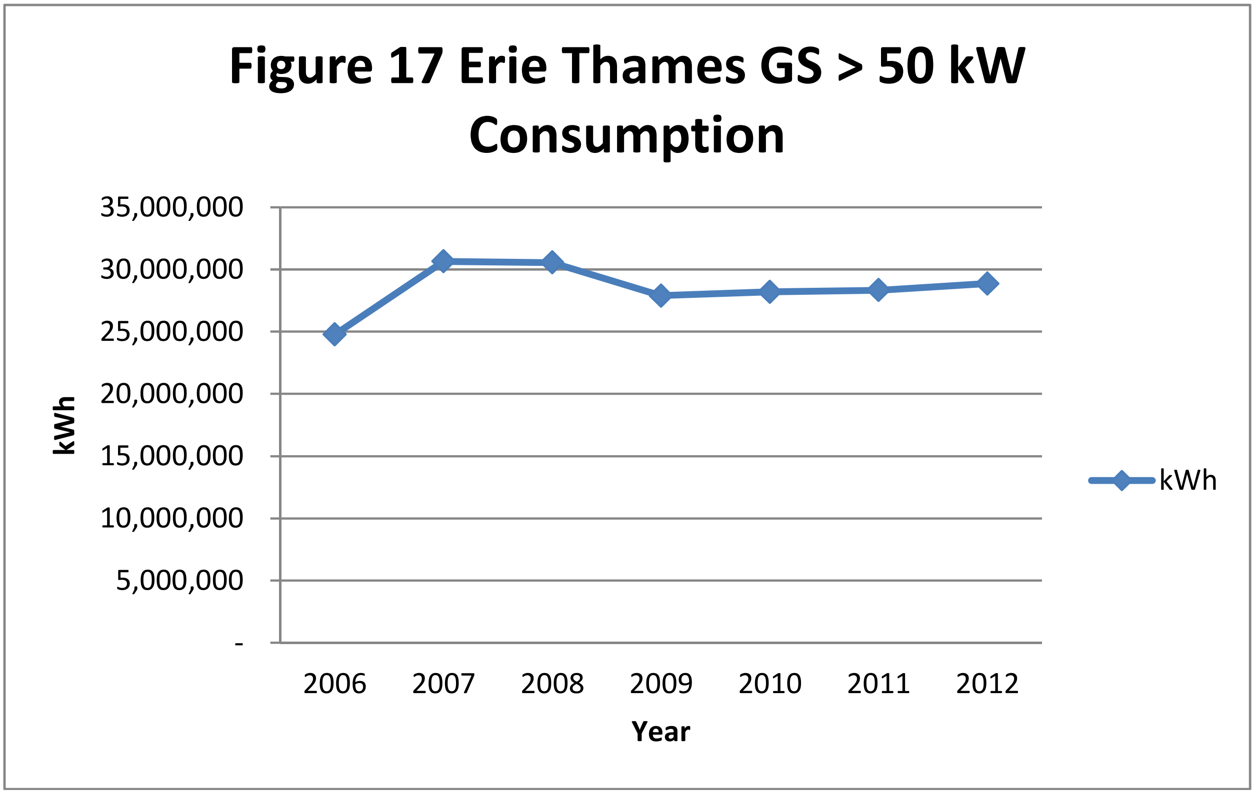
Erie Thames

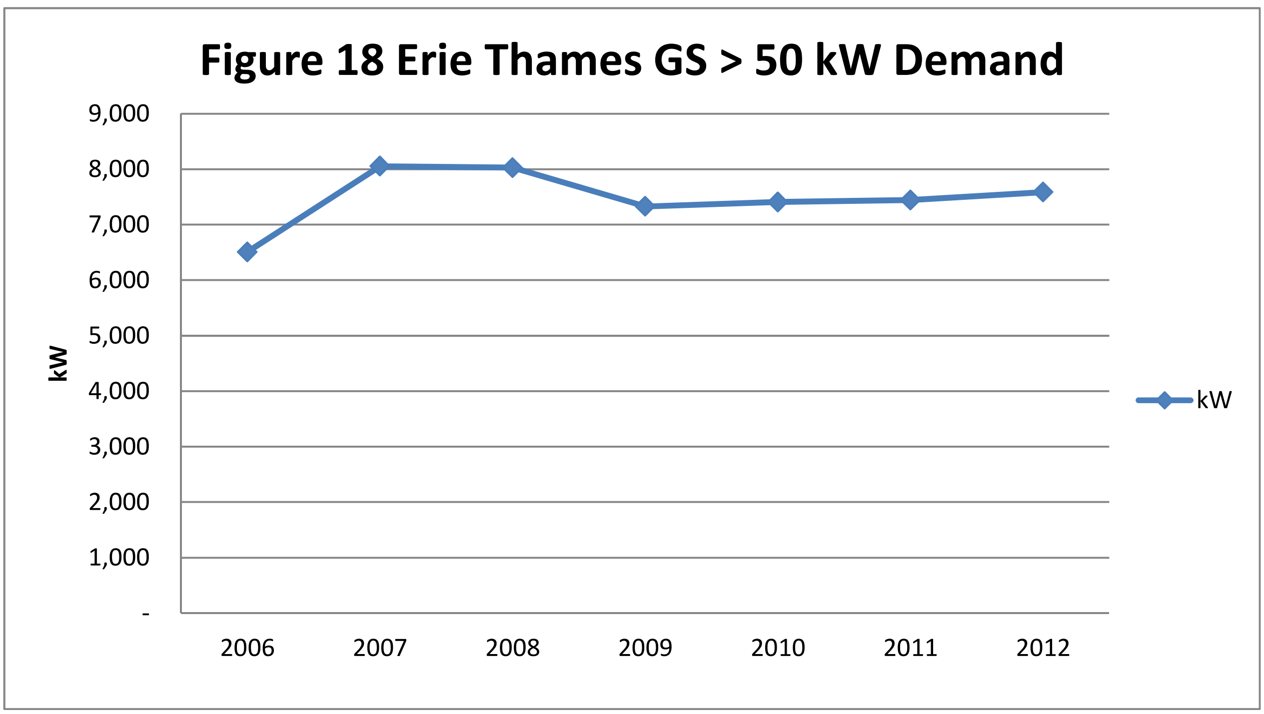
The historical load from 2006 to 2012 are shown in Table 15 below. The 2011 and 2012 values are forecast numbers. Both actual and weather adjusted values are shown.

Table 15 – Erie Thames General Services > 50 kW Annual Load

	2006	2007	2008	2009	2010	2011	2012
Number of Customers	135	138	141	138	138	138	138
kWh	24,776,038	30,653,353	30,553,013	27,896,587	28,190,989	28,331,944	28,870,251
kW	6,510	8,054	8,028	7,330	7,407	7,444	7,586

Figure 17 shows the annual consumption in kWh. Figure 18 shows the peak demand in kW.





Consolidated G > 50 kW

The 2010 cosolidated load of the General Services > 50 kW class was calculated by summing the General Services >50 kW loads of Clinton, West Perth and Erie Thames together. Table 16 shows the 2010 consolidated load. The 2010 annual kWh for this class was 43,335,594. The non-coincident peak was 14,275 kW. The annual coincident peak was 9,042 kW.

Table 16 – 2010 Consolidated Load of General Service > 50 kW

2010	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	4,274,220	6,394	11,082	58%	1/4/2010	18	9,166	92.7%
Feb	4,108,044	6,810	11,354	60%	2/9/2010	19	10,275	100.0%
Mar	4,123,490	6,255	10,744	58%	3/26/2010	8	8,199	73.6%
Apr	3,289,379	5,275	10,763	49%	4/9/2010	9	9,409	87.3%
May	3,473,504	5,381	10,840	50%	5/31/2010	13	9,217	93.9%
Jun	3,276,156	5,321	10,850	49%	6/23/2010	17	8,947	86.0%
Jul	2,670,438	4,374	14,275	31%	7/28/2010	14	7,314	31.8%
Aug	2,756,552	4,503	11,696	39%	8/12/2010	14	6,911	43.4%
Sep	2,988,888	4,934	12,322	40%	9/1/2010	16	10,797	100.0%
Oct	4,397,728	6,633	12,093	55%	10/13/2010	19	10,582	91.9%
Nov	3,893,845	6,117	12,029	51%	11/29/2010	18	8,547	84.9%
Dec	4,083,349	6,114	11,880	51%	12/13/2010	18	9,042	84.6%
Annual	43,335,594		139,928		12/13/2010	18	9,042	84.6%

The 2012 forecast of the consolidated General Service >50 kW class is shown in Table 17 below. The forecast annual kWh is 44,453,178. The forecast non-coincident peak is 14,611 kW. The forecast annual coincident peak is 9,255 kW.

Table 17 – 2012 Consolidated Load of General Service > 50 kW

2012	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	4,382,813	6,543	11,343	58%	1/4/2010	18	9,383	92.7%
Feb	4,212,468	6,970	11,620	60%	2/9/2010	19	10,518	100.0%
Mar	4,228,998	6,401	10,996	58%	3/26/2010	8	8,391	73.6%
Apr	3,374,534	5,397	11,015	49%	4/9/2010	9	9,629	87.3%
May	3,563,341	5,505	11,094	50%	5/31/2010	13	9,434	93.9%
Jun	3,361,533	5,444	11,104	49%	6/23/2010	17	9,157	86.0%
Jul	2,741,550	4,474	14,611	31%	7/28/2010	14	7,483	31.8%
Aug	2,829,854	4,606	11,970	38%	8/12/2010	14	7,071	43.4%
Sep	3,067,438	5,047	12,611	40%	9/1/2010	16	11,050	100.0%
Oct	4,509,923	6,788	12,377	55%	10/13/2010	19	10,831	91.9%
Nov	3,993,586	6,259	12,311	51%	11/29/2010	18	8,748	84.9%
Dec	4,187,140	6,257	12,159	51%	12/13/2010	18	9,255	84.6%
Annual	44,453,178		143,211		12/13/2010	18	9,255	84.6%

5.2 G > 50 I

Clinton

The historical load for General Service greater than 50 kW with interval meters from 2009 to 2010 are shown in Table 18 below. The 2011 and 2012 values are the forecast figures. The annual growth rate for 2011 and 2012 are 0.5% and 1.9% respectively. These values are based on the IESO's 18 month outlook (May 24 2011) for the Ontario Energy Growth forecast.

Table 18 - Clinton General Services > 50 kW with Interval Meters

	2009	2010	2011	2012
Weather adjusted kWh	3,123,586	4,195,742	4,216,721	4,296,838
Actual kWh	3,123,586	4,195,742		
Weather Adjusted kW	1,460	1,564	1,572	1,602
# of GI>50kW customers	1	1	1	1
kWh/customer/month	260,299	349,645	351,393	358,070
kWh/customer/month growth		34.3%	0.5%	1.9%
IESO 18 month outlook (May 24 2011) Ontario Energy Growth			0.50%	1.90%

Figure 19 shows the annual consumption in kWh. Figure 20 shows the peak demand in kW.

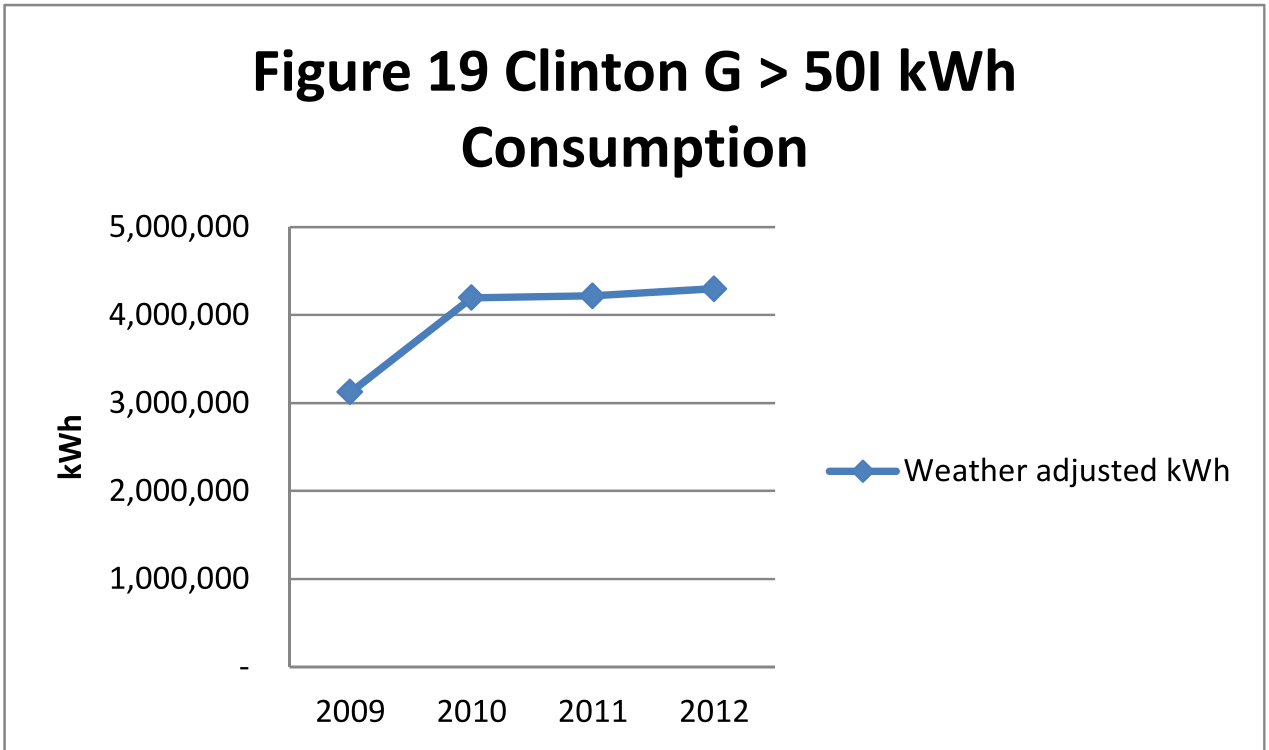


Figure 19 Clinton G > 50I kWh Consumption
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
-
kWh
2009
2010
2011
2012
Weather adjusted kWh

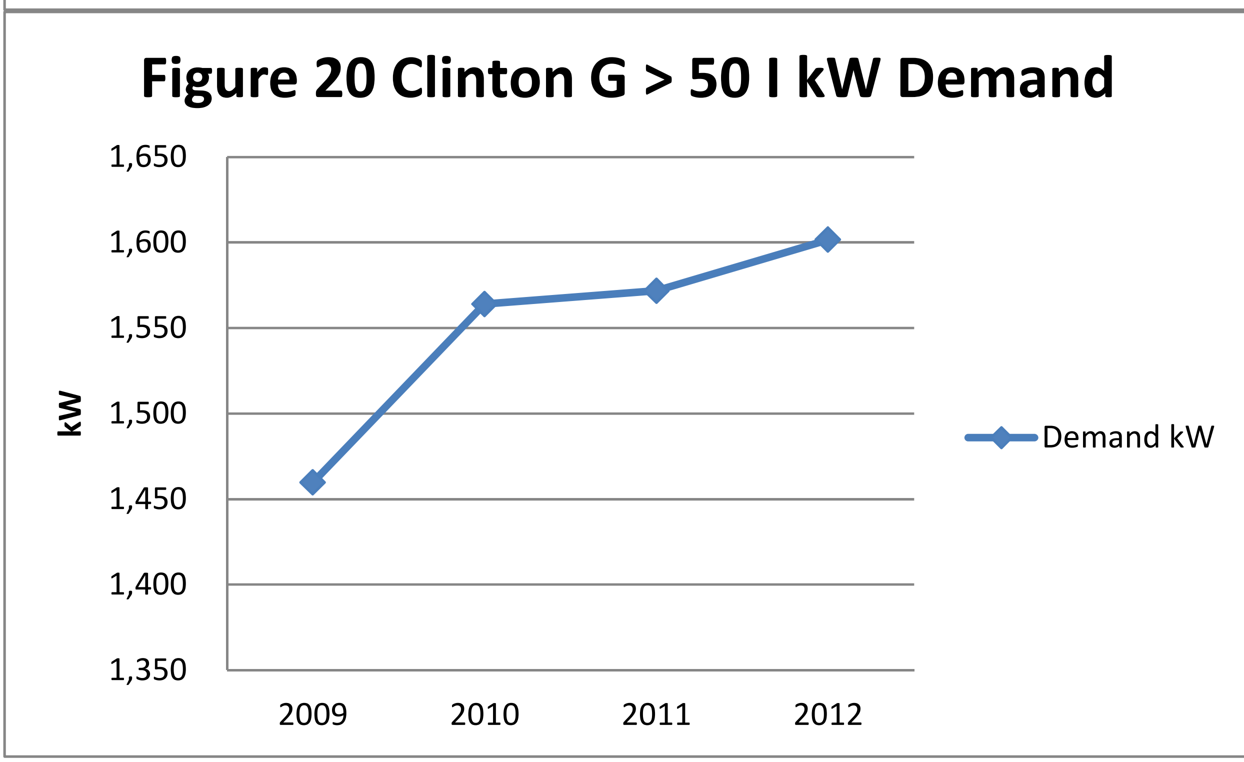


Figure 20 Clinton G > 50 I kW Demand
1,650
1,600
1,550
1,500
1,450
1,400
1,350
kW
2009
2010
2011
2012
Demand kW

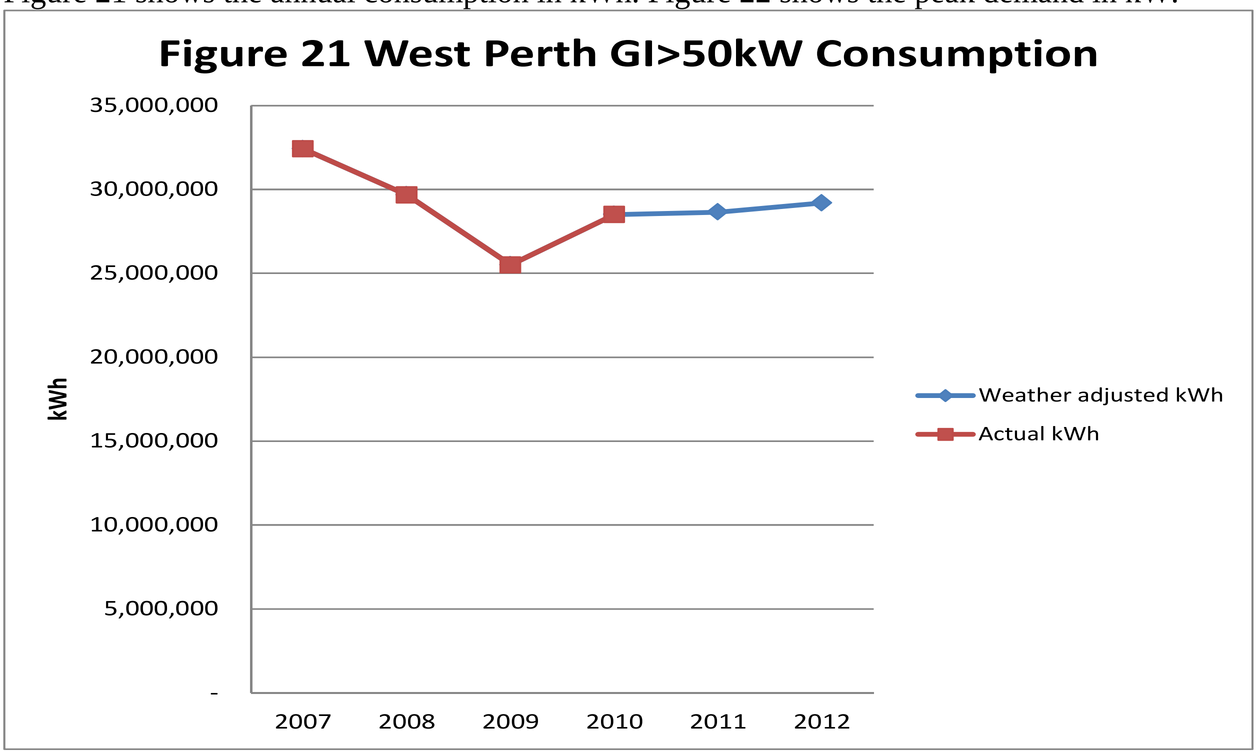
West Perth

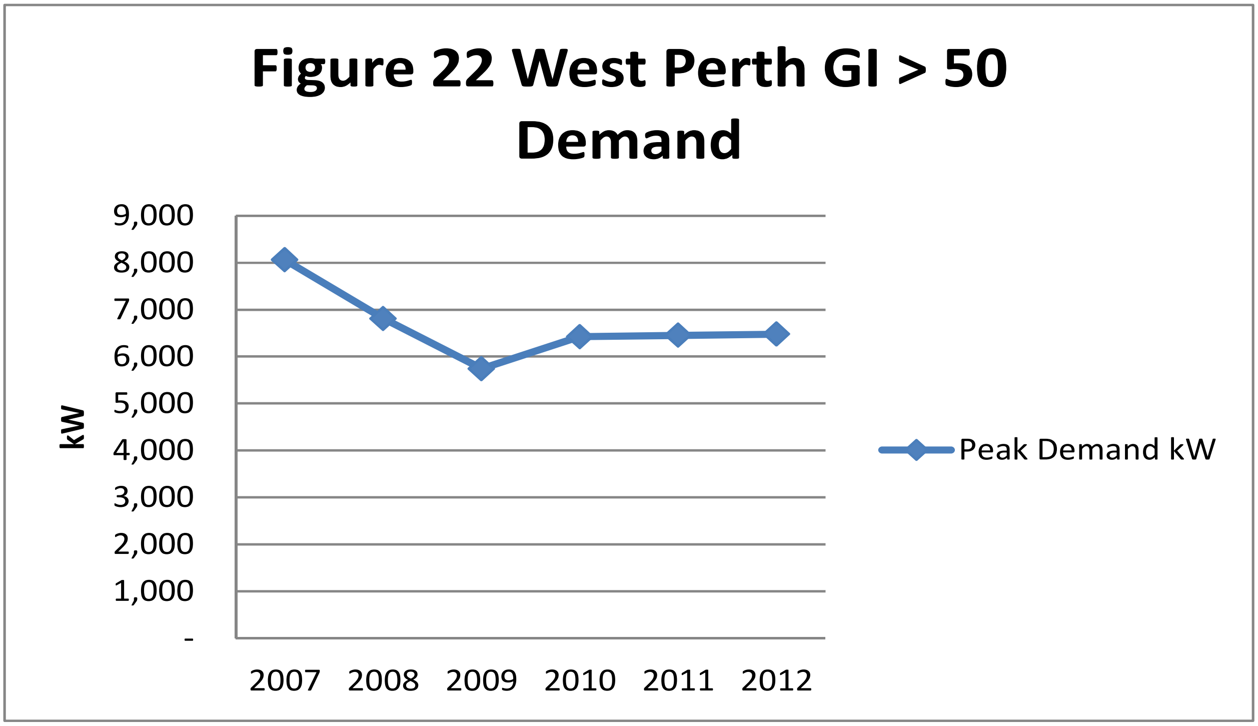
The historical load for General Service greater than 50 kW with interval meters from 2007 to 2010 are shown in Table 19 below. The 2011 and 2012 values are the forecast figures. The annual growth rate for 2011 and 2012 are 0.5% and 1.9% respectively. These values are based on the IESO's 18 month outlook (May 24 2011) for the Ontario Energy Growth forecast.

Table 19 West Perth General Services > 50 kW with Interval Meters

	2007	2008	2009	2010	2011	2012
Weather adjusted kWh	32,417,245	29,676,581	25,501,428	28,502,900	28,645,415	29189678
Actual kWh	32,417,245	29,676,581	25,501,428	28,502,900		
Annual Peak	8,056	6,811	5,739	6,420	6,452	6,477
# of GI>50kW customers	5	5	5	5		
kWh/customer/month	540,287	494,610	425,024	475,048		
kWh/customer/month growth		-8.5%	-14.1%	11.8%		
IESO 18 month outlook (May 2011)					0.50%	1.90%

Figure 21 shows the annual consumption in kWh. Figure 22 shows the peak demand in kW.





Consolidated (GI > 50)

This consolidated classs only consist of Clinton and West Perth. The 2010 cosolidated load of the General Services > 50 kW with interval meters class was calculated by summing the General Services >50 kW with interval meters loads of Clinton and West Perth together. Table 20 shows the 2010 consolidated load. The 2010 annual kWh for this class was 32,698,642. The non-coincident peak was 7,435 kW. The annual coincident peak was 4,566kW.

Table 20 – 2010 consolidated load of General Service > 50 kW with interval meters

2010	kWh	Average kW	Non-coincident Peak kW	% of Annual Peak	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	2,431,068	3,906	6,386	7.7%	61%	1/4/2010	18	3,703	58%
Feb	2,357,470	4,194	6,372	7.7%	66%	2/9/2010	19	4,079	64%
Mar	2,646,756	4,259	6,277	7.6%	68%	3/26/2010	8	5,250	84%
Apr	2,531,217	4,210	6,415	7.7%	66%	4/9/2010	9	5,614	88%
May	2,685,723	4,310	6,840	8.2%	63%	5/31/2010	13	4,416	65%
Jun	2,841,988	4,706	6,989	8.4%	67%	6/23/2010	17	5,175	74%
Jul	3,005,148	4,812	7,353	8.9%	65%	7/28/2010	14	6,555	89%
Aug	3,036,121	4,866	7,339	8.8%	66%	8/12/2010	14	6,507	89%
Sep	2,883,543	4,775	7,413	8.9%	64%	9/1/2010	16	6,136	83%
Oct	3,015,104	4,763	7,435	9.0%	64%	10/13/2010	19	5,975	80%
Nov	2,759,925	4,531	7,265	8.8%	62%	11/29/2010	18	4,297	59%
Dec	2,504,579	3,982	6,865	8.3%	58%	12/13/2010	18	4,566	67%
Annual	32,698,642		82,948		50%	12/13/2010	18	4,566	67%

The 2012 forecast of the consolidated General Service >50 kW with interval meters class is shown in Table 21 below. The forecast annual kWh is 33,395,845. The forecast non-coincident peak is 7,583 kW. The forecast coincident peak is 4,663 kW assuming the total system peak occurs in Decemebr.

Table 21 - 2012 consolidated load of General Service > 50 kW with interval meters

2012	Sum kWh	Average kW	Non-coincident Peak kW	% of Annual Peak	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	2,484,096	3,994	6,523	7.7%	61%	1/4/2010	18	3,780	58%
Feb	2,408,929	4,289	6,512	7.7%	66%	2/9/2010	19	4,165	64%
Mar	2,704,928	4,355	6,416	7.6%	68%	3/26/2010	8	5,367	84%
Apr	2,586,989	4,306	6,557	7.7%	66%	4/9/2010	9	5,740	88%
May	2,743,938	4,407	6,988	8.2%	63%	5/31/2010	13	4,510	65%
Jun	2,903,085	4,811	7,142	8.4%	67%	6/23/2010	17	5,287	74%
Jul	3,069,454	4,918	7,508	8.9%	66%	7/28/2010	14	6,692	89%
Aug	3,101,465	4,975	7,496	8.8%	66%	8/12/2010	14	6,649	89%
Sep	2,945,550	4,881	7,567	8.9%	65%	9/1/2010	16	6,273	83%
Oct	3,074,872	4,862	7,583	9.0%	64%	10/13/2010	19	6,093	80%
Nov	2,816,440	4,627	7,408	8.7%	62%	11/29/2010	18	4,386	59%
Dec	2,556,099	4,067	7,010	8.3%	58%	12/13/2010	18	4,663	67%
Annual	33,395,845		84,710		50%	12/13/2010	18	4,663	67%

6. General Service (1000 kW to 4999 kW)

6.1 GS > 1000

Erie Thames

The historical load for General Service greater than 1000 kW from 2009 to 2011 are shown in Table 22 below. The 2012 value is the forecast figure.

Table 22 - General Service Load greater than 1000 kW

	2009	2010	2011	2012
kWh	56,110,476	57,741,953	57,847,516	59,000,000
kW	93,651	93,487	96,073	96,900

Figure 23 shows the annual consumption in kWh. Figure 24 shows the peak demand in kW.

Figure 23 Erie Thames GS > 1000 kWh

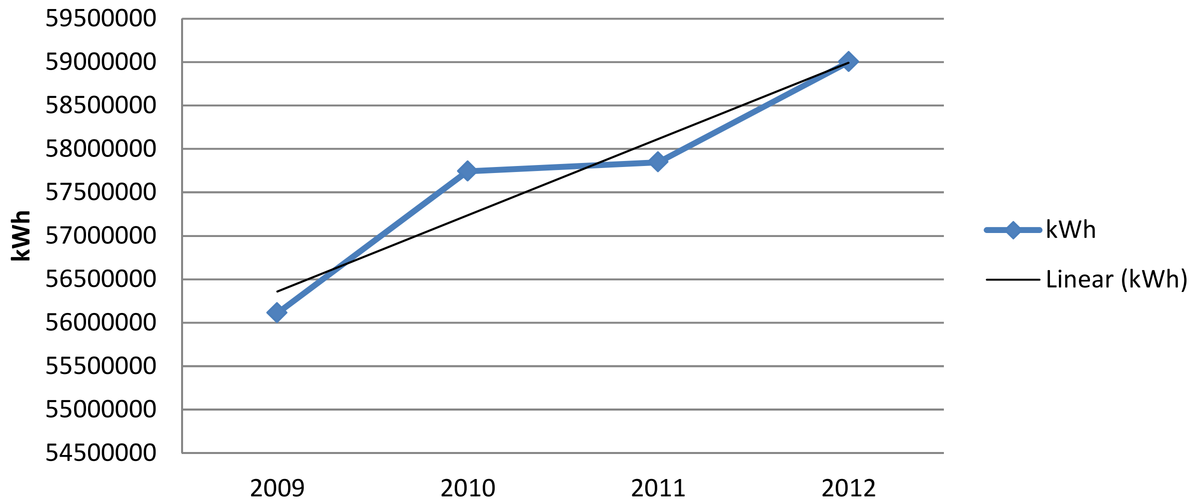
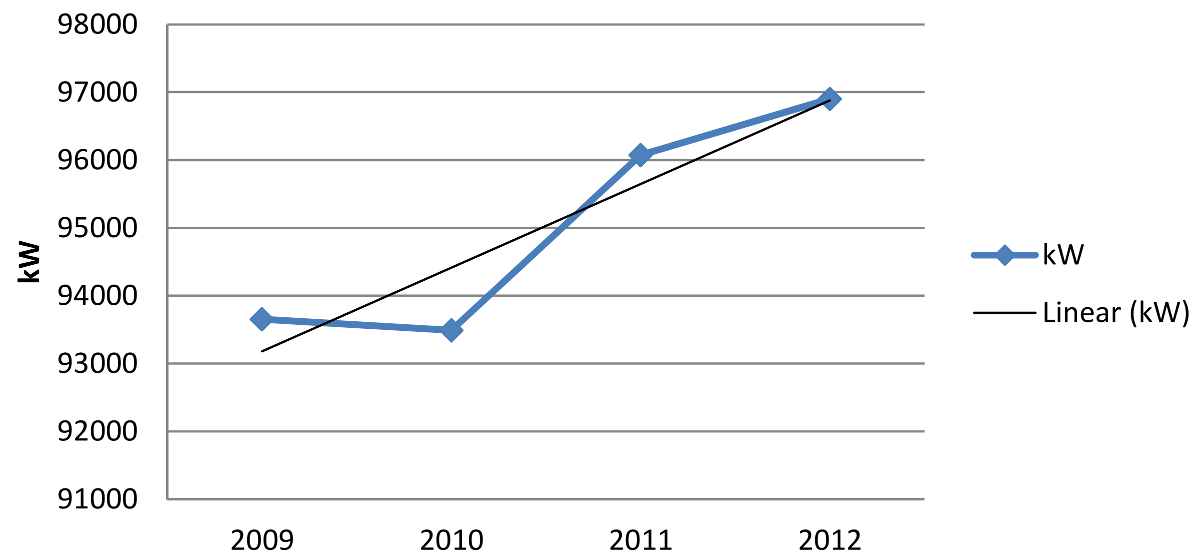


Figure 24 Erie Thames GS > 1000 kW



Consolidated General Services Greter than 1,000 kW

This consolidated class only consist of load from the Erie Thames. Table 23 shows the 2010 consolidated load. The 2010 annual kWh for this class was 57,741,953. The sum of non-coincident peaks was 93,487 kW. The maximum non-coincident peak was 9,239 kW. The annual coincident peak was 6,033 kW.

Table 23 – 2010 consolidated load of General Service > 1,000 kW

2010	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	4,586,792	6,165	7,135	86%	1/4/2010	18	6,270	87.9%
Feb	4,061,569	6,044	6,886	88%	2/9/2010	19	6,343	92.1%
Mar	4,525,423	6,083	7,193	85%	3/26/2010	8	5,731	79.7%
Apr	4,520,828	6,279	7,267	86%	4/9/2010	9	5,940	81.7%
May	4,865,016	6,539	7,583	86%	5/31/2010	13	7,041	92.9%
Jun	5,040,775	7,001	8,467	83%	6/23/2010	17	7,301	86.2%
Jul	5,590,289	7,514	9,048	83%	7/28/2010	14	8,892	98.3%
Aug	5,708,490	7,673	9,239	83%	8/12/2010	14	8,809	95.3%
Sep	5,139,857	7,139	8,814	81%	9/1/2010	16	7,470	84.7%
Oct	4,452,562	5,985	7,294	82%	10/13/2010	19	5,989	82.1%
Nov	4,631,687	6,433	7,358	87%	11/29/2010	18	6,583	89.5%
Dec	4,618,664	6,208	7,204	86%	12/13/2010	18	6,033	83.7%
Annual	57,741,953		93,487	85%	12/13/2010	18	6,033	83.7%

Table 24 shows the 2012 consolidated load. The 2012 annual kWh for this class is 59,000,000. The sum of non-coincident peaks is 96,900 kW. The maximum non-coincident peak is 9,577 kW. The annual coincident peak is 6,253 kW.

Table 24 - 2012 consolidated load of General Service > 1,000 kW

2012	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	4,686,727	6,390	7,395	86%	1/4/2010	18	6,498	87.9%
Feb	4,150,060	6,265	7,137	88%	2/9/2010	19	6,575	92.1%
Mar	4,624,020	6,305	7,455	85%	3/26/2010	8	5,940	79.7%
Apr	4,619,325	6,508	7,532	86%	4/9/2010	9	6,157	81.7%
May	4,971,012	6,778	7,860	86%	5/31/2010	13	7,298	92.9%
Jun	5,150,600	7,257	8,776	83%	6/23/2010	17	7,568	86.2%
Jul	5,712,086	7,788	9,378	83%	7/28/2010	14	9,216	98.3%
Aug	5,832,863	7,953	9,577	83%	8/12/2010	14	9,131	95.3%
Sep	5,251,841	7,399	9,136	81%	9/1/2010	16	7,743	84.7%
Oct	4,549,572	6,203	7,560	82%	10/13/2010	19	6,208	82.1%
Nov	4,732,600	6,668	7,626	87%	11/29/2010	18	6,824	89.5%
Dec	4,719,293	6,434	7,467	86%	12/13/2010	18	6,253	83.7%
Annnual	59,000,000		96,900	83%	12/13/2010	18	6,253	83.7%

6.2 General Service Greater than 3000 kW

GS >3000

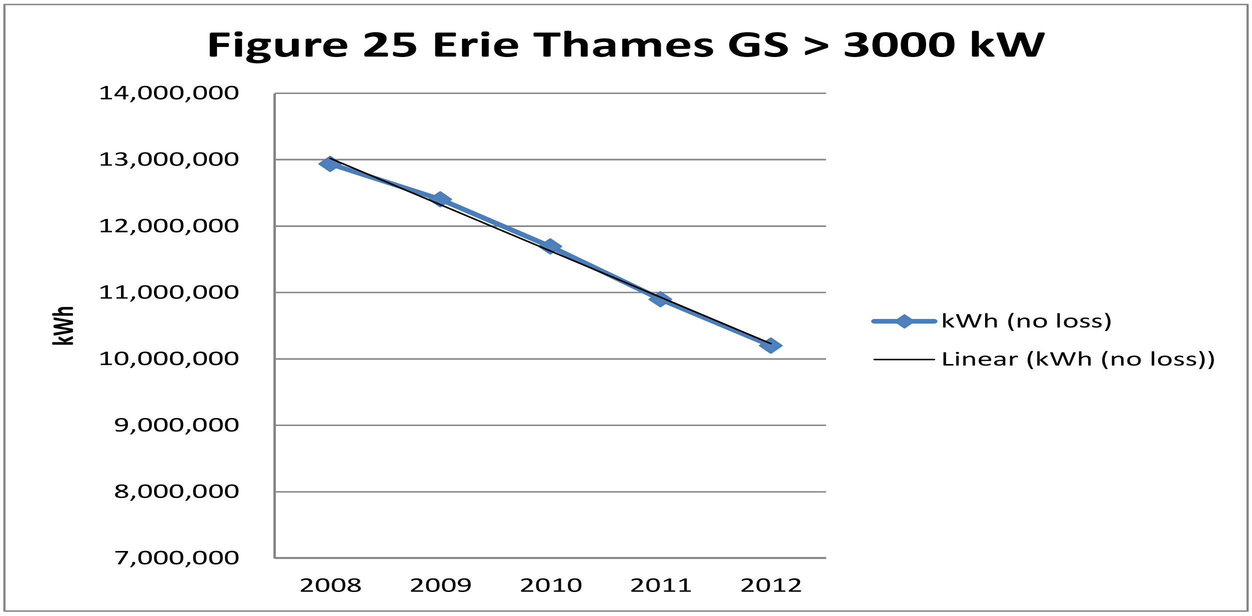
Erie Thames

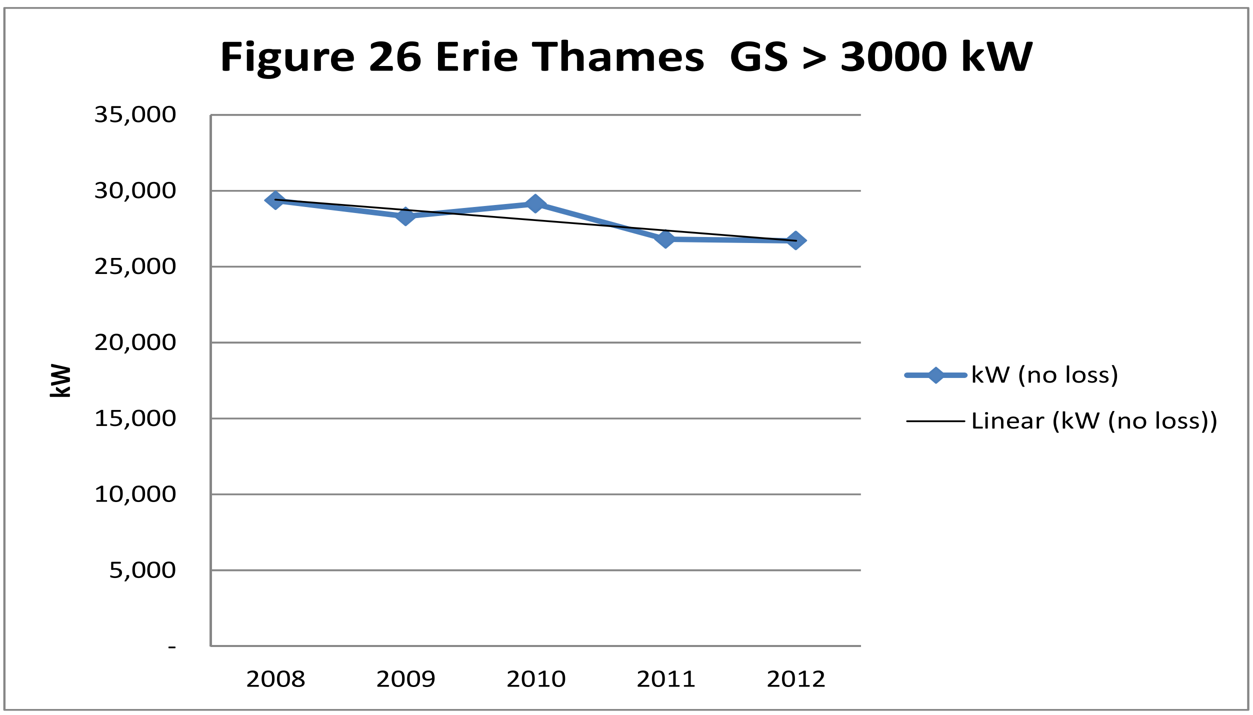
The historical load for General Service greater than 3000 kW from 2008 to 2011 are shown in Table 23 below. The 2012 values are the forecast figures.

Table 25 – General Service Load greater than 3000 kW

GS > 3000	2008	2009	2010	2011	2012
kWh	12,935,014	12,402,337	11,691,664	10,896,179	10,200,000
kW	29,358	28,302	29,134	26,811	26,704

Figure 25 shows the annual consumption in kWh. Figure 26 shows the peak demand in kW.





Consolidated General Services Greter than 3,000 kW
This consolidated class only consists of the load from Erie Thames. Table 26 shows the 2010 consolidated load. The 2010 annual kWh for this class was 11,691,664. The non-coincident peak was 2,684 kW. The annual coincident peak was 1,758 kW.

Table 26 – 2010 Consolidated General Services Greater than 3,000 kW

2010	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	906,344	1,218	2,255	54%	1/4/2010	18	1,661	73.7%
Feb	838,685	1,248	2,126	59%	2/9/2010	19	1,173	55.2%
Mar	941,638	1,266	2,273	56%	3/26/2010	8	1,886	83.0%
Apr	867,642	1,205	2,436	49%	4/9/2010	9	1,062	43.6%
May	940,499	1,264	2,541	50%	5/31/2010	13	2,019	79.4%
Jun	1,062,808	1,476	2,527	58%	6/23/2010	17	1,602	63.4%
Jul	1,131,011	1,520	2,684	57%	7/28/2010	14	2,627	97.9%
Aug	1,120,375	1,506	2,585	58%	8/12/2010	14	2,479	95.9%
Sep	1,014,965	1,410	2,472	57%	9/1/2010	16	1,668	67.5%
Oct	967,268	1,300	2,430	53%	10/13/2010	19	1,438	59.2%
Nov	968,115	1,345	2,525	53%	11/29/2010	18	1,289	51.0%
Dec	932,314	1,253	2,281	55%	12/13/2010	18	1,758	77.1%
Annual	11,691,664		29,135	55%	12/13/2010	18	1,758	77.1%

Table 27 shows the 2012 consolidated load. The 2012 annual kWh for this class is 10,200,000. The non-coincident peak is 2,460 kW. The annual coincident peak is 1,611 kW.

Table 27 – 2012 Consolidated General Services Greater than 3,000 kW

2012	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	790,710	1,117	2,067	54%	1/4/2010	18	1,523	73.7%
Feb	731,683	1,144	1,949	59%	2/9/2010	19	1,075	55.2%
Mar	821,500	1,160	2,083	56%	3/26/2010	8	1,729	83.0%
Apr	756,945	1,105	2,232	49%	4/9/2010	9	973	43.6%
May	820,507	1,159	2,329	50%	5/31/2010	13	1,850	79.4%
Jun	927,211	1,353	2,316	58%	6/23/2010	17	1,468	63.4%
Jul	986,713	1,393	2,460	57%	7/28/2010	14	2,408	97.9%
Aug	977,433	1,380	2,369	58%	8/12/2010	14	2,272	95.9%
Sep	885,473	1,292	2,266	57%	9/1/2010	16	1,529	67.5%
Oct	843,860	1,192	2,228	53%	10/13/2010	19	1,318	59.2%
Nov	844,599	1,232	2,315	53%	11/29/2010	18	1,181	51.0%
Dec	813,366	1,149	2,091	55%	12/13/2010	18	1,611	77.1%
Annual	10,200,000		26,704	52%	12/13/2010	18	1,611	77.1%

6.3 General Services between 1,000 kW and 4,999 kW

The 2010 cosolidated load of the GS class between 1,000 kW and 4,999 kW was calculated by summing the General Services >1000 kW and General Sevices > 3000 kW loads of Erie Thames together. Table 28 shows the 2010 consolidated load. The 2010 annual kWh for this class was 69,433,617. The non-coincident peak was 11,519 kW. Since Erie Thames's total system peak occurred in Decmeber, the annual coincident peak was 7,791 kW.

Table 28 -2010 Consolidated General Services between 1,000 kW and 4,999 kW

2010	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	5,493,137	7,383	8,967	82%	1/4/2010	18	7,931	88.4%
Feb	4,900,254	7,292	8,501	86%	2/9/2010	19	7,516	88.4%
Mar	5,467,061	7,348	8,889	83%	3/26/2010	8	7,617	85.7%
Apr	5,388,470	7,484	8,954	84%	4/9/2010	9	7,002	78.2%
May	5,805,515	7,803	9,790	80%	5/31/2010	13	9,060	92.5%
Jun	6,103,583	8,477	10,802	78%	6/23/2010	17	8,903	82.4%
Jul	6,721,300	9,034	11,519	78%	7/28/2010	14	11,519	100.0%
Aug	6,828,865	9,179	11,374	81%	8/12/2010	14	11,288	99.2%
Sep	6,154,823	8,548	11,204	76%	9/1/2010	16	9,138	81.6%
Oct	5,419,830	7,285	9,550	76%	10/13/2010	19	7,427	77.8%
Nov	5,599,802	7,778	9,489	82%	11/29/2010	18	7,872	83.0%
Dec	5,550,978	7,461	9,164	81%	12/13/2010	18	7,791	85.0%
Annual	69,433,617		118,201	80%	12/13/2010	18	7,791	85.0%

Table 29 shows the 2012 consolidated load forecast. The 2012 annual kWh for this class is 69,200,000. The non-coincident peak is 11,945 kW. The annual coincident peak is 8,147 kW.

Table 29 -2012 Consolidated General Services between 1,000 kW and 4,999 kW

2012	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	5,477,436	7,507	9,462	79%	1/4/2010	18	8,293	87.6%
Feb	4,881,743	7,409	9,086	82%	2/9/2010	19	7,860	86.5%
Mar	5,445,520	7,465	9,538	78%	3/26/2010	8	7,965	83.5%
Apr	5,376,271	7,613	9,764	78%	4/9/2010	9	7,322	75.0%
May	5,791,519	7,936	10,189	78%	5/31/2010	13	9,474	93.0%
Jun	6,077,812	8,610	11,092	78%	6/23/2010	17	9,310	83.9%
Jul	6,698,799	9,181	11,839	78%	7/28/2010	14	12,045	101.7%
Aug	6,810,297	9,333	11,945	78%	8/12/2010	14	11,804	98.8%
Sep	6,137,314	8,691	11,402	76%	9/1/2010	16	9,556	83.8%
Oct	5,393,432	7,395	9,788	76%	10/13/2010	19	7,767	79.4%
Nov	5,577,199	7,900	9,941	79%	11/29/2010	18	8,232	82.8%
Dec	5,532,658	7,583	9,558	79%	12/13/2010	18	8,147	85.2%
Annual	69,200,000		123,604	77%	12/13/2010	18	8,147	85.2%

7. Large Use (ETPC)

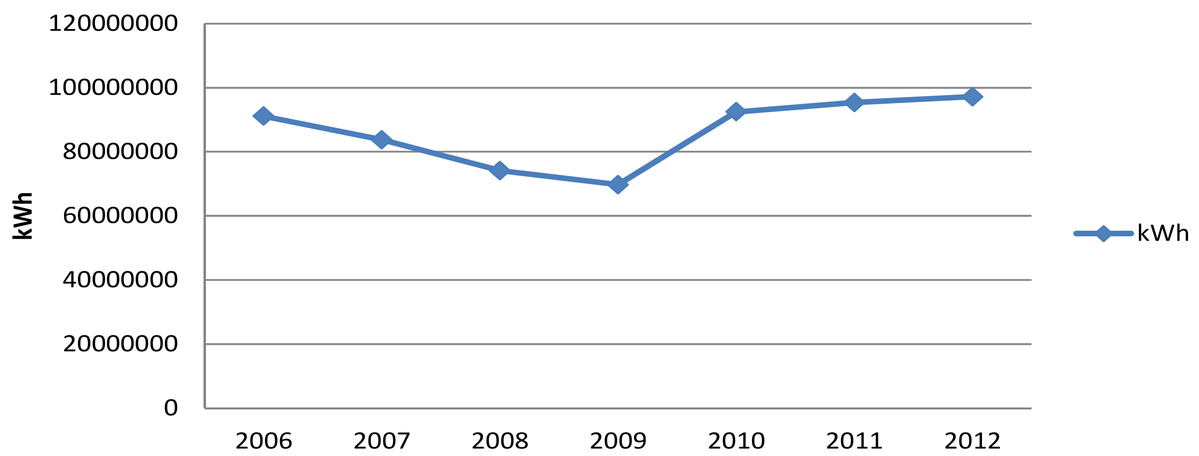
The Large Use class consists of only accounts from Erie Thames. The historical load for the Large Use class with demand greater than 5,000 kW from 2006 to 2012 is shown in Table 30 below. The 2011 and 2012 values are the forecast values.

Table 30 - Large Use Annual kWh and Demand in kW

	2006	2007	2008	2009	2010	2011	2012
kWh	91,130,718	83,755,976	74,125,314	69,719,263	92,434,591	95,335,410	97,146,783
% change kWh		-8.1%	-11.5%	-5.9%	32.6%	3.1%	1.9%
kW	14,168	14,197	13,137	12,625	13,538	13,963	14,228
LF	73.4%	67.3%	64.4%	63.0%	77.9%	77.9%	77.9%

Figure 27 shows the annual consumption in kWh. Figure 28 shows the annual peak in kW.

Figure 27 Large Use Annual Consumption



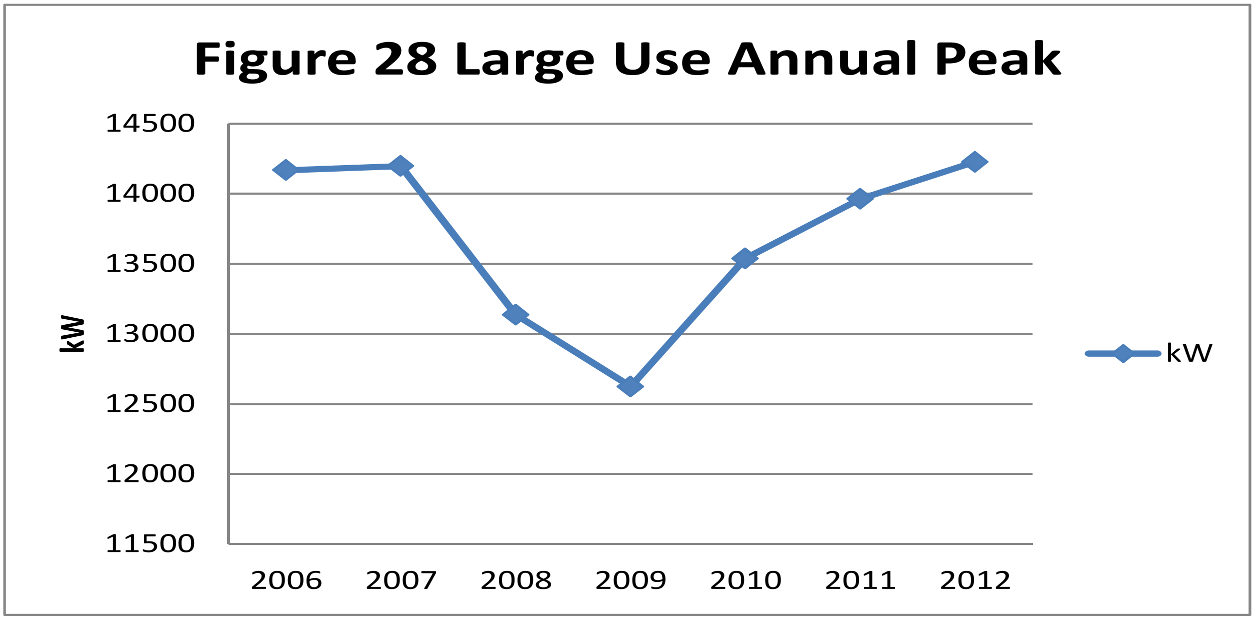


Table 31 shows the 2010 Large Use load. The 2010 annual kWh for this class was 92,434,594. The non-coincident peak was 13,567 kW. The annual coincident peak was 12,589 kW.

Table 31 – 2010 Large Use Load greater than 5,000 kW

2010 with losses	Monthly kWh	Average k	Non-coincident Peak kW	LF	Date of System Peak	Hr	kW	Coincident Factor
Jan	7,545,265	10,141	12,133	84%	1/4/2010	18	11,520	94.9%
Feb	7,292,112	10,851	12,009	90%	2/9/2010	19	11,659	97.1%
Mar	7,997,185	10,749	11,953	90%	3/26/2010	8	11,752	98.3%
Apr	7,105,484	9,869	11,658	85%	4/9/2010	9	10,847	93.0%
May	7,554,135	10,153	12,418	82%	5/31/2010	13	12,224	98.4%
Jun	8,093,475	11,241	12,530	90%	6/23/2010	17	12,045	96.1%
Jul	6,781,589	9,115	13,304	69%	7/28/2010	14	12,704	95.5%
Aug	8,639,053	11,612	13,567	86%	8/12/2010	14	13,384	98.7%
Sep	7,832,387	10,878	13,492	81%	9/1/2010	16	12,638	93.7%
Oct	7,944,964	10,679	13,224	81%	10/13/2010	19	11,391	86.1%
Nov	8,334,409	11,576	13,187	88%	11/29/2010	18	12,315	93.4%
Dec	7,314,536	9,831	13,229	74%	12/13/2010	18	12,589	95.2%
Annual	92,434,594		152,704	78%	12/13/2010	18	12,589	95.2%

Table 32 shows the 2012 Large Use load forecast. The 2012 annual kWh for this class is 97,146,783. The non-coincident peak is 14,228 kW. The annual coincident peak in December is 13,202 kW.

Table 32 – 2012 Large Use Load greater than 5,000 kW

2012 Forecast	Monthly kWh	Average k	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	7,929,912	10,636	12,725	84%	1/4/2010	18	12,081	94.9%
Feb	7,663,853	11,380	12,595	91%	2/9/2010	19	12,228	97.1%
Mar	8,404,871	11,273	12,536	90%	3/26/2010	8	12,325	98.3%
Apr	7,467,712	10,350	12,226	85%	4/9/2010	9	11,376	93.0%
May	7,939,234	10,648	13,023	82%	5/31/2010	13	12,820	98.4%
Jun	8,506,069	11,789	13,141	90%	6/23/2010	17	12,632	96.1%
Jul	7,127,305	9,559	13,953	69%	7/28/2010	14	13,323	95.5%
Aug	9,079,461	12,177	14,228	86%	8/12/2010	14	14,036	98.7%
Sep	8,231,672	11,408	14,149	81%	9/1/2010	16	13,254	93.7%
Oct	8,349,987	11,199	13,868	81%	10/13/2010	19	11,947	86.1%
Nov	8,759,286	12,140	13,830	88%	11/29/2010	18	12,915	93.4%
Dec	7,687,421	10,310	13,873	74%	12/13/2010	18	13,202	95.2%
Annual	97,146,783		160,146	78%	12/13/2010	18	13,202	95.2%

8. Street Light

Clinton

The 2010 Street Light Load was 372,098 kWh. The non coincident peak was 85 kW. The coincident peak was 85 kW.

Table 33 – Clinton 2010 Street Light Loading

2010	Sum kWh	Average k	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	39,071	53	84	63%	1/4/2010	18	84	100.0%
Feb	32,349	48	84	57%	2/9/2010	19	84	100.0%
Mar	32,559	44	84	52%	3/26/2010	8	-	0.0%
Apr	27,728	39	84	46%	4/9/2010	12	-	0.0%
May	25,396	34	84	41%	5/27/2010	17	-	0.0%
Jun	22,686	32	84	38%	6/23/2010	17	-	0.0%
Jul	24,094	32	84	39%	7/28/2010	15	-	0.0%
Aug	27,350	37	84	44%	8/12/2010	14	-	0.0%
Sep	29,618	41	84	49%	9/1/2010	16	-	0.0%
Oct	34,513	46	84	55%	10/13/2010	19	42	50.0%
Nov	36,771	51	85	60%	11/29/2010	18	85	100.0%
Dec	39,962	54	85	64%	12/13/2010	19	85	100.0%
Annual	372,098		1,009	51%	12/13/2010	19	85	100.0%

The 2012 Street Light forecast is shown in Table 34 below. The forecast annual consumption is 372,098 kWh. The non coincident peak is 85 kW. The coincident peak was 85 kW.

Table 34 - Clinton 2012 Street Light Load Forecast

2012	Sum kWh	Average k	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	39,071	53	84	63%	1/4/2010	18	84	100.0%
Feb	32,349	48	84	57%	2/9/2010	19	84	100.0%
Mar	32,559	44	84	52%	3/26/2010	8	-	0.0%
Apr	27,728	39	84	46%	4/9/2010	12	-	0.0%
May	25,396	34	84	41%	5/27/2010	17	-	0.0%
Jun	22,686	32	84	38%	6/23/2010	17	-	0.0%
Jul	24,094	32	84	39%	7/28/2010	15	-	0.0%
Aug	27,350	37	84	44%	8/12/2010	14	-	0.0%
Sep	29,618	41	84	49%	9/1/2010	16	-	0.0%
Oct	34,513	46	84	55%	10/13/2010	19	42	50.0%
Nov	36,771	51	85	60%	11/29/2010	18	85	100.0%
Dec	39,962	54	85	64%	12/13/2010	19	85	100.0%
Annual	372,098		1,009	51%	12/13/2010	19	85	100.0%

West Perth

The 2010 Street Light load is shown in Table 35. The 2010 Street Light Load was 442,973 kWh. The non coincident peak was 101 kW. The coincident peak was 101 kW.

Table 35 – West Perth 2010 Street Light Loading

2010	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	46,513	63	100	63%	1/4/2010	18	100	100.0%
Feb	38,511	57	100	57%	2/9/2010	19	100	100.0%
Mar	38,761	52	100	52%	3/26/2010	8	-	0.0%
Apr	33,009	46	100	46%	4/9/2010	12	-	0.0%
May	30,234	41	100	41%	5/27/2010	17	-	0.0%
Jun	27,008	38	100	38%	6/23/2010	17	-	0.0%
Jul	28,683	39	100	39%	7/28/2010	15	-	0.0%
Aug	32,559	44	100	44%	8/12/2010	14	-	0.0%
Sep	35,260	49	100	49%	9/1/2010	16	-	0.0%
Oct	41,087	55	100	55%	10/13/2010	19	50	50.0%
Nov	43,775	61	101	60%	11/29/2010	18	101	100.0%
Dec	47,574	64	101	64%	12/13/2010	19	101	100.0%
Annual	442,973		1,202	51%	12/13/2010	19	101	100.0%

The 2012 Street Light forecast is shown in Table 36 below. The forecast annual consumption is 442,973 kWh. The non coincident peak is 101 kW. The coincident peak is 101 kW.

Table 36 – West Perth 2012 Street Light Load Forecast

2012	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	46,513	63	100	63%	1/4/2010	18	100	100.0%
Feb	38,511	57	100	57%	2/9/2010	19	100	100.0%
Mar	38,761	52	100	52%	3/26/2010	8	-	0.0%
Apr	33,009	46	100	46%	4/9/2010	12	-	0.0%
May	30,234	41	100	41%	5/27/2010	17	-	0.0%
Jun	27,008	38	100	38%	6/23/2010	17	-	0.0%
Jul	28,683	39	100	39%	7/28/2010	15	-	0.0%
Aug	32,559	44	100	44%	8/12/2010	14	-	0.0%
Sep	35,260	49	100	49%	9/1/2010	16	-	0.0%
Oct	41,087	55	100	55%	10/13/2010	19	50	50.0%
Nov	43,775	61	101	60%	11/29/2010	18	101	100.0%
Dec	47,574	64	101	64%	12/13/2010	19	101	100.0%
Annual	442,973		1,202	51%	12/13/2010	19	101	100.0%

Erie Thames

The 2010 Street Light load is shown in Table 37. The 2010 Street Light Load was 3,149,541 kWh. The non coincident peak was 716 kW. The coincident peak was 716 kW.

Table 37 – Erie Thames 2010 Street Light Loading

2010	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	330,708	445	711	63%	1/4/2010	18	711	100.0%
Feb	273,812	407	711	57%	2/9/2010	19	711	100.0%
Mar	275,590	370	711	52%	3/26/2010	8	0	0.0%
Apr	234,696	326	711	46%	4/9/2010	9	0	0.0%
May	214,960	289	711	41%	5/31/2010	13	0	0.0%
Jun	192,024	267	711	38%	6/23/2010	17	0	0.0%
Jul	203,937	274	711	39%	7/28/2010	14	0	0.0%
Aug	231,496	311	711	44%	8/12/2010	14	0	0.0%
Sep	250,698	348	711	49%	9/1/2010	16	0	0.0%
Oct	292,125	393	711	55%	10/13/2010	19	356	50.0%
Nov	311,243	432	716	60%	11/29/2010	18	716	100.0%
Dec	338,253	455	716	64%	12/13/2010	18	716	100.0%
Annual	3,149,541		8,543	51%	12/13/2010	18	716	100.0%

The 2012 Street Light forecast is shown in Table 38 below. The forecast annual consumption is 3,955,964 kWh. The non coincident peak is 899 kW. The coincident peak is 899 kW.

Table 38 - Erie Thames 2012 Street Light Load Forecast

2012	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	415,384	1,226	893	137%	1/4/2010	18	893	100.0%
Feb	343,920	1,253	893	140%	2/9/2010	19	893	100.0%
Mar	346,153	1,246	893	139%	3/26/2010	8	-	0.0%
Apr	294,789	1,196	893	134%	4/9/2010	12	-	0.0%
May	270,000	1,404	893	157%	5/27/2010	17	-	0.0%
Jun	241,191	1,504	893	168%	6/23/2010	17	-	0.0%
Jul	256,153	1,512	893	169%	7/28/2010	15	-	0.0%
Aug	290,769	1,452	893	163%	8/12/2010	14	-	0.0%
Sep	314,888	1,322	893	148%	9/1/2010	16	-	0.0%
Oct	366,923	1,389	893	155%	10/13/2010	19	447	50.0%
Nov	390,935	1,337	899	149%	11/29/2010	18	899	100.0%
Dec	424,860	1,104	899	123%	12/13/2010	19	899	100.0%
Annual	3,955,964		10,730	51%	12/13/2010	19	899	100.0%

Consolidated Street Light

The 2010 consolidated Street Light load is shown in Table 39. The 2010 Street Light Load was 3,964,612 kWh. The non coincident peak was 901 kW. The coincident peak was 901 kW. The 2012 Street Light forecast is shown in Table 40. The forecast annual consumption is 4,979,730 kWh. The non coincident peak is 1,131 kW. The coincident peak is 1,131 kW.

Table 39 – 2010 Consolidated Street Light Loading

2010	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	416,292	560	895	63%	1/4/2010	18	895	100.0%
Feb	344,672	513	895	57%	2/9/2010	19	895	100.0%
Mar	346,910	466	895	52%	3/26/2010	8	0	0.0%
Apr	295,433	410	895	46%	4/9/2010	9	0	0.0%
May	270,590	364	895	41%	5/31/2010	13	0	0.0%
Jun	241,718	336	895	38%	6/23/2010	17	0	0.0%
Jul	256,713	345	895	39%	7/28/2010	14	0	0.0%
Aug	291,404	392	895	44%	8/12/2010	14	0	0.0%
Sep	315,576	438	895	49%	9/1/2010	16	0	0.0%
Oct	367,725	494	895	55%	10/13/2010	19	448	50.0%
Nov	391,789	544	901	60%	11/29/2010	18	901	100.0%
Dec	425,789	572	901	64%	12/13/2010	18	901	100.0%
Annual	3,964,612		10,754	51%	12/13/2010	18	901	100.0%

Table 40 – 2012 Consolidated Street Light Load Forecast

2012	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	522,881	1,226	1,124	109%	1/4/2010	18	1,124	100.0%
Feb	432,923	1,253	1,124	111%	2/9/2010	19	1,124	100.0%
Mar	435,735	1,246	1,124	111%	3/26/2010	8	-	0.0%
Apr	371,077	1,196	1,124	106%	4/9/2010	12	-	0.0%
May	339,873	1,404	1,124	125%	5/27/2010	17	-	0.0%
Jun	303,609	1,504	1,124	134%	6/23/2010	17	-	0.0%
Jul	322,444	1,512	1,124	134%	7/28/2010	15	-	0.0%
Aug	366,017	1,452	1,124	129%	8/12/2010	14	-	0.0%
Sep	396,378	1,322	1,124	118%	9/1/2010	16	-	0.0%
Oct	461,879	1,389	1,124	124%	10/13/2010	19	562	50.0%
Nov	492,105	1,337	1,131	118%	11/29/2010	18	1,131	100.0%
Dec	534,810	1,104	1,131	98%	12/13/2010	19	1,131	100.0%
Annual	4,979,730		13,507	51%	12/13/2010	19	1,131	100.0%

9. Sentinel Light

Clinton

The 2010 Sentinel Light load is shown in Table 41. The 2010 load was 44,498 kWh. The non coincident peak was 10 kW. The coincident peak was 10 kW. The 2012 Sentinel Light forecast is shown in Table 42. The forecast annual consumption is 44,498 kWh. The non coincident peak is 10 kW. The coincident peak is 10 kW.

Table 41 – Clinton 2010 Sentinel Light Loading

2010	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	4,672	6	10	62%	1/4/2010	18	10	100.0%
Feb	3,869	6	10	57%	2/9/2010	19	10	100.0%
Mar	3,894	5	10	52%	3/26/2010	8	0	0.0%
Apr	3,316	5	10	46%	4/9/2010	9	0	0.0%
May	3,037	4	10	41%	5/31/2010	13	0	0.0%
Jun	2,713	4	10	38%	6/23/2010	17	0	0.0%
Jul	2,881	4	10	39%	7/28/2010	14	0	0.0%
Aug	3,271	4	10	44%	8/12/2010	14	0	0.0%
Sep	3,542	5	10	49%	9/1/2010	16	0	0.0%
Oct	4,127	6	10	55%	10/13/2010	19	5	50.0%
Nov	4,397	6	10	60%	11/29/2010	18	10	100.0%
Dec	4,779	6	10	64%	12/13/2010	18	10	100.0%
Annual	44,498		121	51%	12/13/2010	18	10	100.0%

Table 42 – Clinton 2012 Sentinel Light Load Forecast

2012	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	4,672	1,226	10	12203%	1/4/2010	18	10	100.0%
Feb	3,869	1,253	10	12470%	2/9/2010	19	10	100.0%
Mar	3,894	1,246	10	12396%	3/26/2010	8	-	0.0%
Apr	3,316	1,196	10	11903%	4/9/2010	9	-	0.0%
May	3,037	1,404	10	13969%	5/31/2010	13	-	0.0%
Jun	2,713	1,504	10	14970%	6/23/2010	17	-	0.0%
Jul	2,881	1,512	10	15045%	7/28/2010	14	-	0.0%
Aug	3,271	1,452	10	14455%	8/12/2010	14	-	0.0%
Sep	3,542	1,322	10	13152%	9/1/2010	16	-	0.0%
Oct	4,127	1,389	10	13823%	10/13/2010	19	5	50.0%
Nov	4,397	1,337	10	13230%	11/29/2010	18	10	100.0%
Dec	4,779	1,104	10	10925%	12/13/2010	18	10	100.0%
Annual	44,498		121	51%	12/13/2010	18	10	100.0%

West Perth

The 2010 Sentinel Light load is shown in Table 43. The 2010 load was 17,799 kWh. The non coincident peak was 4 kW. The coincident peak was 4 kW. The 2012 Sentinel Light forecast is shown in Table 44. The forecast annual consumption is 17,799 kWh. The non coincident peak is 4 kW. The coincident peak is 4 kW.

Table 43 – West Perth 2010 Sentinel Light Loading

2010	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	1,869	3	4	63%	1/4/2010	18	4	100.0%
Feb	1,547	2	4	57%	2/9/2010	19	4	100.0%
Mar	1,557	2	4	52%	3/26/2010	8	0	0.0%
Apr	1,326	2	4	46%	4/9/2010	9	0	0.0%
May	1,215	2	4	41%	5/31/2010	13	0	0.0%
Jun	1,085	2	4	38%	6/23/2010	17	0	0.0%
Jul	1,153	2	4	39%	7/28/2010	14	0	0.0%
Aug	1,308	2	4	44%	8/12/2010	14	0	0.0%
Sep	1,417	2	4	49%	9/1/2010	16	0	0.0%
Oct	1,651	2	4	55%	10/13/2010	19	2	50.0%
Nov	1,759	2	4	60%	11/29/2010	18	4	100.0%
Dec	1,912	3	4	64%	12/13/2010	18	4	100.0%
Annual	17,799		48	51%	12/13/2010	18	4	100.0%

Table 44 – West Perth 2012 Sentinel Light Load Forecast

2012	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	1,869	1,226	4	30508%	1/4/2010	18	4	100.0%
Feb	1,547	1,253	4	31176%	2/9/2010	19	4	100.0%
Mar	1,557	1,246	4	30990%	3/26/2010	8	-	0.0%
Apr	1,326	1,196	4	29758%	4/9/2010	9	-	0.0%
May	1,215	1,404	4	34924%	5/31/2010	13	-	0.0%
Jun	1,085	1,504	4	37425%	6/23/2010	17	-	0.0%
Jul	1,153	1,512	4	37613%	7/28/2010	14	-	0.0%
Aug	1,308	1,452	4	36138%	8/12/2010	14	-	0.0%
Sep	1,417	1,322	4	32881%	9/1/2010	16	-	0.0%
Oct	1,651	1,389	4	34557%	10/13/2010	19	2	50.0%
Nov	1,759	1,337	4	33075%	11/29/2010	18	4	100.0%
Dec	1,912	1,104	4	27312%	12/13/2010	18	4	100.0%
Annual	17,799		48	51%	12/13/2010	18	4	100.0%

Erie Thames

The 2010 Sentinel Light load is shown in Table 45. The 2010 load was 222,490 kWh. The non coincident peak was 51 kW. The coincident peak was 51 kW. The 2012 Sentinel Light load forecast is shown in Table 46. The forecast annual consumption is 222,490 kWh. The non coincident peak is 51 kW. The coincident peak is 51 kW.

Table 45 – Erie Thames 2010 Sentinel Light Loading

2010	Sum kWh	Average k	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	23,362	31	50	63%	1/4/2010	18	50	100.0%
Feb	19,343	29	50	57%	2/9/2010	19	50	100.0%
Mar	19,468	26	50	52%	3/26/2010	8	0	0.0%
Apr	16,579	23	50	46%	4/9/2010	9	0	0.0%
May	15,185	20	50	41%	5/31/2010	13	0	0.0%
Jun	13,565	19	50	38%	6/23/2010	17	0	0.0%
Jul	14,406	19	50	39%	7/28/2010	14	0	0.0%
Aug	16,353	22	50	44%	8/12/2010	14	0	0.0%
Sep	17,710	25	50	49%	9/1/2010	16	0	0.0%
Oct	20,636	28	50	55%	10/13/2010	19	25	50.0%
Nov	21,987	31	51	60%	11/29/2010	18	51	100.0%
Dec	23,895	32	51	64%	12/13/2010	18	51	100.0%
Annual	222,490		603	51%	12/13/2010	18	51	100.0%

Table 46 – Erie Thames 2012 Sentinel Light Load Forecast

2012	Sum kWh	Average k	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	23,362	1,226	50	2441%	1/4/2010	18	50	100.0%
Feb	19,343	1,253	50	2494%	2/9/2010	19	50	100.0%
Mar	19,468	1,246	50	2479%	3/26/2010	8	-	0.0%
Apr	16,579	1,196	50	2381%	4/9/2010	9	-	0.0%
May	15,185	1,404	50	2794%	5/31/2010	13	-	0.0%
Jun	13,565	1,504	50	2994%	6/23/2010	17	-	0.0%
Jul	14,406	1,512	50	3009%	7/28/2010	14	-	0.0%
Aug	16,353	1,452	50	2891%	8/12/2010	14	-	0.0%
Sep	17,710	1,322	50	2630%	9/1/2010	16	-	0.0%
Oct	20,636	1,389	50	2765%	10/13/2010	19	25	50.0%
Nov	21,987	1,337	51	2646%	11/29/2010	18	51	100.0%
Dec	23,895	1,104	51	2185%	12/13/2010	18	51	100.0%
Annual	222,490		603	51%	12/13/2010	18	51	100.0%

Consolidated Sentinel Light

The 2010 Consolidated Sentinel Light load is shown in Table 47. The 2010 load was 284,787 kWh. The non coincident peak was 65 kW. The coincident peak was 65 kW. The 2012 Sentinel Light load forecast is shown in Table 48. The forecast annual consumption is 284,787 kWh. The non coincident peak is 65 kW. The coincident peak is 65 kW.

Table 47 – Consolidated 2010 Sentinel Light Loading

2010	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	29,903	40	64	63%	1/4/2010	18	64	100.0%
Feb	24,759	37	64	57%	2/9/2010	19	64	100.0%
Mar	24,919	33	64	52%	3/26/2010	8	0	0.0%
Apr	21,222	29	64	46%	4/9/2010	9	0	0.0%
May	19,437	26	64	41%	5/31/2010	13	0	0.0%
Jun	17,363	24	64	38%	6/23/2010	17	0	0.0%
Jul	18,440	25	64	39%	7/28/2010	14	0	0.0%
Aug	20,932	28	64	44%	8/12/2010	14	0	0.0%
Sep	22,669	31	64	49%	9/1/2010	16	0	0.0%
Oct	26,415	36	64	55%	10/13/2010	19	32	50.0%
Nov	28,143	39	65	60%	11/29/2010	18	65	100.0%
Dec	30,585	41	65	64%	12/13/2010	18	65	100.0%
Annual	284,787		772	51%	12/13/2010	18	65	100.0%

Table 48 – Consolidated 2012 Sentinel Light Load Forecast

2012	Sum kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Coincident Peak kW	Coincident Factor
Jan	29,903	1,226	64	1907%	1/4/2010	18	64	100.0%
Feb	24,759	1,253	64	1949%	2/9/2010	19	64	100.0%
Mar	24,919	1,246	64	1937%	3/26/2010	8	-	0.0%
Apr	21,222	1,196	64	1860%	4/9/2010	12	-	0.0%
May	19,437	1,404	64	2183%	5/27/2010	17	-	0.0%
Jun	17,363	1,504	64	2339%	6/23/2010	17	-	0.0%
Jul	18,440	1,512	64	2351%	7/28/2010	15	-	0.0%
Aug	20,932	1,452	64	2259%	8/12/2010	14	-	0.0%
Sep	22,669	1,322	64	2055%	9/1/2010	16	-	0.0%
Oct	26,415	1,389	64	2160%	10/13/2010	19	32	50.0%
Nov	28,143	1,337	65	2067%	11/29/2010	18	65	100.0%
Dec	30,585	1,104	65	1707%	12/13/2010	19	65	100.0%
Annual	284,787		772	51%	12/13/2010	19	65	100.0%

10. Unmetered Load

The historical and forecast load for the Unmetered Load is shown in Table 49 below. The loads of 2011 and 2012 are forecast values.

Table 49 – Unmetered Load Forecast

	2008		2009		2010		2011		2012	
	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW
Clinton	56,070	13	59,245	14	56,040	13	56,040	13	56,040	13
Erie Thames	500,236	114	538,055	123	533,136	122	535,802	122	545,982	125
West Perth	16,368	4	16,368	4	16,319	4	16,319	4	16,319	4
Consolidated	572,674	131	613,668	140	605,495	138	608,161	139	618,341	141

11. Embedded Distributors

This class of customers only applies to the Erie Thames supply area. It does not apply to Clinton or West Perth.

The historical kWh load for the Embedded Distributors from 2006 to 2010 is shown in Table 50 below. The 2011 and 2012 are forecast values.

Table 50 – Embedded Distributors Annual kWh Forecast

	2006	2007	2008	2009	2010	2011	2012
non-weather adjusted	17,916,584	18,577,150	16,433,707	18,513,267	17,518,323	17,400,000	17,350,000
weather adjusted	17,896,299	18,558,538	16,442,775	18,594,719	17,451,503	17,400,000	17,350,000

The historical kW Demand for the Embedded Distributors from 2006 to 2010 is shown in Table 51 below. The 2011 and 2012 are forecast values.

Table 51 – Embedded Distributors Annual kW Forecast

	2006	2007	2008	2009	2010	2011	2012
non-weather adjusted	4,277	4,434	3,923	4,419	4,182	4,153	4,141
weather adjusted	4,272	4,430	3,925	4,438	4,166	4,153	4,141

Table 52 shows the 2010 Embedded Distributors' load. The 2010 annual energy was 17,518,323 kWh. The non-coincident peak was 4,182 kW. The coincident peak was 3,023 kW.

Table 52 – 2010 Embedded Distributors

2010	kWh	Average kW	Max kW	LF	Date of System Peak	Hr	Co-Incident Peak kW	Coincident Factor
Jan	1,745,171	2,346	3,389	69%	1/4/2010	18	3,010	88.8%
Feb	1,577,594	2,348	3,456	68%	2/9/2010	19	3,353	97.0%
Mar	1,443,971	1,941	3,426	57%	3/26/2010	8	3,176	92.7%
Apr	1,204,940	1,674	2,930	57%	4/9/2010	9	2,074	70.8%
May	1,222,862	1,644	2,657	62%	5/31/2010	13	1,768	66.5%
Jun	1,269,052	1,763	2,690	66%	6/23/2010	17	2,164	80.4%
Jul	1,510,636	2,030	3,276	62%	7/28/2010	14	2,014	61.5%
Aug	1,461,439	1,964	4,182	47%	8/12/2010	14	2,271	54.3%
Sep	1,126,103	1,564	2,564	61%	9/1/2010	16	2,304	89.9%
Oct	1,736,798	2,334	3,719	63%	10/13/2010	19	3,233	86.9%
Nov	1,438,684	1,998	3,765	53%	11/29/2010	18	2,494	66.2%
Dec	1,781,074	2,394	3,612	66%	12/13/2010	18	3,023	83.7%
Annual	17,518,323		39,665	5%	12/13/2010	18	3,023	83.7%

Table 53 shows the 2012 Embedded Distributors load forecast. The 2012 annual energy is 17,350,000 kWh. The non-coincident peak is 4,141 kW. The coincident peak is 2,994 kW.

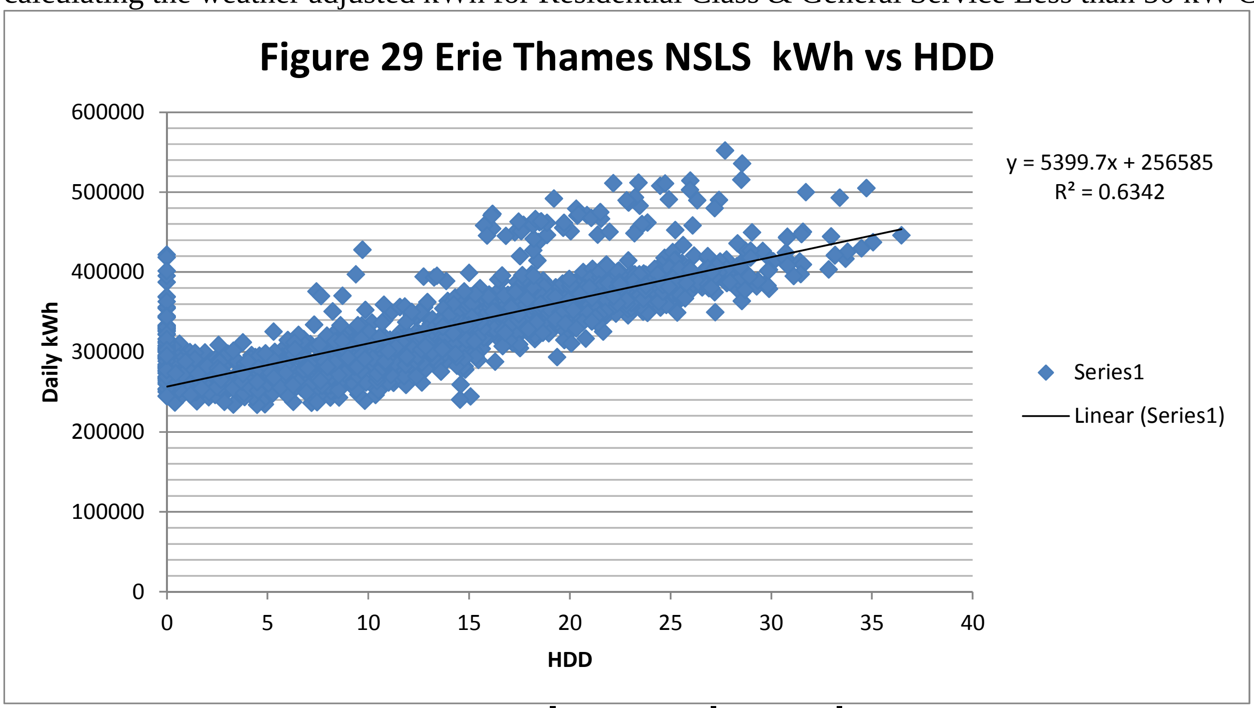
Table 53 – 2012 Embedded Distributors Load Forecast

2012	kWh	Average kW	Non-coincident Peak kW	LF	Date of System Peak	Hr	Co-Incident Peak kW	Coincident Factor
Jan	1,728,403	2,323	3,357	69%	1/4/2010	18	2,981	88.8%
Feb	1,562,435	2,325	3,423	68%	2/9/2010	19	3,320	97.0%
Mar	1,430,096	1,922	3,393	57%	3/26/2010	8	3,146	92.7%
Apr	1,193,363	1,657	2,902	57%	4/9/2010	9	2,054	70.8%
May	1,211,112	1,628	2,631	62%	5/31/2010	13	1,751	66.5%
Jun	1,256,858	1,746	2,664	66%	6/23/2010	17	2,143	80.4%
Jul	1,496,121	2,011	3,245	62%	7/28/2010	14	1,995	61.5%
Aug	1,447,397	1,945	4,141	47%	8/12/2010	14	2,249	54.3%
Sep	1,115,283	1,549	2,539	61%	9/1/2010	16	2,282	89.9%
Oct	1,720,111	2,312	3,683	63%	10/13/2010	19	3,202	86.9%
Nov	1,424,860	1,979	3,729	53%	11/29/2010	18	2,470	66.2%
Dec	1,763,961	2,371	3,578	66%	12/13/2010	18	2,994	83.7%
Annual	17,350,000		39,284	5%	12/13/2010	18	2,994	83.7%

12. Load Forecast Methodology

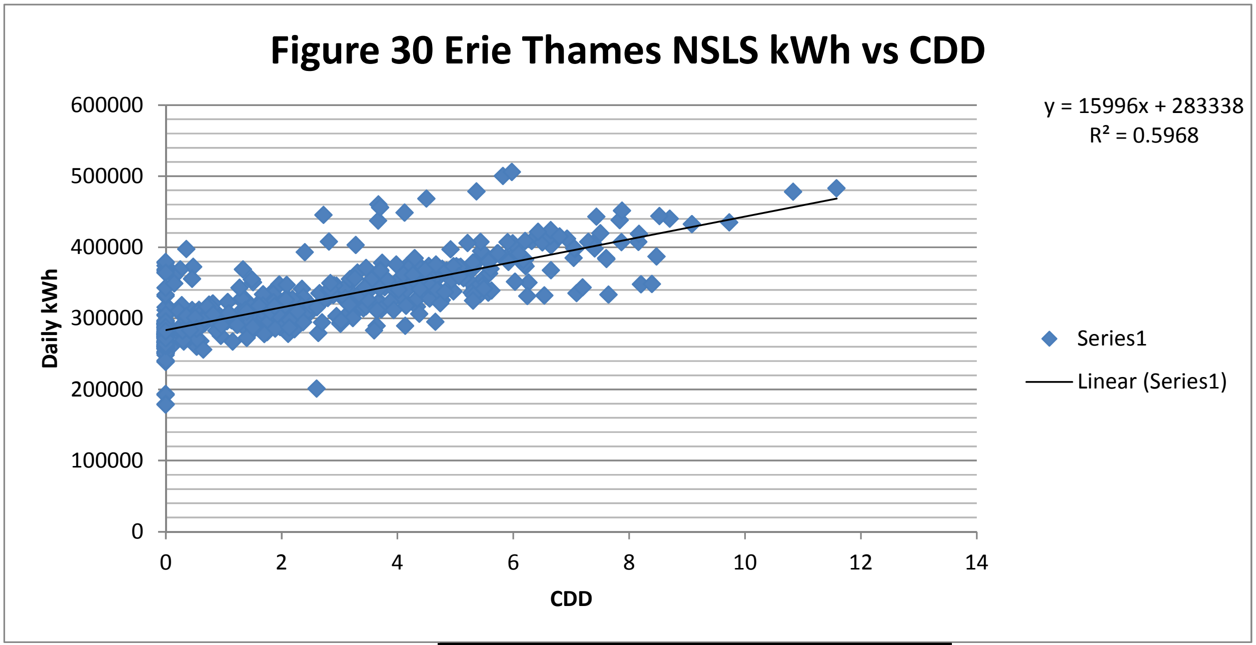
12.1 Residential Class & General Service Less than 50 kW

The model was developed using the daily kWh load data of the Net System Load Shape from 2006 to 2010. The Heating Degree Days (HDD) and the Cooling Degree Days (CDD) for each day were calculated from 2006 to 2010.
Figure 29 shows the 2006 to 2010 Erie Thames Daily NSLS kWh consumption versus the HDD. The data were selected from non-summer days only. The slope of the linear equation is 5399.7. The five year average daily kWh for the non-summer months is 329,429. Based on the slope and the five-year average daily kWh, the daily kWh weather adjustment factor is 1.6% per HDD. This adjustment factor was used for calculating the weather adjusted kWh for Residential Class & General Service Less than 50 kW Class.



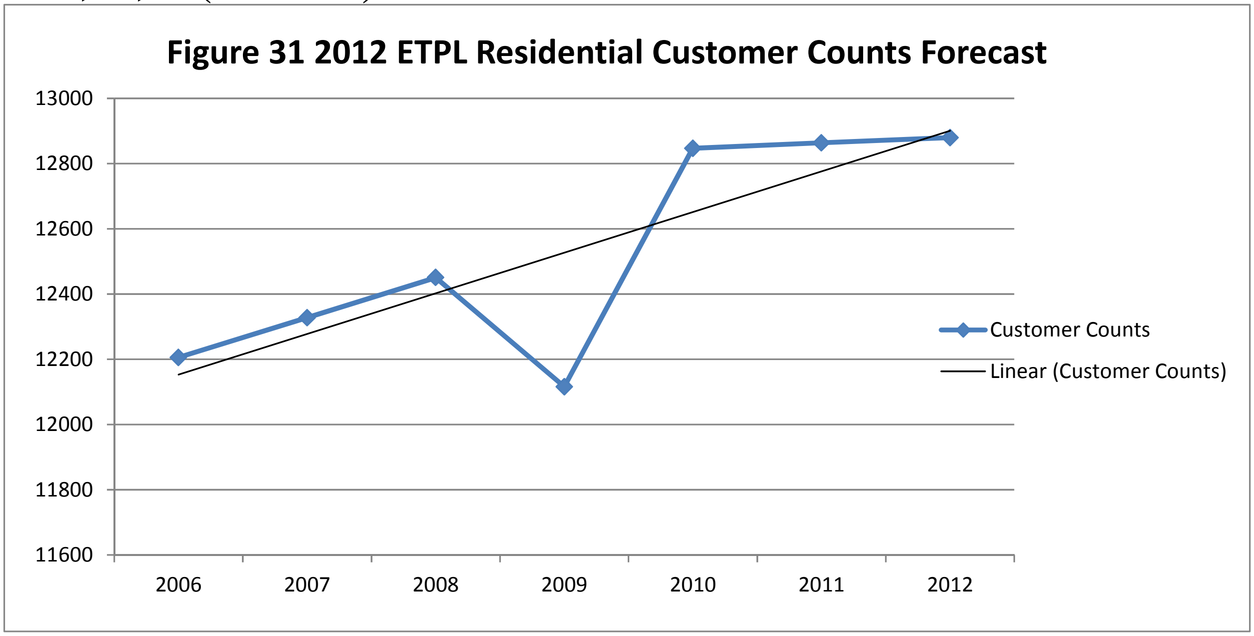
5 yr average	329,429
kWh/HDD	5399.7
% kWh/HDD	1.6%

Figure 30 shows the 2006 to 2010 Daily NSLS kWh consumption versus the CDD. The data were selected from summer days only. The slope of the linear quation is 15996. The average daily kWh of the Net System Load Shape for the summer months is 324,405 kWh. The daily kWh weather adjustment is 4.9 % per cooling degree day. This adjustment factor was used for calculating the weather adjusted kWh for Residential Class & General Service Less than 50 kW Class.



5 yr average	324,405	kWh
kWh/CDD	15996	
% kWh/CDD	4.9%	

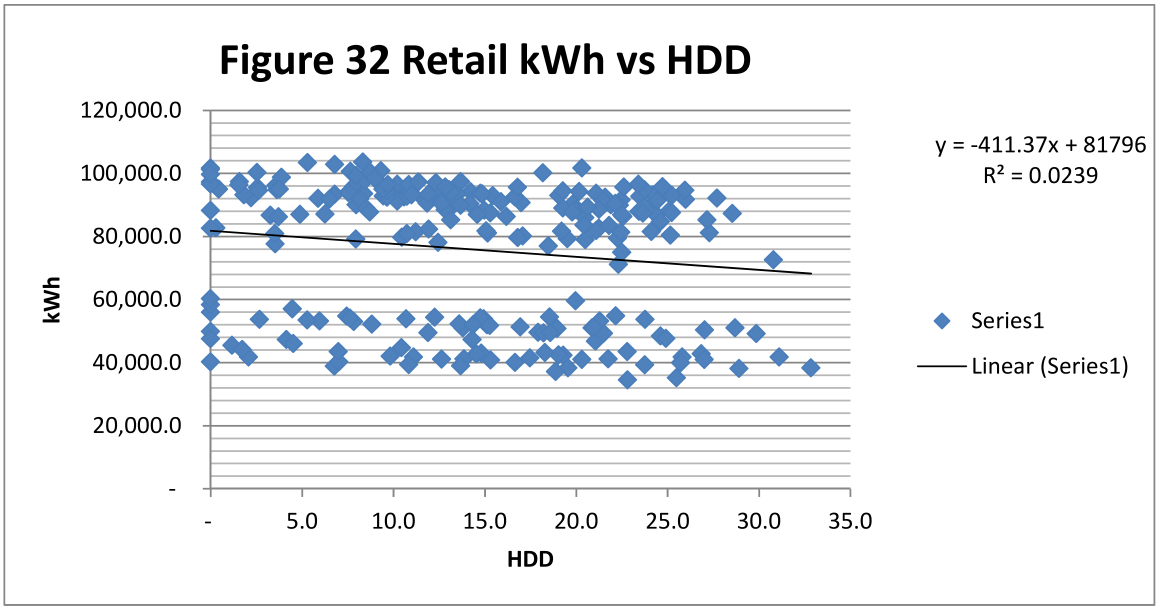
A linear trendline projection was used to project the customer growth in 2012. The 2012 forecast is based on the projected customer count and the weather adjusted kWh per customer per month. In Figure 31, the projected number of residential customers for Erie Thames before consolidation in 2012 is 12,880. The weather adjusted kWh/customer/month in 2010 is 775. The weather adjusted forecast annual kWh in 2012 is 119,707,075 (See Table 5).



The same forecast methodology was used for the forecast of residential class and general service class less than 50 kW for West Perth and Clinton.

12.2 General Service Greater than 50 kW

The model was developed using the 2010 hourly kWh data of the Total Grid Delivery and subtracted the Net System Load Shape and the interval meter accounts larger than 1000 kW. The The Heating Degree Days (HDD) and the Cooling Degree Days (CDD) for each day were calculated. As shown in Figures 32 and 33, there were no meaningful correlation between HDD and kWh or CDD and kWh. No weather adjustment was applied for this class. Historic trending and extrapolation were used for the forecast of this class.



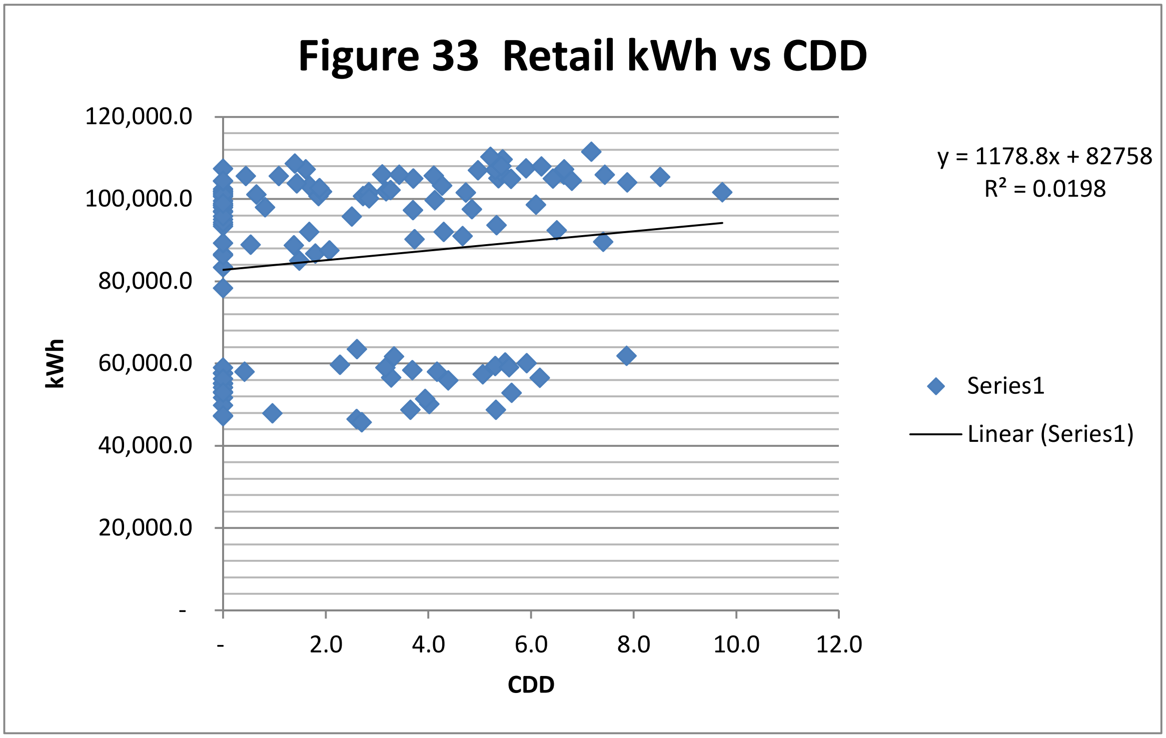
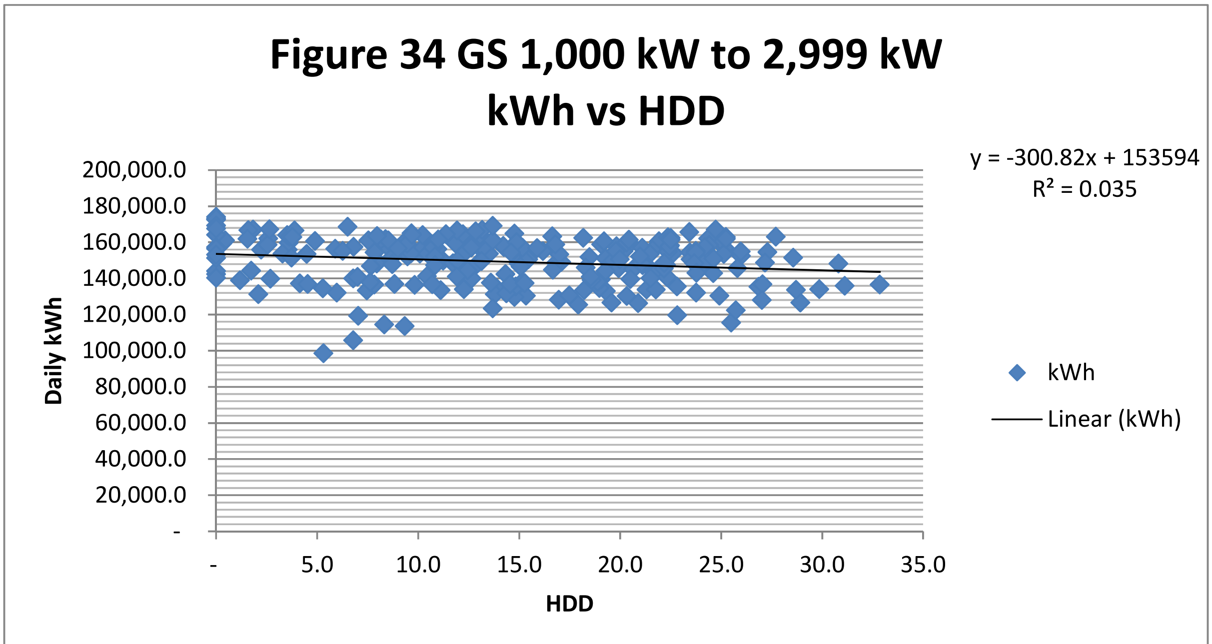
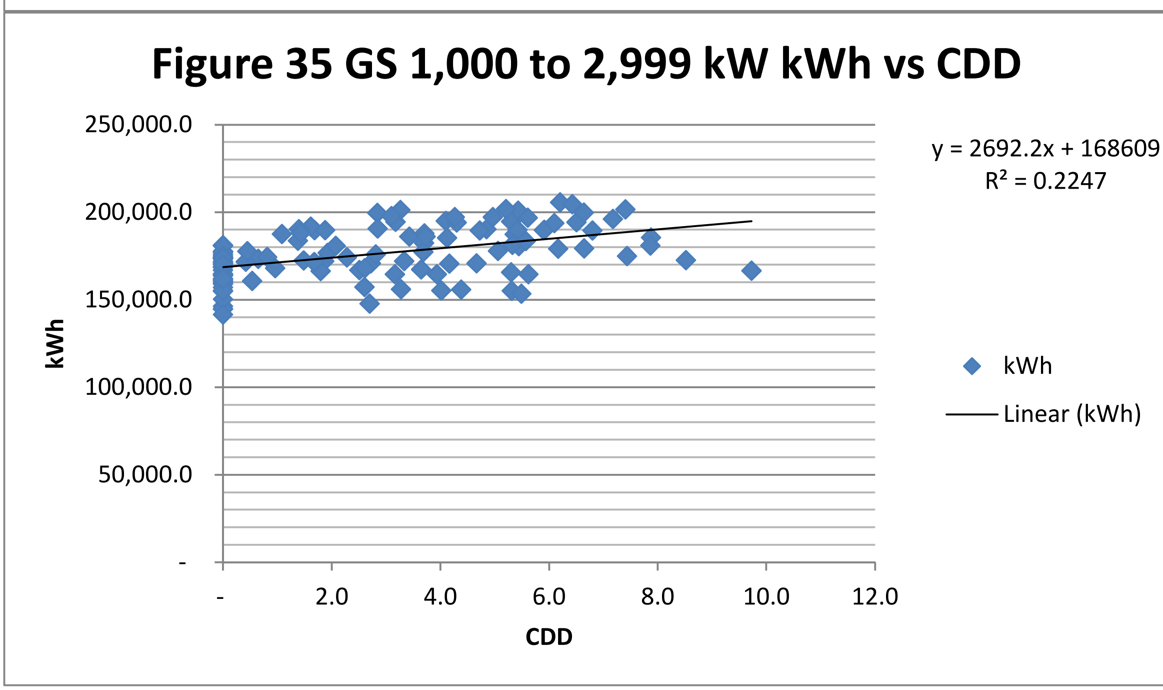


Figure 33 Retail kWh vs CDD
120,000.0
100,000.0
80,000.0
60,000.0
40,000.0
20,000.0
-
kWh
-
2.0
4.0
6.0
8.0
10.0
12.0
CDD
y = 1178.8x + 82758
R² = 0.0198
Series1
Linear (Series1)

12.3 General Services between 1,000 kW and 2999 kW

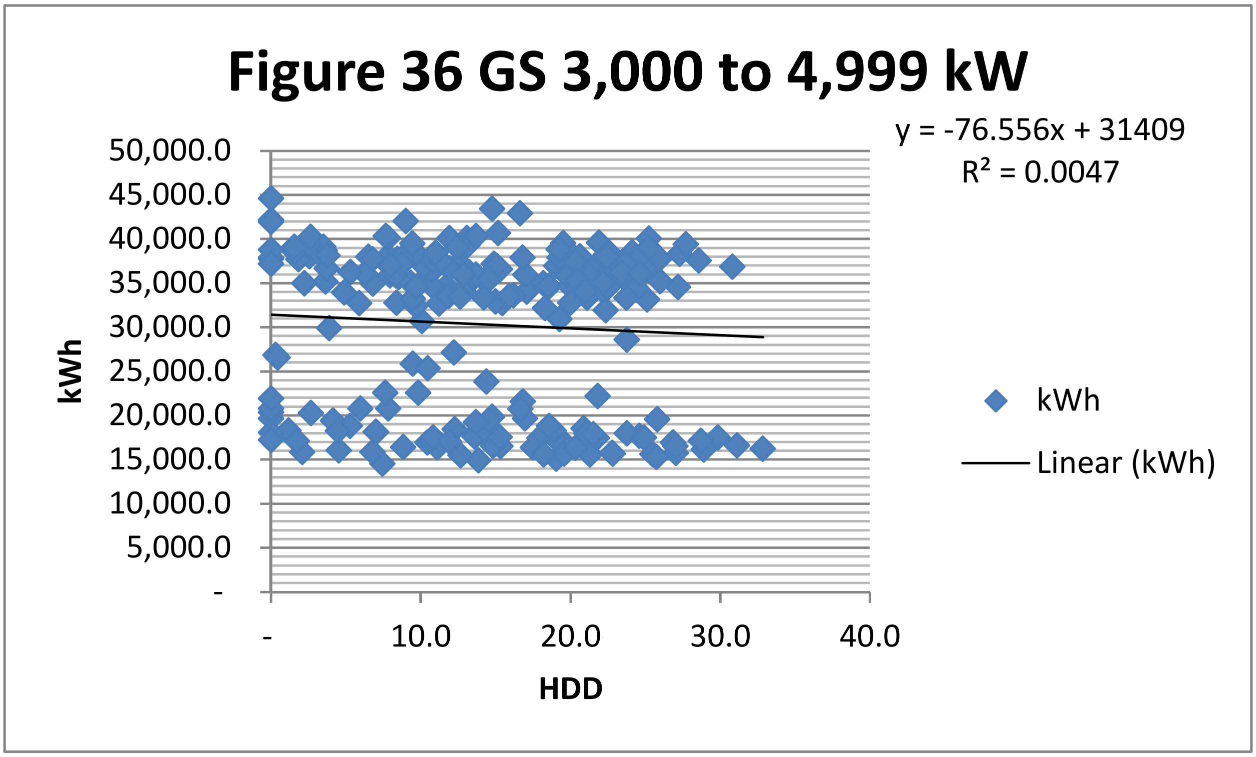
The model was developed using the 2010 hourly interval meter data of the customers in this class. The Heating Degree Days (HDD) and the Cooling Degree Days (CDD) for each day were calculated. As shown in Figures 34 and 35, there were no significant correlation between HDD and kWh or CDD and kWh. No weather adjustment was applied for this class. Historic trending and extrapolation were used for the forecast of this class.

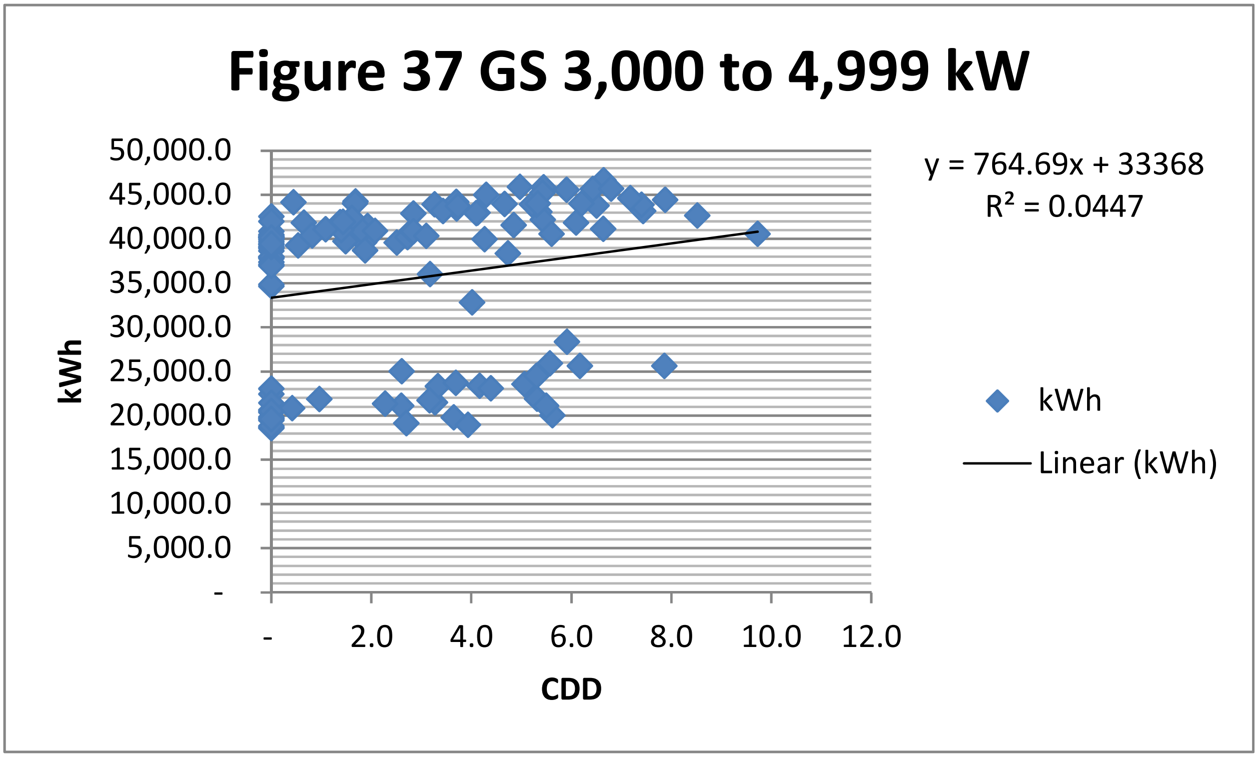




12.4 General Services between 3,000 kW and 4,999 kW

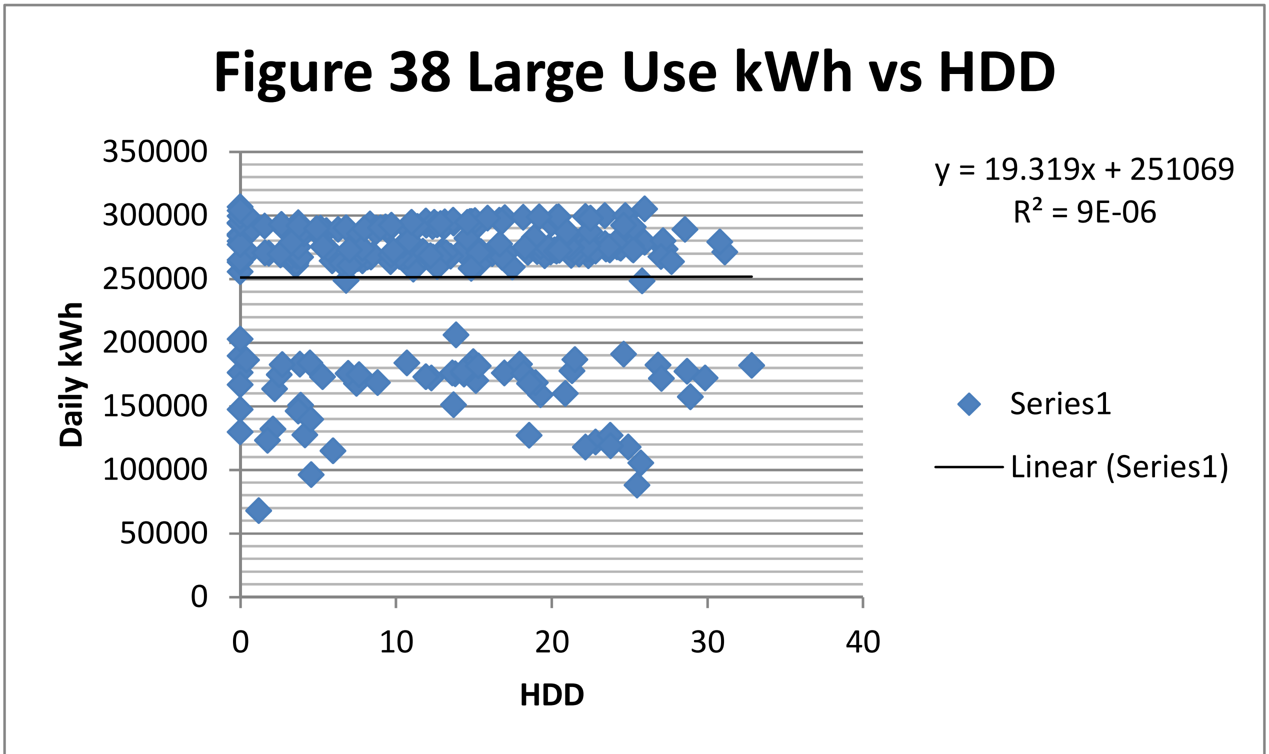
The model was developed using the 2010 hourly interval meter data of the customers in this class. The Heating Degree Days (HDD) and the Cooling Degree Days (CDD) for each day were calculated. As shown in Figures 36 and 37, there were no meaningful correlation between HDD and kWh or CDD and kWh. No weather adjustment was applied for this class. Historic trending and extrapolation were used for the forecast of this class.

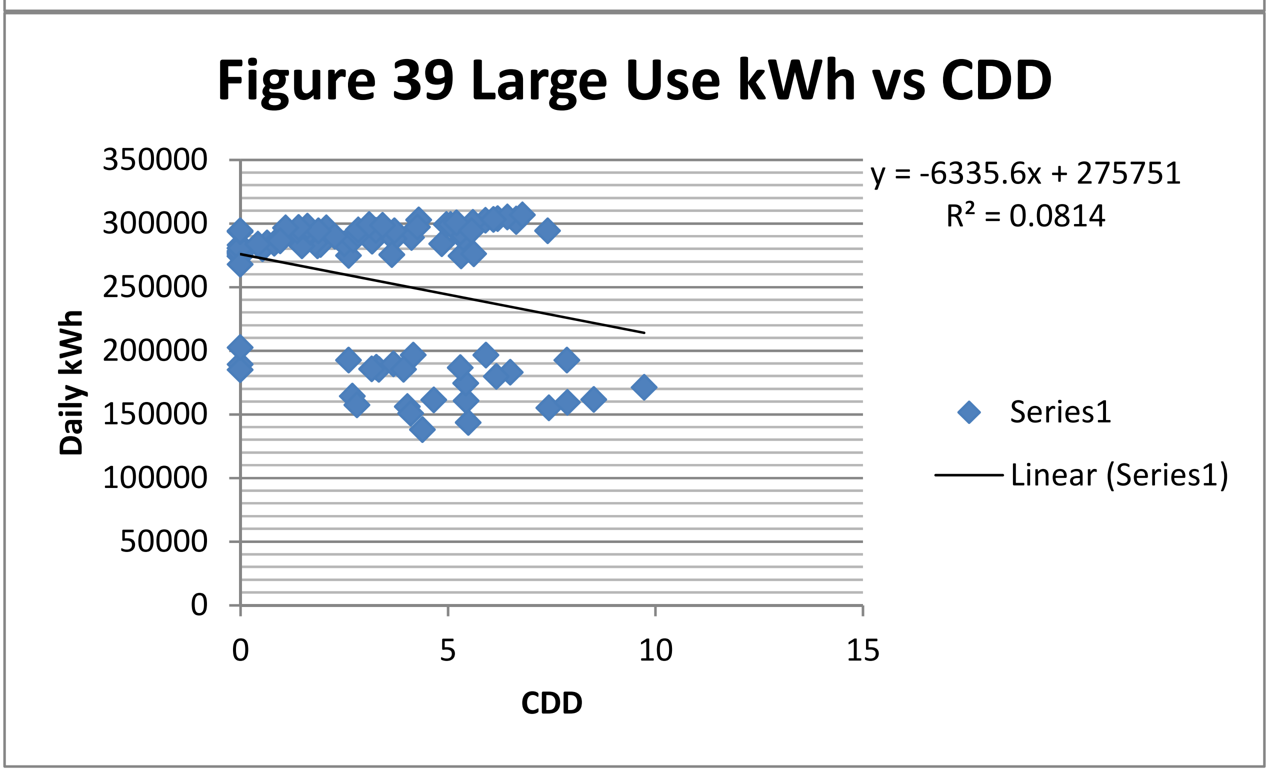




12.5 Large Use

The model was developed using the 2010 hourly interval meter data of the customers in this class. The Heating Degree Days (HDD) and the Cooling Degree Days (CDD) for each day were calculated. As shown in Figures 38 and 39, there were no meaningful correlation between HDD and kWh or CDD and kWh. No weather adjustment was applied for this class.





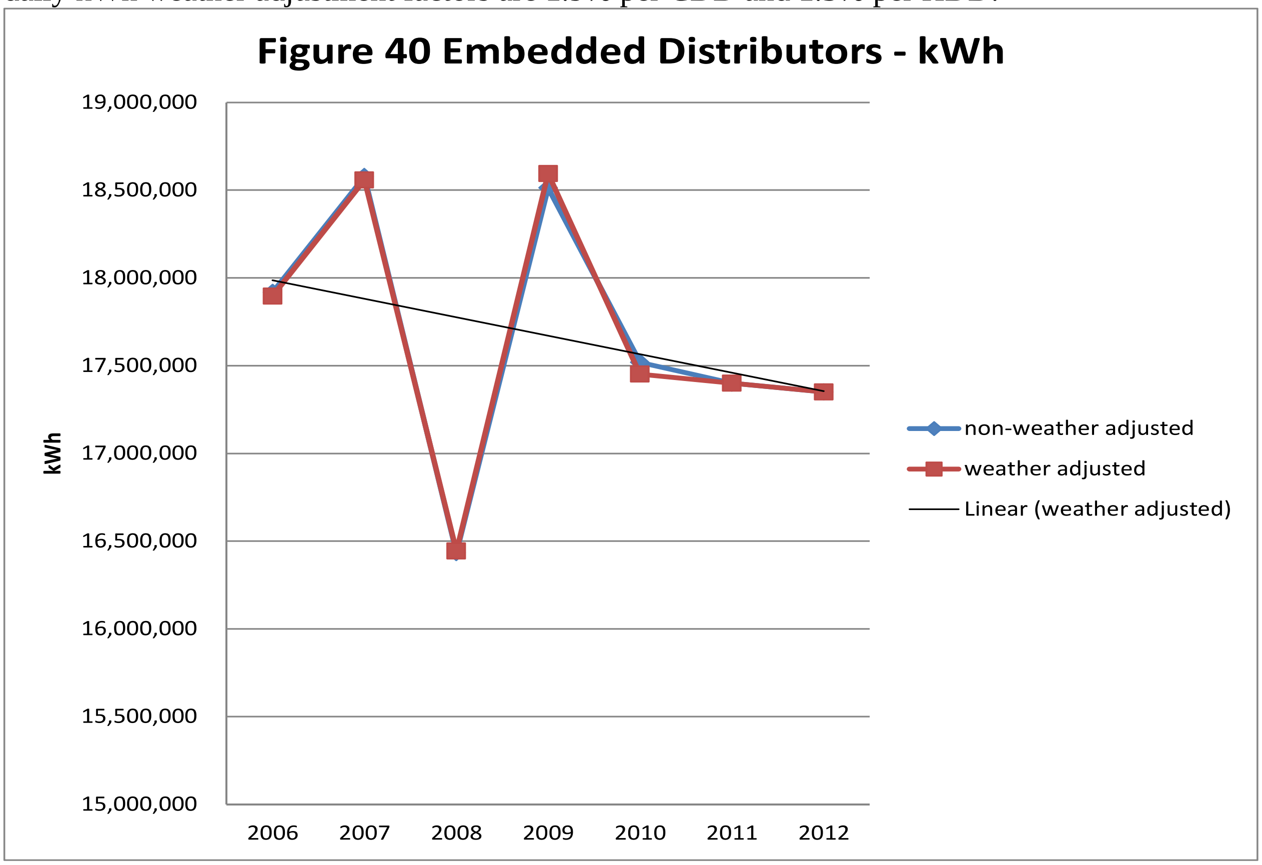
The forecast annual growth rate for 2011 and 2012 are 3.1% and 1.9% respectively. The 2011 forecast was based on the actual kWh from January to May and then prorated to the whole year assuming similiar monthly consumption patterns as compared to 2010. The 2012 forecast of 1.9% growth was based on the IESO’s 18 month outlook (May 24 2011) for the Ontario energy growth forecast.

12.6 Street Lights, Sential Lights and Unmetered Loads

These loads are not sensitive to weather or economic conditions. The 2012 load was updated using April 2012 actual data.

12.7 Embedded Distributors

The model was developed using the monthly kWh and kWdata from 2006 to 2010. Historic trending and extrapolation were used for the forecast of this class. Figures 40 and 41 show the trending of the kWh and kW respectively for this class. Figues 42 and 43 show the weather adjustment analysis for this class. The daily kWh weather adjustment factors are 1.9% per CDD and 1.3% per HDD.



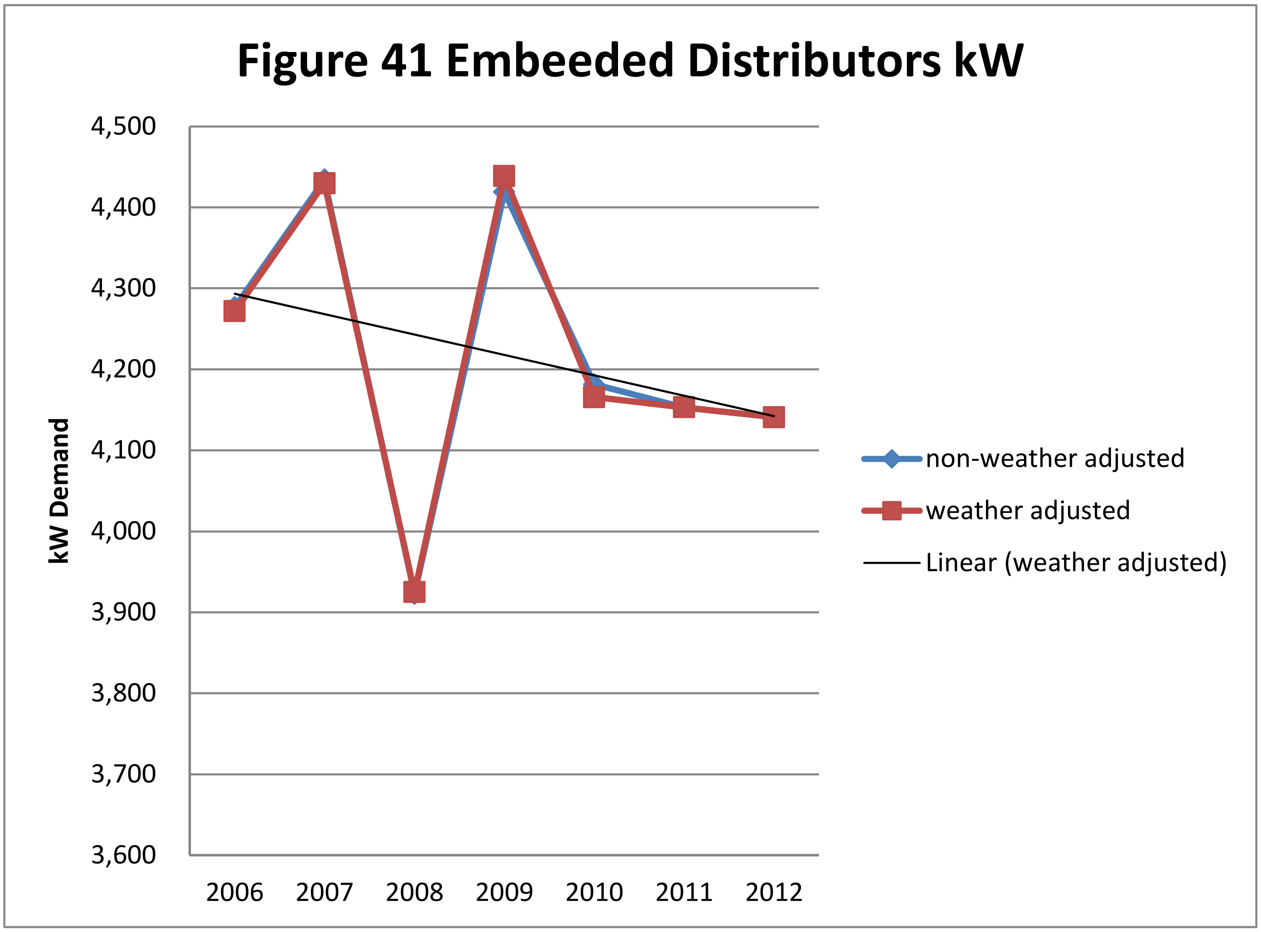
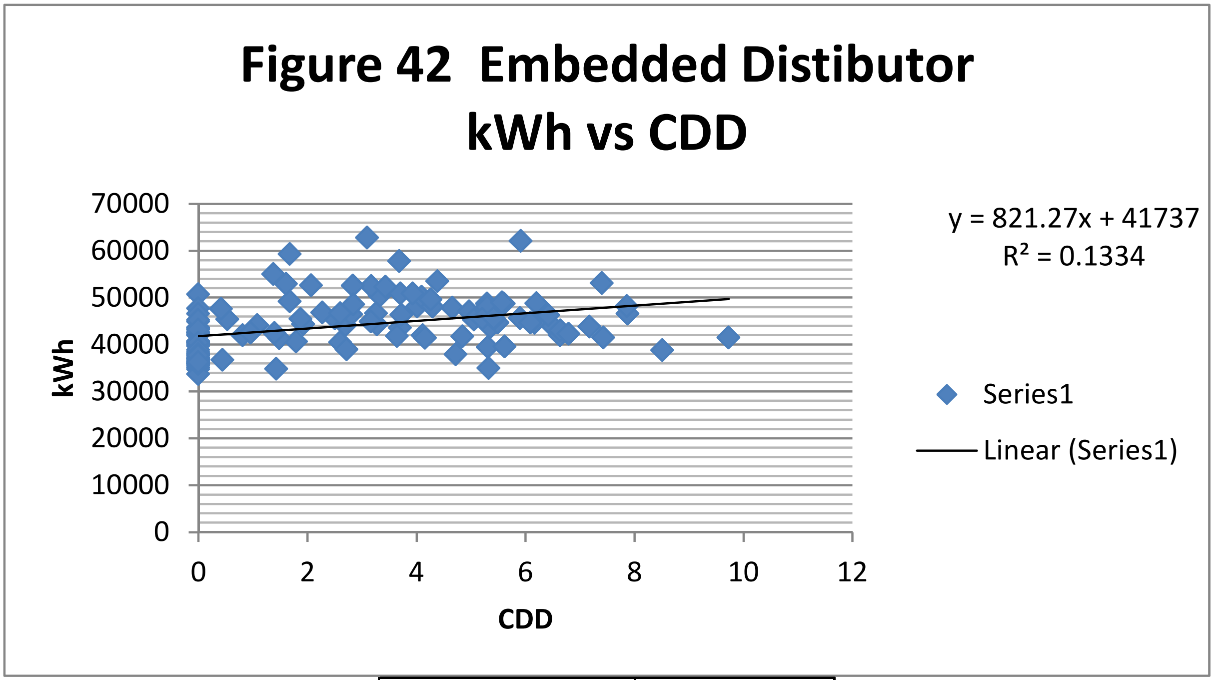
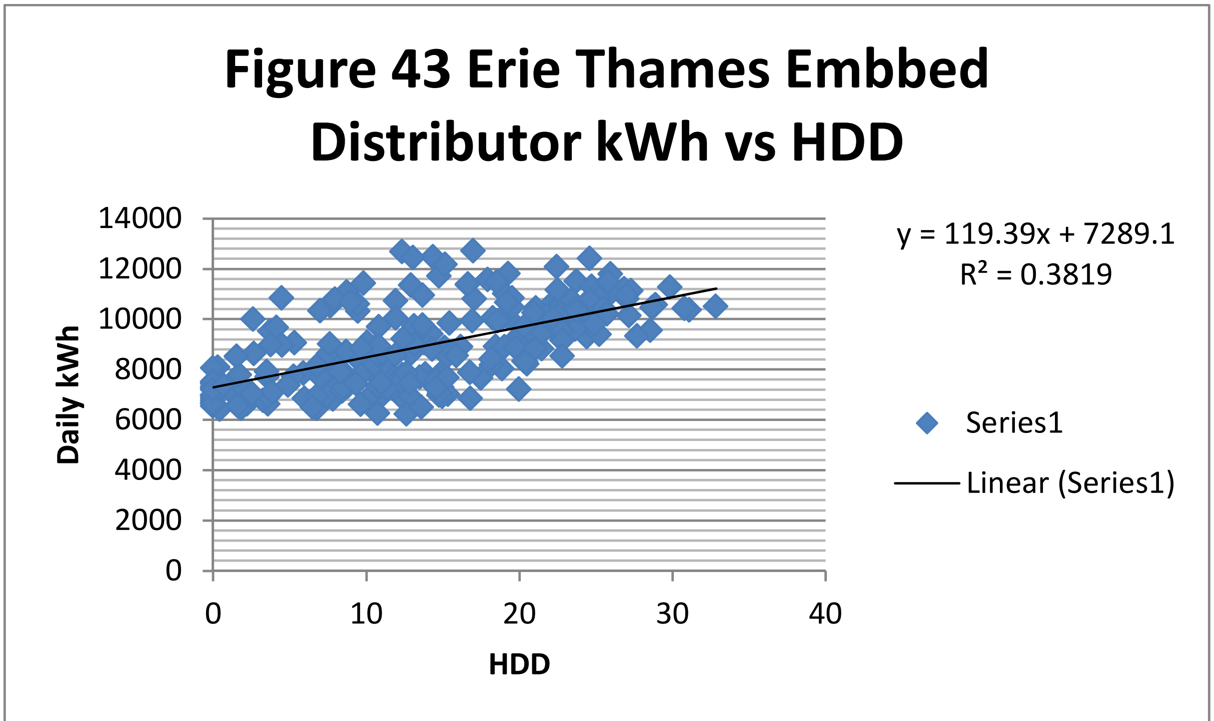


Figure 41 Embeeded Distributors kW
kW Demand
4,500
4,400
4,300
4,200
4,100
4,000
3,900
3,800
3,700
3,600
2006
2007
2008
2009
2010
2011
2012
non-weather adjusted
weather adjusted
Linear (weather adjusted)



Daily Average kWh	43,993.7
kWh/CDD	821.27
% kWh/CDD	1.9%



Daily Average kWh	9,011.8
kWh/HDD	119.39
% kWh/HDD	1.3%

Customer & Normalized Volume Forecast

Customer Forecast

The table below presents historical and forecast customer numbers, by class, for Erie Thames Power, Clinton Power and West Perth Power historically and forecasted on a Consolidated basis. The historic customer growth has been less than 1% and Erie Thames is projecting approximately 0.5% growth. The numbered was developed based upon a number of factors including: (i) no new residential subdivisions are planned, (ii) very limited infill possibilities for new customers; (iii) relatively poor performance of the southwestern Ontario economy. The economy within the communities served by Erie Thames has been impacted by business closures in London and St. Thomas and other area. As such, Erie Thames feels a 0.5% growth forecast is reasonable in the circumstances.

ERIE THAMES POWERLINES CUSTOMER COUNT TABLE					
	2006	**2007**	**2008**	**2009**	**2010**
Residential	12206	12328	12451	12710	12847
GS<50	1375	1375	1388	1382	1378
GS>50 to 999 kW	135	138	141	138	138
#REF!	8	8	8	7	7
#REF!	1	1	1	1	1
Large Use	1	1	1	2	2
Unmetered Scattered Load	95	95	95	100	105
Sentinel Lighting	256	256	256	256	256
Street Lighting	2870	2870	2956	2956	2956
Embedded Distributor	0	2	2	3	3
	16947	***17074***	***17299***	***17555.11***	***17693***

WEST PERTH POWER CUSTOMER COUNT	2006	2007	2008	2009	2010
Residential	1,747	1,764	1,769	1,786	1,797
GS<50	219	235	239	241	243
GS>50 to 499 kW	18	20	20	20	20
Unmetered Scattered Load	5	5	5	5	5
Sentinel Lighting	7	7	7	7	7
Street Lighting	618	618	618	618	618
	2,614	***2,649***	***2,658***	***2,677***	***2,690***

CLINTON POWER CUSTOMER COUNT TABLE	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual
Residential	1,391	1,402	1,393	1,411	1,414
GS<50	225	227	220	221	221
GS>50 to 499 kW	17	17	17	17	17
Unmetered Scattered Load	11	11	11	11	11
Sentinel Lighting	38	38	38	38	38
Street Lighting	709	709	709	709	709
	2,391	**2,404**	**2,388**	**2,407**	**2,410**

CUSTOMER COUNT FORECAST TABLE	2008 Actual	2009 Actual	Variance from 2008 Actual	2009 Actual	2010 Actual	Variance from 2009 Actual	2010 Actual	2011 Bridge	Variance from 2010 Actual	2012 Test	Variance from 2011 Bridge
Residential	15,613	15,907	294	15,907	16,058	151	16,058	16,379	321	16,461	82
GS<50	1,847	1,844	(3)	1,844	1,842	(2)	1,842	1,858	16	1,860	2
GS>50 to 999 kW	178	175	(3)	175	175	-	175	176	1	176	-
GS>1000 kW to 4999 kW	8	7	(1)	7	7	-	7	5	(2)	5	-
Large Use	1	2	1	2	2	-	2	1	(1)	1	-
Unmetered Scattered Load	111	116	5	116	121	5	121	121	-	121	-
Sentinel Lighting	301	301	-	301	301	-	301	301	-	301	-
Street Lighting	4,283	4,283	-	4,283	4,283	-	4,283	4,283	-	4,283	-
Embedded Distributor	2	3	1	3	3	-	3	3	-	3	-
	22,344	**22638**	**294**	**22,638**	**22,792**	**154**	**22,792**	**23,127**	**335**	**23,211**	**84**

Residential – The customer counts in Erie Thames Powerlines' service territory has been relatively stagnant over the 2006 to 2011 period with this minimal annual change in its customer base WPPI has projected an average change in its customer number of 82 for 2012.

GS<50 – As with the residential class above, there has been minimal growth in the GS < 50 kW customer class coupled with business closures during the economic downturn and with no new business forecast or apparent and the loss of several customers during 2011 forecasting any significant customer count increase would not be prudent and as such a forecast of 2 customer additions have been utilized.

GS>50 all classes– No change in these rate classes would be expected in the future, and historically the IGPC Ethanol Plant originally forecast in the Large Use class has moved to the GS>500 to 4999 kW class since their load did not materialize. Secondly this customer class remains with 7 customers despite the addition of the Ethanol Plant due to the closure of Atlantic Packaging in Ingersoll Ontario.

Load Forecast

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Erie ThamesPower has utilized the services of Lawrence Wu in the development of its weather normalized load forecasting. A detailed explanation of the data and the results of the forecast have been provided above in Tab 2 Schedule 2 of this exhibit.

Normalized Average Consumption kWh					
	2008	**2009**	**2010**	**2011**	**2012**
RESIDENTIAL					
Regular	144,875,027	146,275,664	148,114,381	141,607,881	147,767,075
GENERAL SERVICE					
GS<50	51,840,761	50,474,522	50,456,016	48,940,695	50,460,667
GS>50 to 999 kW	77,268,716	70,853,891	76,034,237	76,414,560	77,849,023
Greater than 1,000 to 4,999 kW	97,948,640	97,507,175	125,102,697	99,303,972	69,200,000
Large Use	74,125,314	69,719,263	92,434,594	95,335,410	97,146,783
Unmetered Scattered Load	572,674	613,668	605,495	608,161	618,341
Sentinel Lighting	56,273	46,235	54,410	54,410	54,410
Street Lighting	3,996,786	4,028,338	4,074,076	4,189,868	4,289,868
Embedded Distributor	16,433,707	18,513,267	17,518,323	17,400,000	17,350,000
	467,117,898	**458,032,023**	**514,394,228**	**483,854,957**	**464,736,166**

Customer Counts (Historical and Projected)

CUSTOMER COUNT TABLE							
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Residential	15,344	15,494	15,613	15,907	16,058	16,379	16,461
GS<50	1,819	1,837	1,847	1,844	1,842	1,858	1,860
GS>50 to 999 kW	170	175	178	175	175	176	176
Greater than 1,000 to 4,999 kW	8	8	8	7	7	5	5
Large Use	1	1	1	2	2	1	1
Unmetered Scattered Load	111	111	111	116	121	121	121
Sentinel Lighting	301	301	301	301	301	301	301
Street Lighting	4,197	4,197	4,283	4,283	4,283	4,283	4,283
Embedded Distributor	-	2	2	3	3	3	3
	21,951	***22,126***	***22,344***	***22,638***	***22,792***	***23,127***	***23,211***

VARIANCE ANALYSIS ON NORMALIZED VOLUME FORECAST

Fiscal 2012 Test Year

Comparison to Fiscal 2011 Bridge Year

Due to weather normalization the 2012 Test Year forecast projects an increase in kWh's of 10,985,181 excluding the GS 1,000 to 4,999 kW class and a total decrease in kW of 37,876. In total kWh has been forecasted to decrease by 19,118,791 kWh's due to the loss of a major customer in 2011. A copy of the news article announcing the plant closure is provided as part of this application. In total the GS> 1000 to 4999 class consumption has reduced by 30 million kWh. Some of this change is with respect to the movement of customers from this class to the GS> 50 to 999 kW class as a result of decreasing demand and the rest is directly attributable to the loss of customer.

Note: unmetered, sentinel light and street light classes are based on engineering calculations and are not subject to load changes (with the exception of the addition of new connection points).

2011 Bridge (Actual) Year & 2012 Test Year to Historical Years (2008, 2009 & 2010)

The differences in actual stats are based on economic changes, customer class changes and weather impacts that have affects on consumption and load profiles.

VARIANCE ANALYSIS ON CUSTOMER COUNT FORECAST

Fiscal 2012 Test Year

Comparison to Fiscal 2011 Bridge Year

Erie Thames Power has forecasted a net increase of 84 customers within its service territory. The residential class is responsible for almost the entire increase of with 82 customers, while the GS < 50 class contributes 2 and the remaining classes are contributing no additional customers. While the forecast increase in customers for 2012 may seem very low it is in keeping with the economic uncertainty facing the region with significant unemployment rates in London and the surrounding area and new home starts in Erie Thames Services territory stagnating.

2011 Bridge Year

Comparison to Fiscal 2010 Actual

Erie Thames Power has experienced an increase of 336 customers in the 2011 counts. The residential class increased by 321 customers, the GS < 50 class added 16 customers and the GS > 50 class contributed no additional customers while in fact losing one large user over 2010. As stated earlier this large user remains a customer and was reclassified down to the GS>1,000 class, another customer was reclassified down to GS>50 and a GS>1,000 customer is no longer in business leaving that class with 5 customers.

Exhibit: 3
Tab: 3
Schedule: 1
Page: 1

OTHER DISTRIBUTION REVENUE

OTHER DISTRIBUTION REVENUE	2008 Board Approved	2008 Actual	Variance from 2008 Board Approved		2008 Actual	2009 Actual	Variance from 2008 Actual		2009 Actual	2010 Actual	Variance from 2009 Actual		2010 Actual	2011 Bridge	Variance from 2010 Actual		2011 Bridge	2012 Test	Variance from 2011 Bridge
	($'s)	($'s)	($'s)		($'s)	($'s)													
Other Distribution Revenue																			
Retail Services Revenues	$19,065	$19,098	$33		$19,098	$20,303	$1,205		$20,303	$20,595	$292		$20,595		-$20,595		$0		$0
Service Transaction Requests (STR) Revenues	$10,917	$10,619	-$298		$10,619	$10,400	-$219		$10,400	$10,854	$454		$10,854	$36,120	$25,266		$36,120	$37,204	$1,084
Electric Services Incidental to Energy Sales	$0		$0		$0		$0		$0		$0		$0		$0		$0		$0
Rent from Electric Property	$88,401	$72,716	-$15,685		$72,716	$71,098	-$1,618		$71,098	$104,362	$33,265		$104,362	$153,538	$49,176		$153,538	$156,609	$3,071
Other Utility Operating Income	$64,213	$363,787	$299,574		$363,787	$284,527	-$79,260		$284,527	$324,253	$39,727		$324,253	$166,519	-$157,734		$166,519	$167,352	$833
Other Electric Revenues	$92,075	$0	-$92,075		$0	$0	$0		$0		$0		$0		$0		$0		$0
Late Payment Charges	$95,447	$73,786	-$21,661		$73,786	$88,295	$14,509		$88,295	$84,480	-$3,815		$84,480	$139,262	$54,782		$139,262	$143,440	$4,178
Sales of Water and Water Power	$0		$0		$0		$0		$0		$0		$0		$0		$0		$0
Miscellaneous Service Revenues	$161,584	$6,238	-$155,346		$6,238	$3,011	-$3,227		$3,011	$10,716	$7,705		$10,716	$415,974	$405,258		$415,974	$428,454	$12,479
TOTAL	$531,702	$546,244	$14,542		$546,244	$477,633	-$68,611		$477,633	$555,261	$77,628		$555,261	$911,414	$356,153		$911,414	$933,058	$21,644

MATERIALITY ANALYSIS ON OTHER DISTRIBUTION REVENUE

For any Other Revenue item related variance exceeding the materiality threshold of 1%, a detailed explanation is required. Materiality of 1% of 2008 board approved distribution expenses of $4,222,268 is $42,225.

2008 Actual vs. Board approved

2008 Actual vs. Board approved see several variances greater than the threshold they are all due to the accounts in which the revenues were posted in the chart of accounts for 2008 and as a whole the revenue has not materially changed.

2009 Actual v. 2008 Actual?

In 2009 other operating income was down almost $70,000 over 2008. This decrease is solely attributable to the 18 week work interruption experienced at Erie Thames Powerlines, and the fact that due to a shortage of resources disconnection notices and the usual collection process was not followed at that time.

2010 to 2009 Actual

There were no material changes in revenue in 2010.

2011 Bridge to 2010 Actual

In 2011 Erie Thames began collecting third party billing services revenue from its affiliate for the use of Powerlines staff to fulfill their contracts. Historically the billing staff had not been part of Erie Thames's workforce and in 2011 the staff were moved over from the affiliate. Erie Thames bills its affiliate fully burdened costs to perform the third party work. This change in business structure explains the $405,000 increase in Miscellaneous Service Revenues. Erie Thames also saw a reduction in its other operating income by almost $160,000, a portion of which is attributable to how the revenues were posted to the GL by West Perth and Clinton vs. Erie Thames and the remainder is due to the changes in the distribution system code that has further limited LDC's in how they can collect outstanding balances from its customers.

2012 Forecast to 2011 Bridge

There are no material changes anticipated in 2012.

RATE OF RETURN ON OTHER DISTRIBUTION ACTIVITIES

In this application Erie Thames Power has applied for the same Specific Service Charges schedule previously approved in the 2011 Tariffs of Rates and Charges from EB-2010-0080 Rate Order, dated April 7th 2011.

Distribution Revenue Data

DISTRIBUTION REVENUE DATA				
	2008 Board Approved			
	Customers (Year-End)	Consumption (kWh / KW)	Distribution Revenues ($)	Unit Revenues $/kWh
Residential	12,458	123,245,746	$3,913,662	$0.0318
GS<50	1,401	40,839,870	$754,516	$0.0185
GS>50 to 999 kW	144	367,309	$1,002,726	$2.7299
Greater than 1,000 to 2,999 kW	8	135,587	$649,464	$4.7900
Greater than 3,000 to 4,999 kW	2	83,687	$166,568	$1.9904
Large Use	1	165,609	$455,028	$2.7476
Unmetered Scattered Load	95	606,271	$11,236	$0.0185
Sentinel Lighting	256	931	$29,230	$31.3961
Street Lighting	2,956	9,432	$235,761	$24.9958
Embedded Distributor	2	99,771	$219,224	$2.1973
TOTAL	17,323	165,454,442	$7,437,415	
	2008 Actual			
	Customers (Year-End)	Consumption (kWh / KW)	Distribution Revenues ($)	Unit Revenues $/kWh
Residential	12,747	115,637,295	$3,585,527	$0.0310
GS<50	1,406	35,519,590	$983,548	$0.0277
GS>50 to 999 kW	147	254,381	$1,072,236	$4.2151
Greater than 1,000 to 2,999 kW	9	93,901	$852,138	$9.0749
Greater than 3,000 to 4,999 kW	1	57,958	$177,972	$3.0707
Large Use	2	212,723	$536,279	$2.5210
Unmetered Scattered Load	95	625,000	$28,327	$0.0453
Sentinel Lighting	219	925	$15,505	$16.7627
Street Lighting	2,956	7,381	$44,897	$6.0828
Embedded Distributor	3	32,094	$11,087	$0.3455
TOTAL	17,585	152,409,154	$7,307,516	

	2009 Actual			
	Customers	**Consumption**	**Distribution Revenues**	**Unit Revenues**
	(Year-End)	**(kWh / KW)**	**($)**	**$/kWh**
Residential	12,550	112,395,473	$3,780,878	$0.0336
GS<50	1,234	33,991,973	$819,593	$0.0241
GS>50 to 999 kW	137	262,519	$1,002,045	$3.8170
Greater than 1,000 to 2,999 kW	8	96,905	$664,676	$6.8590
Greater than 3,000 to 4,999 kW	2	59,812	$148,796	$2.4877
Large Use	2	181,443	$742,353	$4.0914
Unmetered Scattered Load	105	516,445	$12,418	$0.0240
Sentinel Lighting	228	948	$36,012	$37.9877
Street Lighting	2,956	7,968	$439,079	$55.1052
Embedded Distributor	2	35,968	$144,455	$4.0162
TOTAL	17,224	147,549,454	$7,790,306	
	2010 Actual			
	Customers	**Consumption**	**Distribution Revenues**	**Unit Revenues**
	(Year-End)	**(kWh / KW)**	**($)**	**$/kWh**
Residential	12,787	115,184,785	$3,746,942	$0.0325
GS<50	1,371	35,509,255	$670,004	$0.0189
GS>50 to 999 kW	138	85,219	$467,222	$5.4826
Greater than 1,000 to 2,999 kW	7	319,665	$1,093,200	$3.4198
Greater than 3,000 to 4,999 kW	1	32,291	$57,037	$1.7663
Large Use	2	166,857	$571,733	$3.4265
Unmetered Scattered Load	105	493,902	$9,707	$0.0197
Sentinel Lighting	228	948	$27,701	$29.2200
Street Lighting	2,956	8,509	$331,300	$38.9364
Embedded Distributor	3	37,282	$142,471	$3.8214
TOTAL	17,598	151,838,714	$7,117,316	

	2011 Bridge			
	Customers	Consumption	Distribution Revenues	Unit Revenues
	(Year-End)	(kWh / KW)	($)	$/kWh
Residential	16,379	147,975,246	$4,831,071	$0.0326
GS<50	1,858	49,295,162	$1,168,144	$0.0237
GS>50 to 999 kW	176	116,096	$870,713	$7.4999
Greater than 1,000 to 2,999 kW	5	58,534	$396,338	$6.7711
Greater than 3,000 to 4,999 kW	0	-	$0	#DIV/0!
Large Use	1	160,146	$510,381	$3.1870
Unmetered Scattered Load	121	629,179	$14,437	$0.0229
Sentinel Lighting	301	61	$30,055	$491.5784
Street Lighting	4,283	1,098	$314,766	$286.5991
Embedded Distributor	3	23,768	$166,268	$6.9953
TOTAL	23,127	198,259,291	$8,302,173.28	

	2012 Test Using Existing Rates ETPL			
	Customers	Consumption	Distribution Revenues	Unit Revenues
	(Year-End)	(kWh / KW)	($)	$/kWh
Residential	13,250	119,707,075	$3,980,001	$0.0332
GS<50	1,396	37,037,700	$713,586	$0.0193
GS>50 to 999 kW	138	91,030	$502,432	$5.5194
Greater than 1,000 to 2,999 kW	7	81,947	$456,134	$5.5662
Greater than 3,000 to 4,999 kW	1	26,704	$59,512	$2.2286
Large Use	1	160,146	$445,561	$2.7822
Unmetered Scattered Load	105	545,982	$10,823	$0.0198
Sentinel Lighting	256	52	$16,431	$315.9829
Street Lighting	2,956	758	$140,388	$185.2085
Embedded Distributor	3	23,768	$119,649	$5.0339
TOTAL	18,113	157,675,163	$6,444,516.81	

	2012 Test Using Existing Rates WPPI			
	Customers	**Consumption**	**Distribution Revenues**	**Unit Revenues**
	(Year-End)	**(kWh / KW)**	**($)**	**$/kWh**
Residential	1,797	16,400,000	$485,275	$0.0296
GS<50	243	8,000,000	$160,446	$0.0201
GS>50 to 999 kW	20	27,500	$120,769	$4.3916
Unmetered Scattered Load	5	16,319	$479	$0.0294
Sentinel Lighting	7	46	$362	$7.8808
Street Lighting	618	1,196	$25,828	$21.5968
TOTAL	2,690	24,445,061	$793,159.96	

	2012 Test Using Existing Rates CPC			
	Customers	**Consumption**	**Distribution Revenues**	**Unit Revenues**
	(Year-End)	**(kWh / KW)**	**($)**	**$/kWh**
Residential	1,414	11,660,000	$403,402	$0.0346
GS<50	221	5,422,967	$148,697	$0.0274
GS>50 to 999 kW	17	21,458	$133,190	$6.2070
Unmetered Scattered Load	11	56,040	$2,593	$0.0463
Sentinel Lighting	38	108	$346	$3.2034
Street Lighting	709	1,008	$24,461	$24.2667
TOTAL	2,410	17,161,581	$712,689.39	

	2012 Test Using Existing Rates Total			
	Customers	**Consumption**	**Distribution Revenues**	**Unit Revenues**
	(Year-End)	**(kWh / KW)**	**($)**	**$/kWh**
Residential	16,461	147,767,075	$4,868,678	$0.0329
GS<50	1,860	50,460,667	$1,022,730	$0.0203
GS>50 to 999 kW	175	139,988	$756,391	$5.4032
Greater than 1,000 to 2,999 kW	7	81,947	$456,134	$5.5662
Greater than 3,000 to 4,999 kW	1	26,704	$59,512	$2.2286
Large Use	1	160,146	$445,561	$2.7822
Unmetered Scattered Load	121	618,341	$13,896	$0.0225
Sentinel Lighting	301	206	$17,140	$83.1974
Street Lighting	4,283	2,962	$190,677	$64.3761
Embedded Distributor	3	23,768	$119,649	$5.0339
TOTAL	23,213	199,281,804	$7,950,366.16	

	2012 Test Using Proposed Rates			
	Customers	Consumption	Distribution Revenues	Unit Revenues
	(Year-End)	(kWh / KW)	($)	$/kWh
Residential	13,250	147,767,075	$5,176,750	$0.0350
GS<50	1,396	50,460,667	$1,244,340	$0.0247
GS>50 to 999 kW	138	139,988	$1,276,274	$9.1170
Greater than 1,000 to 4,999 kW	7	81,947	$522,514	$6.3762
Large Use	1	160,146	$401,551	$2.5074
Unmetered Scattered Load	105	618,341	$88,716	$0.1435
Sentinel Lighting	256	206	$32,568	$158.0902
Street Lighting	2,956	2,962	$399,745	$134.9615
Embedded Distributor	3	23,768	$182,106	$7.6616
TOTAL	18,113	199,281,804	$9,324,564.32	

DESCRIPTION OF REVENUE SHARING

Erie Thames Power does not participate in revenue sharing.

it Times INGERSOLL

« Back

Ingersoll plant closure leaves 50 people out of work

Posted 2 days ago

An estimated 50 people are without jobs after Atlantic Packaging Products Ltd. announced it is permanently closing its Ingersoll plant.

Without warning, employees were gathered together at 11 a.m. Friday and given letters announcing the closure, said Kevin Piper, who has worked at Atlantic's Ingersoll facility since 1988.

"It's a shock," he said, explaining that some people were laid off about a month ago and production had slowed down but "I don't think anybody expected it'd be a permanent cease in the operations."

The Ingersoll plant is one of five corrugated packaging manufacturing facilities owned by Atlantic.

Signed by Mark Ragotte, Atlantic's vice-president of manufacturing, the letter employees received attributed the closure to the depressed economy and high dollar, "resulting in a decline in Canadian manufacturing, which has also reduced total corrugated demand."

The letter also provided employees with "eight weeks notice of termination of employment" and notified them that they would not have to report for work during that time.

"Most of them were pretty shocked," said Piper about his co-workers' reaction to the news, adding that some of them had recently purchased homes. "I was hoping to retire out of there."

Piper and two other employees tied the laces of their work boots together and hung them on a fence as they left the plant Friday as a visual reminder of the human impact of the closure.

As workers were being notified of the closure, officials with CEP Local 333, which represents employees at Atlantic Packaging, were in Toronto negotiating a new contract for employees at the Ingersoll plant.

"Our plan for the day was to go there and secure a collective agreement the way we did in (Atlantic's) Mississauga facility last week," said Ken Cole, president and business agent with the union.

He said he received news about the closure at the same time the announcement was made in Ingersoll.

"We knew the industry isn't doing all that well but we didn't think they were going to close," he said. "We were in the middle of bargaining."

Cole said the Ingersoll plant used to be a three-shift operation but was downgraded to a single shift in recent years.

He said the majority of the employees in Ingersoll have been with the company for a long time.

"They're devastated, completely devastated," said Cole about their reaction.

Having served employees at the Ingersoll Plant for 23 years, he said he is also feeling the impact of the closure on a personal level.

"Some of (the employees), I consider very good friends," said Cole.

On Friday, Cole said he planned to contact the company on Monday to start negotiating a closure agreement, including an enhanced severance package for employees.

Contacted by The Ingersoll Times, the company indicated it would have someone available for comment on Monday.

An information meeting on the closure is scheduled for Monday, March 7, at the CAW Hall at 10 a.m. Representatives from Service Canada are expected to be in attendance.

OVERVIEW OF OPERATING COSTS

Operating Costs

The operating costs presented in this exhibit represent the annual expenditures required to sustain Distribution Operations for Erie Thames Powerlines. The information presented in this exhibit is grouped into two different categories: Operation & Maintenance and Other Costs which include items such as Administration & General, Depreciation, Amortization and Depletion and Loss Adjustment Factor.

The second category includes Income Tax, Large Corporation Tax and Ontario Capital Taxes. Exhibit 4, Tab 1, Schedule 2 provides a summary of The Applicant's Operating Costs for the historical, bridge and test years.

OM&A Costs

The OM&A costs in this exhibit represents ETPL's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and Government direction; and to maintain distribution business service quality and reliability at targeted performance levels. These costs also include providing services to customers connected to the Applicant's Distribution system, and to meet the service levels stipulated in the Standard Supply Service Code and the Retailer Settlement Codes.

OM&A expenditures are set out in the following table:

SUMMARY OF OPERATING COSTS TABLE

SUMMARY OF OPERATING COSTS		**2008 Board Approved**	**2008 Actual**	**2009 Actual**	**2010 Actual**	**2011 Bridge**	**2012 Test**
OM&A expenses							
Operation (Working Capital)		$34,756	$275,864	$262,100	$284,838	$274,004	$282,215
Maintenance (Working Capital)		$1,461,897	$1,951,406	$629,843	$768,548	$693,543	$724,349
Billing and Collections		$1,073,486	$923,393	$971,351	$1,172,439	$1,034,231	$1,099,131
Community Relations		$28,879	$48,057	$248,494	$183,856	$144,449	$148,783
Administrative and General Expenses		$1,594,790	$2,682,570	$3,558,052	$3,557,661	$3,686,891	$3,346,759
Amortization Expenses		$935,609	$949,932	$1,017,711	$1,177,338	$1,810,506	$2,013,671
Cost of Power		$32,919,566	$34,025,046	$37,011,378	$40,082,660	$39,963,276	$36,951,817
Other Operating Costs		$0	$0	$0	$0	$0	$0
LCT,OCT and Income Taxes		$0					
Total Operating Costs		**$38,048,983**	**$40,856,269**	**$43,698,929**	**$47,227,340**	**$47,606,900**	**$44,566,724**

OM&A COSTS TABLE COMBINED ENTITY

Account	Description	2008 Actual	2009 Actual	2010 Actual	Bridge Year	Test Year
Operations						
5005	Operation Supervision and Engineering	$ 44,234	$ 70,139	$ 185,439	$ 187,413	$ 193,036
5010	Load Dispatching	$ -	$ 55	$ 837		
5012	Station Buildings and Fixtures Expense	$ 36	$ -	$ -		
5014	Transformer Station Equipment - Operation Labour	$ -	$ -	$ -		
5015	Transformer Station Equipment - Operation Supplies and Expenses	$ 620	$ -	$ -		
5016	Distribution Station Equipment - Operation Labour	$ -	$ -	$ -		
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ 39,666	$ 21,832	$ 28,247	$ 3,416	$ 3,519
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 6,703	$ 5,771	$ 17,774	$ 3,576	$ 3,683
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 2,194	$ 10,322	$ 2,385	$ 1,399	$ 1,441
5030	Overhead Sub-transmission Feeders - Operation	$ -	$ -	$ -		
5035	Overhead Distribution Transformers - Operation	$ 254	$ 556	$ 1,022		
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 964	$ 687	$ 2,520	$ 373	$ 384
5045	Underground Distribution Lines and Feeders - Operation Supplies and Exper	$ 502	$ 322	$ 8	$ 27	$ 28
5050	Underground Sub-transmission Feeders - Operation	$ -	$ -	$ -		
5055	Underground Distribution Transformers - Operation	$ 742	$ 278	$ 100		
5060	Street Lighting and Signal System Expense	$ 1,204	$ -	$ -		
5065	Meter Expense	-$ 6,329	$ 51,513	-$ 14,782	$ 5,971	$ 6,150
5070	Customer Premises - Operation Labour	$ -	$ 512	$ -	$ 190	$ 196
5075	Customer Premises - Operation Materials and Expenses	$ -	$ 5,961	$ 4,104	$ 18	$ 9
5085	Miscellaneous Distribution Expenses	$ 135,789	$ 92,685	$ 56,836	$ 71,621	$ 73,770
5090	Underground Distribution Lines and Feeders - Rental Paid	$ 1,050	$ 245	$ -		
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ 3,029	$ 588	$ -		
5096	Other Rent	$ 45,206	$ 635	$ 347		
Total - Operations		$ 275,864	$ 262,100	$ 284,838	$ 274,004	$ 282,215
Account	**Description**	**2008 Actual**	**2009 Actual**	**2010 Actual**	**Bridge Year**	**Test Year**

Account	Description	2008 Actual	2009 Actual	2010 Actual	Bridge Year	Test Year
Maintenance						
5105	Maintenance Supervision and Engineering	$ -	$ 3,284	$ 636		
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$ 1,402,007	$ 66,240	$ 117,201	$ 93,146	$ 95,941
5112	Maintenance of Transformer Station Equipment	$ -	-$ 8	$ 89		
5114	Maintenance of Distribution Station Equipment	$ 32,579	$ 38,614	$ 13,742	$ 3,287	$ 3,386
5120	Maintenance of Poles, Towers and Fixtures	$ 129,504	$ 91,571	$ 44,471	$ 28,923	$ 39,790
5125	Maintenance of Overhead Conductors and Devices	$ 31,685	$ 20,011	$ 9,225	$ 5,676	$ 5,846
5130	Maintenance of Overhead Services	$ 48,481	$ 87,438	$ 97,358	$ 73,848	$ 76,064
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 39,536	$ 71,116	$ 74,467	$ 111,568	$ 114,915
5145	Maintenance of Underground Conduit	$ 229	$ 576	$ 150,431	$ 140,828	$ 145,053
5150	Maintenance of Underground Conductors and Devices	$ 32,933	$ 63,121	$ 71,584	$ 52,886	$ 54,472
5155	Maintenance of Underground Services	$ 63,438	$ 49,537	$ 52,231	$ 53,555	$ 55,162
5160	Maintenance of Line Transformers	$ 89,286	$ 61,109	$ 65,975	$ 100,102	$ 103,105
5165	Maintenance of Street Lighting and Signal Systems	$ 18	$ -	$ -		
5170	Sentinel Lights - Labour	$ -	$ -	$ -		
5172	Sentinel Lights - Materials and Expenses	$ 7	$ -	$ -		
5175	Maintenance of Meters	$ 81,702	$ 77,235	$ 71,136	$ 29,724	$ 30,616
5178	Customer Installations Expenses - Leased Property	$ -	$ -	$ -		
5195	Maintenance of Other Installations on Customer Premises	$ -	$ -	$ -		
Total - Maintenance		$ 1,951,406	$ 629,843	$ 768,548	$ 693,543	$ 724,349

Account	Description	2008 Actual	2009 Actual	2010 Actual	Bridge Year	Test Year
Billing and Collecting						
5305	Supervision	$ 802	$ -	$ -	$ 18,088	$ 18,631
5310	Meter Reading Expense	$ 63,178	$ 49,053	$ 111,444	$ 33,213	$ 34,209
5315	Customer Billing	$ 750,077	$ 636,816	$ 835,310	$ 846,846	$ 906,125
5320	Collecting	$ 83,881	$ 48,189	$ 30,175	$ 21,187	$ 21,823
5325	Collecting - Cash Over and Short	-$ 100	$ 21	-$ 11,160		
5330	Collection Charges	-$ 17,988	$ 246,554	$ 184,212	$ 114,870	$ 118,316
5335	Bad Debt Expense	$ 15,892	-$ 9,274	$ 20,635	-$ 50,600	$ -
5340	Miscellaneous Customer Accounts Expenses	$ 27,650	-$ 9	$ 1,823	$ 26	$ 27
Total - Billing and Collecting		$ 923,393	$ 971,351	$ 1,172,439	$ 983,630	$ 1,099,131
Account	**Description**	**2008 Actual**	**2009 Actual**	**2010 Actual**	**Bridge Year**	**Test Year**
Community Relations						
5405	Supervision	$ 38,659	$ 2,430	$ 38,166	$ 2,097	$ 2,160
5410	Community Relations - Sundry	$ 414	$ 46,717	$ 21,782	$ 18,620	$ 19,179
5415	Energy Conservation	$ -	$ 77,261	$ -		
5420	Community Safety Program	$ -	$ 1,321	$ -		
5425	Miscellaneous Customer Service and Informational Expenses	$ -	$ 107,158	$ 112,726	$ 116,533	$ 120,029
5505	Supervision	$ -	$ -	$ -		
5510	Demonstrating and Selling Expense	$ -	$ -	$ -		
5515	Advertising Expenses	$ 8,985	$ 13,608	$ 11,183	$ 7,199	$ 7,415
5520	Miscellaneous Sales Expense	$ -	$ -	$ -		
Total - Community Relations		$ 48,057	$ 248,494	$ 183,856	$ 144,449	$ 148,783
Account	**Description**	**2008 Actual**	**2009 Actual**	**2010 Actual**	**Bridge Year**	**Test Year**

Account	Description	2008 Actual	2009 Actual	2010 Actual	Bridge Year	Test Year
Administrative and General Expenses						
5605	Executive Salaries and Expenses	$ 237,337	$ 226,658	$ 804,878	$ 212,029	$ 218,390
5610	Management Salaries and Expenses	$ 971,562	$ 1,011,874	$ 698,032	$ 1,316,530	$ 1,194,776
5615	General Administrative Salaries and Expenses	$ 459,386	$ 192,595	$ 249,762	$ 351,093	$ 361,626
5620	Office Supplies and Expenses	$ 150,619	$ 236,876	$ 207,524	$ 139,536	$ 143,722
5625	Administrative Expense Transferred - Credit	$ -	$ -	$ -		$ -
5630	Outside Services Employed	$ 336,184	$ 772,533	$ 423,980	$ 353,514	$ 180,378
5635	Property Insurance	$ 75,834	$ 55,967	$ 51,089		$ -
5640	Injuries and Damages	$ -	$ -	$ -	$ 13,047	$ 13,438
5645	Employee Pensions and Benefits	$ 12,611	$ 191,713	$ 271,145	$ 463,625	$ 413,502
5650	Franchise Requirements	$ -	$ -	$ -		$ -
5655	Regulatory Expenses	$ 158,967	$ 221,070	$ 157,540	$ 104,232	$ 115,000
5660	General Advertising Expenses	$ -	$ 41	$ 2,167		$ -
5665	Miscellaneous General Expenses	$ 110,449	$ 440,685	$ 290,174	$ 325,378	$ 295,456
5670	Rent	$ 99,009	$ 172,365	$ 282,923	$ 322,401	$ 322,401
5675	Maintenance of General Plant	$ 67,935	$ 33,474	$ 15,759	$ 77,868	$ 80,204
5680	Electrical Safety Authority Fees	$ 2,679	$ 2,201	$ 317	$ 7,636	$ 7,865
5685	Independent Electricity System Operator Fees and Penalties	$ -	$ -	$ 102,370		$ -
5695	OM&A Contra Account	$ -	$ -	$ -		$ -
6205	Donations (Charitable Contributions)	$ -	$ -	$ -		$ -
Total - Administrative and General Expenses		$ 2,682,570	$ 3,558,052	$ 3,557,661	$ 3,686,891	$ 3,346,759
Total OM&A		$ 5,881,291	$ 5,669,841	$ 5,967,342	$ 5,782,518	$ 5,601,237

OM&A COSTS TABLE 2008 DETAILED SEPARATELY

Account	Description	CPC	WPPI	ETPL	Total
Operations					
5005	Operation Supervision and Engineering	$ 10,975	$ 2,100	$ 31,159	$ 44,234
5010	Load Dispatching				$ -
5012	Station Buildings and Fixtures Expense		$ 36		$ 36
5014	Transformer Station Equipment - Operation Labour				$ -
5015	Transformer Station Equipment - Operation Supplies and Expenses		$ 620		$ 620
5016	Distribution Station Equipment - Operation Labour				$ -
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ 39,666			$ 39,666
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 1,345	$ 5,358		$ 6,703
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses		$ 2,194		$ 2,194
5030	Overhead Sub-transmission Feeders - Operation				$ -
5035	Overhead Distribution Transformers - Operation		$ 254		$ 254
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 45	$ 919		$ 964
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses		$ 502		$ 502
5050	Underground Sub-transmission Feeders - Operation				$ -
5055	Underground Distribution Transformers - Operation	$ 742			$ 742
5060	Street Lighting and Signal System Expense		$ 1,204		$ 1,204
5065	Meter Expense	$ 772	-$ 7,100		-$ 6,329
5070	Customer Premises - Operation Labour				$ -
5075	Customer Premises - Operation Materials and Expenses				$ -
5085	Miscellaneous Distribution Expenses	$ 52,003	$ 83,785		$ 135,789
5090	Underground Distribution Lines and Feeders - Rental Paid		$ 1,050		$ 1,050
5095	Overhead Distribution Lines and Feeders - Rental Paid		$ 3,029		$ 3,029
5096	Other Rent		$ 45,206		$ 45,206
Total - Operations		$ 105,548	$ 139,158	$ 31,159	$ 275,864

Account	Description	CPC	WPPI	ETPL	Total
Maintenance					
5105	Maintenance Supervision and Engineering				$ -
5110	Maintenance of Buildings and Fixtures - Distribution Stations			$ 1,402,007	$ 1,402,007
5112	Maintenance of Transformer Station Equipment				$ -
5114	Maintenance of Distribution Station Equipment		$ 8,275	$ 24,304	$ 32,579
5120	Maintenance of Poles, Towers and Fixtures	$ 5,584	$ 47,970	$ 75,950	$ 129,504
5125	Maintenance of Overhead Conductors and Devices	$ 9,202	$ 22,483		$ 31,685
5130	Maintenance of Overhead Services	$ 11,370	$ 11,377	$ 25,735	$ 48,481
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 18,777	$ 11,714	$ 9,045	$ 39,536
5145	Maintenance of Underground Conduit	$ 112	$ 117		$ 229
5150	Maintenance of Underground Conductors and Devices	$ 2,890	$ 7,307	$ 22,736	$ 32,933
5155	Maintenance of Underground Services	$ 19,274	$ 23,835	$ 20,329	$ 63,438
5160	Maintenance of Line Transformers	$ 19,077	$ 3,170	$ 67,039	$ 89,286
5165	Maintenance of Street Lighting and Signal Systems		$ 18		$ 18
5170	Sentinel Lights - Labour				$ -
5172	Sentinel Lights - Materials and Expenses		$ 7		$ 7
5175	Maintenance of Meters	$ 4,258	$ 1,456	$ 75,989	$ 81,702
5178	Customer Installations Expenses - Leased Property				$ -
5195	Maintenance of Other Installations on Customer Premises				$ -
Total - Maintenance		$ 90,544	$ 137,727	$ 1,723,135	$ 1,951,406

Account	Description	CPC	WPPI	ETPL	Total
Billing and Collecting					
5305	Supervision	$ 802			$ 802
5310	Meter Reading Expense	$ 25,603	$ 37,575		$ 63,178
5315	Customer Billing	$ 30,376	$ 119,404	$ 600,296	$ 750,077
5320	Collecting	$ 54,605	$ 29,276		$ 83,881
5325	Collecting - Cash Over and Short			-$ 100	-$ 100
5330	Collection Charges	-$ 13,590	-$ 5,100	$ 702	-$ 17,988
5335	Bad Debt Expense	$ 19,359	$ 10,940	-$ 14,407	$ 15,892
5340	Miscellaneous Customer Accounts Expenses	$ 50	$ 27,600		$ 27,650
Total - Billing and Collecting		$ 117,206	$ 219,695	$ 586,492	$ 923,393
Account	**Description**	**CPC**	**WPPI**	**ETPL**	**Total**
Community Relations					
5405	Supervision			$ 38,659	$ 38,659
5410	Community Relations - Sundry	$ 414			$ 414
5415	Energy Conservation				$ -
5420	Community Safety Program				$ -
5425	Miscellaneous Customer Service and Informational Expenses				$ -
5505	Supervision				$ -
5510	Demonstrating and Selling Expense				$ -
5515	Advertising Expenses	$ 324		$ 8,661	$ 8,985
5520	Miscellaneous Sales Expense				$ -
Total - Community Relations		$ 738	$ -	$ 47,320	$ 48,057

Account	Description	CPC	WPPI	ETPL	Total
Administrative and General Expenses					
5605	Executive Salaries and Expenses	$ 13,559		$ 223,778	$ 237,337
5610	Management Salaries and Expenses	$ 19,197		$ 952,365	$ 971,562
5615	General Administrative Salaries and Expenses	$ 2,944		$ 456,442	$ 459,386
5620	Office Supplies and Expenses	$ 18,205		$ 132,414	$ 150,619
5625	Administrative Expense Transferred - Credit				$ -
5630	Outside Services Employed	$ 21,149	$ 41,636	$ 273,399	$ 336,184
5635	Property Insurance	$ 2,976	$ 6,370	$ 66,488	$ 75,834
5640	Injuries and Damages				$ -
5645	Employee Pensions and Benefits	$ 6,127	-$ 3,641	$ 10,125	$ 12,611
5650	Franchise Requirements				$ -
5655	Regulatory Expenses	$ 16,512		$ 142,454	$ 158,967
5660	General Advertising Expenses				$ -
5665	Miscellaneous General Expenses	$ 16,983	$ 2,767	$ 90,698	$ 110,449
5670	Rent			$ 99,009	$ 99,009
5675	Maintenance of General Plant	$ 13,028	$ 54,907		$ 67,935
5680	Electrical Safety Authority Fees	$ 2,679			$ 2,679
5685	Independent Electricity System Operator Fees and Penalties				$ -
5695	OM&A Contra Account				$ -
6205	Donations (Charitable Contributions)				$ -
Total - Administrative and General Expenses		$ 133,359	$ 102,039	$ 2,447,172	$ 2,682,570
Total OM&A		$ 447,395	$ 598,619	$ 4,835,277	$ 5,881,291

OM&A COSTS TABLE 2009 DETAILED SEPARATELY

Account	Description	CPC	WPPI	ETPL	Total
Operations					
5005	Operation Supervision and Engineering	$ 14,648	$ 9,863	$ 45,628	$ 70,139
5010	Load Dispatching		$ 55		$ 55
5012	Station Buildings and Fixtures Expense				$ -
5014	Transformer Station Equipment - Operation Labour				$ -
5015	Transformer Station Equipment - Operation Supplies and Expenses				$ -
5016	Distribution Station Equipment - Operation Labour				$ -
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ 21,832			$ 21,832
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 1,114	$ 4,657		$ 5,771
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 3,559	$ 6,713	$ 50	$ 10,322
5030	Overhead Sub-transmission Feeders - Operation				$ -
5035	Overhead Distribution Transformers - Operation		$ 556		$ 556
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 94	$ 593		$ 687
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 29	$ 294		$ 322
5050	Underground Sub-transmission Feeders - Operation				$ -
5055	Underground Distribution Transformers - Operation	$ 278			$ 278
5060	Street Lighting and Signal System Expense				$ -
5065	Meter Expense	$ 472	$ 51,041		$ 51,513
5070	Customer Premises - Operation Labour		$ 512		$ 512
5075	Customer Premises - Operation Materials and Expenses		$ 5,961		$ 5,961
5085	Miscellaneous Distribution Expenses	$ 45,440	$ 42,340	$ 4,905	$ 92,685
5090	Underground Distribution Lines and Feeders - Rental Paid		$ 245		$ 245
5095	Overhead Distribution Lines and Feeders - Rental Paid		$ 588		$ 588
5096	Other Rent			$ 635	$ 635
Total - Operations		$ 87,466	$ 123,417	$ 51,217	$ 262,100

Account	Description	CPC	WPPI	ETPL	Total
Maintenance					
5105	Maintenance Supervision and Engineering			$ 3,284	$ 3,284
5110	Maintenance of Buildings and Fixtures - Distribution Stations			$ 66,240	$ 66,240
5112	Maintenance of Transformer Station Equipment	-$ 8			-$ 8
5114	Maintenance of Distribution Station Equipment		$ 31,619	$ 6,995	$ 38,614
5120	Maintenance of Poles, Towers and Fixtures	$ 52,078	$ 6,496	$ 32,996	$ 91,571
5125	Maintenance of Overhead Conductors and Devices	$ 13,884	$ 6,127		$ 20,011
5130	Maintenance of Overhead Services	$ 30,362	$ 9,856	$ 47,220	$ 87,438
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 18,014	$ 14,725	$ 38,377	$ 71,116
5145	Maintenance of Underground Conduit	$ 83	$ 493		$ 576
5150	Maintenance of Underground Conductors and Devices	$ 10,505	$ 4,479	$ 48,137	$ 63,121
5155	Maintenance of Underground Services	$ 18,218	$ 10,364	$ 20,955	$ 49,537
5160	Maintenance of Line Transformers	$ 23,168	$ 2,257	$ 35,684	$ 61,109
5165	Maintenance of Street Lighting and Signal Systems				$ -
5170	Sentinel Lights - Labour				$ -
5172	Sentinel Lights - Materials and Expenses				$ -
5175	Maintenance of Meters	$ 1,171	$ 9,332	$ 66,733	$ 77,235
5178	Customer Installations Expenses - Leased Property				$ -
5195	Maintenance of Other Installations on Customer Premises				$ -
Total - Maintenance		$ 167,476	$ 95,748	$ 366,619	$ 629,843

Account	Description	CPC	WPPI	ETPL	Total
Billing and Collecting					
5305	Supervision				$ -
5310	Meter Reading Expense	$ 26,049	$ 23,003		$ 49,053
5315	Customer Billing	$ 54,832	$ 97,077	$ 484,907	$ 636,816
5320	Collecting	$ 48,094	$ 95		$ 48,189
5325	Collecting - Cash Over and Short			$ 21	$ 21
5330	Collection Charges	-$ 9,751	$ 450	$ 255,855	$ 246,554
5335	Bad Debt Expense	-$ 36,724		$ 27,450	-$ 9,274
5340	Miscellaneous Customer Accounts Expenses	-$ 9			-$ 9
Total - Billing and Collecting		$ 82,492	$ 120,625	$ 768,233	$ 971,351
Account	**Description**	**CPC**	**WPPI**	**ETPL**	**Total**
Community Relations					
5405	Supervision			$ 2,430	$ 2,430
5410	Community Relations - Sundry	$ 11,384	$ 120	$ 35,213	$ 46,717
5415	Energy Conservation		$ 77,261		$ 77,261
5420	Community Safety Program		$ 1,321		$ 1,321
5425	Miscellaneous Customer Service and Informational Expenses			$ 107,158	$ 107,158
5505	Supervision				$ -
5510	Demonstrating and Selling Expense				$ -
5515	Advertising Expenses	$ 2,014	$ 1,470	$ 10,124	$ 13,608
5520	Miscellaneous Sales Expense				$ -
Total - Community Relations		$ 13,398	$ 80,173	$ 154,924	$ 248,494

Account	Description	CPC	WPPI	ETPL	Total
Administrative and General Expenses					
5605	Executive Salaries and Expenses	$ 900	$ 15,818	$ 209,940	$ 226,658
5610	Management Salaries and Expenses	$ 20,363	$ 1,853	$ 989,658	$ 1,011,874
5615	General Administrative Salaries and Expenses	$ 331	$ 64,716	$ 127,548	$ 192,595
5620	Office Supplies and Expenses	$ 19,372	$ 17,536	$ 199,969	$ 236,876
5625	Administrative Expense Transferred - Credit				$ -
5630	Outside Services Employed	$ 30,577	$ 160,521	$ 581,435	$ 772,533
5635	Property Insurance	$ 2,691	$ 1,774	$ 51,502	$ 55,967
5640	Injuries and Damages				$ -
5645	Employee Pensions and Benefits	$ 21,844	$ 24,791	$ 145,079	$ 191,713
5650	Franchise Requirements				$ -
5655	Regulatory Expenses	$ 21,094	$ 3,898	$ 196,079	$ 221,070
5660	General Advertising Expenses		$ 41		$ 41
5665	Miscellaneous General Expenses	$ 65,670	$ 44,818	$ 330,198	$ 440,685
5670	Rent		$ 10,798	$ 161,566	$ 172,365
5675	Maintenance of General Plant	$ 8,040	$ 25,434		$ 33,474
5680	Electrical Safety Authority Fees	$ 495	$ 1,706		$ 2,201
5685	Independent Electricity System Operator Fees and Penalties				$ -
5695	OM&A Contra Account				$ -
6205	Donations (Charitable Contributions)				$ -
Total - Administrative and General Expenses		$ 191,376	$ 373,703	$ 2,992,974	$ 3,558,052
Total OM&A		$ 542,207	$ 793,666	$ 4,333,967	$ 5,669,841

OM&A COSTS TABLE 2010 DETAILED SEPARATELY

Account	Description	CPC	WPPI	ETPL	Total
Operations					
5005	Operation Supervision and Engineering	$ 9,064	$ 6,939	$ 169,436	$ 185,439
5010	Load Dispatching		$ 837		$ 837
5012	Station Buildings and Fixtures Expense				$ -
5014	Transformer Station Equipment - Operation Labour				$ -
5015	Transformer Station Equipment - Operation Supplies and Expenses				$ -
5016	Distribution Station Equipment - Operation Labour				$ -
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ 18,001	$ 10,246		$ 28,247
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 15,922	$ 1,852		$ 17,774
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 1,940	$ 445		$ 2,385
5030	Overhead Sub-transmission Feeders - Operation				$ -
5035	Overhead Distribution Transformers - Operation	$ 860	$ 162		$ 1,022
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 663	$ 1,857		$ 2,520
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses		$ 8		$ 8
5050	Underground Sub-transmission Feeders - Operation				$ -
5055	Underground Distribution Transformers - Operation	$ 100			$ 100
5060	Street Lighting and Signal System Expense				$ -
5065	Meter Expense	-$ 20,105	$ 5,323		-$ 14,782
5070	Customer Premises - Operation Labour				$ -
5075	Customer Premises - Operation Materials and Expenses		$ 4,104		$ 4,104
5085	Miscellaneous Distribution Expenses	-$ 19,618	$ 36,545	$ 39,908	$ 56,836
5090	Underground Distribution Lines and Feeders - Rental Paid				$ -
5095	Overhead Distribution Lines and Feeders - Rental Paid				$ -
5096	Other Rent			$ 347	$ 347
Total - Operations		$ 6,827	$ 68,320	$ 209,691	$ 284,838

Account	Description	CPC	WPPI	ETPL	Total
Maintenance					
5105	Maintenance Supervision and Engineering	$ 636			$ 636
5110	Maintenance of Buildings and Fixtures - Distribution Stations			$ 117,201	$ 117,201
5112	Maintenance of Transformer Station Equipment	$ 89			$ 89
5114	Maintenance of Distribution Station Equipment	$ 2,383	-$ 8,764	$ 20,124	$ 13,742
5120	Maintenance of Poles, Towers and Fixtures	-$ 10,302	$ 7,257	$ 47,516	$ 44,471
5125	Maintenance of Overhead Conductors and Devices	$ 5,747	$ 3,479		$ 9,225
5130	Maintenance of Overhead Services	$ 5,755	$ 8,577	$ 83,027	$ 97,358
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 7,303	$ 13,713	$ 53,452	$ 74,467
5145	Maintenance of Underground Conduit	$ 2,227	$ 78	$ 148,126	$ 150,431
5150	Maintenance of Underground Conductors and Devices	$ 3,703	$ 2,264	$ 65,618	$ 71,584
5155	Maintenance of Underground Services	$ 10,090	$ 14,108	$ 28,033	$ 52,231
5160	Maintenance of Line Transformers	$ 6,321	$ 1,635	$ 58,019	$ 65,975
5165	Maintenance of Street Lighting and Signal Systems				$ -
5170	Sentinel Lights - Labour				$ -
5172	Sentinel Lights - Materials and Expenses				$ -
5175	Maintenance of Meters	$ 13,375	$ 3,094	$ 54,666	$ 71,136
5178	Customer Installations Expenses - Leased Property				$ -
5195	Maintenance of Other Installations on Customer Premises				$ -
Total - Maintenance		$ 47,326	$ 45,440	$ 675,782	$ 768,548

Account	Description	CPC	WPPI	ETPL	Total
Billing and Collecting					
5305	Supervision				$ -
5310	Meter Reading Expense	$ 43,316	$ 68,128		$ 111,444
5315	Customer Billing	$ 48,345	$ 90,896	$ 696,069	$ 835,310
5320	Collecting	$ 27,942	$ 2,233		$ 30,175
5325	Collecting - Cash Over and Short	-$ 11,160			-$ 11,160
5330	Collection Charges	-$ 63,989		$ 248,201	$ 184,212
5335	Bad Debt Expense		-$ 7,645	$ 28,280	$ 20,635
5340	Miscellaneous Customer Accounts Expenses	$ 1,823			$ 1,823
Total - Billing and Collecting		$ 46,278	$ 153,611	$ 972,550	$ 1,172,439

Account	Description	CPC	WPPI	ETPL	Total
Community Relations					
5405	Supervision		$ 200	$ 37,966	$ 38,166
5410	Community Relations - Sundry	$ 120	$ 21,662		$ 21,782
5415	Energy Conservation				$ -
5420	Community Safety Program				$ -
5425	Miscellaneous Customer Service and Informational Expenses			$ 112,726	$ 112,726
5505	Supervision				$ -
5510	Demonstrating and Selling Expense				$ -
5515	Advertising Expenses		$ 1,409	$ 9,774	$ 11,183
5520	Miscellaneous Sales Expense				$ -
Total - Community Relations		$ 120	$ 23,270	$ 160,466	$ 183,856

Account	Description	CPC	WPPI	ETPL	Total
Administrative and General Expenses					
5605	Executive Salaries and Expenses	$ 28,552	$ 32,314	$ 744,013	$ 804,878
5610	Management Salaries and Expenses	$ 148,832	$ 158,834	$ 390,366	$ 698,032
5615	General Administrative Salaries and Expenses	$ 33,390	$ 114,737	$ 101,636	$ 249,762
5620	Office Supplies and Expenses	$ 21,610	$ 18,996	$ 166,918	$ 207,524
5625	Administrative Expense Transferred - Credit				$ -
5630	Outside Services Employed	$ 157,937	$ 201,185	$ 64,859	$ 423,980
5635	Property Insurance	$ 12	$ 1,970	$ 49,107	$ 51,089
5640	Injuries and Damages				$ -
5645	Employee Pensions and Benefits	$ 16,796	$ 37,936	$ 216,413	$ 271,145
5650	Franchise Requirements				$ -
5655	Regulatory Expenses	$ 32,576	$ 42,895	$ 82,068	$ 157,540
5660	General Advertising Expenses	$ 2,167			$ 2,167
5665	Miscellaneous General Expenses	$ 14,882	$ 41,955	$ 233,336	$ 290,174
5670	Rent		$ 15,489	$ 267,433	$ 282,923
5675	Maintenance of General Plant	$ 2,912	$ 12,847		$ 15,759
5680	Electrical Safety Authority Fees	$ 317			$ 317
5685	Independent Electricity System Operator Fees and Penalties			$ 102,370	$ 102,370
5695	OM&A Contra Account				$ -
6205	Donations (Charitable Contributions)				$ -
Total - Administrative and General Expenses		$ 459,983	$ 679,159	$ 2,418,519	$ 3,557,661
Total OM&A		$ 560,534	$ 969,800	$ 4,437,008	$ 5,967,342

MANAGERS SUMMARY
DEPARTMENTAL AND CORPORATE OM&A ACTIVITIES:

OPERATIONS & MAINTENANCE:

The expenses for this department include all costs relating to the operation (5000-5095) and maintenance (5105-5195) of the Erie Thames Powerlines Corp electrical system. This includes both direct labor costs and non-capital material spending to support both scheduled and reactive maintenance events. In addition, costs are allocated from support departments to cover the costs of Labour Burden, Engineering, Stores, Garage, and Service Center. Erie Thames Powerlines Corp's maintenance strategy is, to the extent possible, to minimize reactive and emergency-type work through an effective planned maintenance program (including predictive and preventative actions). Erie Thames Powerlines Corp's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with Erie Thames Powerlines Corp's capital project work, so that where maintenance programs have identified matters the correction of which require capital investments, Erie Thames Powerlines Corp may adjust its capital spending priorities to address those matters.

Predictive Maintenance:

Predictive maintenance activities involve the testing of elements of the Erie Thames Powerlines Corp distribution system. These activities include, but not limited to, transformer oil analysis, and planned visual inspections. These analysis and inspections are all administered using a planned schedule. Any identified deficiencies found are prioritized and addressed within a suitable time frame. In establishing the predictive maintenance requirements, ETPL considers the distribution system code requirements, ESA regulation 22/04 and good utility practices.

Preventative Maintenance:

Preventative maintenance activities include inspection, servicing and repair of network components. This includes tree trimming, overhead and pad-mounted load break switch maintenance, and cleaning/inspection of underground vaults. Also included are regular inspection and repair of substation components, relays, and ancillary equipment. The work is performed using a combination of time and condition based methodologies. In establishing the preventative maintenance requirements, ETPL considers the distribution system code requirements, ESA regulation 22/04 and good utility practices.

Emergency Maintenance:

This item includes unexpected system repairs to the electrical system that must be addressed immediately. The costs include those related to repairs caused by storm damage, emergency tree trimming and on-call premiums. Erie Thames Powerlines Corp constantly evaluates its maintenance data to adjust predictive and preventative actions. The objective is to keep this emergency maintenance to a minimum.

Service Work:

The majority of costs related to this work pertain to service upgrades requested by customers, and requests to provide safety coverage for work (overhead line cover ups). This includes service disconnections and reconnections by Erie Thames Powerlines Corp for all service classes; assisting pre-approved contractors; the making of final connections after Electrical Safety Authority ("ESA") inspection for service upgrades; and changes of service locations.

Metering:

The Metering function is a combination of in-house and third party personnel. They are responsible for the installation, testing, and commissioning of new and existing simple and complex metering installations. Testing of complex metering installations ensures the accuracy of the installation and verifies meter multipliers for billing purposes. Revenue Protection is another key activity performed by Metering, by proactively investigating potential diversion and theft of Powerlines.

Substation Services:

Substation services activities address the maintenance of all equipment at Erie Thames Powerlines Corp's substations. This includes both labor costs and non-capital material spending to support both scheduled and emergency maintenance events. As with the maintenance activities, Erie Thames Powerlines Corp's substation maintenance strategy focuses on minimizing, to the extent possible, emergency-type work by improving the effectiveness of Erie Thames Powerlines Corp planned maintenance program (including predictive and preventative actions) for its substations. Erie Thames Powerlines Corp is primarily an old 4kV system which has just started to convert to a modern 27kV system. This will ultimately allow Erie Thames Powerlines Corp to decommission its two old municipal substations, which in return will reduce distribution losses and ongoing operating costs. Erie Thames Powerlines used both internal and external third party personnel to maintain our two substations, this is the most efficient and cost effective method for us.

Engineering Department:

Engineering is responsible for delivering underground utility locating services for excavating contractors and for design and construction activities including new capital projects and customer connections. Engineering also provides distribution system asset information too many departments within Erie Thames Powerlines Corp. Engineering costs are allocated to operations, maintenance, capital, and Third Party receivable accounts based on direct labor costs. A standard overhead percentage is set at the beginning of the year and adjusted throughout the year as necessary. Due to ETPL's size some engineering functions are outsourced helping to reduce ongoing O & M costs.

Stores/Warehouse:

Stores staff are accountable for control, and movement of materials within Erie Thames Powerlines Corp's service centres in Ingersoll, Aylmer and Mitchell. This includes monitoring inventory levels, issuing material receipts, material issues, and material returns as required. The cost of the stores department is allocated to all departmental, capital, intercompany receivables, and Third Party receivable accounts as an overhead cost based on direct material costs. A standard overhead percentage is set at the beginning of the year and adjusted throughout the year as necessary. Erie Thames Powerlines is part of a purchasing group and Purchases are administrated by Eire Thames Powerlines Line on our behalf.

Garage/Fleet:

Management is responsible for the maintenance and control of all vehicles. Its objectives include maintenance of vehicle reliability and safety, and the minimization of vehicle down time. Vehicle costs are allocated to operations, maintenance, capital, intercompany receivables, and Third Party receivable accounts based on number of hours used. A standard hourly cost/hr is set for all vehicles within the fleet.

Labour Burden:

Management collects the cost of all employee benefits and payroll taxes such as EI, CPP, EHT, WSIB, and group insurances. Costs are allocated to all departments, capital projects, intercompany receivable and Third Party receivable amounts based on direct labour. An overhead rate is set at the beginning of each year and adjusted throughout the year as necessary.

Safety & Health:

Costs include Health & Safety program supplies, the costs of third party training facilitators, as well internal labour costs associated with safety training and meetings. Erie Thames Powerlines Corp is committed to maximizing productivity and reducing risk of injury by initiating safety and health measures that focus on preventative actions. The commitment to safety and health is significant, and involves documenting unsafe behaviors, monitoring conformance to established standards and policies, determining the effectiveness of safety training and monitoring the resolution of safety recommendations/audits; commitment to continuous improvement in training; and identifying and correcting root causes for system deficiencies. The costs of Safety and Health for lineman are allocated to capital and O & M expenses based on standard overhead set at the beginning of the year, and adjusted throughout the year as necessary. Health and Safety costs for employees other than lineman are charged directly to each general ledger account for a given department.

Customer Service:

Customer Service is responsible for the customer care activities for the customers in Erie Thames Powerlines Corp's service area. These activities include meter reading, billing, call centre, collections, and other back office functions. Erie Thames Powerlines aspires to achieve customer service excellence in its processes and customer programs. The costs associated with the Customer Service department are collected in accounts 5305 to 5515. This function is handled by Erie Thames Powerlines staff beginning in 2011 and prior to it was outsourced to ETPL's affiliate Ecaliber for the entire Billing, Collecting and Call Centre function. ETPL continues to outsource a portion of its costs to Ecaliber, however this arrangement is currently for the provision, hosting and maintenance of the Harris billing software system. All other functions are performed by ETPL staff. ETPL provides services to Ecaliber, for billing its third party customers, on a time and material basis. The revenues for these services are provided as part of the other revenue section of the application. Going forward ETPL expects to record these revenues as an offset to the billing department costs in order to portray an accurate picture of ETPL's true costs.

Meter Reading:

Meter reading services are contracted out to Utilismart under a service contract agreement.

Billing:

Erie Thames Powerlines Corp customers are on monthly billing. An annual billing schedule is created based on the meter reading schedule to ensure timely billing of services. The billing functions include the VEE processes; account adjustments; processing meter changes; various account related field service orders and mailing services and EBT and retailer settlement functions for retailer accounts. Erie Thames Powerlines Corp offers customers a number of billing and payment options including an equal payment plan, electronic payments billing, and a preauthorized payment plan. This service is outsourced to Ecaliber Inc.

Collections:

Collections are outsourced to Ecaliber Inc. who is responsible for a combination of activities, including the collection of overdue active accounts, security deposits and final bills for service termination. In determining the bad debt expenses for the year, Erie Thames Powerlines Corp refers to its past history of losses by rate class to establish amounts for the year. There are also specific adjustments to the current provision based on other factors such as the economic factors, with special considerations for specific industries facing difficulties. In an effort to minimize credit losses, Erie Thames Powerlines Corp enforces prudent credit policies in accordance with the Distribution System Code. Customer deposits are required according to the Distribution system Code, and are outlined in Erie Thames Powerlines Corp's Conditions of Service. Active overdue accounts are collected by in-house staff through notices, letters and direct telephone contact.

Customer Service:

The Customer Service function is outsourced to Ecaliber Inc. who are responsible for such activities as payment processing; move in and out requests; and call centre activities for Erie Thames Powerlines Corp's service territory. Call volumes are fairly constant year over year, but may vary due to factors such as storm damages/outages, distribution rate changes, and retailers going door to door in the service territory.

Community Relations:

Erie Thames Powerlines Corp is committed to providing consumer information and responses, in a timely and proactive manner, on electricity distribution and related issues. Since LDCs are the "face-to-the-customer" for the electricity industry, Erie Thames Powerlines Corp has an important role to play in educating the public about electricity safety and energy conservation, as described below:

Education – Electricity Safety:

Erie Thames Powerlines Corp supports elementary schools in its service territory by providing Electricity Safety and Conservation sessions for students in grades five. These highly interactive sessions educate children in the dangers of electricity.

Education – Energy Conservation:

Building a conservation culture continues to be an important objective for Erie Thames Powerlines Corp. ETPL is very active in the community promoting conservation initiatives, attending a number of community events each year, distributing compact florescent light bulbs and energy conservation handbooks. Erie Thames Powerlines Corp dispersed all of its third tranche funding on various CDM programs. It has since actively participated with the OPA in administering their programs directed at Energy Conservation, which includes Every Kilowatt Counts, Great Refrigerator Round Up, Summer Sweepstakes, Electricity Rebate Incentive Program (ERIP), Powerlines Savings Blitz and PeakSaver Program.

Administration & General Expenses:

Administrative and general expenses include expenses incurred in connection with the general administration of the utility's operations. Within Erie Thames Powerlines Corp, the following functional areas are considered to be part of general administration and, as such, all expenses incurred within these functional areas are accounted for as administrative and general expenses:

- Executive Management (5605);
- General Administrative Salaries and Expenses (5615);

Executive Salaries and Expenses: 5605

Remuneration and other expenses of the members of the Erie Thames Powerlines Corp Board of Directors are included in this account. The President is responsible for all aspects of Erie Thames Powerlines Corp and his salary and benefits are charged to account 5605.

General Administrative Salaries and Expenses: 5615

Financial/Regulatory Services:

Management, third party accountants and Regulatory specialists are responsible for the preparation of statutory, management and Board of Directors financial reporting in accordance with GAAP/IFRS; all daily accounting functions, including accounts payable, accounts receivable, and general accounting; treasury functions including cash management, risk management, accounting systems and internal control processes; preparation of consolidated budgets and forecasts; and supporting tax compliance. Expenses include salaries and all related expenses associated with the Financial and Regulatory Analyst, Senior Accountant, Accounts Payable Clerk, and General Office Clerk. The Finance Department is also responsible for all regulatory reporting and compliance with applicable codes and legislation governing Erie Thames Powerlines Corp. Regulatory reporting includes development and preparation of rate filings, performance reporting, and compliance. Expenses include salary and related costs associated with the Financial and Regulatory Analyst.

Information Technology Services:

Management and third party specialists are responsible for the development, operation, maintenance and security of all business system applications utilized by the utility in its operations. These include the customer information, financial management and work management systems. Expenses and all related costs associated with the Manager of Information Systems are charged to an account then re-allocated to other departments.

Outside Service Employed: 5630

Outside Services Employed include, but are not limited to, consulting and professional fees of accountants and auditors, actuaries, legal services, environmental monitoring costs, human resource professionals and tax consultants. Professional and other expenses related to the 2010 Cost of Service Rate Application is included in 5655 Regulatory Expenses.

Employee Post-Retirement Benefits: 5645

Employee Post-Retirement Benefits include annual expenses for post-retirement benefits provided to eligible Erie Thames Powerlines Corp employees in accordance with company policy and as provided in the collective bargaining agreement between Erie Thames Powerlines Corp and its union. The annual expense and liability are determined in accordance with Section 3461 of the CICA Handbook and supported by an actuarial valuation that is completed every three years. Also included in this account are actual premiums paid for benefits for existing retirees.

Regulatory Expenses: 5655

Regulatory Expenses include those expenses incurred in connection with Decisions and Orders on Cost Awards for hearings, proceedings, technical sessions, and other matters before the OEB or other regulatory bodies, including annual assessment fees paid to a regulatory body. Annual fees assessed by the OEB are included in this expenditure category. All incremental costs associated with the 2012 Cost of Service Rate Application are included in this account and are included at one fourth their cost to allow for recovery over four years.

Miscellaneous General Expense: 5665

Miscellaneous General Expense includes EDA membership fees. Also included in this category are health and safety costs (general – not charged to specific departments) and other miscellaneous costs.

Electrical Safety Authority Fees: 5680

Expenses under Electrical Safety Authority ("ESA") fees include all annual charges from the ESA.

VARIANCE ANALYSIS ON OM&A COSTS

VARIANCE ANALYSIS ON OM&A COSTS:

Erie Thames Powerlines Corp has provided a detailed OM&A cost table covering the periods from 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year and 2012 Test Year including the variances year over year in Exhibit 4, Tab 2, Schedule 3, above. Before moving to a variance analysis for each account that exceeds the materiality threshold, a summary of total OM&A expenses (excluding depreciation) are presented below along with an analysis of the total movement from 2006 Actual in the first column through to 2010 Test Year in the final column.

OM&A Cost per Customer and per FTEE

	LRY - Board Approved	2008	2009	2010	Bridge Year	Test Year
Number of Customers	17,299	17,299	16,813	17,693	23,129	23,213
Total OM&A from Appendix 2-G	$ 4,193,808	$ 5,881,291	$ 5,669,841	$ 5,967,342	$ 5,782,518	$ 5,601,237
OM&A cost per customer	$ 242.43	$ 339.98	$ 337.23	$ 337.27	$ 250.01	$ 241.30
Number of FTEEs	2	2	15	34	45	45
Customers/FTEEs	8,649.50	8,649.50	1,120.86	520.38	513.98	515.84
OM&A Cost per FTEE	$2,096,904.00	$2,940,645.42	$ 377,989.37	$ 175,510.06	$ 128,500.40	$ 124,471.93

In addition, a table is provided indicating OM&A cost per customer and OM&A cost per FTE for 2006 through 2010 as well as a table that highlights various regulatory costs incurred and expected in the bridge and test years. The following table identifies key cost drivers from 2008 to 2012 Test year:

OM&A Cost Driver Table

OM&A	LRY - Actual	2009	2010	Bridge Year	Test Year
Opening Balance	$ 5,881,291	$ 5,669,840	$ 5,967,342	$ 5,782,517	$ 5,601,237
Wage savings during labour disruption	-$ 374,345				
Excess third pary costs due to Labour disruption/security	$ 436,349				
No Cost of Service Rate Application Costs in 2009	-$ 199,708				
Addition of staff transferred from Affiliate	$ 1,247,816				
Reduction in Fixed Price Affiliate Contract after addition of Staff	-$ 1,321,563				
Less Outside services due to no labour disruption		-$ 348,553			
Increase in employee costs due to movement of line staff back into the utility		$ 79,431	$ 192,481		
Increase in rent costs due to new non Affiliate structure		$ 110,558	$ 39,478		
Increase in labour costs due to movement of staff back from the affiliate		$ 1,615,946	$ 1,025,240		
Decrease in Affiliate costs due to labour moved back from the affiliate		-$ 1,419,135	$ (900,373)		
No Cost of Service Rate Application Costs in 2011 for WPPI and CPC		$ 259,255	-$ 259,255		
Increase in Capitalized labour in 2011 results in decreased expense for line staff			-$ 234,887		
Change in community relations expenses			-$ 47,509		
Increase in billing costs due to full year of Time of Use billing				$ 115,501	
Increase in Capitalized labour in 2012 results in decreased expense for line staff				-$ 226,467	
Decrease in outside service due to completion of merger and corporate structure changes				-$ 70,315	
Closing Balance	$ 5,669,840	$ 5,967,342	$ 5,782,517	$ 5,601,237	$ 5,601,237

As the above table indicates there has been a reduction in costs over time as the utility has merged and gained efficiencies.

Labour:

The variation in labour should not be viewed as being inconsistent. Since deregulation and the approach that Erie Thames Powerlines chose to implement with the affiliate model, Erie Thames has had very little labour costs, only employing two direct staff from deregulation until 2008 when some key LDC specific staff were moved within the regulated entity. Following the labour interruption in 2009 ETPL then added the Lineman staff to its labour complement, and finally in January of 2011 ETPL took over the Customer Service staff in the last step of moving away from the virtual utility model. The amount of labour charged to OM&A is also dependent on the amount of labour spent on capital projects, third party work and smart Meter installation. These amounts have increased over time as ETPL gained more control over the deployment of its labour force and the need for increased spending on its aging infrastructure became apparent. Lastly as ETPL has merged with West Perth and Clinton Power, the staff complement has grown and evolved to meet the needs of the geographically diverse distribution system.

Appendix 2-J
OM&A Variance Analysis
(excluding Depreciation and Amortization)

Account	Description	Last Board-approved Rebasing Year (2008 Actuals)	Most Current Actual Year (2010)	Test Year (2012)	Test Year Versus Last Rebasing Variance ($)	Test Year Versus Last Rebasing Percentage	Test Year Versus Most Current Actuals Variance ($)	Test Year Versus Most Current Actuals Percentage
Operations								
5005	Operation Supervision and Engineering	$ 44,234	$ 185,439	$ 193,036	$ 148,802	336.40%	$ 7,596	4.10%
5010	Load Dispatching	$ -	$ 837	$ -	$ -		-$ 837	-100.00%
5012	Station Buildings and Fixtures Expense	$ 36	$ -	$ -	-$ 36	-100.00%	$ -	
5014	Transformer Station Equipment - Operation Labour	$ -	$ -	$ -	$ -		$ -	
5015	Transformer Station Equipment - Operation Supplies and Expenses	$ 620	$ -	$ -	-$ 620	-100.00%	$ -	
5016	Distribution Station Equipment - Operation Labour	$ -	$ -	$ -	$ -		$ -	
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ 39,666	$ 28,247	$ 3,519	-$ 36,147	-91.13%	-$ 24,728	-87.54%
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 6,703	$ 17,774	$ 3,683	-$ 3,020	-45.05%	-$ 14,091	-79.28%
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 2,194	$ 2,385	$ 1,441	-$ 754	-34.34%	-$ 944	-39.59%
5030	Overhead Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -		$ -	
5035	Overhead Distribution Transformers - Operation	$ 254	$ 1,022	$ -	-$ 254	-100.00%	-$ 1,022	-100.00%
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 964	$ 2,520	$ 384	-$ 581	-60.20%	-$ 2,136	-84.77%
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 502	$ 8	$ 28	-$ 474	-94.45%	$ 20	253.81%
5050	Underground Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -		$ -	
5055	Underground Distribution Transformers - Operation	$ 742	$ 100	$ -	-$ 742	-100.00%	-$ 100	-100.00%
5060	Street Lighting and Signal System Expense	$ 1,204	$ -	$ -	-$ 1,204	-100.00%	$ -	
5065	Meter Expense	-$ 6,329	-$ 14,782	$ 6,150	$ 12,478	-197.17%	$ 20,931	-141.60%
5070	Customer Premises - Operation Labour	$ -	$ -	$ 196	$ 196		$ 196	
5075	Customer Premises - Operation Materials and Expenses	$ -	$ 4,104	$ 9	$ 9		-$ 4,095	-99.78%
5085	Miscellaneous Distribution Expenses	$ 135,789	$ 56,836	$ 73,770	-$ 62,019	-45.67%	$ 16,934	29.79%
5090	Underground Distribution Lines and Feeders - Rental Paid	$ 1,050	$ -	$ -	-$ 1,050	-100.00%	$ -	
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ 3,029	$ -	$ -	-$ 3,029	-100.00%	$ -	
5096	Other Rent	$ 45,206	$ 347	$ -	-$ 45,206	-100.00%	-$ 347	-100.00%
Total - Operations		$ 275,864	$ 284,838	$ 282,215	$ 6,350	2.30%	-$ 2,624	-0.92%
Account	**Description**							
Maintenance								
5105	Maintenance Supervision and Engineering	$ -	$ 636	$ -	$ -		-$ 636	-100.00%
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$ 1,402,007	$ 117,201	$ 95,941	-$ 1,306,066	-93.16%	-$ 21,260	-18.14%
5112	Maintenance of Transformer Station Equipment	$ -	$ 89	$ -	$ -		-$ 89	-100.00%
5114	Maintenance of Distribution Station Equipment	$ 32,579	$ 13,742	$ 3,386	-$ 29,194	-89.61%	-$ 10,356	-75.36%
5120	Maintenance of Poles, Towers and Fixtures	$ 129,504	$ 44,471	$ 39,790	-$ 89,714	-69.27%	-$ 4,681	-10.52%
5125	Maintenance of Overhead Conductors and Devices	$ 31,685	$ 9,225	$ 5,846	-$ 25,839	-81.55%	-$ 3,379	-36.63%
5130	Maintenance of Overhead Services	$ 48,481	$ 97,358	$ 76,064	$ 27,582	56.89%	-$ 21,295	-21.87%
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 39,536	$ 74,467	$ 114,915	$ 75,379	190.66%	$ 40,448	54.32%
5145	Maintenance of Underground Conduit	$ 229	$ 150,431	$ 145,053	$ 144,824	63244.64%	-$ 5,378	-3.58%
5150	Maintenance of Underground Conductors and Devices	$ 32,933	$ 71,584	$ 54,472	$ 21,539	65.40%	-$ 17,112	-23.90%
5155	Maintenance of Underground Services	$ 63,438	$ 52,231	$ 55,162	-$ 8,276	-13.05%	$ 2,931	5.61%
5160	Maintenance of Line Transformers	$ 89,286	$ 65,975	$ 103,105	$ 13,819	15.48%	$ 37,129	56.28%
5165	Maintenance of Street Lighting and Signal Systems	$ 18	$ -	$ -	-$ 18	-100.00%	$ -	
5170	Sentinel Lights - Labour	$ -	$ -	$ -	$ -		$ -	
5172	Sentinel Lights - Materials and Expenses	$ 7	$ -	$ -	-$ 7	-100.00%	$ -	
5175	Maintenance of Meters	$ 81,702	$ 71,136	$ 30,616	-$ 51,087	-62.53%	-$ 40,520	-56.96%
5178	Customer Installations Expenses - Leased Property	$ -	$ -	$ -	$ -		$ -	
5195	Maintenance of Other Installations on Customer Premises	$ -	$ -	$ -	$ -		$ -	
Total - Maintenance		$ 1,951,406	$ 768,548	$ 724,349	-$ 1,227,057	-62.88%	-$ 44,199	-5.75%

Account Description							
Billing and Collecting							
5305 Supervision	$ 802	$ -	$ 18,631	$ 17,829	2223.05%	$ 18,631	
5310 Meter Reading Expense	$ 63,178	$ 111,444	$ 34,209	-$ 28,969	-45.85%	-$ 77,235	-69.30%
5315 Customer Billing	$ 750,077	$ 835,310	$ 906,125	$ 156,048	20.80%	$ 70,815	8.48%
5320 Collecting	$ 83,881	$ 30,175	$ 21,823	-$ 62,059	-73.98%	-$ 8,353	-27.68%
5325 Collecting - Cash Over and Short	-$ 100	-$ 11,160	$ -	$ 100	-100.00%	$ 11,160	-100.00%
5330 Collection Charges	-$ 17,988	$ 184,212	$ 118,316	$ 136,304	-757.75%	-$ 65,895	-35.77%
5335 Bad Debt Expense	$ 15,892	$ 20,635	$ -	-$ 15,892	-100.00%	-$ 20,635	-100.00%
5340 Miscellaneous Customer Accounts Expenses	$ 27,650	$ 1,823	$ 27	-$ 27,623	-99.90%	-$ 1,796	-98.53%
Total - Billing and Collecting	$ 923,393	$ 1,172,439	$ 1,099,131	$ 175,739	19.03%	-$ 73,308	-6.25%
Account Description							
Community Relations							
5405 Supervision	$ 38,659	$ 38,166	$ 2,160	-$ 36,499	-94.41%	-$ 36,006	-94.34%
5410 Community Relations - Sundry	$ 414	$ 21,782	$ 19,179	$ 18,765	4535.69%	-$ 2,603	-11.95%
5415 Energy Conservation	$ -	$ -	$ -	$ -		$ -	
5420 Community Safety Program	$ -	$ -	$ -	$ -		$ -	
5425 Miscellaneous Customer Service and Informational Expenses	$ -	$ 112,726	$ 120,029	$ 120,029		$ 7,303	6.48%
5505 Supervision	$ -	$ -	$ -	$ -		$ -	
5510 Demonstrating and Selling Expense	$ -	$ -	$ -	$ -		$ -	
5515 Advertising Expenses	$ 8,985	$ 11,183	$ 7,415	-$ 1,570	-17.47%	-$ 3,768	-33.69%
5520 Miscellaneous Sales Expense	$ -	$ -	$ -	$ -		$ -	
Total - Community Relations	$ 48,057	$ 183,856	$ 148,783	$ 100,725	209.59%	-$ 35,074	-19.08%
Account Description							
Administrative and General Expenses							
5605 Executive Salaries and Expenses	$ 237,337	$ 804,878	$ 218,390	-$ 18,947	-7.98%	-$ 586,488	-72.87%
5610 Management Salaries and Expenses	$ 971,562	$ 698,032	$ 1,194,776	$ 223,214	22.97%	$ 496,744	71.16%
5615 General Administrative Salaries and Expenses	$ 459,386	$ 249,762	$ 361,626	-$ 97,760	-21.28%	$ 111,864	44.79%
5620 Office Supplies and Expenses	$ 150,619	$ 207,524	$ 143,722	-$ 6,897	-4.58%	-$ 63,802	-30.74%
5625 Administrative Expense Transferred - Credit	$ -	$ -	$ -	$ -		$ -	
5630 Outside Services Employed	$ 336,184	$ 423,980	$ 180,378	-$ 155,805	-46.35%	-$ 243,602	-57.46%
5635 Property Insurance	$ 75,834	$ 51,089	$ -	-$ 75,834	-100.00%	-$ 51,089	-100.00%
5640 Injuries and Damages	$ -	$ -	$ 13,438	$ 13,438		$ 13,438	
5645 Employee Pensions and Benefits	$ 12,611	$ 271,145	$ 413,502	$ 400,891	3178.98%	$ 142,357	52.50%
5650 Franchise Requirements	$ -	$ -	$ -	$ -		$ -	
5655 Regulatory Expenses	$ 158,967	$ 157,540	$ 115,000	-$ 43,967	-27.66%	-$ 42,540	-27.00%
5660 General Advertising Expenses	$ -	$ 2,167	$ -	$ -		-$ 2,167	-100.00%
5665 Miscellaneous General Expenses	$ 110,449	$ 290,174	$ 295,456	$ 185,007	167.51%	$ 5,282	1.82%
5670 Rent	$ 99,009	$ 282,923	$ 322,401	$ 223,392	225.63%	$ 39,478	13.95%
5675 Maintenance of General Plant	$ 67,935	$ 15,759	$ 80,204	$ 12,270	18.06%	$ 64,445	408.93%
5680 Electrical Safety Authority Fees	$ 2,679	$ 317	$ 7,865	$ 5,186	193.63%	$ 7,548	2379.21%
5685 Independent Electricity System Operator Fees and Penalties	$ -	$ 102,370	$ -	$ -		-$ 102,370	-100.00%
5695 OM&A Contra Account	$ -	$ -	$ -	$ -		$ -	
6205 Donations (Charitable Contributions)	$ -	$ -	$ -	$ -		$ -	
Total - Administrative and General Expenses	$ 2,682,570	$ 3,557,661	$ 3,346,759	$ 664,189	24.76%	-$ 210,901	-5.93%
Total OM&A	$ 5,881,291	$ 5,967,342	$ 5,601,237	-$ 280,054	-4.76%	-$ 366,105	-6.14%

EMPLOYEE DESCRIPTION

OVERVIEW:

Erie Thames Powerlines has undergone radical change since its last Cost of Service application. Not only has it completed a merger with two other LDC's (Clinton and West Perth), it has moved from a virtual utility with only two employees in 2008 to a fully staffed and operational LDC in 2011. 2011 represents the culmination of all of these changes and from an employee perspective this changes are detailed below.

Number of employees (Full-time equivalents (FTE's)):

ETPL 33 unionized staff:

- 19- Operations Staff
- 3- Engineering Staff
- 11-Customer Service/Office Staff

Executive/Management:

- 1 – Executive
- 5 - Management
- 6 - Supervisors

Contract

Erie Thames Powerlines Corp. staff has a formal contract which expires on December 31st 2012, the current contracts pay rates is in line with other LDC's in the Southwestern Region.

Benefits

A comprehensive and competitive benefits package exists with include medical insurance, life insurance, vacation and a defined pension plan (see below) which are in line with other LDC's in the Province.

Pension

ETPL and its employees contribute to the Ontario Municipal Employees Retirement Service (OMERS), a defined benefit pension plan.

Employee Incentive

ETPL does not currently have an incentive plan.

Post Retirement Benefits

ETPL has ongoing Post Retirement Benefits for retirees prior to 2006 and ongoing.

Appendix 2-K
Employee Costs

	LRY - Board Approved	LRY - Actual	2009	2010	Bridge Year	Test Year
Number of Employees (FTEs including Part-Time)[1]						
Executive						
Management	2	2	6	10	12	12
Non-Union						
Union			9	24	33	33
Total	2	2	15	34	45	45
Number of Part-Time Employees						
Executive						
Management						
Non-Union						
Union						
Total	-	-	-	-	-	-
Total Salary and Wages						
Executive						
Management			$ 482,754	$ 829,474	$ 1,026,153	$ 1,080,161
Non-Union						
Union			$ 357,331	$ 1,473,530	$ 2,088,767	$ 2,153,368
Total	$ -	$ -	$ 840,085	$ 2,303,004	$ 3,114,920	$ 3,233,529
Current Benefits						
Executive						
Management			$ 193,101	$ 331,789	$ 410,461	$ 432,064
Non-Union						
Union			$ 214,629	$ 885,070	$ 1,254,609	$ 1,293,412
Total	$ -	$ -	$ 407,731	$ 1,216,859	$ 1,665,071	$ 1,725,476
Accrued Pension and Post-Retirement Benefits						
Executive						
Management						
Non-Union						
Union						
Total	$ -	$ -	$ -	$ -	$ -	$ -
Total Benefits (Current + Accrued)						
Executive	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ -	$ -	$ 193,101	$ 331,789	$ 410,461	$ 432,064
Non-Union	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ -	$ -	$ 214,629	$ 885,070	$ 1,254,609	$ 1,293,412
Total	$ -	$ -	$ 407,731	$ 1,216,859	$ 1,665,071	$ 1,725,476
Total Compensation (Salary, Wages, & Benefits)						
Executive	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ -	$ -	$ 675,855	$ 1,161,263	$ 1,436,614	$ 1,512,225
Non-Union	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ -	$ -	$ 571,961	$ 2,358,600	$ 3,343,377	$ 3,446,780
Total	$ -	$ -	$ 1,247,816	$ 3,519,863	$ 4,779,991	$ 4,959,005
Compensation - Average Yearly Base Wages						
Executive						
Management	$ -	$ -	$ 80,458.94	$ 82,947.36	$ 85,512.75	$ 90,013.42
Non-Union						
Union	#DIV/0!	#DIV/0!	$ 39,703.46	$ 61,397.10	$ 63,295.98	$ 65,253.58
Total						

Compensation - Average Yearly Overtime						
Executive						
Management	$ -	$ -	$ -	$ -	$ -	$ -
Non-Union						
Union			$ -	$ 169,261.21	$ 180,065.11	$ 191,558.63
Total						
Compensation - Average Yearly Incentive Pay						
Executive						
Management						
Non-Union						
Union						
Total						
Compensation - Average Yearly Benefits						
Executive						
Management			$ 32,184	$ 33,179	$ 34,205	$ 36,005
Non-Union						
Union			$ 23,848	$ 36,878	$ 38,018	$ 39,194
Total						
Total Compensation	$ -	$ -	$ 1,247,816	$ 3,519,863	$ 4,779,991	$ 4,959,005
Total Compensation Charged to OM&A			$ 1,247,816	$ 2,863,761.74	$ 3,889,001.75	$ 3,662,535.20
Total Compensation Capitalized	$ -	$ -	$ -	$ 656,102	$ 890,989	$ 1,296,470

PURCHASE OF PRODUCTS AND SERVICES FROM NON-AFFILIATES

Erie Thames Powerlines, like other distributors, purchases many services and products from third parties.

The ETPL purchase policy is as follows:
The purchasing of goods and services fall into one of four categories:

- Tenders – are used for non-stock items or service contracts valued at $50,000 or more.
- Quotations – above $5,000
- Routine purchases -
- Local Purchase orders

Tender:

A Tender can only be issued by the President, or the purchasing department.
Tender packages will typically be sent directly to at least three (3) vendors known to specialize in the item or service, however, a Request for Tender may be advertised if there are an insufficient number of known vendors. A period of at least two (2) weeks is required for the vendors to review the tender package and respond. Receipt of tenders must be in sealed envelopes clearly marked as to the contents. Tenders will be opened at the time of closing by the President, or designate. Unless otherwise specified by the Board of Directors, bidders are not permitted to attend the tender opening. The tenders will be evaluated by one or more suitable employees, and a recommendation prepared for approval by the Board of Directors. For specialized goods or services, it is permitted to have the tenders evaluated by an external third party such as an engineering consultant. Following award of the tender by the Board of Directors, the successful bidder will be immediately notified by the appropriate manager, and a purchase order initiated via a material requisition. The remaining bidders will be notified in writing of the name of the successful bidder.

Quotations:

If quotations are used for purchases above $5,000 they do not fit the tender category. Quotations may be issued by any Manager. The Request for Quotation package will typically be sent to at least three (3) vendors known to specialize in the item or service; however, there are some items and services with fewer than three (3) vendors. A period of two (2) weeks for evaluation and response is recommended for items that are usually made to order, or for service contracts such as line construction. Shorter periods are acceptable for “off the shelf” items or routine services. Quotations are normally accepted in hardcopy, fax, or email format but their contents must be kept confidential until the closing date. Sealed quotations are recommended for purchases above $25,000. The quotations will be reviewed by the appropriate employee(s) after the closing date, and a recommendation made to the appropriate manager. Approval by the President is required for quotes valued above $10,000 for stock items, and above $2,500 for non-stock items or service contracts. The President will approve quotes for service contracts. Approval by the appropriate Manager is required for quotes above $2,500 for stock items. Once approval has been obtained, the successful bidder will be immediately notified by the appropriate manager, and a purchase order initiated via a material requisition.

Routine Purchases:

For routine purchases of items or services such as office supplies, computer support, low value stock items, safety equipment, cleaning supplies, lawn restoration, vacuum excavation, vehicle supplies and vehicle servicing, it is acceptable to request pricing once, then use the same low bidder(s) for a fixed period of time, generally not exceeding two (2) years. For routine purchases of higher value stock items, formal supplier alliances may be formed with the approval of the President.

Local Purchase:

Local Purchase Orders – are used for purchases under $250. These may be issued by any employee but require the approval of a Manager.
Recurring Invoices – are monthly fees typically for services that have been awarded via a quotation or a tender. These invoices are to be approved for payment by the appropriate Manager. Signing Authority may be delegated if necessary to avoid delays in the purchasing process. This delegation should be documented in a memo or email to the affected parties.

Exemptions:

- On the recommendation by the President and at the Sole Discretion of the Board of Directors may be renewed or extended, any Tender or Purchasing agreement.
- The Board of Directors, on the recommendation of the President, may Sole Source any product or service that it deems are in the best interest of the Company.

Shared Services/Affiliate Purchases:

The following is a summary of expenses incurred by ETPL from affiliate organizations. Prior to 2010 ETPL was a virtual utility model and almost all of its services were purchased from an affiliate. ETPL has provided detail on the services that continue to be provided by affiliates into the 2012 test year for comparison purposes.

Shared Services/Corporate Cost Allocation

Year: 2012

Name of Company		Service Offered	Pricing Methdology	Cost for the Service
From	To			$
ERTH Corp	Erie Thames Powerlines	Executive Managemen	Allocated Cost	$ 658,824.87
ERTH Corp	Erie Thames Powerlines	Human Resources	Allocated Cost	$ 103,143.79
ERTH Corp	Erie Thames Powerlines	Legal Service	Time and Materials	$ 63,750.00
ERTH Corp	Erie Thames Powerlines	IT Services	Time and Materials	$ 69,252.11
ERTH Corp	Erie Thames Powerlines	Rent	Cost Per Square Foot	$ 250,000.00
Ecaliber	Erie Thames Powerlines	Billing Service provider	Cost per bill	$ 108,375.65

Year: 2011

Name of Company		Service Offered	Pricing Methdology	Cost for the Service
From	To			$
ERTH Corp	Erie Thames Powerlines	Executive Managemen	Allocated Cost	$ 639,635.80
ERTH Corp	Erie Thames Powerlines	Human Resources	Allocated Cost	$ 100,139.60
ERTH Corp	Erie Thames Powerlines	Legal Service	Time and Materials	$ 85,000.00
ERTH Corp	Erie Thames Powerlines	IT Services	Time and Materials	$ 67,235.06
ERTH Corp	Erie Thames Powerlines	Rent	Cost Per Square Foot	$ 250,000.00
Ecaliber	Erie Thames Powerlines	Billing Service provider	Cost per bill	$ 102,956.87

Year: 2010

Name of Company		Service Offered	Pricing Methdology	Cost for the Service
From	To			$
ERTH Corp	Erie Thames Powerlines	Executive Managemen	Allocated Cost	$ 753,302.96
ERTH Corp	Erie Thames Powerlines	Human Resources	Allocated Cost	$ 31,784.79
ERTH Corp	Erie Thames Powerlines	Legal Service	Time and Materials	$ 41,950.32
ERTH Corp	Erie Thames Powerlines	IT Services	Time and Materials	$ 51,185.24
ERTH Corp	Erie Thames Powerlines	Rent	Cost Per Square Foot	$ 200,000.00
Ecaliber	Erie Thames Powerlines	Billing Service provider	Cost per bill	$ 835,310.33

DEPRECIATION, AMORTIZATION AND DEPLETION

DEPRECIATION, AMORTIZATION AND DEPLETION	2008 Actual	Depreciation Rate	Depreciation	2009 Actual		Depreciation	20010 Actual		Depreciation	2011 Bridge		Depreciation	2012 Test		Depreciation
	($'s)			($'s)		($'s)	($'s)		($'s)	($'s)		($'s)	($'s)		($'s)
Land	$150,428.71	0.00%	$0.00	$150,428.71	0.00%	$0.00	$150,673.07	0.00%	$0.00	$158,943.96	0.00%	$0.00	$158,943.96	0.00%	$0.00
Buildings	$136,009.00	3.80%	$5,174.95	$148,263.12	3.80%	$5,623.23	$154,555.12	3.80%	$5,994.15	$174,881.70	3.80%	$6,526.53	$234,881.70	3.80%	$6,933.06
Leasehold Improvements	$7,040.00	20.00%	$1,408.00	$7,040.00	20.00%	$1,408.00	$7,040.00	20.00%	$1,408.00	$161,500.94	20.00%	$9,131.05	$161,500.94	20.00%	$19,854.09
TS Primary Above 50	$0.00	3.33%	$0.00	$0.00	3.33%	$0.00	$0.00	3.33%	$0.00	$0.00	3.33%	$0.00	$0.00	3.33%	$0.00
DS	$499,228.76	3.30%	$17,445.34	$499,228.76	3.30%	$17,936.54	$499,228.76	3.30%	$17,936.54	$499,228.76	3.30%	$17,936.54	$499,228.76	3.30%	$17,936.54
Poles and Wires	$4,336,711.31	4.00%	$191,344.06	$4,660,838.59	4.00%	$205,171.06	$5,068,092.07	4.00%	$219,798.67	$5,418,373.41	4.00%	$234,949.37	$6,151,373.41	4.00%	$256,615.00
Line Transformers	$5,699,174.26	4.00%	$225,331.76	$5,975,585.15	4.00%	$241,756.10	$6,453,338.22	4.00%	$256,839.38	$7,146,590.34	4.00%	$280,259.48	$7,628,590.34	4.00%	$303,764.53
Services and Meters	$5,055,370.90	4.00%	$177,033.03	$5,518,805.97	4.00%	$195,078.33	$5,861,953.96	4.00%	$211,209.99	$6,208,466.93	4.00%	$225,003.21	$6,652,466.93	4.00%	$240,813.47
General Plant	$15,386,041.66	4.00%	$568,513.25	$16,492,223.71	4.00%	$621,924.62	$17,350,068.51	4.00%	$661,205.15	$17,991,407.86	4.00%	$691,188.84	$18,957,407.86	4.00%	$723,335.62
IT Assets	$641,710.86	20.00%	$77,950.54	$691,320.82	20.00%	$97,761.04	$755,281.36	20.00%	$109,118.09	$785,695.70	20.00%	$118,555.57	$810,695.70	20.00%	$124,097.01
Equipment	$325,991.04	10.00%	$19,870.78	$462,402.50	10.00%	$34,188.84	$2,367,003.51	10.00%	$162,835.82	$3,001,505.37	10.00%	$323,629.08	$3,616,505.37	10.00%	$411,833.36
Other Distribution Assets	-$2,426,114.64	4.00%	-$98,792.44	-$2,852,310.69	4.00%	-$121,080.31	-$3,295,792.80	4.00%	-$138,473.87	-$3,741,235.45	4.00%	-$156,252.36	-$4,226,235.45	4.00%	-$174,861.22
GROSS ASSET TOTAL	**$29,811,591.86**		**$1,185,279.27**	**$31,753,826.64**		**$1,299,767.45**	**$35,371,441.78**		**$1,507,871.93**	**$37,805,359.52**		**$1,750,927.31**	**$40,645,359.52**		**$1,930,321.46**

LOSS ADJUSTMENT FACTOR CALCULATION

Below is the Erie Thames Powerlines's loss factor calculation based on a 5 year average using 2007, 2008, 2009, 2010 and 2011 results.

	LOSS ADJUSTMENT FACTOR CALCULATION						
		2007	**2008**	**2009**	**2010**	**2011**	**5 year average**
A	"Wholesale" kWh (IESO)	527,418,576	522,623,901	501,679,625	487,368,346	516,204,336	**2,032,670,882**
B	Wholesale kWh for Large Use customer(s) (IESO)	90,722,466	83,380,765	73,793,286	69,407,035	92,020,500	**325,943,287**
C	Net "Wholesale" kWh (A)-(B)	436,696,110	439,243,136	427,886,339	417,961,310	424,183,836	**1,706,727,595**
D	Retail kWh (Distributor)	506,160,591	506,306,437	484,550,970	472,494,953	500,537,934	**1,963,744,448**
E	Retail kWh for Large Use Customer(s) (1% loss)	90,722,466	83,380,765	73,793,286	69,407,035	92,020,500	**325,943,287**
F	Net "Retail" kWh (D)-(E)	415,438,125	422,925,671	410,757,685	403,087,918	408,517,434	**1,637,801,161**
G	Loss Factor [(C)/(F)]	1.0512	1.0386	1.0417	1.0369	1.0383	**1.0421**
H	Distribution Loss Adjustment Factor						
	Total Utility Loss Adjustment Factor	**LAF**					
	Supply Facility Loss Factor	1.006					
	Distribution Loss Factors						
	Secondary Metered Customer						
	Total Loss Factor - Secondary Metered Customer < 5,000kW	1.0421					
	Total Loss Factor - Secondary Metered Customer > 5,000kW	1.0100					
	Primary Metered Customer						
	Total Loss Factor - Primary Metered Customer < 5,000kW	1.0317					
	Total Loss Factor - Primary Metered Customer > 5,000kW	1.0000					
	Total Loss Factor						
	Secondary Metered Customer						
	Total Loss Factor - Secondary Metered Customer < 5,000kW	1.0483					
	Total Loss Factor - Secondary Metered Customer > 5,000kW	1.0161					
	Primary Metered Customer						
	Total Loss Factor - Primary Metered Customer < 5,000kW	1.0379					
	Total Loss Factor - Primary Metered Customer > 5,000kW	1.006					

MATERIALITY ANALYSIS ON DISTRIBUTION LOSSES

The calculated loss factor is below the OEB 5% target.

TAX CALCULATIONS

Summary of Income Tax Calculation

							Wires Only	
Regulatory Taxable Income							$ 1,637,542	**A**
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	11.25%	**B**	$	184,224	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**					
	Rate reduction	-6.75%	**E**	-$	33,750	**F = D * E**		
Ontario Income tax							$ 150,474	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate				9.19%	**K = J / A**		
	Federal tax rate				15.00%	**L**		
	Combined tax rate						24.19%	**M = L + L**
Total Income Taxes							**$ 396,105**	**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							**$ 396,105**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up [1]					75.81%	**S = 1 - M**	**$ 126,385**	**T = R / S - N**
Income Tax (grossed-up)							**$ 522,490**	**U = R + T**

CAPITAL COST ALLOWANCE										
2008 Actual										
Class	**Class Description**	**UCC Opening Balance**	**Additions**	**Dispositions**	**UCC Before 1/2 Yr Adjustment**	**1/2 Year Rule {1/2 Additions Less Disposals}**	**Reduced UCC**	**Rate %**	**CCA**	**UCC Ending Balance**
1	Distribution System - 1988 to 22-Feb-2005	$22,274,868	$0		$22,274,868	$0	$22,274,868	4%	$0	$22,274,868
2	Distribution System - pre 1988	$0			$0	$0	$0	6%	$0	$0
8	General Office/Stores Equip	$255,259	$85,439		$340,698	$42,720	$297,979	20%	$0	$340,698
10	Computer Hardware/ Vehicles	$53,139	$0		$53,139	$0	$53,139	30%	$0	$53,139
10.1	Certain Automobiles	$0			$0	$0	$0	30%	$0	$0
12	Computer Software	$0	$143,626		$143,626	$71,813	$71,813	100%	$71,813	$71,813
13 1	Lease # 1	$0			$0	$0	$0		$0	$0
13 2	Lease #2	$0			$0	$0	$0		$0	$0
13 3	Lease # 3	$0			$0	$0	$0		$0	$0
13 4	Lease # 4	$0			$0	$0	$0		$0	$0
14	Franchise	$0			$0	$0	$0		$0	$0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$0			$0	$0	$0	8%	$0	$0
43.1	Certain Energy-Efficient Electrical Generating Equipment	$0			$0	$0	$0		$0	$0
45	Computers & Systems Software acq'd post Mar 22/04	$0			$0	$0	$0		$0	$0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$0			$0	$0	$0		$0	$0
47	Distribution System - post 22-Feb-2005	$4,457,063	$2,939,805		$7,396,868	$1,469,903	$5,926,965	8%	$474,157	$6,922,711
98	No CCA	$0	$10,160		$10,160	$5,080	$5,080		$0	$10,160
	TOTAL	$27,040,328	$3,179,031	$0	$30,219,359	$1,589,515	$28,629,844		$545,970	$29,673,389

2009 Actual										
Class	**Class Description**	**UCC Opening Balance**	**Additions**	**Dispositions**	**UCC Before 1/2 Yr Adjustment**	**1/2 Year Rule {1/2 Additions Less Disposals}**	**Reduced UCC**	**Rate %**	**CCA**	**UCC Ending Balance**
1	Distribution System - 1988 to 22-Feb-2005	$22,274,868			$22,274,868	$0	$22,274,868	4%	$890,995	$21,383,873
2	Distribution System - pre 1988	$0			$0	$0	$0	6%	$0	$0
8	General Office/Stores Equip	$340,698	$136,412		$477,110	$68,206	$408,904	20%	$81,781	$395,329
10	Computer Hardware/ Vehicles	$53,139	$4,720		$57,859	$2,360	$55,499	30%	$16,650	$41,209
10.1	Certain Automobiles	$0			$0	$0	$0	30%	$0	$0
12	Computer Software	$71,813	$44,890		$116,703	$22,445	$94,258	100%	$94,258	$22,445
13 1	Lease # 1	$0			$0	$0	$0	20%	$0	$0
13 2	Lease #2	$0			$0	$0	$0		$0	$0
13 3	Lease # 3	$0			$0	$0	$0		$0	$0
13 4	Lease # 4	$0			$0	$0	$0		$0	$0
14	Franchise	$0			$0	$0	$0		$0	$0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$0			$0	$0	$0	8%	$0	$0
43.1	Certain Energy-Efficient Electrical Generating Equipment	$0			$0	$0	$0		$0	$0
45	Computers & Systems Software acq'd post Mar 22/04	$0			$0	$0	$0	45%	$0	$0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$0			$0	$0	$0		$0	$0
47	Distribution System - post 22-Feb-2005	$6,922,711	$2,170,155		$9,092,866	$1,085,078	$8,007,788	8%	$640,623	$8,452,243
98	No CCA	$10,160	$12,254		$22,414	$6,127	$16,287		$0	$22,414
	TOTAL	$29,673,389	$2,368,431	$0	$32,041,820	$1,184,215	$30,857,604		$1,724,306	$30,317,513

2010 Actual										
Class	**Class Description**	**UCC Opening Balance**	**Additions**	**Dispositions**	**UCC Before 1/2 Yr Adjustment**	**1/2 Year Rule {1/2 Additions Less Disposals}**	**Reduced UCC**	**Rate %**	**CCA**	**UCC Ending Balance**
1	Distribution System - 1988 to 22-Feb-2005	$21,383,873			$21,383,873	$0	$21,383,873	4%	$855,355	$20,528,518
2	Distribution System - pre 1988	$0			$0	$0	$0	6%	$0	$0
8	General Office/Stores Equip	$395,329	$33,266		$428,594	$16,633	$411,962	20%	$82,392	$346,202
10	Computer Hardware/ Vehicles	$41,209	$1,873,900		$1,915,109	$936,950	$978,159	30%	$293,448	$1,621,661
10.1	Certain Automobiles	$0			$0	$0	$0	30%	$0	$0
12	Computer Software	$22,445	$61,396		$83,841	$30,698	$53,143	100%	$53,143	$30,698
13 1	Lease # 1	$0			$0	$0	$0	20%	$0	$0
13 2	Lease #2	$0			$0	$0	$0		$0	$0
13 3	Lease # 3	$0			$0	$0	$0		$0	$0
13 4	Lease # 4	$0			$0	$0	$0		$0	$0
14	Franchise	$0			$0	$0	$0		$0	$0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$0			$0	$0	$0	8%	$0	$0
43.1	Certain Energy-Efficient Electrical Generating Equipment	$0			$0	$0	$0		$0	$0
45	Computers & Systems Software acq'd post Mar 22/04	$0			$0	$0	$0	45%	$0	$0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$0			$0	$0	$0		$0	$0
47	Distribution System - post 22-Feb-2005	$8,452,243	$2,085,999		$10,538,242	$1,043,000	$9,495,243	8%	$759,619	$9,778,623
98	No CCA	$22,414	$6,536		$28,950	$3,268	$25,682		$0	$28,950
	TOTAL	$30,317,513	$4,061,097	$0	$34,378,611	$2,030,549	$32,348,062		$2,043,957	$32,334,653

2011 Bridge										
Class	**Class Description**	**UCC Opening Balance**	**Additions**	**Dispositions**	**UCC Before 1/2 Yr Adjustment**	**1/2 Year Rule {1/2 Additions Less Disposals}**	**Reduced UCC**	**Rate %**	**CCA**	**UCC Ending Balance**
1	Distribution System - 1988 to 22-Feb-2005	$20,528,518			$20,528,518	$0	$20,528,518	4%	$821,141	$19,707,377
2	Distribution System - pre 1988	$0			$0	$0	$0	6%	$0	$0
8	General Office/Stores Equip	$346,202	$37,817		$384,019	$18,908	$365,111	20%	$73,022	$310,997
10	Computer Hardware/ Vehicles	$1,621,661	$607,492		$2,229,154	$303,746	$1,925,407	30%	$577,622	$1,651,531
10.1	Certain Automobiles	$0			$0	$0	$0	30%	$0	$0
12	Computer Software	$30,698	$19,607		$50,305	$9,803	$40,502	100%	$40,502	$9,803
13 1	Lease # 1	$0			$0	$0	$0	20%	$0	$0
13 2	Lease #2	$0			$0	$0	$0		$0	$0
13 3	Lease # 3	$0			$0	$0	$0		$0	$0
13 4	Lease # 4	$0			$0	$0	$0		$0	$0
14	Franchise	$0			$0	$0	$0		$0	$0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$0			$0	$0	$0	8%	$0	$0
43.1	Certain Energy-Efficient Electrical Generating Equipment	$0			$0	$0	$0		$0	$0
45	Computers & Systems Software acq'd post Mar 22/04	$0			$0	$0	$0	45%	$0	$0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$0			$0	$0	$0		$0	$0
47	Distribution System - post 22-Feb-2005	$9,778,623	$2,031,386		$11,810,009	$1,015,693	$10,794,316	8%	$863,545	$10,946,463
98	No CCA	$28,950	$183,058		$212,009	$91,529	$120,480		$0	$212,009
	TOTAL	$32,334,653	$2,879,360	$0	$35,214,013	$1,439,680	$33,774,333		$2,375,832	$32,838,182

2012 Test

Class	Class Description	UCC Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	$19,707,377			$19,707,377	$0	$19,707,377	4%	$788,295	$18,919,082
2	Distribution System - pre 1988	$0			$0	$0	$0	6%	$0	$0
8	General Office/Stores Equip	$310,997	$35,000		$345,997	$17,500	$328,497	20%	$65,699	$280,298
10	Computer Hardware/ Vehicles	$1,651,531	$605,000		$2,256,531	$302,500	$1,954,031	30%	$586,209	$1,670,322
10.1	Certain Automobiles	$0			$0	$0	$0	30%	$0	$0
12	Computer Software	$9,803			$9,803	$0	$9,803	100%	$9,803	$0
13 1	Lease # 1	$0			$0	$0	$0	20%	$0	$0
13 2	Lease #2	$0			$0	$0	$0		$0	$0
13 3	Lease # 3	$0			$0	$0	$0		$0	$0
13 4	Lease # 4	$0			$0	$0	$0		$0	$0
14	Franchise	$0			$0	$0	$0		$0	$0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$0			$0	$0	$0	8%	$0	$0
43.1	Certain Energy-Efficient Electrical Generating Equipment	$0			$0	$0	$0		$0	$0
45	Computers & Systems Software acq'd post Mar 22/04	$0			$0	$0	$0	45%	$0	$0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$0			$0	$0	$0		$0	$0
47	Distribution System - post 22-Feb-2005	$10,946,463	$2,625,000		$13,571,463	$1,312,500	$12,258,963	8%	$980,717	$12,590,746
98	No CCA	$212,009	$60,000		$272,009	$30,000	$242,009		$0	$272,009
	TOTAL	$32,838,182	$3,325,000	$0	$36,163,182	$1,662,500	$34,500,682		$2,430,724	$33,732,457

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
Erie Thames Powerlines Corporation

Business Number	Tax year	From (Y M D)	To (Y M D)
86371 9498 RC0001		2010-01-01	2010-12-31

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)	586,137
Part I tax payable (line 700)	
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)	
Provincial tax on large corporations (line 765)	

Part C – Certification and authorization

I, Pettit (Last name in block letters) Jeff (First name in block letters) President & CEO (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.

Date (yyyy/mm/dd)	Signature of an authorized signing officer of the corporation	Telephone number
2011-06-29		(519) 518-6117

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: KPMG LLP
Electronic filer number:

Privacy Act, Personal Information Bank number CRA PPU 047

Canada Revenue Agency / Agence du revenu du Canada

200

T2 CORPORATION INCOME TAX RETURN

EXEMPT FROM TAX

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** 86371 9498 RC0001

Corporation's name

002 Erie Thames Powerlines Corporation

Address of head office

Has this address changed since the last time you filed your T2 return? . . . . **010** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 011 to 018.)

011 143 Bell Street

012 PO Box 157

City	Province, territory, or state
015 Ingersoll	**016** ON
Country (other than Canada)	Postal code/Zip code
017 CA	**018** N5C 3K5

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? . . . . **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 you filed your T2 return? . . . . **030** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 031 to 038.)

031 143 Bell Street

032 PO Box 157

City	Province,territory, or state
035 Ingersoll	**036** ON
Country (other than Canada)	Postal code/Zip code
037 CA	**038** N5C 3K5

040 Type of corporation at the end of the tax year

1 [X] Canadian-controlled private corporation (CCPC)
4 [ ] Corporation controlled by a public corporation
2 [ ] Other private corporation
5 [ ] Other corporation (specify, below)
3 [ ] Public corporation

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** 2010-01-01 (YYYY MM DD) Tax year-end **061** 2010-12-31 (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 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 [X] Exempt under other paragraphs of section 149

Do not use this area

091	**092**	**093**	**094**	**095**	**096**
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **Yes** response, **attach** to the T2 return the schedule that applies.

Question	Line	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
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	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		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation (or its associated corporations) 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	X	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

	Line	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

	Line	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
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281		X

What is the corporation's major business activity? (only complete if **yes** was entered at line 281) 282 ______

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 1 Wholesale [ ] 2 Retail [ ]

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

Line	Product or service	Line	%
284	Distribution of Electricity	285	100.000 %
286		287	%
288		289	%

	Line	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

	Line		Amount	
Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		586,137	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")			586,137	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		586,137	
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 3.2 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	586,137	A
Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 1/(0.38 - X**) 3.57143 times the amount on line 636***, and **minus** any amount that, because of federal law, is exempt form Part I tax	405		B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

400,000	x	Number of days in the tax year before 2009 / Number of days in the tax year	/ 365	=		1
500,000	x	Number of days in the tax year after 2008 / Number of days in the tax year	365 / 365	=	500,000	2
				Add amounts at lines 1 and 2	500,000	4

Business limit (see notes 1 and 2 below)	410	500,000	C

Notes:
1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C	500,000	x	415 **** 70,764 D / 11,250	=		3,145,067	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.

* 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				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, whichever is the least		E		
Aggregate investment income from line 440*		F		
Total of amounts B to F		▶		G
Amount A **minus** amount G (if negative, enter "0")				H

Amount H		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x 8.5 %	=	I
Amount H		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 %	=	J
Amount H		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 / 365	x 10 %	=	K
Amount H		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	x 11.5 %	=	L
Amount H		x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x 13 %	=	L.1

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L.1 ..... M
Enter amount M on line 638.

* 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, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x 8.5 %	=	T
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 %	=	U
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 / 365	x 10 %	=	V
Amount S		x	Number of days in the tax year after December 31, 2010, and before January 2012 / Number of days in the tax year	/ 365	x 11.5 %	=	W
Amount S		x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x 13 %	=	W.1

General tax reduction – Total of amounts T to W.1 X
Enter amount X on line 639.

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				
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			586,137		
Deduct:					
Amount from line 400, 405, 410, or 425, whichever is the least					
Foreign non-business income tax credit from line 632	x 25 / 9 =				
Foreign business income tax credit from line 636	x 1(0.38 - X*) / 3.57143 =				
			586,137		
			x 26 2/3 % =	156,303	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780)					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	533		
Deduct: Dividend refund for the previous tax year	465			
		533	533	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		533	

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 of Schedule 3		x 1 / 3		I
Refundable dividend tax on hand at the end of the tax year from line 485 above			533	J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784)				

Part I tax

Base amount of Part I tax – Taxable income (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			i
Taxable income from line 360	586,137		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least			
Net amount	586,137 ▶	586,137	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			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	638		
General tax reduction from amount X	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.

Summary of tax and credits

Federal tax

Part I tax payable	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 (New Brunswick* and Nova Scotia)	765	
Total tax payable	770	A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	B

Refund code 894 Overpayment

Balance (line A **minus** line B)

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 X

* The New Brunswick tax on large corporations is eliminated effective January 1, 2009.

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, 950 Pettit (Last name in block letters) 951 Jeff (First name in block letters) 954 President & CEO (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2011-06-29 Date (yyyy/mm/dd) — Signature of the authorized signing officer of the corporation — 956 (519) 518-6117 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes X 2 No ☐

958 Name in block letters 959 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

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	8,474,035	7,958,934
	Total tangible capital assets	2008	+	18,548,964	25,112,668
	Total accumulated amortization of tangible capital assets	2009	–		6,853,983
	Total intangible capital assets	2178	+	100,000	100,000
	Total accumulated amortization of intangible capital assets	2179	–	23,333	23,333
	Total long-term assets	2589	+	3,811,910	2,361,731
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	30,911,576	28,656,017
	Liabilities				
	Total current liabilities	3139	+	12,982,875	12,025,734
	Total long-term liabilities	3450	+	9,315,522	8,293,751
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	22,298,397	20,319,485
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	8,613,179	8,336,532
	Total liabilities and shareholder equity	3640	=	30,911,576	28,656,017
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	574,655	298,008

***** Generic item

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Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence Number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	39,293,536	36,249,817
	Cost of sales	8518	–	33,038,373	30,561,051
	Gross profit/loss	8519	=	6,255,163	5,688,766
	Cost of sales	8518	+	33,038,373	30,561,051
	Total operating expenses	9367	+	6,314,339	5,989,406
	Total expenses (mandatory field)	9368	=	39,352,712	36,550,457
	Total revenue (mandatory field)	8299	+	40,066,831	36,771,461
	Total expenses (mandatory field)	9368	–	39,352,712	36,550,457
	Net non-farming income	9369	=	714,119	221,004
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	714,119	221,004
	Total other comprehensive income	9998	=		
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	187,000	92,000
	Deferred income tax provision	9995	–		
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	527,119	129,004

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year-end Year Month Day
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI) for Corporations* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule, and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant preparing or reporting on the financial statements

Does the accountant have a professional designation? . . . **095** 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . **097** 1 Yes [ ] 2 No [X]

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note: If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report . . . 1 [ ]

Completed a review engagement report . . . 2 [ ]

Conducted a compilation engagement . . . 3 [X]

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . **099** 1 Yes [ ] 2 No [ ]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

Prepared the tax return (financial statements prepared by client) . . . 1 [ ]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . 2 [ ]

Were notes to the financial statements prepared? . . . **101** 1 Yes [X] 2 No [ ]

If **yes**, complete lines 102 to 107 below:

Are any values presented at other than cost? . . . **102** 1 Yes [ ] 2 No [X]

Has there been a change in accounting policies since the last return? . . . **103** 1 Yes [ ] 2 No [X]

Are subsequent events mentioned in the notes? . . . **104** 1 Yes [X] 2 No [ ]

Is re-evaluation of asset information mentioned in the notes? . . . **105** 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . **106** 1 Yes [X] 2 No [ ]

Is information regarding commitments mentioned in the notes? . . . **107** 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . **108** 1 Yes [ ] 2 No [X]

If **yes**, complete line 109 below:

Are you filing financial statements of the joint venture(s) or partnership(s)? . . . **109** 1 Yes [ ] 2 No [ ]

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
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

- 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				527,119 A
Add:				
Provision for income taxes – current		101	187,000	
Interest and penalties on taxes		103	700	
Amortization of tangible assets		104	1,177,338	
Non-deductible meals and entertainment expenses		121	2,901	
Non-deductible life insurance premiums		123	2,838	
Subtotal of additions			1,370,777	1,370,777
Other additions:				
Miscellaneous other additions:				
600 Capital lease interest		290	33,828	
601 Post retirement - accrual 2010		291	263,629	
602 Smart meter recovery for tax purposes		292	167,415	
604				
Total		294		
Subtotal of other additions		199	464,872	464,872
Total additions		500	1,835,649	1,835,649
Deduct:				
Capital cost allowance from Schedule 8		403	1,181,378	
Cumulative eligible capital deduction from Schedule 10		405	22,998	
Subtotal of deductions			1,204,376	1,204,376
Other deductions:				
Miscellaneous other deductions:				
700 Post retirement - accrual 2009		390	255,227	
701 Smart meter expense for tax purposes		391	44,364	
702 Actual capital tax		392	17,731	
703 Settlement of late charges	51,909			
Total	51,909	393	51,909	
704 Capital lease payments	203,024			
Total	203,024	394	203,024	
Subtotal of other deductions		499	572,255	572,255
Total deductions		510	1,776,631	1,776,631
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				586,137

T2 SCH 1 E (10) Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

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 (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	Buildings		6,292	93,974	0	3,146	97,120	4	0	0	3,885	96,381
2.	1	Distrib/Sub Station			133,107	0		133,107	4	0	0	5,324	127,783
3.	1	Poles Towers Fixture			1,546,911	0		1,546,911	4	0	0	61,876	1,485,035
4.	1	Wires Meters Transf			10,919,519	0		10,919,519	4	0	0	436,781	10,482,738
5.	8	Office Furn/Equip		6,258	9,207	0	3,129	12,336	20	0	0	2,467	12,998
6.	8	Tools and equipment		7,742	8,131	0	3,871	12,002	20	0	0	2,400	13,473
7.	8	Smart Meters		1,391,222	28,997	0	695,611	724,608	20	0	0	144,922	1,275,297
8.	10	Computer Equipment			773	0		773	30	0	0	232	541
9.	10	Transportation Equipment			82,517	0		82,517	30	0	0	24,755	57,762
10.	12	Computer Software			6,974	0		6,974	100	0	0	6,974	
11.	45	Computer equipment purchased			200	0		200	45	0	0	90	110
12.	47	Utility Transmission Equipment		953,357	4,843,063	0	476,679	5,319,741	8	0	0	425,579	5,370,841
13.	50	Computers - after March 18 2007			3,877	0		3,877	55	0	0	2,132	1,745
14.	52			63,961		0		63,961	100	0	0	63,961	
15.	94			209,033		0	104,517	104,516	0	0	0		209,033
		Total		2,637,865	17,677,250		1,286,953	19,028,162				1,181,378	19,133,737

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*.

**** 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
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

This schedule is to be completed by a corporation having one or more of the following:
– related corporation(s)
– associated corporations(s)

	Name 100	Country of residence (if other than Canada) 200	Business Number (Canadian corporation only) (see note 1) 300	Relationship code (see note 2) 400	Number of common shares owned 500	% of common shares owned 550	Number of preferred shares owned 600	% of preferred shares owned 650	Book value of capital stock 700
1.	Coulter Water Meter Service Inc.		10117 1486 RC0001	3					
2.	Erie Thames Solutions Inc.		84357 0920 RC0001	3					
3.	ERTH Corporation		86356 4324 RC0001	1	7	100.000	8,038,517	100.000	8,038,524
4.	CRU Solutions Inc.		86371 9696 RC0001	3					
5.	RDI Consulting Inc.		89380 0581 RC0001	3					
6.	Utilismart Corporation		86443 9450 RC0001	3					
7.	Quadra Technology Services Inc.		83055 2360 RC0001	3					
8.	Enerconnect Inc.		87367 1499 RC0001	3					
9.	Wattsworth Analysis Inc.		87746 8108 RC0001	3					
10.	Enermajica Ontario Inc.		88660 6409 RC0001	3					
11.	ERTH360 Generation & Consulting I		82960 2226 RC0001	3					
12.	Ecaliber (Canada) Inc.		82954 1895 RC0001	3					
13.	The SPi Group (formerly 1504419 C		87013 2917 RC0001	3					
14.	ERTH (Holdings) Inc.		NR	3					
15.	West Perth Power Inc.		86922 9377 RC0001	3					

Note 1: Enter "NR" if a corporation is not registered.
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(99)

Canada

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")			200		A
Add: Cost of eligible capital property acquired during the taxation year	222				
Other adjustments	226	438,049			
Subtotal (line 222 plus line 226)		438,049 x 3 / 4 =	328,537 B		
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228	x 1 / 2 =	C		
amount B minus amount C (if negative, enter "0")			328,537 ▶	328,537	D
Amount transferred on amalgamation or wind-up of subsidiary			224		E
Subtotal (add amounts A, D, and E)			230	328,537	F
Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242		G		
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244		H		
Other adjustments	246		I		
(add amounts G,H, and I)		x 3 / 4 =	248		J
Cumulative eligible capital balance (amount F minus amount J) (if amount K is negative, enter "0" at line M and proceed to Part 2)				328,537	K
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business			249		
amount K		328,537			
less amount from line 249					
Current year deduction		328,537 x 7.00 % =	250	22,998 *	
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)			22,998 ▶	22,998	L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")			300	305,539	M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)					N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			400	1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			401	2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402	3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408	4			
Line 3 minus line 4 (if negative, enter "0")		▶		5	
Total of lines 1, 2 and 5				6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400		7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000		8			
Subtotal (line 7 plus line 8)	409	▶		9	
Line 6 minus line 9 (if negative, enter "0")				▶	O
Line N minus line O (if negative, enter "0")					P
Line 5			x 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")					R
Amount R			x 2 / 3 =		S
Amount N or amount O, whichever is less					T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)				410	

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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 2010

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	Erie Thames Powerlines Corporation	86371 9498 RC0001	1	500,000	100.0000	500,000
2	Coulter Water Meter Service Inc.	10117 1486 RC0001	1	500,000		
3	Erie Thames Solutions Inc.	84357 0920 RC0001	1	500,000		
4	ERTH Corporation	86356 4324 RC0001	1	500,000		
5	CRU Solutions Inc.	86371 9696 RC0001	1	500,000		
6	RDI Consulting Inc.	89380 0581 RC0001	1	500,000		
7	Utilismart Corporation	86443 9450 RC0001	1	500,000		
8	Quadra Technology Services Inc.	83055 2360 RC0001	1	500,000		
9	Enerconnect Inc.	87367 1499 RC0001	1	500,000		
10	Wattsworth Analysis Inc.	87746 8108 RC0001	1	500,000		
11	Enermajica Ontario Inc.	88660 6409 RC0001	1	500,000		
12	ERTH360 Generation & Consulting Inc.	82960 2226 RC0001	1	500,000		
13	Ecaliber (Canada) Inc.	82954 1895 RC0001	1	500,000		

	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	
14	The SPi Group (formerly 1504419 Ontario Limi	87013 2917 RC0001	1	500,000			
15	ERTH (Holdings) Inc.	NR	1	500,000			
16	West Perth Power Inc.	86922 9377 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 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

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	ERTH Corporation	86356 4324 RC0001			100.000	100.000
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada

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SCHEDULE 516

CAPITAL DEDUCTION ELECTION OF ASSOCIATED GROUP FOR THE ALLOCATION OF NET DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

- Complete this schedule to allocate the associated group's net deduction for the capital deduction election under subsection 83(2) of the *Taxation Act, 2007* (Ontario). The associated group includes the filing corporation (see line 190 of Part 2 of Schedule 515, *Ontario Capital Tax on Other than Financial Institutions*).
- If you need more space, attach more schedules.
- File this schedule with the *T2 Corporation Income Tax Return*.

	A Names of eligible corporations in the associated group 100	B Business Number of associated corporations (enter "NR" if a corporation is not registered) 200	C Ontario allocation factor (OAF)* (enter as a percentage) 300	D Total assets** 400	E Net deduction ($15 million x line 300) **multiplied** by line 400 / line 700 500	F Allocation of net deduction *** 600
1.	Erie Thames Powerlines Corporation	86371 9498 RC0001	100.000	28,656,017	11,067,628	
2.	Coulter Water Meter Service Inc.	10117 1486 RC0001				15,000,000
3.	Erie Thames Solutions Inc.	84357 0920 RC0001				
4.	ERTH Corporation	86356 4324 RC0001				
5.	CRU Solutions Inc.	86371 9696 RC0001				
6.	RDI Consulting Inc.	89380 0581 RC0001				
7.	Utilismart Corporation	86443 9450 RC0001	100.000	2,834,958	1,094,927	
8.	Quadra Technology Services Inc.	83055 2360 RC0001				
9.	Enerconnect Inc.	87367 1499 RC0001	100.000	1,457,122	562,775	
10.	Wattsworth Analysis Inc.	87746 8108 RC0001	100.000	597,624	230,816	
11.	Enermajica Ontario Inc.	88660 6409 RC0001	100.000	290,932	112,365	
12.	ERTH360 Generation & Consulting Inc.	82960 2226 RC0001				
13.	Ecaliber (Canada) Inc.	82954 1895 RC0001				
14.	The SPi Group (formerly 1504419 Ontario Limited)	87013 2917 RC0001				
15.	ERTH (Holdings) Inc.	NR				
16.	West Perth Power Inc.	86922 9377 RC0001	100.000	5,000,961	1,931,489	

Total assets of associated group (total of amounts in column D) **700** 38,837,614

Total net deduction (total of amounts in column E) **800** 15,000,000

Total allocated net deduction (total of amounts in column F) (not to exceed amount on line 800) **900** 15,000,000

* OAF from the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends.

** Total assets of each corporation in the associated group as recorded in the books and records for the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends. If the corporation is not resident in Canada, enter the amount of its total assets situated in Canada.

*** Enter the amount from this column allocated to the filing corporation on line 300 of Schedule 515.

T2 SCH 516

Canada

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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
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

- 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)
Erie Thames Powerlines Corporation

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	2000-07-07	1428821

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
143	Bell Street	

240 Additional address information if applicable (line 220 must be completed first)
PO Box 157

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
Ingersoll	ON	CA	N5C 3K5

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 Pettit (Last name) **451** Jeff (First name)

454 ______ , (Middle name(s))

460 1 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.

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2011-12-31

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
2011-01-31	16,424			16,424
2011-02-28	16,424			16,424
2011-03-31	16,424			16,424
2011-04-30	16,424			16,424
2011-05-31	16,424			16,424
2011-06-30	16,424			16,424
2011-07-31	16,424			16,424
2011-08-31	16,424			16,424
2011-09-30	16,424			16,424
2011-10-31	16,424			16,424
2011-11-30	16,424			16,424
2011-12-31	16,422			16,422
Total	197,086			197,086

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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 86371 9498 RC0001

Corporation's name
002 Erie Thames Powerlines Corporation

Address of head office
Has this address changed since the last time you filed your T2 return? . . . . 010 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 143 Bell Street
012 PO Box 157

City	Province, territory, or state
015 Ingersoll	016 ON
Country (other than Canada)	Postal code/Zip code
017 CA	018 N5C 3K5

Mailing address (if different from head office address)
Has this address changed since the last time you filed your T2 return? . . . . 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 you filed your T2 return? . . . . 030 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
031 143 Bell Street
032 PO Box 157

City	Province,territory, or state
035 Ingersoll	036 ON
Country (other than Canada)	Postal code/Zip code
037 CA	038 N5C 3K5

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 2010-01-01 YYYY MM DD
Tax year-end 061 2010-12-31 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 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

091	092	093	094	095	096
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **Yes** response, **attach** to the T2 return the schedule that applies.

Question	Line	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
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	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 (or its associated corporations) 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	X	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

	Code	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

	Code	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
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281		X

What is the corporation's major business activity? (only complete if **yes** was entered at line 281) 282

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 1 Wholesale ☐ 2 Retail ☐

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

Code	Product or service	Code	%
284	Distribution of Electricity	285	100.000 %
286		287	%
288		289	%

	Code	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

	Code		Amount	
Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		586,137	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")			586,137	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		586,137	
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)			586,137	Z

* This amount is equal to 3.2 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	**400**	586,137	A
Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 1/(0.38 - X**) 3.57143 times the amount on line 636***, and **minus** any amount that, because of federal law, is exempt form Part I tax	**405**	586,137	B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

400,000	x	Number of days in the tax year before 2009 / Number of days in the tax year	/ 365	=		1
500,000	x	Number of days in the tax year after 2008 / Number of days in the tax year	365 / 365	=	500,000	2
			Add amounts at lines 1 and 2		500,000	4

Business limit (see notes 1 and 2 below)	**410**	500,000	C

Notes:
1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C	500,000	x	**415** **** 72,780 D / 11,250	=	3,234,667 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.

* 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		586,137	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, whichever is the least	E		
Aggregate investment income from line 440*	F		
Total of amounts B to F	▶		G
Amount A **minus** amount G (if negative, enter "0")		586,137	H

Amount H	586,137	x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	I
Amount H	586,137	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 %	=	J
Amount H	586,137	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 / 365	x	10 %	= 58,614	K
Amount H	586,137	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	x	11.5 %	=	L
Amount H	586,137	x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x	13 %	=	L.1

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L.1 .... 58,614 M

Enter amount M on line 638.

* 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, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	T
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 %	=	U
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 / 365	x	10 %	=	V
Amount S		x	Number of days in the tax year after December 31, 2010, and before January 2012 / Number of days in the tax year	/ 365	x	11.5 %	=	W
Amount S		x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x	13 %	=	W.1

General tax reduction – Total of amounts T to W.1 X

Enter amount X on line 639.

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					
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			586,137	
Deduct:				
Amount from line 400, 405, 410, or 425, whichever is the least				
Foreign non-business income tax credit from line 632	x 25 / 9 =			
Foreign business income tax credit from line 636	x 1(0.38 - X*) / 3.57143 =			
			586,137	
			x 26 2 / 3 % =	156,303 D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780)				105,504 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	533		
Deduct: Dividend refund for the previous tax year	465			
		533	533	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		533	

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 of Schedule 3		x 1 / 3		I
Refundable dividend tax on hand at the end of the tax year from line 485 above			533	J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784)				

Part I tax

Base amount of Part I tax – Taxable income (line 360 or amount Z, whichever applies) **multiplied** by 38 %			550	222,732	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			i
Taxable income from line 360	586,137		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least			
Net amount	586,137 ▶	586,137	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)		222,732	D

Deduct:

Small business deduction from line 430			1		
Federal tax abatement	608	58,614			
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	638	58,614			
General tax reduction from amount X	639				
Federal logging tax credit from Schedule 21	640				
Federal qualifying environmental trust tax credit	648				
Investment tax credit from Schedule 31	652				
Subtotal		117,228	▶	117,228	E

Part I tax payable – Line D **minus** line E	105,504	F

Enter amount F on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	105,504
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		105,504

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	91,582	
Provincial tax on large corporations (New Brunswick* and Nova Scotia)	765		
		91,582 ►	91,582
Total tax payable	770		197,086 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	► B

Refund code 894 Overpayment

Balance (line A **minus** line B) 197,086

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 197,086

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 ☒

* The New Brunswick tax on large corporations is eliminated effective January 1, 2009.

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, 950 Pettit (Last name in block letters) 951 Jeff (First name in block letters) 954 President & CEO (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2011-06-29 Date (yyyy/mm/dd) — Signature of the authorized signing officer of the corporation — 956 (519) 518-6117 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes ☒ 2 No ☐

958 Name in block letters — 959 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

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
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

- 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				527,119 A
Add:				
Provision for income taxes – current		101	187,000	
Interest and penalties on taxes		103	700	
Amortization of tangible assets		104	1,177,338	
Non-deductible meals and entertainment expenses		121	2,901	
Non-deductible life insurance premiums		123	2,838	
Subtotal of additions			1,370,777 ▶	1,370,777
Other additions:				
Miscellaneous other additions:				
600 Capital lease interest		290	33,828	
601 Post retirement - accrual 2010		291	263,629	
602 Smart meter recovery for tax purposes		292	167,415	
604				
Total		294		
Subtotal of other additions		199	464,872 ▶	464,872
Total additions		500	1,835,649 ▶	1,835,649
Deduct:				
Capital cost allowance from Schedule 8		403	1,181,378	
Cumulative eligible capital deduction from Schedule 10		405	22,998	
Subtotal of deductions			1,204,376 ▶	1,204,376
Other deductions:				
Miscellaneous other deductions:				
700 Post retirement - accrual 2009		390	255,227	
701 Smart meter expense for tax purposes		391	44,364	
702 Actual capital tax		392	17,731	
703 Settlement of late charges	51,909			
Total	51,909	393	51,909	
704 Capital lease payments	203,024			
Total	203,024	394	203,024	
Subtotal of other deductions		499	572,255 ▶	572,255
Total deductions		510	1,776,631 ▶	1,776,631
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				586,137

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

- 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*.

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.

T2 SCH 5 E (10)

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
586,137		586,137	36,171

Description	Line	Amount		Total	Ref
Ontario basic income tax (from Schedule 500)	270	76,150			
Deduct: Ontario small business deduction (from schedule 500)	402	39,979			
Subtotal (if negative, enter "0")		36,171	►	36,171	A6
Add:					
Surtax re Ontario small business deduction (from Schedule 500)	272	37,680			
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		37,680	►	37,680	B6
Subtotal (amount A6 **plus** amount B6)				73,851	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")				73,851	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")				73,851	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")				73,851	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	17,731			
Subtotal		17,731	►	17,731	H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)				91,582	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	91,582	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	91,582

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
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

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 (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	Buildings	93,974	6,292		0	3,146	97,120	4	0	0	3,885	96,381
2.	1	Distrib/Sub Station	133,107			0		133,107	4	0	0	5,324	127,783
3.	1	Poles Towers Fixture	1,546,911			0		1,546,911	4	0	0	61,876	1,485,035
4.	1	Wires Meters Transf	10,919,519			0		10,919,519	4	0	0	436,781	10,482,738
5.	8	Office Furn/Equip	9,207	6,258		0	3,129	12,336	20	0	0	2,467	12,998
6.	8	Tools and equipment	8,131	7,742		0	3,871	12,002	20	0	0	2,400	13,473
7.	8	Smart Meters	28,997	1,391,222		0	695,611	724,608	20	0	0	144,922	1,275,297
8.	10	Computer Equipment	773			0		773	30	0	0	232	541
9.	10	Transportation Equipment	82,517			0		82,517	30	0	0	24,755	57,762
10.	12	Computer Software	6,974			0		6,974	100	0	0	6,974	
11.	45	Computer equipment purchased	200			0		200	45	0	0	90	110
12.	47	Utility Transmission Equipment	4,843,063	953,357		0	476,679	5,319,741	8	0	0	425,579	5,370,841
13.	50	Computers - after March 18 2007	3,877			0		3,877	55	0	0	2,132	1,745
14.	52			63,961		0		63,961	100	0	0	63,961	
15.	94			209,033		0	104,517	104,516	0	0	0		209,033
		Total	17,677,250	2,637,865			1,286,953	19,028,162				1,181,378	19,133,737

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*.

**** 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.

T2 SCH 8 (06)

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

This schedule is to be completed by a corporation having one or more of the following:
- – related corporation(s)
- – associated corporations(s)

	Name 100	Country of residence (if other than Canada) 200	Business Number (Canadian corporation only) (see note 1) 300	Relationship code (see note 2) 400	Number of common shares owned 500	% of common shares owned 550	Number of preferred shares owned 600	% of preferred shares owned 650	Book value of capital stock 700
1.	Coulter Water Meter Service Inc.	CA	10117 1486 RC0002	3					
2.	ERTH Corporation	CA	86356 4324 RC0001	1	7	100.000	8,038,517	100.000	8,038,524
3.	CRU Solutions Inc.	CA	86371 9696 RC0001	3					
4.	Utilismart Corporation	CA	86443 9450 RC0001	3					
5.	Enerconnect Inc.	CA	87367 1499 RC0001	3					
6.	Wattsworth Analysis Inc.	CA	87746 8108 RC0001	3					
7.	Enermajica Ontario Inc.	CA	88660 6409 RC0001	3					
8.	ERTH360 Generation & Consulting I	CA	82960 2226 RC0001	3					
9.	Ecaliber (Canada) Inc.	CA	82954 1895 RC0001	3					
10.	The SPI Group Inc.	CA	87013 2917 RC0001	3					
11.	ERTH (Holdings) Inc.	CA	82642 4293 RC0002	3					
12.	West Perth Power Inc.	CA	86922 9377 RC0001	3					
13.	ERTH Limited	CA	83794 3117 RC0001	3					
14.	Clinton Power Corporation	CA	86985 8779 RC0001	3					

Note 1: Enter "NR" if a corporation is not registered.
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(99)

Canada

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Description	Line	Amount		Line	Amount	
Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")				200	328,537	A
Add: Cost of eligible capital property acquired during the taxation year	222					
Other adjustments	226					
Subtotal (line 222 plus line 226)		x 3 / 4 =	B			
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228	x 1 / 2 =	C			
amount B minus amount C (if negative, enter "0")			►			D
Amount transferred on amalgamation or wind-up of subsidiary				224		E
Subtotal (add amounts A, D, and E)				230	328,537	F
Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242		G			
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244		H			
Other adjustments	246		I			
(add amounts G,H, and I)		x 3 / 4 =		248		J
Cumulative eligible capital balance (amount F minus amount J) (if amount K is negative, enter "0" at line M and proceed to Part 2)					328,537	K
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business				249		
amount K		328,537				
less amount from line 249						
Current year deduction		328,537 x 7.00 % =		250	22,998 *	
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)					22,998 ►	
					22,998	L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")				300	305,539	M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)					N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			400		1
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			401		2
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3		
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4		
Line 3 minus line 4 (if negative, enter "0")			▶		5
Total of lines 1, 2 and 5					6
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7		
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8		
Subtotal (line 7 plus line 8)	409		▶		9
Line 6 minus line 9 (if negative, enter "0")				▶	O
Line N minus line O (if negative, enter "0")					P
Line 5		x 1 / 2 =			Q
Line P minus line Q (if negative, enter "0")					R
Amount R		x 2 / 3 =			S
Amount N or amount O, whichever is less					T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)				410	

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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 2010

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	Erie Thames Powerlines Corporation	86371 9498 RC0001	1	500,000	100.0000	500,000
2	Coulter Water Meter Service Inc.	10117 1486 RC0002	1	500,000		
3	ERTH Corporation	86356 4324 RC0001	1	500,000		
4	CRU Solutions Inc.	86371 9696 RC0001	1	500,000		
5	Utilismart Corporation	86443 9450 RC0001	1	500,000		
6	Enerconnect Inc.	87367 1499 RC0001	1	500,000		
7	Wattsworth Analysis Inc.	87746 8108 RC0001	1	500,000		
8	Enermajica Ontario Inc.	88660 6409 RC0001	1	500,000		
9	ERTH360 Generation & Consulting Inc.	82960 2226 RC0001	1	500,000		
10	Ecaliber (Canada) Inc.	82954 1895 RC0001	1	500,000		
11	The SPI Group Inc.	87013 2917 RC0001	1	500,000		
12	ERTH (Holdings) Inc.	82642 4293 RC0002	1	500,000		
13	West Perth Power Inc.	86922 9377 RC0001	1	500,000		

	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**	
14	ERTH Limited	83794 3117 RC0001	1	500,000			
15	Clinton Power Corporation	86985 8779 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 33

TAXABLE CAPITAL EMPLOYED IN CANADA – LARGE CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms "financial institution," "long-term debt," and "reserves."
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If you are filing a provincial capital tax return with your *T2 Corporation Income Tax Return*, also file a completed Schedule 33 with the return no later than six months from the end of the tax year.
- This schedule may contain changes that had not yet become law at the time of publishing.

If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, "Taxable capital employed in Canada."

Part 1 – Capital

Add the following amounts at the end of the year:

	Line	Amount		
Reserves that have not been deducted in computing income for the year under Part I	101	514,103		
Capital stock (or members' contributions if incorporated without share capital)	103	8,038,524		
Retained earnings	104	574,655		
Contributed surplus	105			
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108	14,710,553		
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109			
Any dividends declared but not paid by the corporation before the end of the year	110			
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111			
Proportion of the amount, if any, by which the total of all amounts (see note below) for the partnership of which the corporation is a member at the end of the year exceeds the amount of the partnership's deferred unrealized foreign exchange losses	112			
Subtotal		23,837,835	23,837,835	A

Deduct the following amounts:

	Line	Amount		
Deferred tax debit balance at the end of the year	121			
Any deficit deducted in computing its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122			
Any amount deducted under subsection 135(1) in computing income under Part I for the year, as long as the amount may reasonably be regarded as being included in any of lines 101 to 112 above	123			
The amount of deferred unrealized foreign exchange losses at the end of the year	124			
Subtotal				B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190		23,837,835	

Note: Lines 101, 107, 108, 109, 111, and 112 are determined as follows:

- If the partnership is a member of another partnership (tiered partnerships), include the amounts of the partnership and tiered partnerships.
- Amounts for the partnership and tiered partnerships are those that would be determined for lines 101, 107, 108, 109, 111, and 112 as if they apply in the same way that they apply to corporations.
- Do not include amounts owing to the member or to other corporations that are members of the partnership.
- Amounts are determined at the end of the last fiscal period of the partnership ending in the year of the corporation.
- The proportion of the total amounts is determined by the corporation's share of the partnership's income or loss for the fiscal period of the partnership.

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend receivable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim, or similar obligation of, a partnership all of the members of which, throughout the year, were other corporations (other than financial institutions) that were not exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)]	406	
An interest in a partnership (see note 1 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	

Notes:

1. Where the corporation has an interest in a partnership or in tiered partnerships, consider the following:
   - the investment allowance of a partnership is deemed to be the amount calculated at line 490 above, at the end of its fiscal period, as if it was a corporation;
   - the total of the carrying value of each asset of the partnership described in the above lines is for its last fiscal period ending at or before the end of the corporation's tax year; and
   - the carrying value of a partnership member's interest at the end of the year is its specified proportion [as defined in subsection 248(1)] of the partnership's investment allowance.
2. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)].
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation, according to subsection 181.2(6).

Part 3 – Taxable capital

Capital for the year (line 190)		23,837,835	C
Deduct: Investment allowance for the year (line 490)			D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	23,837,835	

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 23,837,835 x (Taxable income earned in Canada **610** 586,137 / Taxable income 586,137) = **Taxable capital employed in Canada** **690** 23,837,835

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada			701	
Deduct the following amounts:				
Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada	711			
Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada	712			
Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below)	713			
Total deductions (add lines 711, 712, and 713)		►		E
Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0")			790	

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (line 690 or 790, whichever applies)		F
Deduct:	10,000,000	G
Excess (amount F **minus** amount G) (if negative, enter "0")		H
Calculation for purposes of the small business deduction (amount H x 0.00225)		I

Enter this amount at line 415 of the T2 return

Attached Schedule with Total

Part 1 – All loans and advances to the corporation

Title Part 1 – All loans and advances to the corporation

Description	Amount	
Due to related party	5,101,657	00
Long term debt	8,615,808	00
Customer Deposits	993,088	00
Total	14,710,553	00

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	ERTH Corporation	86356 4324 RC0001			100.000	100.000
2						
3						
4						
5						
6						
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Canada

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SCHEDULE 500

ONTARIO CORPORATION TAX CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

- 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.
- References to subsections and paragraphs are from the federal *Income Tax Act*.
- 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	181 / 365	x	14.00 %	=	6.94247 %	A1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	184 / 365	x	12.00 %	=	6.04932 %	A2
Number of days in the tax year after June 30, 2011, and before July 1, 2012 / Number of days in the tax year	/ 365	x	11.50 %	=	%	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) 12.99179 ▶ 12.99179 % A6

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . 586,137 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A6 from Part 1) . . . . 76,150 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.

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)	586,137	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)	586,137	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 ** = 586,137.00 / 586,137 =	1.00000	E
Ontario small business income (amount D **multiplied** by amount E)	500,000	F

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	181 / 365	x	8.50 %	=	4.21507 %	G1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	184 / 365	x	7.50 %	=	3.78082 %	G2
Number of days in the tax year after June 30, 2011, and before July 1, 2012 / Number of days in the tax year	/ 365	x	7.00 %	=	%	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)	7.99589 %	G6
Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G6)	39,979	H

Enter amount H on line 402 of Schedule 5.

* 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 *	586,137	I		
Adjusted taxable income of all associated corporations (amount from line 500 of Schedule 501)	1,701,757	J		
Aggregate adjusted taxable income (amount I **plus** amount J)	2,287,894	▶	2,287,894	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)			1,787,894	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: 181 / 365 x 4.25 % = 2.10753 % M

Amount L x % on line M = 37,680 N

Amount N 37,680 x Ontario small business income (amount F from Part 3) / 500,000 : 500,000 / 500,000 = 37,680 O

Surtax re Ontario small business deduction: lesser of amount O and OSBD (amount H from Part 3) 37,680 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.

Amount D 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) 7.99589 % : 37,680 / 0.07996 = 471,236 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") 28,764 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)	7.99589 %		
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.

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SCHEDULE 501

ONTARIO ADJUSTED TAXABLE INCOME OF ASSOCIATED CORPORATIONS TO DETERMINE SURTAX RE ONTARIO SMALL BUSINESS DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

- For use by Canadian-controlled private corporations (CCPCs) to report the adjusted taxable income of all corporations (Canadian and foreign) with which the filing corporation was associated at any time during the tax year.
- Include the adjusted taxable income for the tax year of the associated corporation that ends at or before the date of the filing corporation's tax year-end.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations* 100	Business number of associated corporations** 200	Tax year-end 300	Adjusted taxable income *** (if loss, enter "0") 400
1	Coulter Water Meter Service Inc.	10117 1486 RC0002	2010-12-31	
2	ERTH Corporation	86356 4324 RC0001	2010-12-31	
3	CRU Solutions Inc.	86371 9696 RC0001	2010-12-28	
4	Utilismart Corporation	86443 9450 RC0001	2010-12-31	1,208,178
5	Enerconnect Inc.	87367 1499 RC0001	2010-12-31	85,601
6	Wattsworth Analysis Inc.	87746 8108 RC0001	2010-12-31	407,293
7	Enermajica Ontario Inc.	88660 6409 RC0001	2010-12-31	685
8	ERTH360 Generation & Consulting Inc.	82960 2226 RC0001	2010-12-31	
9	Ecaliber (Canada) Inc.	82954 1895 RC0001	2010-12-31	
10	The SPI Group Inc.	87013 2917 RC0001	2010-12-31	
11	ERTH (Holdings) Inc.	82642 4293 RC0002	2010-12-28	
12	West Perth Power Inc.	86922 9377 RC0001	2010-12-31	
13	ERTH Limited	83794 3117 RC0001	2010-12-31	
14	Clinton Power Corporation	86985 8779 RC0001	2010-12-31	
			Total 500	1,701,757

Enter the total adjusted taxable income from line 500 on line J in Part 4 of Schedule 500, *Ontario Corporation Tax Calculation.*

* Subsection 256(2) of the federal *Income Tax Act* may deem the filing corporation to be associated with another corporation, because both corporations are associated with a third corporation. If so, do not list the other corporation, nor the third corporation if it is not a CCPC or has elected under subsection 256(2) of the federal Act not to be associated for purposes of section 125 of the federal Act.

** Enter "NR" if a corporation is not registered.

***** Rules for adjusted taxable income:**

- If the associated corporation's tax year ends after December 31, 2008, its adjusted taxable income is equal to its taxable income or taxable income earned in Canada **plus** its adjusted Crown royalties **minus** its notional resource allowance for the year.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's adjusted taxable income by 365 and **divide** by the number of days in the associated corporation's tax year.
- If the associated corporation has two or more tax years ending in the filing corporation's tax year, enter the last tax year-end date on line 300 and, for the entry on line 400, **multiply** the sum of the adjusted taxable income for each of those tax years by 365, and **divide** by the total number of days in all of those tax years.

T2 SCH 501 E (10)

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SCHEDULE 510

ONTARIO CORPORATE MINIMUM TAX

Name of corporation	Business Number	Tax year-end Year Month Day
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	30,911,576
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	94,772,172
Total assets (total of lines 112 to 116)		125,683,748
Total revenue of the corporation for the tax year **	142	40,066,831
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	31,784,754
Total revenue (total of lines 142 to 146)		71,851,585

The corporation is subject to CMT if:
– for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
– for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Calculation of adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	527,119	
Add (to the extent reflected in income/loss):					
Provision for current income taxes/cost of current income taxes	220	187,000			
Provision for deferred income taxes (debits)/cost of future income taxes	222				
Equity losses from corporations	224				
Financial statement loss from partnerships and joint ventures	226				
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230				
Other additions (see note below):					
Share of adjusted net income of partnerships and joint ventures **	228				
Total patronage dividends received, not already included in net income/loss	232				
281	282				
283	284				
Subtotal		187,000	▶	187,000	A
Deduct (to the extent reflected in income/loss):					
Provision for recovery of current income taxes/benefit of current income taxes	320				
Provision for deferred income taxes (credits)/benefit of future income taxes	322				
Equity income from corporations	324				
Financial statement income from partnerships and joint ventures	326				
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330				
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332				
Gain on donation of listed security or ecological gift	340				
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342				
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344				
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346				
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348				
Other deductions (see note below):					
Share of adjusted net loss of partnerships and joint ventures **	328				
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334				
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336				
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338				
381	382				
383	384				
385	386				
387	388				
389	390				
Subtotal			▶		B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	714,119	

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

– Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – Calculation of CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)	515			
Deduct:				
CMT loss available (amount R from Part 7)				
Minus: Adjustment for an acquisition of control *	518			
Adjusted CMT loss available				C
Net income subject to CMT calculation (if negative, enter "0")	520			

Amount from line 520 ______ x (Number of days in the tax year before July 1, 2010 / Number of days in the tax year) 181 / 365 x 4 % = ______ 1

Amount from line 520 ______ x (Number of days in the tax year after June 30, 2010 / Number of days in the tax year) 184 / 365 x 2.7 % = ______ 2

Subtotal (amount 1 **plus** amount 2) ______ 3

Gross CMT: amount on line 3 above x OAF **	540		
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")			D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		73,851	
Net CMT payable (if negative, enter "0")			E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** ______ = ______

Ontario allocation factor 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *			G		
Deduct:					
CMT credit expired *	600				
CMT credit carryforward at the beginning of the current tax year * (see note below)			▶	620	
Add:					
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)				650	
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)					H
Deduct:					
CMT credit deducted in the current tax year (amount P from Part 5)					I
Subtotal (amount H **minus** amount I)					J
Add:					
Net CMT payable (amount E from Part 3)					
SAT payable (amount O from Part 6 of Schedule 512)					
Subtotal			▶		K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)				670	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)					M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		73,851	1		
For a corporation that is not a life insurance corporation:					
CMT after foreign tax credit deduction (amount D from Part 3)		2			
For a life insurance corporation:					
Gross CMT (line 540 from Part 3)		3			
Gross SAT (line 460 from Part 6 of Schedule 512)		4			
The **greater** of amounts 3 and 4		5			
Deduct: line 2 or line 5, whichever applies:			6		
Subtotal (if negative, enter "0")		73,851	▶	73,851	N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		73,851			
Deduct:					
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)					
Subtotal (if negative, enter "0")		73,851	▶	73,851	O
CMT credit deducted in the current tax year (least of amounts M, N, and O)					P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? **675** 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . ______ Q

Deduct:

CMT loss expired * . . . . 700 ______

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . ______ ► 720 ______

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) . . . . 750 ______

CMT loss available (line 720 **plus** line 750) . . . . ______ R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . ______

Subtotal (if negative, enter "0") ______ S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) . . . . 760 ______

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . 770 ______ T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not transfer a loss on a vertical amalgamation under subsection 87(2.11) of the federal Act or other amalgamation of a parent and its subsidiary.
Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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SCHEDULE 515

ONTARIO CAPITAL TAX ON OTHER THAN FINANCIAL INSTITUTIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

- Complete this schedule for a corporation with a permanent establishment in Ontario at any time in the tax year and that is a corporation other than a financial institution. The Ontario capital tax on other than financial institutions is levied under section 64 of the *Taxation Act, 2007* (Ontario).
- The Ontario capital tax is eliminated effective July 1, 2010. You do not have to complete this schedule if the corporation's tax year begins after June 30, 2010. For businesses mainly engaged in qualifying manufacturing and resource activities in Ontario, the capital tax is eliminated effective January 1, 2007.
- To complete this schedule, you have to complete Schedule 33, *Part I.3 Tax on Large Corporations* (renamed *Taxable Capital Employed in Canada – Large Corporations* for 2010 and later tax years). File completed copies of both schedules with the *T2 Corporation Income Tax Return* within six months of the end of the tax year.
- A corporation is exempt from Ontario capital tax if it was one of the following:
  1) a corporation that is liable to the special additional tax according to section 74 of the *Corporations Tax Act* (Ontario);
  2) a credit union;
  3) a deposit insurance corporation according to section 137.1 of the federal *Income Tax Act*;
  4) a family farm corporation for the year as defined by subsection 64(3) of the *Taxation Act*, 2007 (Ontario), other than a corporation for which a determination has been made under subsection 31(2) of the federal Act;
  5) a family fishing corporation, as defined by subsection 64(3) of the *Taxation Act, 2007* (Ontario); or
  6) a corporation exempt from income tax according to section 149 of the federal Act.

Part 1 – Taxable capital of a corporation resident in Canada other than a financial institution

	Line	Amount		Total	
Amount A from Part 1 of Schedule 33	100	23,837,835			
Add:					
Accumulated other comprehensive income at the end of the year	105				
Subtotal		23,837,835	▶	23,837,835	A
Deduct:					
Amount B from Part 1 of Schedule 33	110				
Amount on line 490 from Part 2 of Schedule 33	115				
Subtotal			▶		B
Taxable capital (amount A **minus** amount B) (if negative, enter "0")	120			23,837,835	

Part 2 – Capital deduction

Complete this part only if the corporation is associated.

Are you electing under subsection 83(2) of the *Taxation Act, 2007* (Ontario)? **190** 1 Yes [X] 2 No [ ]

If you answered **no** to the question at line 190, complete line 220. If you answered **yes** to the question at line 190, complete line 305 by using Schedule 516, *Capital Deduction Election of Associated Group for the Allocation of Net Deduction*, to calculate the amount to be entered on line 300.

$$\frac{\text{Taxable capital (from line 120) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (from line 790 in Part 4 of Schedule 33)} \quad \mathbf{200}\ \_\_\_\_}{\text{Taxable capital or taxable capital employed in Canada of every corporation with a permanent establishment in Canada and associated for the last tax year *} \quad \mathbf{210}} \times 15{,}000{,}000\ \$ = \textbf{Capital deduction}\ \mathbf{220}\ \_\_\_\_$$

* This amount includes the filing corporation's taxable capital or taxable capital employed in Canada. Do not include an amount from a financial institution or corporation that is exempt from capital tax under Division E of the *Taxation Act, 2007* (Ontario) or Part III of the *Corporations Tax Act* (Ontario).

$$\frac{\text{Allocation of net deduction (from line 600 for the filing corporation from Schedule 516)} \quad \mathbf{300}\ \_\_\_\_}{\text{Ontario allocation factor (OAF) (amount I in Part 3)} \quad 1.00000} = \textbf{Capital deduction}\ \mathbf{305}\ \_\_\_\_$$

Part 3 – Ontario capital tax payable

Taxable capital (enter amount from line 120 in Part 1) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (enter amount from line 790 in Part 4 of Schedule 33), whichever applies	320	23,837,835	
Deduct: Capital deduction (Enter $15,000,000 if the corporation is not associated. Otherwise, enter the amount from line 220 or line 305, whichever applies, from Part 2)			B
Net amount (line 320 **minus** amount B) (if negative, enter "0")		23,837,835	C

Note: For days in the tax year after June 30, 2010, the Ontario capital tax rate is 0%.

Amount C 23,837,835 x (Number of days in the tax year before January 1, 2010 / Number of days in the tax year) (/ 365) x 0.00225 = ______ D

Amount C 23,837,835 x (Number of days in the tax year after December 31, 2009 and before July 1, 2010 / Number of days in the tax year) (181 / 365) x 0.00150 = 17,731 E

Subtotal (amount D **plus** amount E) 17,731 F

Amount F 17,731 x OAF (amount on line I) 1.00000 = 17,731 G

Amount G 17,731 x (Number of days in the tax year * / 365) (365 / 365) = 17,731 H

Deduct:

Capital tax credit for manufacturers (enter amount J from Part 4) 350 ______

Ontario capital tax payable (amount H **minus** line 350) (if negative, enter "0") 400 17,731

Enter amount from line 400 on line 282 of Schedule 5, *Tax Calculation Supplementary - Corporations*.

* Enter either 365 if there are at least 51 weeks in the tax year, or the number of days in the year, whichever applies.

Calculation of the Ontario allocation factor (OAF)

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line I.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation and enter the result on line I:

(Ontario taxable income ** / Taxable income ***) ______ = ______

Ontario allocation factor 1.00000 I

** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*** Enter the taxable income amount from line 360 or line Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – Capital tax credit for manufacturers

(Ontario manufacturing labour cost* 405 / Total Ontario labour cost** 410) ______ x 100 = 420 ______ %

If the percentage on line 420 is 20% or less, enter "0" on line J.

If the percentage on line 420 is at least 50%, enter amount H from Part 3 on line J.

If the percentage on line 420 is more than 20% but less than 50%, complete the following calculation and enter the result on line J:

((percentage from line 420) – 20% / 30%) (% / 30 %) x 17,731 Amount H from Part 3 = ______

Capital tax credit for manufacturers ______ J

Enter amount J on line 350 in Part 3.

* As defined in subsection 83.1(4) of the *Taxation Act, 2007* (Ontario)

** As defined in subsection 83.1(5) of the *Taxation Act, 2007* (Ontario)

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SCHEDULE 516

CAPITAL DEDUCTION ELECTION OF ASSOCIATED GROUP FOR THE ALLOCATION OF NET DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

- Complete this schedule to allocate the associated group's net deduction for the capital deduction election under subsection 83(2) of the *Taxation Act, 2007* (Ontario). The associated group includes the filing corporation (see line 190 of Part 2 of Schedule 515, *Ontario Capital Tax on Other than Financial Institutions*).
- If you need more space, attach more schedules.
- File this schedule with the *T2 Corporation Income Tax Retum*.

	A Names of eligible corporations in the associated group 100	B Business Number of associated corporations (enter "NR" if a corporation is not registered) 200	C Ontario allocation factor (OAF)* (enter as a percentage) 300	D Total assets** 400	E Net deduction ($15 million x line 300) **multiplied** by line 400 / line 700 500	F Allocation of net deduction *** 600
1.	Erie Thames Powerlines Corporation	86371 9498 RC0001	100.000	28,656,017	3,847,412	
2.	Coulter Water Meter Service Inc.	10117 1486 RC0002	100.000	1,283,896	172,378	1,067,115
3.	ERTH Corporation	86356 4324 RC0001	100.000	35,640,589	4,785,174	1,387,718
4.	CRU Solutions Inc.	86371 9696 RC0001	100.000	7,635,968	1,025,220	2,623,084
5.	Utilismart Corporation	86443 9450 RC0001	100.000	2,834,958	380,627	
6.	Enerconnect Inc.	87367 1499 RC0001	100.000	1,457,122	195,636	
7.	Wattsworth Analysis Inc.	87746 8108 RC0001	100.000	597,624	80,238	
8.	Enermajica Ontario Inc.	88660 6409 RC0001	100.000	290,932	39,061	
9.	ERTH360 Generation & Consulting Inc.	82960 2226 RC0001	100.000	251,277	33,737	37,113
10.	Ecaliber (Canada) Inc.	82954 1895 RC0001	100.000	3,786,979	508,447	4,404,486
11.	The SPI Group Inc.	87013 2917 RC0001	100.000	6,994,745	939,128	4,160,526
12.	ERTH (Holdings) Inc.	82642 4293 RC0002	100.000	14,106,975	1,894,030	1,319,958
13.	West Perth Power Inc.	86922 9377 RC0001	100.000	5,000,961	671,439	
14.	ERTH Limited	83794 3117 RC0001				
15.	Clinton Power Corporation	86985 8779 RC0001	100.000	3,183,875	427,473	

Total assets of associated group (total of amounts in column D) **700** 111,721,918

Total net deduction (total of amounts in column E) **800** 15,000,000

Total allocated net deduction (total of amounts in column F) (not to exceed amount on line 800) **900** 15,000,000

* OAF from the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends.

** Total assets of each corporation in the associated group as recorded in the books and records for the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends. If the corporation is not resident in Canada, enter the amount of its total assets situated in Canada.

*** Enter the amount from this column allocated to the filing corporation on line 300 of Schedule 515.

T2 SCH 516

Canada

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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
Erie Thames Powerlines Corporation	86371 9498 RC0001	2010-12-31

- 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)
Erie Thames Powerlines Corporation

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	2000-07-07	1428821

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
143	Bell Street	

240 Additional address information if applicable (line 220 must be completed first)
PO Box 157

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
Ingersoll	ON	CA	N5C 3K5

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 Pettit (Last name) **451** Jeff (First name)

454 ______________________, (Middle name(s))

460 1 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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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
Clinton Power Corporation

Business Number	Tax year ▶	From Y M D	To Y M D
86985 8779 RC0001		2010-01-01	2010-12-31

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)	-52,930
Part I tax payable (line 700)	
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)	
Provincial tax on large corporations (line 765)	

Part C – Certification and authorization

I, Pettit (Last name in block letters) Jeff (First name in block letters) President & CEO (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.

2011-06-29		(519) 518-6117
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: KPMG LLP

Electronic filer number:

Privacy Act, Personal Information Bank number CRA PPU 047

Canada Revenue Agency / Agence du revenu du Canada

200

T2 CORPORATION INCOME TAX RETURN

EXEMPT FROM TAX

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** 86985 8779 RC0001

Corporation's name

002 Clinton Power Corporation

Address of head office

Has this address changed since the last time you filed your T2 return? . . . . **010** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 011 to 018.)

011 23 Albert Street

012 PO Box 520

City	Province, territory, or state
015 Clinton	**016** ON
Country (other than Canada)	Postal code/Zip code
017	**018** N0M 1L0

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? . . . . **020** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 021 to 028.)

021 c/o

022 200-295 Wolfe Street

023

City	Province, territory, or state
025 London	**026** ON
Country (other than Canada)	Postal code/Zip code
027	**028** N6B 2C4

Location of books and records

Has the location of books and records changed since the last time you filed your T2 return? . . . . **030** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 031 to 038.)

031 200-295 Wolfe Street

032

City	Province,territory, or state
035 London	**036** ON
Country (other than Canada)	Postal code/Zip code
037	**038** N6B 2C4

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** 2010-01-01 (YYYY MM DD)

Tax year-end **061** 2010-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . **063** 1 Yes [X] 2 No [ ]

If **yes**, provide the date control was acquired . . . . **065** 2010-01-01 (YYYY MM DD)

Is the date on line 061 a deemed tax year-end in accordance with 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 [X] Exempt under other paragraphs of section 149

Do not use this area

091	**092**	**093**	**094**	**095**	**096**
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **Yes** response, **attach** to the T2 return the schedule that applies.

Question	Line	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
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	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		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation (or its associated corporations) 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		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
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281		X

What is the corporation's major business activity? (only complete if **yes** was entered at line 281) 282

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 1 Wholesale ☐ 2 Retail ☐

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electricity Distribution	285	100.000 %
286		287	%
288		289	%

		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	-52,930	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 3.2 times the Part VI.1 tax payable at line 724.

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, **minus** 10/3 of the amount on line 632*, **minus** 1/(0.38 - X**) 3.57143
times the amount on line 636***, and **minus** any amount that, because of federal law, is exempt form Part I tax . . . . **405** ________ B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

400,000	x	Number of days in the tax year before 2009 / Number of days in the tax year	____ / 365	=	. . . . ________	1
500,000	x	Number of days in the tax year after 2008 / Number of days in the tax year	365 / 365	=	 500,000	2
			Add amounts at lines 1 and 2		500,000	4

Business limit (see notes 1 and 2 below) . . . . **410** ________ C

Notes:
1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C ________ x **415** **** 72,780 / 11,250 D = ... ________ 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.

* 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			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, whichever is the least		E	
Aggregate investment income from line 440*		F	
Total of amounts B to F		▶	G
Amount A **minus** amount G (if negative, enter "0")			H

Amount H		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	I
Amount H		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 %	=	J
Amount H		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 / 365	x	10 %	=	K
Amount H		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	x	11.5 %	=	L
Amount H		x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x	13 %	=	L.1

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L.1 . . . M
Enter amount M on line 638.

* 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, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	T
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 %	=	U
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 / 365	x	10 %	=	V
Amount S		x	Number of days in the tax year after December 31, 2010, and before January 2012 / Number of days in the tax year	/ 365	x	11.5 %	=	W
Amount S		x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x	13 %	=	W.1

General tax reduction – Total of amounts T to W.1 . . . X
Enter amount X on line 639.

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		______		
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		______		
Deduct:				
Amount from line 400, 405, 410, or 425, whichever is the least	______			
Foreign non-business income tax credit from line 632 ______ x 25 / 9 =	______			
Foreign business income tax credit from line 636 ______ x 1(0.38 - X*) / 3.57143 =	______			
	______ ▶	______		
		______ x 26 2/3 % =	______	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780)			______	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 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)		______	

Part I tax

Base amount of Part I tax – Taxable income (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			i
Taxable income from line 360			
Deduct:			
Amount from line 400, 405, 410, or 425, 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			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	638				
General tax reduction from amount X	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.

Summary of tax and credits

Federal tax

Part I tax payable	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 (New Brunswick* and Nova Scotia)	765	

Total tax payable 770 ______ A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	

B

Refund code 894 ______ Overpayment ______

Balance (line A **minus** line B) ______

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 X

* The New Brunswick tax on large corporations is eliminated effective January 1, 2009.

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, 950 Pettit (Last name in block letters) 951 Jeff (First name in block letters) 954 President & CEO (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2011-06-29 Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (519) 518-6117 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes X 2 No ☐

958 ______ Name in block letters 959 ______ 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

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	979,023	1,516,260
	Total tangible capital assets	2008	+	2,148,816	1,808,119
	Total accumulated amortization of tangible capital assets	2009	–	561,227	482,034
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	542,999	341,530
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	3,109,611	3,183,875
	Liabilities				
	Total current liabilities	3139	+	1,717,149	2,590,766
	Total long-term liabilities	3450	+	900,000	
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	2,617,149	2,590,766
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	492,462	593,109
	Total liabilities and shareholder equity	3640	=	3,109,611	3,183,875
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	-206,324	-105,677

***** Generic item

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SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence Number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	2,730,868	2,547,559
	Cost of sales	8518	–	2,220,809	2,036,176
	Gross profit/loss	8519	=	510,059	511,383
	Cost of sales	8518	+	2,220,809	2,036,176
	Total operating expenses	9367	+	715,674	599,520
	Total expenses (mandatory field)	9368	=	2,936,483	2,635,696
	Total revenue (mandatory field)	8299	+	2,835,837	2,596,837
	Total expenses (mandatory field)	9368	–	2,936,483	2,635,696
	Net non-farming income	9369	=	-100,646	-38,859
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	-100,646	-38,859
	Total other comprehensive income	9998	=		
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–		
	Deferred income tax provision	9995	–		
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	-100,646	-38,859

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year-end Year Month Day
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI) for Corporations* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule, and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant preparing or reporting on the financial statements

Does the accountant have a professional designation? . . . 095 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . 097 1 Yes [ ] 2 No [X]

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note: If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: 198

Completed an auditor's report . . . 1 [X]

Completed a review engagement report . . . 2 [ ]

Conducted a compilation engagement . . . 3 [ ]

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . 099 1 Yes [ ] 2 No [X]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: 110

Prepared the tax return (financial statements prepared by client) . . . 1 [ ]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . 2 [ ]

Were notes to the financial statements prepared? . . . 101 1 Yes [X] 2 No [ ]

If **yes**, complete lines 102 to 107 below:

Are any values presented at other than cost? . . . 102 1 Yes [ ] 2 No [X]

Has there been a change in accounting policies since the last return? . . . 103 1 Yes [X] 2 No [ ]

Are subsequent events mentioned in the notes? . . . 104 1 Yes [X] 2 No [ ]

Is re-evaluation of asset information mentioned in the notes? . . . 105 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . 106 1 Yes [X] 2 No [ ]

Is information regarding commitments mentioned in the notes? . . . 107 1 Yes [ ] 2 No [X]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . 108 1 Yes [ ] 2 No [X]

If **yes**, complete line 109 below:

Are you filing financial statements of the joint venture(s) or partnership(s)? . . . 109 1 Yes [ ] 2 No [ ]

T2 BAR CODE RETURN

Name: **Clinton Power Corporation**

BN: **86985 8779 RC 0001**

Tax Year Start: **2010-01-01**

Tax Year End: **2010-12-31**

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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
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

- 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				-100,646 A
Add:				
Amortization of tangible assets		104	79,194	
Non-deductible meals and entertainment expenses		121	2,882	
Subtotal of additions			82,076 ▶	82,076
Other additions:				
Miscellaneous other additions:				
601 Gold Fees		291	65	
602 Smart Meter Recovery		292	33,822	
603 Adjustment for spare parts	36,734			
Total	36,734	293	36,734	
604				
Total		294		
Subtotal of other additions		199	70,621 ▶	70,621
Total additions		500	152,697 ▶	152,697
Deduct:				
Capital cost allowance from Schedule 8		403	101,662	
Subtotal of deductions			101,662 ▶	101,662
Other deductions:				
Miscellaneous other deductions:				
700 Actual Capital Tax		390	1,930	
701 Capital tax recovery		391	1,389	
704				
Total		394		
Subtotal of other deductions		499	3,319 ▶	3,319
Total deductions		510	104,981 ▶	104,981
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				-52,930

T2 SCH 1 E (10)

Canada

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SCHEDULE 4

CORPORATION LOSS CONTINUITY AND APPLICATION

Name of corporation	Business Number	Tax year-end Year Month Day
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

- 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			-52,930
Deduct: (increase a loss)			
Net capital losses deducted in the year (enter as a positive amount)			
Taxable dividends deductible under sections 112, 113(1), or subsection 138(6)			
Amount of Part VI.1 tax deductible			
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)			
		►	
Subtotal (if positive, enter "0")			-52,930
Deduct: (increase a loss)			
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions			
Subtotal			-52,930
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 this amount on line 310.)			
Current-year non-capital loss (if positive, enter "0"; if negative, enter this amount on line 110 as a positive)			-52,930

Continuity of non-capital losses and request for a carryback

	Line			
Non-capital loss at the end of the previous tax year		84,691		
Deduct: Non-capital loss expired*	100			
Non-capital losses at the beginning of the tax year	102	84,691	►	84,691
Add:				
Non-capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	105			
Current-year non-capital loss (from calculation above)	110	52,930		
		52,930	►	52,930
Subtotal				137,621

Part 1 – Non-capital losses (continued)

Subtotal from page 1			137,621
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	150		
Section 80 – Adjustments for forgiven amounts	140		
Subsection 111(10) – Adjustments for fuel tax rebate			
Non-capital losses of previous tax years applied in the current tax year (enter on line 331 of the T2 return)	130		
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		
		▶	
Amount of non-capital losses available to carry back or carry forward to other years			137,621
Deduct – Request to carry back non-capital loss to:			
First previous tax year to reduce taxable income	901		
Second previous tax year to reduce taxable income	902		
Third previous tax year to reduce taxable income	903		
First previous tax year to reduce taxable dividends subject to Part IV tax	911		
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		
		▶	
Closing balance of non-capital losses to be carried forward to future tax years		180	137,621

* 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 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200		
Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	205		
		▶	
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	250		
Section 80 – Adjustments for forgiven amounts	240		
		▶	
Subtotal			
Add: Current-year capital loss (from the calculation on Schedule 6)		210	
Unused non-capital losses that expired in the tax year*		A	
Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year**		B	
Enter amount from line A or B, whichever is less	215		
ABILs expired as non-capital loss: line 215 **divided** by the inclusion rate*** 50.0000 %		220	
Subtotal			

Part 2 – Capital losses (continued)

Subtotal from page 2

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 at line 220 above.

Deduct: Capital losses from previous tax years applied against the current-year net capital gain (see Note 1) **225**

Amount of capital losses available to carry back or carry forward to other years

Deduct – Request to carry back capital loss to (see Note 2):

	Capital gain (100%)		Amount carried back (100%)
First previous tax year		951	
Second previous tax year		952	
Third previous tax year		953	

Capital losses – Closing balance **280**

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.

* 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 A.

** 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 B.

*** This inclusion rate is the rate used to calculate your ABIL referred to at line B. Therefore, use one of the following inclusion rates, whichever applies:

- For ABILs incurred in the 1999 and previous tax years, use 0.75.
- For ABILs incurred in the 2000 and 2001 tax years, the inclusion rate is equal to amount M on Schedule 6 – Version T2SCH6(01)
- For ABILs incurred in the 2002 and later tax years, use 0.50.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year . . . .

Deduct: Farm loss expired* **300**

Farm losses at the beginning of the tax year . . . . **302** ▶

Add:

Farm losses transferred on the amalgamation or the windup of a subsidiary corporation **305**

Current-year farm loss **310**

▶

Subtotal

Part 3 – Farm losses (continued)

Subtotal from page 3			
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	350		
Section 80 – Adjustments for forgiven amounts	340		
Amount applied against taxable income (enter on line 334 of the T2 return)	330		
Amount applied against taxable dividends subject to Part IV tax	335		
			▶
Amount of farm losses available to carry back or carry forward to other years			
Deduct – Request to carry back farm loss to:			
First previous tax year to reduce taxable income	921		
Second previous tax year to reduce taxable income	922		
Third previous tax year to reduce taxable income	923		
First previous tax year to reduce taxable dividends subject to Part IV tax	931		
Second previous tax year to reduce taxable dividends subject to Part IV tax	932		
Third previous tax year to reduce taxable dividends subject to Part IV tax	933		
			▶
Farm losses – Closing balance	380		

* 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		C
Minus the deductible farm loss:				
$2,500 **plus** D or E, whichever is less		2,500		
(amount C above ______ – $2,500) **divided** by 2 =	D			
6,250	E			
		2,500	▶ 2,500	F
Current-year restricted farm loss (amount C **minus** amount F) (enter this amount on line 410)				

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			
Deduct: Restricted farm loss expired*	400		
Restricted farm losses at the beginning of the tax year	402		▶
Add:			
Restricted farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation	405		
Current-year restricted farm loss (enter on line 233 of Schedule 1)	410		
			▶
Subtotal			

Part 4 – Restricted farm losses (continued)

Subtotal from page 4			
Deduct:			
Amount applied against farming income (enter on line 333 of the T2 return)	430		
Section 80 – Adjustments for forgiven amounts	440		
Other adjustments	450		►
Amount of restricted farm losses available to carry back or carry forward to other years			
Deduct – Request to carry back restricted farm loss to:			
First previous tax year to reduce farming income	941		
Second previous tax year to reduce farming income	942		
Third previous tax year to reduce farming income	943		►
Restricted farm losses – Closing balance		480	

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			
Deduct: Listed personal property loss expired after seven tax years	500		
Listed personal property losses at the beginning of the tax year	502		►
Add: Current-year listed personal property loss (from Schedule 6)		510	
Subtotal			
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		
Other adjustments	550		►
Amount of listed personal property losses available to carry back or carry forward to other years			
Deduct – Request to carry back listed personal property loss to:			
First previous tax year to reduce listed personal property gains	961		
Second previous tax year to reduce listed personal property gains	962		
Third previous tax year to reduce listed personal property gains	963		►
Listed personal property losses – Closing balance		580	

Part 7 – Limited partnership losses

Current-year limited partnership losses

1	2	3	4	5	6	7
Partnership identifier 600	Tax year ending YYYY/MM/DD 602	Corporation's share of limited partnership loss 604	Corporation's at-risk amount 606	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses 608	Column 4 **minus** column 5 (if negative, enter "0")	Current-year limited partnership losses (column 3 **minus** 6) 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 630	Tax year ending YYYY/MM/DD 632	Limited partnership losses at the end of the previous tax year 634	Corporation's at-risk amount 636	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses 638	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) 650

Continuity of limited partnership losses that can be carried forward to future tax years

1	2	3	4	5	6
Partnership identifier 660	Limited partnership losses at the end of the previous tax year 662	Limited partnership losses transferred on an amalgamation or the windup of a subsidiary 664	Current-year limited partnership losses (from column 620) 670	Limited partnership losses applied in the current year (cannot be more than column 650) 675	Current year limited partnership losses closing balance to be carried forward to future years (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, please 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		Balance at end of year
					Taxable income	Part IV tax	
Current	N/A	52,930			N/A		52,930
1st preceding taxation year 2009-12-31	73,442	N/A		N/A			73,442
2nd preceding taxation year 2008-12-31	11,249	N/A		N/A			11,249
3rd preceding taxation year 2007-12-31		N/A		N/A			
4th preceding taxation year 2008-06-30		N/A		N/A			
5th preceding taxation year 2007-06-30		N/A		N/A			
6th preceding taxation year 2006-06-30		N/A		N/A			
7th preceding taxation year 2005-06-30		N/A		N/A			
8th preceding taxation year 2004-06-30		N/A		N/A			
9th preceding taxation year 2003-06-30		N/A		N/A			
10th preceding taxation year 2002-06-30		N/A		N/A			
11th preceding taxation year 2001-06-30		N/A		N/A			
12th preceding taxation year 2000-06-30		N/A		N/A			
13th preceding taxation year 1999-06-30		N/A		N/A			
14th preceding taxation year 1998-06-30		N/A		N/A			
15th preceding taxation year 1997-06-30		N/A		N/A			
16th preceding taxation year 1996-06-30		N/A		N/A			
17th preceding taxation year 1995-06-30		N/A		N/A			
18th preceding taxation year 1994-06-30		N/A		N/A			
19th preceding taxation year 1993-06-30		N/A		N/A			
20th preceding taxation year 1992-06-30		N/A		N/A			*
Total	84,691	52,930					137,621

* **This balance expires this year and will not be available next year.**

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

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 (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				1,105,252	0		1,105,252	4	0	0	44,210	1,061,042
2.	8			112,179	55,957	0	56,090	112,046	20	0	0	22,409	145,727
3.	10				15,870	0		15,870	30	0	0	4,761	11,109
4.	12			13,219	489	0	6,610	7,098	100	0	0	7,098	6,610
5.	47			309,603	134,997	0	154,802	289,798	8	0	0	23,184	421,416
6.	94	Software Not In Use		19,889		0	9,945	9,944	0	0	0		19,889
		Total		454,890	1,312,565		227,447	1,540,008				101,662	1,665,793

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*.

**** 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
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

This schedule is to be completed by a corporation having one or more of the following:
– related corporation(s)
– associated corporations(s)

	Name 100	Country of residence (if other than Canada) 200	Business Number (Canadian corporation only) (see note 1) 300	Relationship code (see note 2) 400	Number of common shares owned 500	% of common shares owned 550	Number of preferred shares owned 600	% of preferred shares owned 650	Book value of capital stock 700
1.	Erie Thames Powerlines Corporatior	CA	86371 9498 RC0001	3					
2.	Coulter Water Meter Service Inc.	CA	10117 1486 RC0002	3					
3.	ERTH Corporation	CA	86356 4324 RC0001	1					
4.	CRU Solutions Inc.	CA	86371 9696 RC0001	3					
5.	Utilismart Corporation	CA	86443 9450 RC0001	3					
6.	Enerconnect Inc.	CA	87367 1499 RC0001	3					
7.	Wattsworth Analysis Inc.	CA	87746 8108 RC0001	3					
8.	Enermajica Ontario Inc.	CA	88660 6409 RC0001	3					
9.	ERTH360 Generation & Consulting I	CA	82960 2226 RC0001	3					
10.	Ecaliber (Canada) Inc.	CA	82954 1895 RC0001	3					
11.	The SPI Group Inc.	CA	87013 2917 RC0001	3					
12.	ERTH (Holdings) Inc.	CA	82642 4293 RC0002	3					
13.	West Perth Power Inc.	CA	86922 9377 RC0001	3					
14.	ERTH Limited	CA	83794 3117 RC0001	3					

Note 1: Enter "NR" if a corporation is not registered.
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 2010

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 ☒

	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	Clinton Power Corporation	86985 8779 RC0001	1	500,000		
2	Erie Thames Powerlines Corporation	86371 9498 RC0001	1	500,000	100.0000	500,000
3	Coulter Water Meter Service Inc.	10117 1486 RC0002	1	500,000		
4	ERTH Corporation	86356 4324 RC0001	1	500,000		
5	CRU Solutions Inc.	86371 9696 RC0001	1	500,000		
6	Utilismart Corporation	86443 9450 RC0001	1	500,000		
7	Enerconnect Inc.	87367 1499 RC0001	1	500,000		
8	Wattsworth Analysis Inc.	87746 8108 RC0001	1	500,000		
9	Enermajica Ontario Inc.	88660 6409 RC0001	1	500,000		
10	ERTH360 Generation & Consulting Inc.	82960 2226 RC0001	1	500,000		
11	Ecaliber (Canada) Inc.	82954 1895 RC0001	1	500,000		
12	The SPI Group Inc.	87013 2917 RC0001	1	500,000		
13	ERTH (Holdings) Inc.	82642 4293 RC0002	1	500,000		

	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	
14	West Perth Power Inc.	86922 9377 RC0001	1	500,000			
15	ERTH Limited	83794 3117 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 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

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)	Provide only one number per shareholder: Business Number (If a corporation is not registered, enter "NR")	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
	100	200	300	350	400	500
1	ERTH Corporation	86356 4324 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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SCHEDULE 516

CAPITAL DEDUCTION ELECTION OF ASSOCIATED GROUP FOR THE ALLOCATION OF NET DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

- Complete this schedule to allocate the associated group's net deduction for the capital deduction election under subsection 83(2) of the *Taxation Act, 2007* (Ontario). The associated group includes the filing corporation (see line 190 of Part 2 of Schedule 515, *Ontario Capital Tax on Other than Financial Institutions*).
- If you need more space, attach more schedules.
- File this schedule with the *T2 Corporation Income Tax Return*.

	A Names of eligible corporations in the associated group 100	B Business Number of associated corporations (enter "NR" if a corporation is not registered) 200	C Ontario allocation factor (OAF)* (enter as a percentage) 300	D Total assets** 400	E Net deduction ($15 million x line 300) **multiplied** by line 400 / line 700 500	F Allocation of net deduction *** 600
1.	Clinton Power Corporation	86985 8779 RC0001	100.000	3,183,875	427,473	
2.	Erie Thames Powerlines Corporation	86371 9498 RC0001	100.000	28,656,017	3,847,412	
3.	Coulter Water Meter Service Inc.	10117 1486 RC0002	100.000	1,283,896	172,378	1,067,115
4.	ERTH Corporation	86356 4324 RC0001	100.000	35,640,589	4,785,174	1,387,718
5.	CRU Solutions Inc.	86371 9696 RC0001	100.000	7,635,968	1,025,220	2,623,084
6.	Utilismart Corporation	86443 9450 RC0001	100.000	2,834,958	380,627	
7.	Enerconnect Inc.	87367 1499 RC0001	100.000	1,457,122	195,636	
8.	Wattsworth Analysis Inc.	87746 8108 RC0001	100.000	597,624	80,238	
9.	Enermajica Ontario Inc.	88660 6409 RC0001	100.000	290,932	39,061	
10.	ERTH360 Generation & Consulting Inc.	82960 2226 RC0001	100.000	251,277	33,737	37,113
11.	Ecaliber (Canada) Inc.	82954 1895 RC0001	100.000	3,786,979	508,447	4,404,486
12.	The SPI Group Inc.	87013 2917 RC0001	100.000	6,994,745	939,128	4,160,526
13.	ERTH (Holdings) Inc.	82642 4293 RC0002	100.000	14,106,975	1,894,030	1,319,958
14.	West Perth Power Inc.	86922 9377 RC0001	100.000	5,000,961	671,439	
15.	ERTH Limited	83794 3117 RC0001				

Total assets of associated group (total of amounts in column D) 700 111,721,918

Total net deduction (total of amounts in column E) 800 15,000,000

Total allocated net deduction (total of amounts in column F) (not to exceed amount on line 800) 900 15,000,000

* OAF from the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends.

** Total assets of each corporation in the associated group as recorded in the books and records for the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends. If the corporation is not resident in Canada, enter the amount of its total assets situated in Canada.

*** Enter the amount from this column allocated to the filing corporation on line 300 of Schedule 515.

T2 SCH 516

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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
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

- 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)
Clinton Power Corporation

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	2000-01-21	1397749

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
23	Albert Street	

240 Additional address information if applicable (line 220 must be completed first)
PO Box 520

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
Clinton	ON	CA	N0M 1L0

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 Pettit (Last name) **451** Jeff (First name)

454 ______________, (Middle name(s))

460 3 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.

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 86985 8779 RC0001

Corporation's name
002 Clinton Power Corporation

Address of head office
Has this address changed since the last time you filed your T2 return? . . . . 010 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 23 Albert Street
012 PO Box 520
City: 015 Clinton
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal code/Zip code: 018 N0M 1L0

Mailing address (if different from head office address)
Has this address changed since the last time you filed your T2 return? . . . . 020 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028.)
021 c/o
022 200-295 Wolfe Street
023
City: 025 London
Province, territory, or state: 026 ON
Country (other than Canada): 027
Postal code/Zip code: 028 N6B 2C4

Location of books and records
Has the location of books and records changed since the last time you filed your T2 return? . . . . 030 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
031 200-295 Wolfe Street
032
City: 035 London
Province,territory, or state: 036 ON
Country (other than Canada): 037
Postal code/Zip code: 038 N6B 2C4

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 2010-01-01 (YYYY MM DD)
Tax year-end: 061 2010-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . 063 1 Yes [X] 2 No [ ]

If **yes**, provide the date control was acquired . . . . 065 2010-01-01 (YYYY MM DD)

Is the date on line 061 a deemed tax year-end in accordance with 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

091	092	093	094	095	096
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **Yes** response, **attach** to the T2 return the schedule that applies.

Question	Line	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
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	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 (or its associated corporations) 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

Question	Line	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

Question	Line	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
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281		X

What is the corporation's major business activity? (only complete if **yes** was entered at line 281) 282

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 1 Wholesale ☐ 2 Retail ☐

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

Line	Product or service	Line	%
284	Electricity Distribution	285	100.000 %
286		287	%
288		289	%

Question	Line	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

	Line	Amount		
Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		-52,930	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 3.2 times the Part VI.1 tax payable at line 724.

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, **minus** 10/3 of the amount on line 632*, **minus** 1/(0.38 - X**) 3.57143
times the amount on line 636***, and **minus** any amount that, because of federal law, is exempt form Part I tax . . . . **405** ______ B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

400,000	x	Number of days in the tax year before 2009 / Number of days in the tax year	/ 365	=		1
500,000	x	Number of days in the tax year after 2008 / Number of days in the tax year	365 / 365	=	500,000	2
				Add amounts at lines 1 and 2	500,000	4

Business limit (see notes 1 and 2 below) . . . . **410** ______ C

Notes:
1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C ______ x **415** **** 72,780 / 11,250 D = ... ______ 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.

* 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			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, whichever is the least		E	
Aggregate investment income from line 440*		F	
Total of amounts B to F		►	G
Amount A **minus** amount G (if negative, enter "0")			H

Amount H		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	I
Amount H		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 %	=	J
Amount H		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 / 365	x	10 %	=	K
Amount H		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	x	11.5 %	=	L
Amount H		x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x	13 %	=	L.1

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L.1 .... M
Enter amount M on line 638.

* 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, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	T
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 %	=	U
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 / 365	x	10 %	=	V
Amount S		x	Number of days in the tax year after December 31, 2010, and before January 2012 / Number of days in the tax year	/ 365	x	11.5 %	=	W
Amount S		x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x	13 %	=	W.1

General tax reduction – Total of amounts T to W.1 X
Enter amount X on line 639.

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 . . . . ________

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 . . . . ________

Deduct:

Amount from line 400, 405, 410, or 425, whichever is the least . . . . . ________

Foreign non-business income tax credit from line 632 . . . . ________ x 25 / 9 = ________

Foreign business income tax credit from line 636 . . . . ________ x $\frac{1}{3.57143}$(0.38 - X*) = ________

________ ▶ ________

x 26 2 / 3 % = ________ D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780) . . . . ________ 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 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) . . . . ________

Part I tax

Base amount of Part I tax – Taxable income (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 . . . . ______ i

Taxable income from line 360 . . . . ______

Deduct:

Amount from line 400, 405, 410, or 425, 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 . . . . ______ 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 . . . . 638 ______

General tax reduction from amount X . . . . 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.

Summary of tax and credits

Federal tax

Part I tax payable	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	1,930	
Provincial tax on large corporations (New Brunswick* and Nova Scotia)	765		
		1,930 ▶	1,930
Total tax payable	770		1,930 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	▶ B

Refund code 894 Overpayment

Balance (line A **minus** line B) 1,930

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 1,930

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 X

* The New Brunswick tax on large corporations is eliminated effective January 1, 2009.

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, 950 Pettit (Last name in block letters) 951 Jeff (First name in block letters) 954 President & CEO (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2011-06-29 Date (yyyy/mm/dd) — Signature of the authorized signing officer of the corporation — 956 (519) 518-6117 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . . 957 1 Yes X 2 No ☐

958 Name in block letters 959 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

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
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

- 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				-100,646 A
Add:				
Amortization of tangible assets		104	79,194	
Non-deductible meals and entertainment expenses		121	2,882	
Subtotal of additions			82,076 ▶	82,076
Other additions:				
Miscellaneous other additions:				
601 Golf Fees		291	65	
602 Smart Meter Recovery		292	33,822	
603 Adjustment for spare parts	36,734			
Total	36,734	293	36,734	
604				
Total		294		
Subtotal of other additions		199	70,621 ▶	70,621
Total additions		500	152,697 ▶	152,697
Deduct:				
Capital cost allowance from Schedule 8		403	101,662	
Subtotal of deductions			101,662 ▶	101,662
Other deductions:				
Miscellaneous other deductions:				
700 Actual Capital Tax		390	1,930	
701 Capital tax recovery		391	1,389	
704				
Total		394		
Subtotal of other deductions		499	3,319 ▶	3,319
Total deductions		510	104,981 ▶	104,981
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				-52,930

T2 SCH 1 E (10)

Canada

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SCHEDULE 4

CORPORATION LOSS CONTINUITY AND APPLICATION

Name of corporation	Business Number	Tax year-end Year Month Day
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

- 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			-52,930
Deduct: (increase a loss)			
Net capital losses deducted in the year (enter as a positive amount)			
Taxable dividends deductible under sections 112, 113(1), or subsection 138(6)			
Amount of Part VI.1 tax deductible			
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)			
		▶	
Subtotal (if positive, enter "0")			-52,930
Deduct: (increase a loss)			
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions			
Subtotal			-52,930
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 this amount on line 310.)			
Current-year non-capital loss (if positive, enter "0"; if negative, enter this amount on line 110 as a positive)			-52,930

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year		84,691		
Deduct: Non-capital loss expired*	100			
Non-capital losses at the beginning of the tax year	102	84,691	▶	84,691
Add:				
Non-capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	105			
Current-year non-capital loss (from calculation above)	110	52,930		
		52,930	▶	52,930
Subtotal				137,621

Part 1 – Non-capital losses (continued)

Subtotal from page 1			137,621
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	150		
Section 80 – Adjustments for forgiven amounts	140		
Subsection 111(10) – Adjustments for fuel tax rebate			
Non-capital losses of previous tax years applied in the current tax year (enter on line 331 of the T2 return)	130		
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		
		▶	
Amount of non-capital losses available to carry back or carry forward to other years			137,621
Deduct – Request to carry back non-capital loss to:			
First previous tax year to reduce taxable income	901		
Second previous tax year to reduce taxable income	902		
Third previous tax year to reduce taxable income	903		
First previous tax year to reduce taxable dividends subject to Part IV tax	911		
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		
		▶	
Closing balance of non-capital losses to be carried forward to future tax years		180	137,621

* 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 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200		
Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	205		
		▶	
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	250		
Section 80 – Adjustments for forgiven amounts	240		
		▶	
Subtotal			
Add: Current-year capital loss (from the calculation on Schedule 6)		210	
Unused non-capital losses that expired in the tax year*		A	
Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year**		B	
Enter amount from line A or B, whichever is less	215		
ABILs expired as non-capital loss: line 215 **divided** by the inclusion rate*** 50.0000 %		220	
Subtotal			

Part 2 – Capital losses (continued)

Subtotal from page 2 ______

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 at line 220 above.

Deduct: Capital losses from previous tax years applied against the current-year net capital gain (see Note 1) . . . . **225** ______

Amount of capital losses available to carry back or carry forward to other years ______

Deduct – Request to carry back capital loss to (see Note 2):

	Capital gain (100%)		Amount carried back (100%)
First previous tax year		951	
Second previous tax year		952	
Third previous tax year		953	

▶ ______

Capital losses – Closing balance . . . . **280** ______

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.

* 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 A.

** 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 B.

*** This inclusion rate is the rate used to calculate your ABIL referred to at line B. Therefore, use one of the following inclusion rates, whichever applies:
- For ABILs incurred in the 1999 and previous tax years, use 0.75.
- For ABILs incurred in the 2000 and 2001 tax years, the inclusion rate is equal to amount M on Schedule 6 – Version T2SCH6(01)
- For ABILs incurred in the 2002 and later tax years, use 0.50.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year . . . . ______

Deduct: Farm loss expired* . . . . **300** ______

Farm losses at the beginning of the tax year . . . . **302** ______ ▶ ______

Add:

Farm losses transferred on the amalgamation or the windup of a subsidiary corporation . . . . . **305** ______

Current-year farm loss . . . . **310** ______

▶ ______

Subtotal ______

Part 3 – Farm losses (continued)

Subtotal from page 3			
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	350		
Section 80 – Adjustments for forgiven amounts	340		
Amount applied against taxable income (enter on line 334 of the T2 return)	330		
Amount applied against taxable dividends subject to Part IV tax	335		
			▶
Amount of farm losses available to carry back or carry forward to other years			
Deduct – Request to carry back farm loss to:			
First previous tax year to reduce taxable income	921		
Second previous tax year to reduce taxable income	922		
Third previous tax year to reduce taxable income	923		
First previous tax year to reduce taxable dividends subject to Part IV tax	931		
Second previous tax year to reduce taxable dividends subject to Part IV tax	932		
Third previous tax year to reduce taxable dividends subject to Part IV tax	933		
			▶
Farm losses – Closing balance	380		

* 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		C
Minus the deductible farm loss:				
$2,500 **plus** D or E, whichever is less		2,500		
(amount C above ______ – $2,500) **divided** by 2 =	D			
	6,250 E			
		2,500 ▶	2,500	F
Current-year restricted farm loss (amount C **minus** amount F) (enter this amount on line 410)				

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			
Deduct: Restricted farm loss expired*	400		
Restricted farm losses at the beginning of the tax year	402		▶
Add:			
Restricted farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation	405		
Current-year restricted farm loss (enter on line 233 of Schedule 1)	410		
			▶
Subtotal			

Part 4 – Restricted farm losses (continued)

Subtotal from page 4 ______

Deduct:

Amount applied against farming income (enter on line 333 of the T2 return) . . . . **430** ______

Section 80 – Adjustments for forgiven amounts . . . . **440** ______

Other adjustments . . . . **450** ______

► ______

Amount of restricted farm losses available to carry back or carry forward to other years ______

Deduct – Request to carry back restricted farm loss to:

First previous tax year to reduce farming income . . . . **941** ______

Second previous tax year to reduce farming income . . . . **942** ______

Third previous tax year to reduce farming income . . . . **943** ______

► ______

Restricted farm losses – Closing balance . . . . **480** ______

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 . . . . ______

Deduct: Listed personal property loss expired after seven tax years . . . . **500** ______

Listed personal property losses at the beginning of the tax year . . . . **502** ______ ► ______

Add: Current-year listed personal property loss (from Schedule 6) . . . . **510** ______

Subtotal ______

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** ______

Other adjustments . . . . **550** ______

► ______

Amount of listed personal property losses available to carry back or carry forward to other years ______

Deduct – Request to carry back listed personal property loss to:

First previous tax year to reduce listed personal property gains . . . . **961** ______

Second previous tax year to reduce listed personal property gains . . . . **962** ______

Third previous tax year to reduce listed personal property gains . . . . **963** ______

► ______

Listed personal property losses – Closing balance . . . . **580** ______

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, please 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	52,930			N/A		52,930
1st preceding taxation year 2009-12-31	73,442	N/A		N/A			73,442
2nd preceding taxation year 2008-12-31	11,249	N/A		N/A			11,249
3rd preceding taxation year 2007-12-31		N/A		N/A			
4th preceding taxation year 2008-06-30		N/A		N/A			
5th preceding taxation year 2007-06-30		N/A		N/A			
6th preceding taxation year 2006-06-30		N/A		N/A			
7th preceding taxation year 2005-06-30		N/A		N/A			
8th preceding taxation year 2004-06-30		N/A		N/A			
9th preceding taxation year 2003-06-30		N/A		N/A			
10th preceding taxation year 2002-06-30		N/A		N/A			
11th preceding taxation year 2001-06-30		N/A		N/A			
12th preceding taxation year 2000-06-30		N/A		N/A			
13th preceding taxation year 1999-06-30		N/A		N/A			
14th preceding taxation year 1998-06-30		N/A		N/A			
15th preceding taxation year 1997-06-30		N/A		N/A			
16th preceding taxation year 1996-06-30		N/A		N/A			
17th preceding taxation year 1995-06-30		N/A		N/A			
18th preceding taxation year 1994-06-30		N/A		N/A			
19th preceding taxation year 1993-06-30		N/A		N/A			
20th preceding taxation year 1992-06-30		N/A		N/A			*
Total	84,691	52,930					137,621

* **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
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

- 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*.

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

Ontario basic income tax (from Schedule 500)	270			
Deduct: Ontario small business deduction (from schedule 500)	402			
Subtotal (if negative, enter "0")				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	1,930		
Subtotal		1,930	1,930	H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)			1,930	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	1,930	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	1,930

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.

Canada Revenue Agency — Agence du revenu du Canada

SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

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 (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		1,105,252			0		1,105,252	4	0	0	44,210	1,061,042
2.	8		55,957	112,179		0	56,090	112,046	20	0	0	22,409	145,727
3.	10		15,870			0		15,870	30	0	0	4,761	11,109
4.	12		37,223	13,219	-36,734	0	6,610	7,098	100	0	0	7,098	6,610
5.	47		134,997	309,603		0	154,802	289,798	8	0	0	23,184	421,416
6.	94	Software Not In Use		19,889		0	9,945	9,944	0	0	0		19,889
		Total	1,349,299	454,890	-36,734		227,447	1,540,008				101,662	1,665,793

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*.

**** 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
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

This schedule is to be completed by a corporation having one or more of the following:
– related corporation(s)
– associated corporations(s)

	Name	Country of residence (if other than Canada)	Business Number (Canadian corporation only) (see note 1)	Relationship code (see note 2)	Number of common shares owned	% of common shares owned	Number of preferred shares owned	% of preferred shares owned	Book value of capital stock
	100	200	300	400	500	550	600	650	700
1.	Erie Thames Powerlines Corporatior		86371 9498 RC0001	3					
2.	Coulter Water Meter Service Inc.	CA	10117 1486 RC0002	3					
3.	ERTH Corporation	CA	86356 4324 RC0001	1					
4.	CRU Solutions Inc.	CA	86371 9696 RC0001	3					
5.	Utilismart Corporation	CA	86443 9450 RC0001	3					
6.	Enerconnect Inc.	CA	87367 1499 RC0001	3					
7.	Wattsworth Analysis Inc.	CA	87746 8108 RC0001	3					
8.	Enermajica Ontario Inc.	CA	88660 6409 RC0001	3					
9.	ERTH360 Generation & Consulting I	CA	82960 2226 RC0001	3					
10.	Ecaliber (Canada) Inc.	CA	82954 1895 RC0001	3					
11.	The SPI Group Inc.	CA	87013 2917 RC0001	3					
12.	ERTH (Holdings) Inc.	CA	82642 4293 RC0002	3					
13.	West Perth Power Inc.	CA	86922 9377 RC0001	3					
14.	ERTH Limited	CA	83794 3117 RC0001	3					

Note 1: Enter "NR" if a corporation is not registered.
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(99)

Canada

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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 2010

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	Clinton Power Corporation	86985 8779 RC0001	1	500,000		
2	Erie Thames Powerlines Corporation	86371 9498 RC0001	1	500,000	100.0000	500,000
3	Coulter Water Meter Service Inc.	10117 1486 RC0002	1	500,000		
4	ERTH Corporation	86356 4324 RC0001	1	500,000		
5	CRU Solutions Inc.	86371 9696 RC0001	1	500,000		
6	Utilismart Corporation	86443 9450 RC0001	1	500,000		
7	Enerconnect Inc.	87367 1499 RC0001	1	500,000		
8	Wattsworth Analysis Inc.	87746 8108 RC0001	1	500,000		
9	Enermajica Ontario Inc.	88660 6409 RC0001	1	500,000		
10	ERTH360 Generation & Consulting Inc.	82960 2226 RC0001	1	500,000		
11	Ecaliber (Canada) Inc.	82954 1895 RC0001	1	500,000		
12	The SPI Group Inc.	87013 2917 RC0001	1	500,000		
13	ERTH (Holdings) Inc.	82642 4293 RC0002	1	500,000		

	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	
14	West Perth Power Inc.	86922 9377 RC0001	1	500,000			
15	ERTH Limited	83794 3117 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.

T2 SCH 23 (09)

Canada

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SCHEDULE 33

TAXABLE CAPITAL EMPLOYED IN CANADA – LARGE CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms "financial institution," "long-term debt," and "reserves."
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If you are filing a provincial capital tax return with your *T2 Corporation Income Tax Return*, also file a completed Schedule 33 with the return no later than six months from the end of the tax year.
- This schedule may contain changes that had not yet become law at the time of publishing.

If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, "Taxable capital employed in Canada."

Part 1 – Capital

Add the following amounts at the end of the year:

	Line	Amount		Total	
Reserves that have not been deducted in computing income for the year under Part I	101				
Capital stock (or members' contributions if incorporated without share capital)	103	698,786			
Retained earnings	104				
Contributed surplus	105				
Any other surpluses	106				
Deferred unrealized foreign exchange gains	107				
All loans and advances to the corporation	108	1,891,756			
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109	210,014			
Any dividends declared but not paid by the corporation before the end of the year	110				
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111				
Proportion of the amount, if any, by which the total of all amounts (see note below) for the partnership of which the corporation is a member at the end of the year exceeds the amount of the partnership's deferred unrealized foreign exchange losses	112				
Subtotal		2,800,556	▶	2,800,556	A

Deduct the following amounts:

	Line	Amount		Total	
Deferred tax debit balance at the end of the year	121				
Any deficit deducted in computing its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122	206,324			
Any amount deducted under subsection 135(1) in computing income under Part I for the year, as long as the amount may reasonably be regarded as being included in any of lines 101 to 112 above	123				
The amount of deferred unrealized foreign exchange losses at the end of the year	124				
Subtotal		206,324	▶	206,324	B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190			2,594,232	

Note: Lines 101, 107, 108, 109, 111, and 112 are determined as follows:

- If the partnership is a member of another partnership (tiered partnerships), include the amounts of the partnership and tiered partnerships.
- Amounts for the partnership and tiered partnerships are those that would be determined for lines 101, 107, 108, 109, 111, and 112 as if they apply in the same way that they apply to corporations.
- Do not include amounts owing to the member or to other corporations that are members of the partnership.
- Amounts are determined at the end of the last fiscal period of the partnership ending in the year of the corporation.
- The proportion of the total amounts is determined by the corporation's share of the partnership's income or loss for the fiscal period of the partnership.

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend receivable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim, or similar obligation of, a partnership all of the members of which, throughout the year, were other corporations (other than financial institutions) that were not exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)]	406	
An interest in a partnership (see note 1 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	

Notes:

1. Where the corporation has an interest in a partnership or in tiered partnerships, consider the following:
   – the investment allowance of a partnership is deemed to be the amount calculated at line 490 above, at the end of its fiscal period, as if it was a corporation;
   – the total of the carrying value of each asset of the partnership described in the above lines is for its last fiscal period ending at or before the end of the corporation's tax year; and
   – the carrying value of a partnership member's interest at the end of the year is its specified proportion [as defined in subsection 248(1)] of the partnership's investment allowance.
2. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)].
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation, according to subsection 181.2(6).

Part 3 – Taxable capital

Capital for the year (line 190)		2,594,232	C
Deduct: Investment allowance for the year (line 490)			D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	2,594,232	

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 2,594,232 x Taxable income earned in Canada **610** 1,000 / Taxable income 1,000 = **Taxable capital employed in Canada** **690** 2,594,232

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada			701	
Deduct the following amounts:				
Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada	711			
Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada	712			
Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below)	713			
Total deductions (add lines 711, 712, and 713)			►	E
Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0")			790	

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (line 690 or 790, whichever applies)		F
Deduct:	10,000,000	G
Excess (amount F **minus** amount G) (if negative, enter "0")		H
Calculation for purposes of the small business deduction (amount H x 0.00225)		I

Enter this amount at line 415 of the T2 return

Attached Schedule with Total

Part 1 – All loans and advances to the corporation

Title: Part 1 – All loans and advances to the corporation

Description	Amount	
Due to Related Parties	1,837,002	00
CUSTOMER DEPOSITS	54,754	00
Total	1,891,756	00

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

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)	Provide only one number per shareholder: Business Number (If a corporation is not registered, enter "NR")	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
	100	200	300	350	400	500
1	ERTH Corporation	86356 4324 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada

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SCHEDULE 510

ONTARIO CORPORATE MINIMUM TAX

Name of corporation	Business Number	Tax year-end Year Month Day
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	3,109,611
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	122,723,029
Total assets (total of lines 112 to 116)		125,832,640
Total revenue of the corporation for the tax year **	142	2,835,837
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	69,335,576
Total revenue (total of lines 142 to 146)		72,171,413

The corporation is subject to CMT if:
– for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
– for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Calculation of adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	-100,646
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220			
Provision for deferred income taxes (debits)/cost of future income taxes	222			
Equity losses from corporations	224			
Financial statement loss from partnerships and joint ventures	226			
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230			
Other additions (see note below):				
Share of adjusted net income of partnerships and joint ventures **	228			
Total patronage dividends received, not already included in net income/loss	232			
281	282			
283	284			
Subtotal				A
Deduct (to the extent reflected in income/loss):				
Provision for recovery of current income taxes/benefit of current income taxes	320			
Provision for deferred income taxes (credits)/benefit of future income taxes	322			
Equity income from corporations	324			
Financial statement income from partnerships and joint ventures	326			
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330			
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332			
Gain on donation of listed security or ecological gift	340			
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342			
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344			
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346			
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348			
Other deductions (see note below):				
Share of adjusted net loss of partnerships and joint ventures **	328			
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334			
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336			
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338			
381	382			
383	384			
385	386			
387	388			
389	390			
Subtotal				B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	-100,646

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

– Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – Calculation of CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)		515	
Deduct:			
CMT loss available (amount R from Part 7)	159,902		
Minus: Adjustment for an acquisition of control *	518		
Adjusted CMT loss available	159,902 ▶		159,902 C
Net income subject to CMT calculation (if negative, enter "0")		520	

Amount from line 520 ____ x (Number of days in the tax year before July 1, 2010 / Number of days in the tax year) 181 / 365 x 4 % = ____ 1

Amount from line 520 ____ x (Number of days in the tax year after June 30, 2010 / Number of days in the tax year) 184 / 365 x 2.7 % = ____ 2

Subtotal (amount 1 **plus** amount 2) ____ 3

Gross CMT: amount on line 3 above x OAF **	540	
Deduct:		
Foreign tax credit for CMT purposes ***	550	
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		D
Deduct:		
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		
Net CMT payable (if negative, enter "0")		E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** ____ = ____

Ontario allocation factor 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year * . . . . G

Deduct:

CMT credit expired * 600

CMT credit carryforward at the beginning of the current tax year * (see note below) . . . . ▶ 620

Add:

CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below) 650

CMT credit available for the tax year (amount on line 620 **plus** amount on line 650) . . . . H

Deduct:

CMT credit deducted in the current tax year (amount P from Part 5) I

Subtotal (amount H **minus** amount I) J

Add:

Net CMT payable (amount E from Part 3) . . . .

SAT payable (amount O from Part 6 of Schedule 512) . . . .

Subtotal ▶ K

CMT credit carryforward at the end of the tax year (amount J **plus** amount K) . . . . 670 L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4) . . . . M

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) 1

For a corporation that is not a life insurance corporation:

CMT after foreign tax credit deduction (amount D from Part 3) . . 2

For a life insurance corporation:

Gross CMT (line 540 from Part 3) 3

Gross SAT (line 460 from Part 6 of Schedule 512) 4

The **greater** of amounts 3 and 4 5

Deduct: line 2 or line 5, whichever applies: 6

Subtotal (if negative, enter "0") ▶ N

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) . . . .

Deduct:

Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5) . . . .

Subtotal (if negative, enter "0") ▶ O

CMT credit deducted in the current tax year (least of amounts M, N, and O) . . . . P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? . . . . 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year *		159,902 Q		
Deduct:				
CMT loss expired *	700			
CMT loss carryforward at the beginning of the tax year * (see note below)		159,902 ▶	720	159,902
Add:				
CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below)			750	
CMT loss available (line 720 **plus** line 750)				159,902 R
Deduct:				
CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3)				
Subtotal (if negative, enter "0")				159,902 S
Add:				
Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount)			760	100,646
CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760)			770	260,548 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not transfer a loss on a vertical amalgamation under subsection 87(2.11) of the federal Act or other amalgamation of a parent and its subsidiary.
Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	Erie Thames Powerlines Corporation	86371 9498 RC0001	31,060,468	40,161,013
2	Coulter Water Meter Service Inc.	10117 1486 RC0002	1,238,258	775,159
3	ERTH Corporation	86356 4324 RC0001	41,204,038	3,748,389
4	CRU Solutions Inc.	86371 9696 RC0001	7,421,203	3,177,065
5	Utilismart Corporation	86443 9450 RC0001	3,761,949	3,634,861
6	Enerconnect Inc.	87367 1499 RC0001	1,449,751	679,605
7	Wattsworth Analysis Inc.	87746 8108 RC0001	748,288	983,689
8	Enermajica Ontario Inc.	88660 6409 RC0001	707,435	180,776
9	ERTH360 Generation & Consulting Inc.	82960 2226 RC0001	192,443	684,833
10	Ecaliber (Canada) Inc.	82954 1895 RC0001	4,627,131	4,010,875
11	The SPI Group Inc.	87013 2917 RC0001	7,720,177	5,092,910
12	ERTH (Holdings) Inc.	82642 4293 RC0002	16,929,131	225,646
13	West Perth Power Inc.	86922 9377 RC0001	5,662,757	5,980,755
14	ERTH Limited	83794 3117 RC0001	0	0
		Total	450 122,723,029	550 69,335,576

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

– Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
– Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

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SCHEDULE 515

ONTARIO CAPITAL TAX ON OTHER THAN FINANCIAL INSTITUTIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

- Complete this schedule for a corporation with a permanent establishment in Ontario at any time in the tax year and that is a corporation other than a financial institution. The Ontario capital tax on other than financial institutions is levied under section 64 of the *Taxation Act, 2007* (Ontario).
- The Ontario capital tax is eliminated effective July 1, 2010. You do not have to complete this schedule if the corporation's tax year begins after June 30, 2010. For businesses mainly engaged in qualifying manufacturing and resource activities in Ontario, the capital tax is eliminated effective January 1, 2007.
- To complete this schedule, you have to complete Schedule 33, *Part I.3 Tax on Large Corporations* (renamed *Taxable Capital Employed in Canada – Large Corporations* for 2010 and later tax years). File completed copies of both schedules with the *T2 Corporation Income Tax Return* within six months of the end of the tax year.
- A corporation is exempt from Ontario capital tax if it was one of the following:
  1) a corporation that is liable to the special additional tax according to section 74 of the *Corporations Tax Act* (Ontario);
  2) a credit union;
  3) a deposit insurance corporation according to section 137.1 of the federal *Income Tax Act*;
  4) a family farm corporation for the year as defined by subsection 64(3) of the *Taxation Act*, 2007 (Ontario), other than a corporation for which a determination has been made under subsection 31(2) of the federal Act;
  5) a family fishing corporation, as defined by subsection 64(3) of the *Taxation Act, 2007* (Ontario); or
  6) a corporation exempt from income tax according to section 149 of the federal Act.

Part 1 – Taxable capital of a corporation resident in Canada other than a financial institution

Amount A from Part 1 of Schedule 33	100	2,800,556		
Add:				
Accumulated other comprehensive income at the end of the year	105			
Subtotal		2,800,556 ►	2,800,556	A
Deduct:				
Amount B from Part 1 of Schedule 33	110	206,324		
Amount on line 490 from Part 2 of Schedule 33	115			
Subtotal		206,324 ►	206,324	B
Taxable capital (amount A **minus** amount B) (if negative, enter "0")	120		2,594,232	

Part 2 – Capital deduction

Complete this part only if the corporation is associated.

Are you electing under subsection 83(2) of the *Taxation Act, 2007* (Ontario)? . . . 190 1 Yes [X] 2 No [ ]

If you answered **no** to the question at line 190, complete line 220. If you answered **yes** to the question at line 190, complete line 305 by using Schedule 516, *Capital Deduction Election of Associated Group for the Allocation of Net Deduction*, to calculate the amount to be entered on line 300.

Taxable capital (from line 120) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (from line 790 in Part 4 of Schedule 33) **200** ______ / Taxable capital or taxable capital employed in Canada of every corporation with a permanent establishment in Canada and associated for the last tax year * **210** ______ x 15,000,000 $ = **Capital deduction** **220** ______

* This amount includes the filing corporation's taxable capital or taxable capital employed in Canada. Do not include an amount from a financial institution or corporation that is exempt from capital tax under Division E of the *Taxation Act, 2007* (Ontario) or Part III of the *Corporations Tax Act* (Ontario).

Allocation of net deduction (from line 600 for the filing corporation from Schedule 516) **300** ______ / Ontario allocation factor (OAF) (amount I in Part 3) 1.00000 = **Capital deduction** **305** ______

Part 3 – Ontario capital tax payable

Taxable capital (enter amount from line 120 in Part 1) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (enter amount from line 790 in Part 4 of Schedule 33), whichever applies **320** 2,594,232

Deduct:
Capital deduction (Enter $15,000,000 if the corporation is not associated. Otherwise, enter the amount from line 220 or line 305, whichever applies, from Part 2) . . . . B

Net amount (line 320 **minus** amount B) (if negative, enter "0") . . . . 2,594,232 C

Note: For days in the tax year after June 30, 2010, the Ontario capital tax rate is 0%.

Amount C 2,594,232 x (Number of days in the tax year before January 1, 2010 / Number of days in the tax year) (/ 365) x 0.00225 = D

Amount C 2,594,232 x (Number of days in the tax year after December 31, 2009 and before July 1, 2010 / Number of days in the tax year) (181 / 365) x 0.00150 = 1,930 E

Subtotal (amount D **plus** amount E) 1,930 F

Amount F 1,930 x OAF (amount on line I) 1.00000 = ... 1,930 G

Amount G 1,930 x (Number of days in the tax year * / 365) (365 / 365) = ... 1,930 H

Deduct:
Capital tax credit for manufacturers (enter amount J from Part 4) **350**

Ontario capital tax payable (amount H **minus** line 350) (if negative, enter "0") **400** 1,930
Enter amount from line 400 on line 282 of Schedule 5, *Tax Calculation Supplementary - Corporations*.

* Enter either 365 if there are at least 51 weeks in the tax year, or the number of days in the year, whichever applies.

Calculation of the Ontario allocation factor (OAF)

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line I.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation and enter the result on line I:

Ontario taxable income ** / Taxable income *** =

Ontario allocation factor . . . . 1.00000 I

** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.
*** Enter the taxable income amount from line 360 or line Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – Capital tax credit for manufacturers

Ontario manufacturing labour cost* **405** / Total Ontario labour cost** **410** x 100 = ... **420** %

If the percentage on line 420 is 20% or less, enter "0" on line J.
If the percentage on line 420 is at least 50%, enter amount H from Part 3 on line J.
If the percentage on line 420 is more than 20% but less than 50%, complete the following calculation and enter the result on line J:

(percentage from line 420) – 20% / 30% (% / 30 %) x 1,930 Amount H from Part 3 =

Capital tax credit for manufacturers . . . . J
Enter amount J on line 350 in Part 3.

* As defined in subsection 83.1(4) of the *Taxation Act, 2007* (Ontario)
** As defined in subsection 83.1(5) of the *Taxation Act, 2007* (Ontario)

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SCHEDULE 516

CAPITAL DEDUCTION ELECTION OF ASSOCIATED GROUP FOR THE ALLOCATION OF NET DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

- Complete this schedule to allocate the associated group's net deduction for the capital deduction election under subsection 83(2) of the *Taxation Act, 2007* (Ontario). The associated group includes the filing corporation (see line 190 of Part 2 of Schedule 515, *Ontario Capital Tax on Other than Financial Institutions*).
- If you need more space, attach more schedules.
- File this schedule with the *T2 Corporation Income Tax Return*.

	A Names of eligible corporations in the associated group 100	B Business Number of associated corporations (enter "NR" if a corporation is not registered) 200	C Ontario allocation factor (OAF)* (enter as a percentage) 300	D Total assets** 400	E Net deduction ($15 million x line 300) **multiplied** by line 400 / line 700 500	F Allocation of net deduction *** 600
1.	Clinton Power Corporation	86985 8779 RC0001	100.000	3,183,875	427,473	
2.	Erie Thames Powerlines Corporation	86371 9498 RC0001	100.000	28,656,017	3,847,412	
3.	Coulter Water Meter Service Inc.	10117 1486 RC0002	100.000	1,283,896	172,378	1,067,115
4.	ERTH Corporation	86356 4324 RC0001	100.000	35,640,589	4,785,174	1,387,718
5.	CRU Solutions Inc.	86371 9696 RC0001	100.000	7,635,968	1,025,220	2,623,084
6.	Utilismart Corporation	86443 9450 RC0001	100.000	2,834,958	380,627	
7.	Enerconnect Inc.	87367 1499 RC0001	100.000	1,457,122	195,636	
8.	Wattsworth Analysis Inc.	87746 8108 RC0001	100.000	597,624	80,238	
9.	Enermajica Ontario Inc.	88660 6409 RC0001	100.000	290,932	39,061	
10.	ERTH360 Generation & Consulting Inc.	82960 2226 RC0001	100.000	251,277	33,737	37,113
11.	Ecaliber (Canada) Inc.	82954 1895 RC0001	100.000	3,786,979	508,447	4,404,486
12.	The SPI Group Inc.	87013 2917 RC0001	100.000	6,994,745	939,128	4,160,526
13.	ERTH (Holdings) Inc.	82642 4293 RC0002	100.000	14,106,975	1,894,030	1,319,958
14.	West Perth Power Inc.	86922 9377 RC0001	100.000	5,000,961	671,439	
15.	ERTH Limited	83794 3117 RC0001				

Total assets of associated group (total of amounts in column D) 700 111,721,918

Total net deduction (total of amounts in column E) 800 15,000,000

Total allocated net deduction (total of amounts in column F) (not to exceed amount on line 800) 900 15,000,000

* OAF from the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends.

** Total assets of each corporation in the associated group as recorded in the books and records for the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends. If the corporation is not resident in Canada, enter the amount of its total assets situated in Canada.

*** Enter the amount from this column allocated to the filing corporation on line 300 of Schedule 515.

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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
Clinton Power Corporation	86985 8779 RC0001	2010-12-31

- 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)
Clinton Power Corporation

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	2000-01-21	1397749

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
23	Albert Street	

240 Additional address information if applicable (line 220 must be completed first)
PO Box 520

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
Clinton	ON	CA	N0M 1L0

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 Pettit (Last name) **451** Jeff (First name)

454 ________________________ ,
Middle name(s)

460 3 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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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
West Perth Power Inc.

Business Number	Tax year	From Y M D	To Y M D
86922 9377 RC0001		2010-01-01	2010-12-31

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)	-532,886
Part I tax payable (line 700)	
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)	
Provincial tax on large corporations (line 765)	

Part C – Certification and authorization

I, Pettit (Last name in block letters) Jeff (First name in block letters) President & CEO (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.

Date (yyyy/mm/dd)	Signature of an authorized signing officer of the corporation	Telephone number
2011-06-29		(519) 518-6177

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: KPMG LLP
Electronic filer number:

Privacy Act, Personal Information Bank number CRA PPU 047

Canada Revenue Agency / Agence du revenu du Canada

200

T2 CORPORATION INCOME TAX RETURN

EXEMPT FROM TAX

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 86922 9377 RC0001

Corporation's name
002 West Perth Power Inc.

Address of head office
Has this address changed since the last time you filed your T2 return? . . . . 010 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 169 St. David Street
012 P.O. Box 220

City	Province, territory, or state
015 Mitchell	016 ON
Country (other than Canada)	Postal code/Zip code
017	018 N0K 1N0

Mailing address (if different from head office address)
Has this address changed since the last time you filed your T2 return? . . . . 020 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028.)
021 c/o
022 200-295 Wolfe Street
023

City	Province, territory, or state
025 London	026 ON
Country (other than Canada)	Postal code/Zip code
027	028 N6B 2C4

Location of books and records
Has the location of books and records changed since the last time you filed your T2 return? . . . . 030 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
031 200-295 Wolfe Street
032

City	Province,territory, or state
035 London	036 ON
Country (other than Canada)	Postal code/Zip code
037	038 N6B 2C4

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 2010-01-01 (YYYY MM DD)
Tax year-end 061 2010-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . 063 1 Yes [X] 2 No [ ]

If **yes**, provide the date control was acquired . . . . 065 2010-01-01 (YYYY MM DD)

Is the date on line 061 a deemed tax year-end in accordance with 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 [X] Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **Yes** response, **attach** to the T2 return the schedule that applies.

Question	Line	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
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	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		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation (or its associated corporations) 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

Question	Line	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

Question	Line	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
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281		X

What is the corporation's major business activity? 282
(only complete if **yes** was entered at line 281)

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 1 Wholesale ☐ 2 Retail ☐

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

Line	Product or service	Line	%
284	Distribution of Electricity	285	100.000 %
286		287	%
288		289	%

Question	Line	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

	Line	Amount	Line	Amount	
Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.			300	-532,886	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 3.2 times the Part VI.1 tax payable at line 724.

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, **minus** 10/3 of the amount on line 632*, **minus** 1/(0.38 - X**) 3.57143
times the amount on line 636***, and **minus** any amount that, because of federal law, is exempt form Part I tax . . . . . **405** ______ B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

400,000	x	Number of days in the tax year before 2009 / Number of days in the tax year	/ 365	=		1
500,000	x	Number of days in the tax year after 2008 / Number of days in the tax year	365 / 365	=	500,000	2
				Add amounts at lines 1 and 2	500,000	4

Business limit (see notes 1 and 2 below) . . . . . **410** ______ C

Notes:
1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C ______ x **415** **** 72,780 / 11,250 D = ... ______ 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.

* 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			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, whichever is the least		E	
Aggregate investment income from line 440*		F	
Total of amounts B to F		▶	G
Amount A **minus** amount G (if negative, enter "0")			H

Amount H	x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x 8.5 %	=	I
Amount H	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 %	=	J
Amount H	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 / 365	x 10 %	=	K
Amount H	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	x 11.5 %	=	L
Amount H	x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x 13 %	=	L.1

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L.1 .... M
Enter amount M on line 638.

* 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, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x 8.5 %	=	T
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 %	=	U
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 / 365	x 10 %	=	V
Amount S	x	Number of days in the tax year after December 31, 2010, and before January 2012 / Number of days in the tax year	/ 365	x 11.5 %	=	W
Amount S	x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x 13 %	=	W.1

General tax reduction – Total of amounts T to W.1 X
Enter amount X on line 639.

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 . . . . ______

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 . . . . ______
Deduct:
Amount from line 400, 405, 410, or 425, whichever is the least . . . . . ______
Foreign non-business income tax credit from line 632 . . . . ______ x 25 / 9 = ______
Foreign business income tax credit from line 636 . . . . ______ x 1(0.38 - X*) / 3.57143 = ______
______ ▶ ______
______ x 26 2 / 3 % = ______ D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780) . . . . ______ 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 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) . . . . ______

Part I tax

Base amount of Part I tax – Taxable income (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			i
Taxable income from line 360			
Deduct:			
Amount from line 400, 405, 410, or 425, 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			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	638		
General tax reduction from amount X	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.

Summary of tax and credits

Federal tax

Part I tax payable	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 (New Brunswick* and Nova Scotia)	765	
Total tax payable	770	A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	B

Refund code 894 Overpayment

Balance (line A **minus** line B)

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 ☒

* The New Brunswick tax on large corporations is eliminated effective January 1, 2009.

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, 950 Pettit (Last name in block letters) 951 Jeff (First name in block letters) 954 President & CEO (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2011-06-29 Date (yyyy/mm/dd) — Signature of the authorized signing officer of the corporation — 956 (519) 518-6177 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes ☒ 2 No ☐

958 Name in block letters — 959 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

Canada Revenue Agency Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
West Perth Power Inc.	86922 9377 RC0001	2010-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	2,196,096	2,347,607
	Total tangible capital assets	2008	+	5,211,315	4,792,656
	Total accumulated amortization of tangible capital assets	2009	–	3,229,758	3,020,302
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	1,485,104	881,000
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	5,662,757	5,000,961
	Liabilities				
	Total current liabilities	3139	+	3,234,177	2,052,941
	Total long-term liabilities	3450	+	979,000	1,183,391
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	4,213,177	3,236,332
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	1,449,580	1,764,629
	Total liabilities and shareholder equity	3640	=	5,662,757	5,000,961
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	-680,370	-353,645

* Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
West Perth Power Inc.	86922 9377 RC0001	2010-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence Number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	5,770,909	4,993,954
	Cost of sales	8518	–	4,982,335	4,235,624
	Gross profit/loss	8519	=	788,574	758,330
	Cost of sales	8518	+	4,982,335	4,235,624
	Total operating expenses	9367	+	1,313,469	1,094,451
	Total expenses (mandatory field)	9368	=	6,295,804	5,330,075
	Total revenue (mandatory field)	8299	+	5,980,755	5,283,447
	Total expenses (mandatory field)	9368	–	6,295,804	5,330,075
	Net non-farming income	9369	=	-315,049	-46,628
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	-315,049	-46,628
	Total other comprehensive income	9998	=		
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–		
	Deferred income tax provision	9995	–		
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	-315,049	-46,628

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

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SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year-end Year Month Day
West Perth Power Inc.	86922 9377 RC0001	2010-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI) for Corporations* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule, and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant preparing or reporting on the financial statements

Does the accountant have a professional designation? . . . . . **095** 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . . . **097** 1 Yes [ ] 2 No [X]

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note: If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report . . . . . 1 [X]

Completed a review engagement report . . . . . 2 [ ]

Conducted a compilation engagement . . . . . 3 [ ]

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . **099** 1 Yes [ ] 2 No [X]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

Prepared the tax return (financial statements prepared by client) . . . . . 1 [ ]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 [ ]

Were notes to the financial statements prepared? . . . . . **101** 1 Yes [X] 2 No [ ]

If **yes**, complete lines 102 to 107 below:

Are any values presented at other than cost? . . . . . **102** 1 Yes [ ] 2 No [X]

Has there been a change in accounting policies since the last return? . . . . . **103** 1 Yes [X] 2 No [ ]

Are subsequent events mentioned in the notes? . . . . . **104** 1 Yes [X] 2 No [ ]

Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . . . **106** 1 Yes [X] 2 No [ ]

Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** 1 Yes [ ] 2 No [X]

If **yes**, complete line 109 below:

Are you filing financial statements of the joint venture(s) or partnership(s)? . . . . . **109** 1 Yes [ ] 2 No [ ]

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
West Perth Power Inc.	86922 9377 RC0001	2010-12-31

- 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			-315,049 A
Add:			
Amortization of tangible assets	104	221,456	
Non-deductible meals and entertainment expenses	121	3,669	
Subtotal of additions		225,125 ▶	225,125
Other additions:			
Miscellaneous other additions:			
601 Recovery of Smart Meter	291	58,608	
604			
Total	294		
Subtotal of other additions	199	58,608 ▶	58,608
Total additions	500	283,733 ▶	283,733
Deduct:			
Capital cost allowance from Schedule 8	403	297,752	
Subtotal of deductions		297,752 ▶	297,752
Other deductions:			
Miscellaneous other deductions:			
700 Regulary liabiliites, beginning of year	390	192,966	
701 Capital Tax actual	391	2,037	
702 Capital tax recovery per FS	392	3,865	
703 Snmart meter - operating expense 4,950			
Total 4,950	393	4,950	
704			
Total	394		
Subtotal of other deductions	499	203,818 ▶	203,818
Total deductions	510	501,570 ▶	501,570
Net income (loss) for income tax purposes – enter on line 300 of the T2 return			-532,886

T2 SCH 1 E (10)

Canada

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SCHEDULE 4

CORPORATION LOSS CONTINUITY AND APPLICATION

Name of corporation	Business Number	Tax year-end Year Month Day
West Perth Power Inc.	86922 9377 RC0001	2010-12-31

- 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			-532,886
Deduct: (increase a loss)			
Net capital losses deducted in the year (enter as a positive amount)			
Taxable dividends deductible under sections 112, 113(1), or subsection 138(6)			
Amount of Part VI.1 tax deductible			
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)			
		▶	
Subtotal (if positive, enter "0")			-532,886
Deduct: (increase a loss)			
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions			
Subtotal			-532,886
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 this amount on line 310.)			
Current-year non-capital loss (if positive, enter "0"; if negative, enter this amount on line 110 as a positive)			-532,886

Continuity of non-capital losses and request for a carryback

	Line			
Non-capital loss at the end of the previous tax year		181,119		
Deduct: Non-capital loss expired*	100			
Non-capital losses at the beginning of the tax year	102	181,119	▶	181,119
Add:				
Non-capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	105			
Current-year non-capital loss (from calculation above)	110	532,886		
		532,886	▶	532,886
Subtotal				714,005

Part 1 – Non-capital losses (continued)

Subtotal from page 1			714,005
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	150		
Section 80 – Adjustments for forgiven amounts	140		
Subsection 111(10) – Adjustments for fuel tax rebate			
Non-capital losses of previous tax years applied in the current tax year (enter on line 331 of the T2 return)	130		
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		
		▶	
Amount of non-capital losses available to carry back or carry forward to other years			714,005
Deduct – Request to carry back non-capital loss to:			
First previous tax year to reduce taxable income	901		
Second previous tax year to reduce taxable income	902		
Third previous tax year to reduce taxable income	903		
First previous tax year to reduce taxable dividends subject to Part IV tax	911		
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		
		▶	
Closing balance of non-capital losses to be carried forward to future tax years		180	714,005

* 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 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200		
Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	205		
		▶	
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	250		
Section 80 – Adjustments for forgiven amounts	240		
		▶	
Subtotal			
Add: Current-year capital loss (from the calculation on Schedule 6)		210	
Unused non-capital losses that expired in the tax year*		A	
Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year**		B	
Enter amount from line A or B, whichever is less	215		
ABILs expired as non-capital loss: line 215 **divided** by the inclusion rate*** 50.0000 %		220	
Subtotal			

Part 2 – Capital losses (continued)

Subtotal from page 2

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 at line 220 above.

Deduct: Capital losses from previous tax years applied against the current-year net capital gain (see Note 1) 225

Amount of capital losses available to carry back or carry forward to other years

Deduct – Request to carry back capital loss to (see Note 2):

	Capital gain (100%)		Amount carried back (100%)
First previous tax year		951	
Second previous tax year		952	
Third previous tax year		953	

Capital losses – Closing balance 280

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.

* 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 A.

** 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 B.

*** This inclusion rate is the rate used to calculate your ABIL referred to at line B. Therefore, use one of the following inclusion rates, whichever applies:

- For ABILs incurred in the 1999 and previous tax years, use 0.75.
- For ABILs incurred in the 2000 and 2001 tax years, the inclusion rate is equal to amount M on Schedule 6 – Version T2SCH6(01)
- For ABILs incurred in the 2002 and later tax years, use 0.50.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year . . . .

Deduct: Farm loss expired* 300

Farm losses at the beginning of the tax year . . . . 302 ▶

Add:

Farm losses transferred on the amalgamation or the windup of a subsidiary corporation 305

Current-year farm loss 310

▶

Subtotal

Part 3 – Farm losses (continued)

Subtotal from page 3			
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	350		
Section 80 – Adjustments for forgiven amounts	340		
Amount applied against taxable income (enter on line 334 of the T2 return)	330		
Amount applied against taxable dividends subject to Part IV tax	335		
			▶
Amount of farm losses available to carry back or carry forward to other years			
Deduct – Request to carry back farm loss to:			
First previous tax year to reduce taxable income	921		
Second previous tax year to reduce taxable income	922		
Third previous tax year to reduce taxable income	923		
First previous tax year to reduce taxable dividends subject to Part IV tax	931		
Second previous tax year to reduce taxable dividends subject to Part IV tax	932		
Third previous tax year to reduce taxable dividends subject to Part IV tax	933		
			▶
Farm losses – Closing balance		380	

* 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	C
Minus the deductible farm loss:			
$2,500 **plus** D or E, whichever is less	2,500		
(amount C above _______ – $2,500) **divided** by 2 = _______ D			
6,250 E			
	2,500	▶ 2,500	F
Current-year restricted farm loss (amount C **minus** amount F) (enter this amount on line 410)			

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			
Deduct: Restricted farm loss expired*	400		
Restricted farm losses at the beginning of the tax year	402		▶
Add:			
Restricted farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation	405		
Current-year restricted farm loss (enter on line 233 of Schedule 1)	410		
			▶
Subtotal			

Part 4 – Restricted farm losses (continued)

Subtotal from page 4

Deduct:

Amount applied against farming income (enter on line 333 of the T2 return)	430		
Section 80 – Adjustments for forgiven amounts	440		
Other adjustments	450		
			▶
Amount of restricted farm losses available to carry back or carry forward to other years			

Deduct – Request to carry back restricted farm loss to:

First previous tax year to reduce farming income	941		
Second previous tax year to reduce farming income	942		
Third previous tax year to reduce farming income	943		
			▶
Restricted farm losses – Closing balance			480

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			
Deduct: Listed personal property loss expired after seven tax years	500		
Listed personal property losses at the beginning of the tax year	502		▶
Add: Current-year listed personal property loss (from Schedule 6)			510
Subtotal			

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		
Other adjustments	550		
			▶
Amount of listed personal property losses available to carry back or carry forward to other years			

Deduct – Request to carry back listed personal property loss to:

First previous tax year to reduce listed personal property gains	961		
Second previous tax year to reduce listed personal property gains	962		
Third previous tax year to reduce listed personal property gains	963		
			▶
Listed personal property losses – Closing balance			580

Part 7 – Limited partnership losses

Current-year limited partnership losses

1	2	3	4	5	6	7
Partnership identifier 600	Tax year ending YYYY/MM/DD 602	Corporation's share of limited partnership loss 604	Corporation's at-risk amount 606	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses 608	Column 4 **minus** column 5 (if negative, enter "0")	Current-year limited partnership losses (column 3 **minus** 6) 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 630	Tax year ending YYYY/MM/DD 632	Limited partnership losses at the end of the previous tax year 634	Corporation's at-risk amount 636	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses 638	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) 650

Continuity of limited partnership losses that can be carried forward to future tax years

1	2	3	4	5	6
Partnership identifier 660	Limited partnership losses at the end of the previous tax year 662	Limited partnership losses transferred on an amalgamation or the windup of a subsidiary 664	Current-year limited partnership losses (from column 620) 670	Limited partnership losses applied in the current year (cannot be more than column 650) 675	Current year limited partnership losses closing balance to be carried forward to future years (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, please 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		Balance at end of year
					Taxable income	Part IV tax	
Current	N/A	532,886			N/A		532,886
1st preceding taxation year 2009-12-31	61,485	N/A		N/A			61,485
2nd preceding taxation year 2008-12-31		N/A		N/A			
3rd preceding taxation year 2007-12-31		N/A		N/A			
4th preceding taxation year 2006-12-31		N/A		N/A			
5th preceding taxation year 2005-12-31		N/A		N/A			
6th preceding taxation year 2004-12-31		N/A		N/A			
7th preceding taxation year 2003-12-31		N/A		N/A			
8th preceding taxation year 2002-12-31		N/A		N/A			
9th preceding taxation year 2001-12-31		N/A		N/A			
10th preceding taxation year 2000-12-31		N/A		N/A			
11th preceding taxation year 1999-12-31		N/A		N/A			
12th preceding taxation year 1998-12-31		N/A		N/A			
13th preceding taxation year 1997-12-31		N/A		N/A			
14th preceding taxation year 1996-12-31		N/A		N/A			
15th preceding taxation year 1995-12-31		N/A		N/A			
16th preceding taxation year 1994-12-31		N/A		N/A			
17th preceding taxation year 1993-12-31		N/A		N/A			
18th preceding taxation year 1992-12-31		N/A		N/A			
19th preceding taxation year 1991-12-31		N/A		N/A			
20th preceding taxation year 1990-12-31		N/A		N/A			*
Total	61,485	532,886					594,371

Non-capital losses – losses that can be carried forward over 10 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		Balance at end of year
					Taxable income	Part IV tax	
Current	N/A	N/A		N/A	N/A	N/A	N/A
1st preceding taxation year 2009-12-31		N/A		N/A			
2nd preceding taxation year 2008-12-31		N/A		N/A			
3rd preceding taxation year 2007-12-31		N/A		N/A			
4th preceding taxation year 2006-12-31		N/A		N/A			
5th preceding taxation year 2005-12-31	119,634	N/A		N/A			119,634
6th preceding taxation year 2004-12-31		N/A		N/A			
7th preceding taxation year 2003-12-31		N/A		N/A			
8th preceding taxation year 2002-12-31		N/A		N/A			
9th preceding taxation year 2001-12-31		N/A		N/A			
10th preceding taxation year 2000-12-31		N/A		N/A			*
Total	119,634	N/A		N/A			119,634

* **This balance expires this year and will not be available next year.**

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
West Perth Power Inc.	86922 9377 RC0001	2010-12-31

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 (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		3,539,229			0		3,539,229	4	0	0	141,569	3,397,660
2.	8		140,588	296,074		0	148,037	288,625	20	0	0	57,725	378,937
3.	10		62,077	306,473		0	153,237	215,313	30	0	0	64,594	303,956
4.	12		1,542	3,384		0	1,692	3,234	100	0	0	3,234	1,692
5.	13		2,816			0		2,816	NA	0	0	1,408	1,408
6.	45		10,059			0		10,059	45	0	0	4,527	5,532
7.	47		217,875	181,622		0	90,811	308,686	8	0	0	24,695	374,802
8.	94	Smart Meter Software not in use		49,661		0	24,831	24,830	0	0	0		49,661
		Total	3,974,186	837,214			418,608	4,392,792				297,752	4,513,648

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*.

**** 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
West Perth Power Inc.	86922 9377 RC0001	2010-12-31

This schedule is to be completed by a corporation having one or more of the following:
– related corporation(s)
– associated corporations(s)

	Name 100	Country of residence (if other than Canada) 200	Business Number (Canadian corporation only) (see note 1) 300	Relationship code (see note 2) 400	Number of common shares owned 500	% of common shares owned 550	Number of preferred shares owned 600	% of preferred shares owned 650	Book value of capital stock 700
1.	Erie Thames Powerlines Corporatior	CA	86371 9498 RC0001	3					
2.	Coulter Water Meter Service Inc.	CA	10117 1486 RC0002	3					
3.	ERTH Corporation	CA	86356 4324 RC0001	1					
4.	CRU Solutions Inc.	CA	86371 9696 RC0001	3					
5.	Utilismart Corporation	CA	86443 9450 RC0001	3					
6.	Enerconnect Inc.	CA	87367 1499 RC0001	3					
7.	Wattsworth Analysis Inc.	CA	87746 8108 RC0001	3					
8.	Enermajica Ontario Inc.	CA	88660 6409 RC0001	3					
9.	ERTH360 Generation & Consulting I	CA	82960 2226 RC0001	3					
10.	Ecaliber (Canada) Inc.	CA	82954 1895 RC0001	3					
11.	The SPI Group Inc.	CA	87013 2917 RC0001	3					
12.	ERTH (Holdings) Inc.	CA	82642 4293 RC0002	3					
13.	ERTH Limited	CA	83794 3117 RC0001	3					
14.	Clinton Power Corporation	CA	86985 8779 RC0001	3					

Note 1: Enter "NR" if a corporation is not registered.
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(99)

Canada

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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 2010

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	West Perth Power Inc.	86922 9377 RC0001	1	500,000		
2	Erie Thames Powerlines Corporation	86371 9498 RC0001	1	500,000	100.0000	500,000
3	Coulter Water Meter Service Inc.	10117 1486 RC0002	1	500,000		
4	ERTH Corporation	86356 4324 RC0001	1	500,000		
5	CRU Solutions Inc.	86371 9696 RC0001	1	500,000		
6	Utilismart Corporation	86443 9450 RC0001	1	500,000		
7	Enerconnect Inc.	87367 1499 RC0001	1	500,000		
8	Wattsworth Analysis Inc.	87746 8108 RC0001	1	500,000		
9	Enermajica Ontario Inc.	88660 6409 RC0001	1	500,000		
10	ERTH360 Generation & Consulting Inc.	82960 2226 RC0001	1	500,000		
11	Ecaliber (Canada) Inc.	82954 1895 RC0001	1	500,000		
12	The SPI Group Inc.	87013 2917 RC0001	1	500,000		
13	ERTH (Holdings) Inc.	82642 4293 RC0002	1	500,000		

	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	
14	ERTH Limited	83794 3117 RC0001	1	500,000			
15	Clinton Power Corporation	86985 8779 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 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
West Perth Power Inc.	86922 9377 RC0001	2010-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	ERTH Corporation	86356 4324 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada

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SCHEDULE 516

CAPITAL DEDUCTION ELECTION OF ASSOCIATED GROUP FOR THE ALLOCATION OF NET DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
West Perth Power Inc.	86922 9377 RC0001	2010-12-31

- Complete this schedule to allocate the associated group's net deduction for the capital deduction election under subsection 83(2) of the *Taxation Act, 2007* (Ontario). The associated group includes the filing corporation (see line 190 of Part 2 of Schedule 515, *Ontario Capital Tax on Other than Financial Institutions*).
- If you need more space, attach more schedules.
- File this schedule with the *T2 Corporation Income Tax Return*.

	A Names of eligible corporations in the associated group 100	B Business Number of associated corporations (enter "NR" if a corporation is not registered) 200	C Ontario allocation factor (OAF)* (enter as a percentage) 300	D Total assets** 400	E Net deduction ($15 million x line 300) **multiplied** by line 400 / line 700 500	F Allocation of net deduction *** 600
1.	West Perth Power Inc.	86922 9377 RC0001	100.000	5,000,961	671,439	
2.	Erie Thames Powerlines Corporation	86371 9498 RC0001	100.000	28,656,017	3,847,412	
3.	Coulter Water Meter Service Inc.	10117 1486 RC0002	100.000	1,283,896	172,378	1,067,115
4.	ERTH Corporation	86356 4324 RC0001	100.000	35,640,589	4,785,174	1,387,718
5.	CRU Solutions Inc.	86371 9696 RC0001	100.000	7,635,968	1,025,220	2,623,084
6.	Utilismart Corporation	86443 9450 RC0001	100.000	2,834,958	380,627	
7.	Enerconnect Inc.	87367 1499 RC0001	100.000	1,457,122	195,636	
8.	Wattsworth Analysis Inc.	87746 8108 RC0001	100.000	597,624	80,238	
9.	Enermajica Ontario Inc.	88660 6409 RC0001	100.000	290,932	39,061	
10.	ERTH360 Generation & Consulting Inc.	82960 2226 RC0001	100.000	251,277	33,737	37,113
11.	Ecaliber (Canada) Inc.	82954 1895 RC0001	100.000	3,786,979	508,447	4,404,486
12.	The SPI Group Inc.	87013 2917 RC0001	100.000	6,994,745	939,128	4,160,526
13.	ERTH (Holdings) Inc.	82642 4293 RC0002	100.000	14,106,975	1,894,030	1,319,958
14.	ERTH Limited	83794 3117 RC0001				
15.	Clinton Power Corporation	86985 8779 RC0001	100.000	3,183,875	427,473	

Total assets of associated group (total of amounts in column D) **700** 111,721,918

Total net deduction (total of amounts in column E) **800** 15,000,000

Total allocated net deduction (total of amounts in column F) (not to exceed amount on line 800) **900** 15,000,000

* OAF from the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends.

** Total assets of each corporation in the associated group as recorded in the books and records for the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends. If the corporation is not resident in Canada, enter the amount of its total assets situated in Canada.

*** Enter the amount from this column allocated to the filing corporation on line 300 of Schedule 515.

T2 SCH 516

Canada

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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** 86922 9377 RC0001

Corporation's name

002 West Perth Power Inc.

Address of head office

Has this address changed since the last time you filed your T2 return? . . . . **010** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 011 to 018.)

011 169 St. David Street

012 P.O. Box 220

City **015** Mitchell — Province, territory, or state **016** ON

Country (other than Canada) **017** — Postal code/Zip code **018** N0K 1N0

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? . . . . **020** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 021 to 028.)

021 c/o

022 200-295 Wolfe Street

023

City **025** London — Province, territory, or state **026** ON

Country (other than Canada) **027** — Postal code/Zip code **028** N6B 2C4

Location of books and records

Has the location of books and records changed since the last time you filed your T2 return? . . . . **030** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 031 to 038.)

031 200-295 Wolfe Street

032

City **035** London — Province,territory, or state **036** ON

Country (other than Canada) **037** — Postal code/Zip code **038** N6B 2C4

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** 2010-01-01 (YYYY MM DD) — Tax year-end **061** 2010-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . **063** 1 Yes [X] 2 No [ ]

If **yes**, provide the date control was acquired . . . . **065** 2010-01-01 (YYYY MM DD)

Is the date on line 061 a deemed tax year-end in accordance with 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

091	092	093	094	095	096
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **Yes** response, **attach** to the T2 return the schedule that applies.

Question	Line	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
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	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 (or its associated corporations) 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

	Line	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

	Line	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
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281		X

What is the corporation's major business activity? (only complete if **yes** was entered at line 281) **282** ______

If the major business activity involves the resale of goods, show whether it is wholesale or retail **283** 1 Wholesale ☐ 2 Retail ☐

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

Line	Product/service	Line	%
284	Distribution of Electricity	285	100.000 %
286		287	%
288		289	%

	Line	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

	Line	Amount	Total	
Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		-532,403	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 3.2 times the Part VI.1 tax payable at line 724.

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, **minus** 10/3 of the amount on line 632*, **minus** 1/(0.38 - X**) 3.57143
times the amount on line 636***, and **minus** any amount that, because of federal law, is exempt form Part I tax . . . . . . **405** ________ B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

400,000	x	Number of days in the tax year before 2009 / Number of days in the tax year	/ 365	=		1
500,000	x	Number of days in the tax year after 2008 / Number of days in the tax year	365 / 365	=	500,000	2
				Add amounts at lines 1 and 2	500,000	4

Business limit (see notes 1 and 2 below) . . . . . . **410** ________ C

Notes:
1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C ________ x **415** **** 72,780 / 11,250 D = ... ________ 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.

* 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			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, whichever is the least		E	
Aggregate investment income from line 440*		F	
Total of amounts B to F		▶	G
Amount A **minus** amount G (if negative, enter "0")			H

Amount H		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	I
Amount H		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 %	=	J
Amount H		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 / 365	x	10 %	=	K
Amount H		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	x	11.5 %	=	L
Amount H		x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x	13 %	=	L.1

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L.1 M
Enter amount M on line 638.

* 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, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	T
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 %	=	U
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 / 365	x	10 %	=	V
Amount S		x	Number of days in the tax year after December 31, 2010, and before January 2012 / Number of days in the tax year	/ 365	x	11.5 %	=	W
Amount S		x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x	13 %	=	W.1

General tax reduction – Total of amounts T to W.1 X
Enter amount X on line 639.

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				
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				
Deduct:				
Amount from line 400, 405, 410, or 425, whichever is the least				
Foreign non-business income tax credit from line 632	x 25 / 9 =			
Foreign business income tax credit from line 636	x $\frac{1}{(0.38 - X^*)}$ 3.57143 =			
		►		
			x 26 2 / 3 % =	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780)				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 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)			

Part I tax

Base amount of Part I tax – Taxable income (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			i
Taxable income from line 360			
Deduct:			
Amount from line 400, 405, 410, or 425, 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			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	638		
General tax reduction from amount X	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.

Summary of tax and credits

Federal tax

Part I tax payable	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	1,554	
Provincial tax on large corporations (New Brunswick* and Nova Scotia)	765		
		1,554	1,554
Total tax payable	770		1,554 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	B

Refund code 894 Overpayment

Balance (line A minus line B) 1,554

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 1,554

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 X

* The New Brunswick tax on large corporations is eliminated effective January 1, 2009.

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, 950 Pettit 951 Jeff 954 President & CEO
Last name in block letters / First name in block letters / Position, office, or rank

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2011-06-29 — Date (yyyy/mm/dd)
Signature of the authorized signing officer of the corporation
956 (519) 518-6117 — Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes X 2 No ☐

958 Name in block letters
959 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

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
West Perth Power Inc.	86922 9377 RC0001	2010-12-31

- 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				-315,049 A
Add:				
Amortization of tangible assets		104	221,456	
Non-deductible meals and entertainment expenses		121	3,669	
Subtotal of additions			225,125 ▶	225,125
Other additions:				
Miscellaneous other additions:				
600 Recovery of Smart Meter		290	58,608	
604				
Total		294		
Subtotal of other additions		199	58,608 ▶	58,608
Total additions		500	283,733 ▶	283,733
Deduct:				
Capital cost allowance from Schedule 8		403	297,752	
Subtotal of deductions			297,752 ▶	297,752
Other deductions:				
Miscellaneous other deductions:				
700 Regulary liabiliites, beginning of year		390	192,966	
701 Capital Tax actual		391	1,554	
702 Capital tax recovery per FS		392	3,865	
703 Smart meter - operating expense	4,950			
Total	4,950	393	4,950	
704				
Total		394		
Subtotal of other deductions		499	203,335 ▶	203,335
Total deductions		510	501,087 ▶	501,087
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				-532,403

T2 SCH 1 E (10)

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SCHEDULE 4

CORPORATION LOSS CONTINUITY AND APPLICATION

Name of corporation	Business Number	Tax year-end Year Month Day
West Perth Power Inc.	86922 9377 RC0001	2010-12-31

- 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			-532,403
Deduct: (increase a loss)			
Net capital losses deducted in the year (enter as a positive amount)			
Taxable dividends deductible under sections 112, 113(1), or subsection 138(6)			
Amount of Part VI.1 tax deductible			
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)			
		▶	
Subtotal (if positive, enter "0")			-532,403
Deduct: (increase a loss)			
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions			
Subtotal			-532,403
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 this amount on line 310.)			
Current-year non-capital loss (if positive, enter "0"; if negative, enter this amount on line 110 as a positive)			-532,403

Continuity of non-capital losses and request for a carryback

	Line			
Non-capital loss at the end of the previous tax year		181,119		
Deduct: Non-capital loss expired*	100			
Non-capital losses at the beginning of the tax year	102	181,119	▶	181,119
Add:				
Non-capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	105			
Current-year non-capital loss (from calculation above)	110	532,403		
		532,403	▶	532,403
Subtotal				713,522

Part 1 – Non-capital losses (continued)

Subtotal from page 1			713,522
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	150		
Section 80 – Adjustments for forgiven amounts	140		
Subsection 111(10) – Adjustments for fuel tax rebate			
Non-capital losses of previous tax years applied in the current tax year (enter on line 331 of the T2 return)	130		
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		
		►	
Amount of non-capital losses available to carry back or carry forward to other years			713,522
Deduct – Request to carry back non-capital loss to:			
First previous tax year to reduce taxable income	901		
Second previous tax year to reduce taxable income	902		
Third previous tax year to reduce taxable income	903		
First previous tax year to reduce taxable dividends subject to Part IV tax	911		
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		
		►	
Closing balance of non-capital losses to be carried forward to future tax years		180	713,522

* 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 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200		
Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	205		
		►	
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	250		
Section 80 – Adjustments for forgiven amounts	240		
		►	
Subtotal			
Add: Current-year capital loss (from the calculation on Schedule 6)		210	
Unused non-capital losses that expired in the tax year*		A	
Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year**		B	
Enter amount from line A or B, whichever is less	215		
ABILs expired as non-capital loss: line 215 **divided** by the inclusion rate*** 50.0000 %		220	
Subtotal			

Part 2 – Capital losses (continued)

Subtotal from page 2

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 at line 220 above.

Deduct: Capital losses from previous tax years applied against the current-year net capital gain (see Note 1) 225

Amount of capital losses available to carry back or carry forward to other years

Deduct – Request to carry back capital loss to (see Note 2):

	Capital gain (100%)		Amount carried back (100%)
First previous tax year		951	
Second previous tax year		952	
Third previous tax year		953	

Capital losses – Closing balance 280

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.

* 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 A.

** 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 B.

*** This inclusion rate is the rate used to calculate your ABIL referred to at line B. Therefore, use one of the following inclusion rates, whichever applies:

- For ABILs incurred in the 1999 and previous tax years, use 0.75.
- For ABILs incurred in the 2000 and 2001 tax years, the inclusion rate is equal to amount M on Schedule 6 – Version T2SCH6(01)
- For ABILs incurred in the 2002 and later tax years, use 0.50.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year . . . .

Deduct: Farm loss expired* 300

Farm losses at the beginning of the tax year . . . . 302 ▶

Add:

Farm losses transferred on the amalgamation or the windup of a subsidiary corporation 305

Current-year farm loss . . . . 310 ▶

Subtotal

Part 3 – Farm losses (continued)

Subtotal from page 3			
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	350		
Section 80 – Adjustments for forgiven amounts	340		
Amount applied against taxable income (enter on line 334 of the T2 return)	330		
Amount applied against taxable dividends subject to Part IV tax	335		
			▶
Amount of farm losses available to carry back or carry forward to other years			
Deduct – Request to carry back farm loss to:			
First previous tax year to reduce taxable income	921		
Second previous tax year to reduce taxable income	922		
Third previous tax year to reduce taxable income	923		
First previous tax year to reduce taxable dividends subject to Part IV tax	931		
Second previous tax year to reduce taxable dividends subject to Part IV tax	932		
Third previous tax year to reduce taxable dividends subject to Part IV tax	933		
			▶
Farm losses – Closing balance	380		

* 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		C
Minus the deductible farm loss:				
$2,500 **plus** D or E, whichever is less		2,500		
(amount C above ____ – $2,500) **divided** by 2 =		D		
	6,250	E		
		2,500 ▶	2,500	F
Current-year restricted farm loss (amount C **minus** amount F) (enter this amount on line 410)				

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			
Deduct: Restricted farm loss expired*	400		
Restricted farm losses at the beginning of the tax year	402		▶
Add:			
Restricted farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation	405		
Current-year restricted farm loss (enter on line 233 of Schedule 1)	410		
			▶
Subtotal			

Part 4 – Restricted farm losses (continued)

Subtotal from page 4

Deduct:

Amount applied against farming income (enter on line 333 of the T2 return)	430	
Section 80 – Adjustments for forgiven amounts	440	
Other adjustments	450	
		►

Amount of restricted farm losses available to carry back or carry forward to other years

Deduct – Request to carry back restricted farm loss to:

First previous tax year to reduce farming income	941	
Second previous tax year to reduce farming income	942	
Third previous tax year to reduce farming income	943	
		►
Restricted farm losses – Closing balance		480

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		
Deduct: Listed personal property loss expired after seven tax years	500	
Listed personal property losses at the beginning of the tax year	502	►
Add: Current-year listed personal property loss (from Schedule 6)		510
		Subtotal

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	
Other adjustments	550	
		►

Amount of listed personal property losses available to carry back or carry forward to other years

Deduct – Request to carry back listed personal property loss to:

First previous tax year to reduce listed personal property gains	961	
Second previous tax year to reduce listed personal property gains	962	
Third previous tax year to reduce listed personal property gains	963	
		►
Listed personal property losses – Closing balance		580

Part 7 – Limited partnership losses

Current-year limited partnership losses

1	2	3	4	5	6	7
Partnership identifier 600	Tax year ending YYYY/MM/DD 602	Corporation's share of limited partnership loss 604	Corporation's at-risk amount 606	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses 608	Column 4 **minus** column 5 (if negative, enter "0")	Current-year limited partnership losses (column 3 **minus** 6) 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 630	Tax year ending YYYY/MM/DD 632	Limited partnership losses at the end of the previous tax year 634	Corporation's at-risk amount 636	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses 638	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) 650

Continuity of limited partnership losses that can be carried forward to future tax years

1	2	3	4	5	6
Partnership identifier 660	Limited partnership losses at the end of the previous tax year 662	Limited partnership losses transferred on an amalgamation or the windup of a subsidiary 664	Current-year limited partnership losses (from column 620) 670	Limited partnership losses applied in the current year (cannot be more than column 650) 675	Current year limited partnership losses closing balance to be carried forward to future years (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, please 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		Balance at end of year
					Taxable income	Part IV tax	
Current	N/A	532,403			N/A		532,403
1st preceding taxation year 2009-12-31	61,485	N/A		N/A			61,485
2nd preceding taxation year 2008-12-31		N/A		N/A			
3rd preceding taxation year 2007-12-31		N/A		N/A			
4th preceding taxation year 2006-12-31		N/A		N/A			
5th preceding taxation year 2005-12-31		N/A		N/A			
6th preceding taxation year 2004-12-31		N/A		N/A			
7th preceding taxation year 2003-12-31		N/A		N/A			
8th preceding taxation year 2002-12-31		N/A		N/A			
9th preceding taxation year 2001-12-31		N/A		N/A			
10th preceding taxation year 2000-12-31		N/A		N/A			
11th preceding taxation year 1999-12-31		N/A		N/A			
12th preceding taxation year 1998-12-31		N/A		N/A			
13th preceding taxation year 1997-12-31		N/A		N/A			
14th preceding taxation year 1996-12-31		N/A		N/A			
15th preceding taxation year 1995-12-31		N/A		N/A			
16th preceding taxation year 1994-12-31		N/A		N/A			
17th preceding taxation year 1993-12-31		N/A		N/A			
18th preceding taxation year 1992-12-31		N/A		N/A			
19th preceding taxation year 1991-12-31		N/A		N/A			
20th preceding taxation year 1990-12-31		N/A		N/A			*
Total	61,485	532,403					593,888

Non-capital losses – losses that can be carried forward over 10 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	N/A		N/A	N/A	N/A	N/A
1st preceding taxation year 2009-12-31		N/A		N/A			
2nd preceding taxation year 2008-12-31		N/A		N/A			
3rd preceding taxation year 2007-12-31		N/A		N/A			
4th preceding taxation year 2006-12-31		N/A		N/A			
5th preceding taxation year 2005-12-31	119,634	N/A		N/A			119,634
6th preceding taxation year 2004-12-31		N/A		N/A			
7th preceding taxation year 2003-12-31		N/A		N/A			
8th preceding taxation year 2002-12-31		N/A		N/A			
9th preceding taxation year 2001-12-31		N/A		N/A			
10th preceding taxation year 2000-12-31		N/A		N/A			*
Total	119,634	N/A		N/A			119,634

* **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
West Perth Power Inc.	86922 9377 RC0001	2010-12-31

- 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*.

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

	Line	Amount		Total	Ref
Ontario basic income tax (from Schedule 500)	270				
Deduct: Ontario small business deduction (from schedule 500)	402				
Subtotal (if negative, enter "0")			►		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	1,554			
Subtotal		1,554	►	1,554	H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)				1,554	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	1,554	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 1,554

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
West Perth Power Inc.	86922 9377 RC0001	2010-12-31

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 (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		3,539,229			0		3,539,229	4	0	0	141,569	3,397,660
2.	8		140,588	296,074		0	148,037	288,625	20	0	0	57,725	378,937
3.	10		62,077	306,473		0	153,237	215,313	30	0	0	64,594	303,956
4.	12		1,542	3,384		0	1,692	3,234	100	0	0	3,234	1,692
5.	13		2,816			0		2,816	NA	0	0	1,408	1,408
6.	45		10,059			0		10,059	45	0	0	4,527	5,532
7.	47		217,875	181,622		0	90,811	308,686	8	0	0	24,695	374,802
8.	94	Smart Meter Software not in use		49,661		0	24,831	24,830	0	0	0		49,661
		Total	3,974,186	837,214			418,608	4,392,792				297,752	4,513,648

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*.

**** 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.

T2 SCH 8 (06)

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
West Perth Power Inc.	86922 9377 RC0001	2010-12-31

This schedule is to be completed by a corporation having one or more of the following:
- related corporation(s)
- associated corporations(s)

	Name 100	Country of residence (if other than Canada) 200	Business Number (Canadian corporation only) (see note 1) 300	Relationship code (see note 2) 400	Number of common shares owned 500	% of common shares owned 550	Number of preferred shares owned 600	% of preferred shares owned 650	Book value of capital stock 700
1.	Erie Thames Powerlines Corporatior	CA	86371 9498 RC0001	3					
2.	Coulter Water Meter Service Inc.	CA	10117 1486 RC0002	3					
3.	ERTH Corporation	CA	86356 4324 RC0001	1					
4.	CRU Solutions Inc.	CA	86371 9696 RC0001	3					
5.	Utilismart Corporation	CA	86443 9450 RC0001	3					
6.	Enerconnect Inc.	CA	87367 1499 RC0001	3					
7.	Wattsworth Analysis Inc.	CA	87746 8108 RC0001	3					
8.	Enermajica Ontario Inc.	CA	88660 6409 RC0001	3					
9.	ERTH360 Generation & Consulting I	CA	82960 2226 RC0001	3					
10.	Ecaliber (Canada) Inc.	CA	82954 1895 RC0001	3					
11.	The SPI Group Inc.	CA	87013 2917 RC0001	3					
12.	ERTH (Holdings) Inc.	CA	82642 4293 RC0002	3					
13.	ERTH Limited	CA	83794 3117 RC0001	3					
14.	Clinton Power Corporation	CA	86985 8779 RC0001	3					

Note 1: Enter "NR" if a corporation is not registered.
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(99)

Canada

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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 2010

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	West Perth Power Inc.	86922 9377 RC0001	1	500,000		
2	Erie Thames Powerlines Corporation	86371 9498 RC0001	1	500,000	100.0000	500,000
3	Coulter Water Meter Service Inc.	10117 1486 RC0002	1	500,000		
4	ERTH Corporation	86356 4324 RC0001	1	500,000		
5	CRU Solutions Inc.	86371 9696 RC0001	1	500,000		
6	Utilismart Corporation	86443 9450 RC0001	1	500,000		
7	Enerconnect Inc.	87367 1499 RC0001	1	500,000		
8	Wattsworth Analysis Inc.	87746 8108 RC0001	1	500,000		
9	Enermajica Ontario Inc.	88660 6409 RC0001	1	500,000		
10	ERTH360 Generation & Consulting Inc.	82960 2226 RC0001	1	500,000		
11	Ecaliber (Canada) Inc.	82954 1895 RC0001	1	500,000		
12	The SPI Group Inc.	87013 2917 RC0001	1	500,000		
13	ERTH (Holdings) Inc.	82642 4293 RC0002	1	500,000		

	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	
14	ERTH Limited	83794 3117 RC0001	1	500,000			
15	Clinton Power Corporation	86985 8779 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 33

TAXABLE CAPITAL EMPLOYED IN CANADA – LARGE CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
West Perth Power Inc.	86922 9377 RC0001	2010-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms "financial institution," "long-term debt," and "reserves."
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If you are filing a provincial capital tax return with your *T2 Corporation Income Tax Return*, also file a completed Schedule 33 with the return no later than six months from the end of the tax year.
- This schedule may contain changes that had not yet become law at the time of publishing.

If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, "Taxable capital employed in Canada."

Part 1 – Capital

Add the following amounts at the end of the year:

	Line	Amount		
Reserves that have not been deducted in computing income for the year under Part I	101			
Capital stock (or members' contributions if incorporated without share capital)	103	2,118,274		
Retained earnings	104			
Contributed surplus	105			
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108			
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109	1,251,185		
Any dividends declared but not paid by the corporation before the end of the year	110			
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111			
Proportion of the amount, if any, by which the total of all amounts (see note below) for the partnership of which the corporation is a member at the end of the year exceeds the amount of the partnership's deferred unrealized foreign exchange losses	112			
Subtotal		3,369,459 ▶	3,369,459	A

Deduct the following amounts:

	Line	Amount		
Deferred tax debit balance at the end of the year	121			
Any deficit deducted in computing its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122	668,694		
Any amount deducted under subsection 135(1) in computing income under Part I for the year, as long as the amount may reasonably be regarded as being included in any of lines 101 to 112 above	123			
The amount of deferred unrealized foreign exchange losses at the end of the year	124			
Subtotal		668,694 ▶	668,694	B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190		2,700,765	

Note: Lines 101, 107, 108, 109, 111, and 112 are determined as follows:

– If the partnership is a member of another partnership (tiered partnerships), include the amounts of the partnership and tiered partnerships.
– Amounts for the partnership and tiered partnerships are those that would be determined for lines 101, 107, 108, 109, 111, and 112 as if they apply in the same way that they apply to corporations.
– Do not include amounts owing to the member or to other corporations that are members of the partnership.
– Amounts are determined at the end of the last fiscal period of the partnership ending in the year of the corporation.
– The proportion of the total amounts is determined by the corporation's share of the partnership's income or loss for the fiscal period of the partnership.

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	11,677
A loan or advance to another corporation (other than a financial institution)	402	599,352
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend receivable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim, or similar obligation of, a partnership all of the members of which, throughout the year, were other corporations (other than financial institutions) that were not exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)]	406	
An interest in a partnership (see note 1 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	611,029

Notes:

1. Where the corporation has an interest in a partnership or in tiered partnerships, consider the following:
   - the investment allowance of a partnership is deemed to be the amount calculated at line 490 above, at the end of its fiscal period, as if it was a corporation;
   - the total of the carrying value of each asset of the partnership described in the above lines is for its last fiscal period ending at or before the end of the corporation's tax year; and
   - the carrying value of a partnership member's interest at the end of the year is its specified proportion [as defined in subsection 248(1)] of the partnership's investment allowance.
2. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)].
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation, according to subsection 181.2(6).

Part 3 – Taxable capital

Capital for the year (line 190)		2,700,765	C
Deduct: Investment allowance for the year (line 490)		611,029	D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	2,089,736	

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 2,089,736 x $\frac{\text{Taxable income earned in Canada} \quad \mathbf{610} \quad 1{,}000}{\text{Taxable income} \quad 1{,}000}$ = **Taxable capital employed in Canada** **690** 2,089,736

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada			701	
Deduct the following amounts:				
Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada	711			
Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada	712			
Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below)	713			
Total deductions (add lines 711, 712, and 713)		►		E
Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0")			790	

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (line 690 or 790, whichever applies)		F
Deduct:	10,000,000	G
Excess (amount F **minus** amount G) (if negative, enter "0")		H
Calculation for purposes of the small business deduction (amount H x 0.00225)		I

Enter this amount at line 415 of the T2 return

Attached Schedule with Total

Part 1 – All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations

Title Part 1 – All indebtedness of the corporation represented by bonds, debentu

Description	Amount	
Demand Note Payable	1,183,391	00
CUSTOMER DEPOSITS	67,794	00
Total	1,251,185	00

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
West Perth Power Inc.	86922 9377 RC0001	2010-12-31

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	ERTH Corporation	86356 4324 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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SCHEDULE 510

ONTARIO CORPORATE MINIMUM TAX

Name of corporation	Business Number	Tax year-end Year Month Day
West Perth Power Inc.	86922 9377 RC0001	2010-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	5,662,757
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	120,169,883
Total assets (total of lines 112 to 116)		125,832,640
Total revenue of the corporation for the tax year **	142	5,980,755
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	65,965,012
Total revenue (total of lines 142 to 146)		71,945,767

The corporation is subject to CMT if:
– for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
– for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.
If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
– Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
– The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
– A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
– Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
– The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
– A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Calculation of adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	-315,049
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220			
Provision for deferred income taxes (debits)/cost of future income taxes	222			
Equity losses from corporations	224			
Financial statement loss from partnerships and joint ventures	226			
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230			
Other additions (see note below):				
Share of adjusted net income of partnerships and joint ventures **	228			
Total patronage dividends received, not already included in net income/loss	232			
281	282			
283	284			
Subtotal				A
Deduct (to the extent reflected in income/loss):				
Provision for recovery of current income taxes/benefit of current income taxes	320			
Provision for deferred income taxes (credits)/benefit of future income taxes	322			
Equity income from corporations	324			
Financial statement income from partnerships and joint ventures	326			
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330			
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332			
Gain on donation of listed security or ecological gift	340			
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342			
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344			
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346			
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348			
Other deductions (see note below):				
Share of adjusted net loss of partnerships and joint ventures **	328			
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334			
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336			
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338			
381	382			
383	384			
385	386			
387	388			
389	390			
Subtotal				B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	-315,049

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

– Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – Calculation of CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)	515			
Deduct:				
CMT loss available (amount R from Part 7)		157,662		
Minus: Adjustment for an acquisition of control *	518			
Adjusted CMT loss available		157,662 ▶	157,662	C
Net income subject to CMT calculation (if negative, enter "0")	520			

Amount from line 520 ______ x (Number of days in the tax year before July 1, 2010 / Number of days in the tax year) 181 / 365 x 4 % = ______ 1

Amount from line 520 ______ x (Number of days in the tax year after June 30, 2010 / Number of days in the tax year) 184 / 365 x 2.7 % = ______ 2

Subtotal (amount 1 **plus** amount 2) ______ 3

Gross CMT: amount on line 3 above x OAF **	540		
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")			D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			
Net CMT payable (if negative, enter "0")			E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** ______ = ______

Ontario allocation factor 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *			G		
Deduct:					
CMT credit expired *	600				
CMT credit carryforward at the beginning of the current tax year * (see note below)			▶	620	
Add:					
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)				650	
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)					H
Deduct:					
CMT credit deducted in the current tax year (amount P from Part 5)					I
Subtotal (amount H **minus** amount I)					J
Add:					
Net CMT payable (amount E from Part 3)					
SAT payable (amount O from Part 6 of Schedule 512)					
Subtotal			▶		K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)				670	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)					M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			1		
For a corporation that is not a life insurance corporation:					
CMT after foreign tax credit deduction (amount D from Part 3)		2			
For a life insurance corporation:					
Gross CMT (line 540 from Part 3)		3			
Gross SAT (line 460 from Part 6 of Schedule 512)		4			
The **greater** of amounts 3 and 4		5			
Deduct: line 2 or line 5, whichever applies:			6		
Subtotal (if negative, enter "0")			▶		N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)					
Deduct:					
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)					
Subtotal (if negative, enter "0")			▶		O
CMT credit deducted in the current tax year (least of amounts M, N, and O)					P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year *		157,662			Q
Deduct:					
CMT loss expired *	700				
CMT loss carryforward at the beginning of the tax year * (see note below)		157,662	► 720	157,662	
Add:					
CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below)			750		
CMT loss available (line 720 **plus** line 750)				157,662	R
Deduct:					
CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3)					
Subtotal (if negative, enter "0")				157,662	S
Add:					
Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount)			760	315,049	
CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760)			770	472,711	T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not transfer a loss on a vertical amalgamation under subsection 87(2.11) of the federal Act or other amalgamation of a parent and its subsidiary.
Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
West Perth Power Inc.	86922 9377 RC0001	2010-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	Erie Thames Powerlines Corporation	86371 9498 RC0001	31,060,468	40,161,013
2	Coulter Water Meter Service Inc.	10117 1486 RC0002	1,238,258	775,159
3	ERTH Corporation	86356 4324 RC0001	41,204,038	3,748,389
4	CRU Solutions Inc.	86371 9696 RC0001	7,421,203	3,177,065
5	Utilismart Corporation	86443 9450 RC0001	3,761,949	3,634,861
6	Enerconnect Inc.	87367 1499 RC0001	1,449,751	679,605
7	Wattsworth Analysis Inc.	87746 8108 RC0001	748,288	983,689
8	Enermajica Ontario Inc.	88660 6409 RC0001	707,435	180,776
9	ERTH360 Generation & Consulting Inc.	82960 2226 RC0001	192,443	684,833
10	Ecaliber (Canada) Inc.	82954 1895 RC0001	4,627,131	4,010,875
11	The SPI Group Inc.	87013 2917 RC0001	7,720,177	5,092,910
12	ERTH (Holdings) Inc.	82642 4293 RC0002	16,929,131	0
13	ERTH Limited	83794 3117 RC0001	0	0
14	Clinton Power Corporation	86985 8779 RC0001	3,109,611	2,835,837
		Total	450 120,169,883	550 65,965,012

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

– Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
– Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

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SCHEDULE 515

ONTARIO CAPITAL TAX ON OTHER THAN FINANCIAL INSTITUTIONS

Name of corporation	Business Number	Tax year-end Year Month Day
West Perth Power Inc.	86922 9377 RC0001	2010-12-31

- Complete this schedule for a corporation with a permanent establishment in Ontario at any time in the tax year and that is a corporation other than a financial institution. The Ontario capital tax on other than financial institutions is levied under section 64 of the *Taxation Act, 2007* (Ontario).
- The Ontario capital tax is eliminated effective July 1, 2010. You do not have to complete this schedule if the corporation's tax year begins after June 30, 2010. For businesses mainly engaged in qualifying manufacturing and resource activities in Ontario, the capital tax is eliminated effective January 1, 2007.
- To complete this schedule, you have to complete Schedule 33, *Part I.3 Tax on Large Corporations* (renamed *Taxable Capital Employed in Canada – Large Corporations* for 2010 and later tax years). File completed copies of both schedules with the *T2 Corporation Income Tax Return* within six months of the end of the tax year.
- A corporation is exempt from Ontario capital tax if it was one of the following:
  1) a corporation that is liable to the special additional tax according to section 74 of the *Corporations Tax Act* (Ontario);
  2) a credit union;
  3) a deposit insurance corporation according to section 137.1 of the federal *Income Tax Act*;
  4) a family farm corporation for the year as defined by subsection 64(3) of the *Taxation Act*, 2007 (Ontario), other than a corporation for which a determination has been made under subsection 31(2) of the federal Act;
  5) a family fishing corporation, as defined by subsection 64(3) of the *Taxation Act, 2007* (Ontario); or
  6) a corporation exempt from income tax according to section 149 of the federal Act.

Part 1 – Taxable capital of a corporation resident in Canada other than a financial institution

	Line	Amount		
Amount A from Part 1 of Schedule 33	100	3,369,459		
Add:				
Accumulated other comprehensive income at the end of the year	105			
Subtotal		3,369,459	3,369,459	A
Deduct:				
Amount B from Part 1 of Schedule 33	110	668,694		
Amount on line 490 from Part 2 of Schedule 33	115	611,029		
Subtotal		1,279,723	1,279,723	B
Taxable capital (amount A **minus** amount B) (if negative, enter "0")	120		2,089,736	

Part 2 – Capital deduction

Complete this part only if the corporation is associated.

Are you electing under subsection 83(2) of the *Taxation Act, 2007* (Ontario)? **190** 1 Yes [X] 2 No [ ]

If you answered **no** to the question at line 190, complete line 220. If you answered **yes** to the question at line 190, complete line 305 by using Schedule 516, *Capital Deduction Election of Associated Group for the Allocation of Net Deduction*, to calculate the amount to be entered on line 300.

Taxable capital (from line 120) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (from line 790 in Part 4 of Schedule 33) **200** ______
divided by
Taxable capital or taxable capital employed in Canada of every corporation with a permanent establishment in Canada and associated for the last tax year * **210** ______
x 15,000,000 $ = **Capital deduction** **220** ______

* This amount includes the filing corporation's taxable capital or taxable capital employed in Canada. Do not include an amount from a financial institution or corporation that is exempt from capital tax under Division E of the *Taxation Act, 2007* (Ontario) or Part III of the *Corporations Tax Act* (Ontario).

Allocation of net deduction (from line 600 for the filing corporation from Schedule 516) **300** ______
divided by
Ontario allocation factor (OAF) (amount I in Part 3) 1.00000
= **Capital deduction** **305** ______

Part 3 – Ontario capital tax payable

Taxable capital (enter amount from line 120 in Part 1) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (enter amount from line 790 in Part 4 of Schedule 33), whichever applies	320	2,089,736	
Deduct:			
Capital deduction (Enter $15,000,000 if the corporation is not associated. Otherwise, enter the amount from line 220 or line 305, whichever applies, from Part 2)			B
Net amount (line 320 **minus** amount B) (if negative, enter "0")		2,089,736	C

Note: For days in the tax year after June 30, 2010, the Ontario capital tax rate is 0%.

Amount C 2,089,736 x (Number of days in the tax year before January 1, 2010 / Number of days in the tax year) ____ / 365 x 0.00225 = ____ D

Amount C 2,089,736 x (Number of days in the tax year after December 31, 2009 and before July 1, 2010 / Number of days in the tax year) 181 / 365 x 0.00150 = 1,554 E

Subtotal (amount D **plus** amount E) 1,554 F

Amount F 1,554 x OAF (amount on line I) 1.00000 = 1,554 G

Amount G 1,554 x (Number of days in the tax year * / 365) 365 / 365 = 1,554 H

Deduct:

Capital tax credit for manufacturers (enter amount J from Part 4) 350 ____

Ontario capital tax payable (amount H **minus** line 350) (if negative, enter "0") 400 1,554

Enter amount from line 400 on line 282 of Schedule 5, *Tax Calculation Supplementary - Corporations*.

* Enter either 365 if there are at least 51 weeks in the tax year, or the number of days in the year, whichever applies.

Calculation of the Ontario allocation factor (OAF)

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line I.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation and enter the result on line I:

Ontario taxable income ** / Taxable income *** ____ = ____

Ontario allocation factor 1.00000 I

** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*** Enter the taxable income amount from line 360 or line Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – Capital tax credit for manufacturers

Ontario manufacturing labour cost* (405) / Total Ontario labour cost** (410) ____ x 100 = 420 ____ %

If the percentage on line 420 is 20% or less, enter "0" on line J.

If the percentage on line 420 is at least 50%, enter amount H from Part 3 on line J.

If the percentage on line 420 is more than 20% but less than 50%, complete the following calculation and enter the result on line J:

(percentage from line 420) – 20% / 30% ____ % / 30 % x 1,554 Amount H from Part 3 = ____

Capital tax credit for manufacturers ____ J

Enter amount J on line 350 in Part 3.

* As defined in subsection 83.1(4) of the *Taxation Act, 2007* (Ontario)

** As defined in subsection 83.1(5) of the *Taxation Act, 2007* (Ontario)

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SCHEDULE 516

CAPITAL DEDUCTION ELECTION OF ASSOCIATED GROUP FOR THE ALLOCATION OF NET DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
West Perth Power Inc.	86922 9377 RC0001	2010-12-31

- Complete this schedule to allocate the associated group's net deduction for the capital deduction election under subsection 83(2) of the *Taxation Act, 2007* (Ontario). The associated group includes the filing corporation (see line 190 of Part 2 of Schedule 515, *Ontario Capital Tax on Other than Financial Institutions*).
- If you need more space, attach more schedules.
- File this schedule with the *T2 Corporation Income Tax Return*.

	A Names of eligible corporations in the associated group 100	B Business Number of associated corporations (enter "NR" if a corporation is not registered) 200	C Ontario allocation factor (OAF)* (enter as a percentage) 300	D Total assets** 400	E Net deduction ($15 million x line 300) **multiplied** by line 400 / line 700 500	F Allocation of net deduction *** 600
1.	West Perth Power Inc.	86922 9377 RC0001	100.000	5,000,961	671,439	
2.	Erie Thames Powerlines Corporation	86371 9498 RC0001	100.000	28,656,017	3,847,412	
3.	Coulter Water Meter Service Inc.	10117 1486 RC0002	100.000	1,283,896	172,378	1,067,115
4.	ERTH Corporation	86356 4324 RC0001	100.000	35,640,589	4,785,174	1,387,718
5.	CRU Solutions Inc.	86371 9696 RC0001	100.000	7,635,968	1,025,220	2,623,084
6.	Utilismart Corporation	86443 9450 RC0001	100.000	2,834,958	380,627	
7.	Enerconnect Inc.	87367 1499 RC0001	100.000	1,457,122	195,636	
8.	Wattsworth Analysis Inc.	87746 8108 RC0001	100.000	597,624	80,238	
9.	Enermajica Ontario Inc.	88660 6409 RC0001	100.000	290,932	39,061	
10.	ERTH360 Generation & Consulting Inc.	82960 2226 RC0001	100.000	251,277	33,737	37,113
11.	Ecaliber (Canada) Inc.	82954 1895 RC0001	100.000	3,786,979	508,447	4,404,486
12.	The SPI Group Inc.	87013 2917 RC0001	100.000	6,994,745	939,128	4,160,526
13.	ERTH (Holdings) Inc.	82642 4293 RC0002	100.000	14,106,975	1,894,030	1,319,958
14.	ERTH Limited	83794 3117 RC0001				
15.	Clinton Power Corporation	86985 8779 RC0001	100.000	3,183,875	427,473	

Total assets of associated group (total of amounts in column D) 700 111,721,918

Total net deduction (total of amounts in column E) 800 15,000,000

Total allocated net deduction (total of amounts in column F) (not to exceed amount on line 800) 900 15,000,000

* OAF from the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends.

** Total assets of each corporation in the associated group as recorded in the books and records for the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends. If the corporation is not resident in Canada, enter the amount of its total assets situated in Canada.

*** Enter the amount from this column allocated to the filing corporation on line 300 of Schedule 515.

Ex.	Tab	Schedule	Contents of Schedule
5 – Cost of Capital and Rate of Return			
	1	1	Overview
		2	Capital Structure
		3	Cost of Debt

Overview:

The purpose of this evidence is to summarize the method and cost of financing capital requirements for the 2012 test year.

CAPITAL STRUCTURE AND COST OF CAPITAL

CAPITAL STRUCTURE

Erie Thames has used the Ontario Energy Board's (the "**Board**") deemed capital structure of 56% long-term debt, 4% short-term debt and 40% common equity for the purpose of this Cost of Service Application. The weighted average cost of capital is 6.6568% on a capital amount of $32,082,258 for a capital cost of $2,135,652. This is consistent with the structure set out in the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* ("**Board Report on CoC and IRM**") dated December 20, 2006 and it is also consistent with Erie Thames's past and current practices. The actual total debt to equity ratio is approximately 53%/47%.

Since the 2008 cost of service rate application, EB-2007-0928, there are a number of changes that have occurred to change the capital structure and the cost of capital. Downward pressure on the cost of capital includes the reduction in deemed equity from 46.7% to 40.0% and the reduction in the cost of both short and long term debt. The applied for short term debt is 2.08% as compared to 4.47% in EB-2007-0928 and an applied for rate of 5.01% for long-term debt as compared to 5.92%.

Upward pressure on the cost of capital has resulted from the increase of 0.85% in the deemed return on equity set by the Board on the 40% equity component. In addition, upward pressures results from the merger of Erie Thames with West Perth Power Inc. and Clinton Power Corporation which increased the total capital of the merged entity; the increase in capital spending; and the additional capital assets that were acquired from a related entity as part of the corporate restructuring following the 2009 strike.

Table 6-1 – Comparison of Summary of Capital Structure and Rates

	EB-2007-0928 Board Approved	2012 Application	EB-2007-0928 Rate	Application Rate
Short Term Debt	4%	4%	4.47%	2.08%
Long Term Debt	49.3%	56%	5.92%	5.01%
Equity	46.7%	40%	8.57%	9.42%
Total	**100%**	**100%**	**7.10%**	**6.66%**

Short Term Debt

Erie Thames has bank facilities with an unrelated major financial institution. For the purposes of the cost of service application test year, Erie Thames has used a forecast of 2.08% for the short term debt rate based on the deemed short term debt rate for 2012 cost of service applications as communicated in the March 2, 2012 letter from the Board. It is recognized that this rate will be updated, if necessary, at the time of the rate decision to reflect the current rate in effect as per the calculations and terms outlined in the December 11, 2009 "*Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*".

Long Term Debt

Erie Thames is using the Board's deemed long-term debt rate of 4.41% as set out in the March 2, 2012 letter. Long term debt is comprised of unrelated and related party debt and long-term capital leases.

The related long-term debt represents amounts, in total $8,038,524, owing to the municipal shareholders the Erie Thames parent ERTH Corporation for purchase of the respective Municipality's Hydro Electric Commission's net assets. The actual rate of interest is currently

7.25% and is set by the Board of Directors, from time to time. There are no fixed repayment terms associated with the principle outstanding and no principal amounts are anticipated to be paid over the next twelve months. The loan is secured by a second position General Security Agreement covering accounts receivable, inventory and equipment, including motor vehicles.

The capital lease obligations of five Freightliner bucket trucks and a backhoe were assumed by Erie Thames Powerlines from CRU Solutions Inc. in 2010. The vehicles are being leased, under a capital lease, for a period of six to seven years on various contracts that began between 2005 to 2011. The interest rate imputed in these leases range from 2.5%-8.8%.

Preference Shares

Erie Thames does not currently have any preference shares issued nor has it forecast for any issuance for the test year.

Common Equity

For the purposes of the Cost of Service Application test year, Erie Thames has used the deemed return on equity for 2011 cost of service applications of 9.12% as communicated in the March 2, 2012 letter from the Board. It is recognized that this rate will be updated at the time of the rate decision to reflect the current rate in effect as per the calculations and terms outlined in the December 11, 2009 "*Report of the Board on* 13 *the Cost of Capital for Ontario's Regulated Utilities*".

EB-2007-0928

In EB-2007-0928, Board approved a capital structure of 46.7% equity with a deemed return of 8.57%; short-term debt of 4% at a rate of 4.47%; and long-term debt of 49.3% at 5.92%. This resulted in an overall cost of capital of 7.10%.

Table 6-2 - EB-2007-0928 Board Approved

Board-approved 2008 Capital Structure and Cost of Capital Capital Component	**% of Total Capital Structure**	**Cost (%)**
Short-Term Debt	4.0	4.47%
Long-Term Debt	49.3	5.92%
Equity	46.7	8.57%
Preference Shares	-	
Total	**100.0**	**7.10%**

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BY E-MAIL AND WEB POSTING

November 10, 2011

To: All Licensed Electricity Distributors and Transmitters
All Gas Distributors
Ontario Power Generation Inc.
All Registered Intervenors in 2012 Cost of Service Applications

Re: Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective January 1, 2012

The Ontario Energy Board (the "Board") has determined the values for the Return on Equity ("ROE") and the deemed Long-Term ("LT") and Short-Term ("ST") debt rates for use in the 2012 rate year cost of service applications for rates effective January 1, 2012. The ROE and the LT and ST debt rates are collectively referred to as the Cost of Capital parameters. The updated Cost of Capital parameters are calculated based on the formulaic methodologies documented in the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (the "Report"), issued December 11, 2009. The Board considers the Cost of Capital parameter values shown in the table that follows, and the relationships between them, reasonable and representative of market conditions at this time.

Cost of Capital parameters for rates effective January 1, 2012

Based on the methodologies set out in the Report and September 2011 data from the Bank of Canada, *Consensus Forecasts* and Bloomberg LLP, the Board has determined that the updated Cost of Capital parameters for 2012 cost of service rate applications for rates effective January 1, 2012 are:

Cost of Capital Parameter	**Value for 2012 Cost of Service Applications for January 1, 2012 rate changes**
ROE	9.42%
Deemed LT Debt rate	5.01%
Deemed ST Debt rate	2.08%

Detailed calculations of the Cost of Capital parameters are attached.

Every year, the Board updates the Cost of Capital parameters for use in setting rates for natural gas and electricity utilities for the coming rate year. The Board has normally updated the parameters once each year for rates effective May 1. Beginning in 2011, in light of certain applications requesting and approved for January 1 effective dates for rate changes, the Board advanced its determination of the values for the Cost of Capital parameters based on the data available three months in advance of the January 1, 2011 date. On November 15, 2010, the Board issued a letter announcing updated Cost of Capital parameters for rates effective January 1, 2011. Also in that letter the Board stated that cost of service applications with rates effective May 1, 2011 would have updated Cost of Capital parameters based on data for January 2011. The Board is continuing this approach of calculating and publishing updated Cost of Capital parameters at least twice a year, for effective dates for rates of January 1 and May 1.

For rates with effective dates in 2012, beginning with January 1, 2012, the Board has updated the Deemed ST Debt rate parameters based on: (i) the September 2011 survey from Canadian banks for the spread over the Bankers' Acceptance rate of 3-month short-term loans for R1-low commercial customers for the short-term debt rate; and (ii) data for three months prior to the effective date of January 1, 2012 from the Bank of Canada, *Consensus Forecasts*, and Bloomberg LLP, per the methodologies documented in the Report.

Updated Cost of Capital parameters for rates effective May 1, 2012 will be published once data for January 2012 become available.

All queries on the Cost of Capital parameters should be directed to the Board's Market Operations hotline, at 416 440-7604 or market.operations@ontarioenergyboard.ca.

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

Attachment

Ontario Energy Board
Commission de l'Énergie de l'Ontario

Attachment: Cost of Capital Parameter Calculations

(assuming January 1, 2012 effective date for rate changes)

Return on Equity and Deemed Long-term Debt Rate

Step 1: Analysis of Business Day Information in the Month

Month: September 2011

		Bond Yields (%)			Bond Yield Spreads (%)	
		Government of Canada		A-rated Utility	30-yr Govt over 10-yr Govt	30-yr Util over 30-yr Govt
	Day	10-yr	30-yr	30-yr		
1	1-Sep-11	2.39	3.04	4.62	0.65	1.58
2	2-Sep-11	2.30	2.96	4.55	0.66	1.59
3	3-Sep-11					
4	4-Sep-11					
5	5-Sep-11	2.30	2.96	4.55	0.66	1.59
6	6-Sep-11	2.24	2.92	4.51	0.68	1.59
7	7-Sep-11	2.27	2.95	4.54	0.68	1.59
8	8-Sep-11	2.21	2.89	4.50	0.68	1.61
9	9-Sep-11	2.11	2.81	4.41	0.70	1.60
10	10-Sep-11					
11	11-Sep-11					
12	12-Sep-11	2.14	2.81	4.39	0.67	1.58
13	13-Sep-11	2.20	2.84	4.43	0.64	1.59
14	14-Sep-11	2.20	2.85	4.44	0.65	1.58
15	15-Sep-11	2.30	2.92	4.55	0.62	1.63
16	16-Sep-11	2.29	2.93	4.54	0.64	1.61
17	17-Sep-11					
18	18-Sep-11					
19	19-Sep-11	2.19	2.87	4.46	0.68	1.59
20	20-Sep-11	2.20	2.86	4.44	0.67	1.58
21	21-Sep-11	2.12	2.77	4.37	0.64	1.61
22	22-Sep-11	2.02	2.68	4.32	0.66	1.64
23	23-Sep-11	2.08	2.71	4.28	0.63	1.58
24	24-Sep-11					
25	25-Sep-11					
26	26-Sep-11	2.15	2.77	4.37	0.62	1.60
27	27-Sep-11	2.20	2.83	4.43	0.63	1.61
28	28-Sep-11	2.20	2.83	4.47	0.63	1.65
29	29-Sep-11	2.22	2.84	4.51	0.62	1.67
30	30-Sep-11	2.16	2.77	4.41	0.62	1.64
31						
		2.20	2.85	4.46	**0.652**	**1.605**
	Sources:	*Bank of Canada*		*Bloomberg L.P.*	❶	❷

Step 2: 10-Year Government of Canada Bond Yield Forecast

Source: *Consensus Forecasts*	Publication Date:	September 12, 2011		
	3-month	12-month		Average
September 2011	2.600	2.900	❸	**2.750** %

Step 3: Long Canada Bond Forecast

10 Year Government of Canada Concensus Forecast (from Step 2)	③	2.750 %
Actual Spread of 30-year over 10-year Government of Canada Bond Yield (from Step 1)	①	0.652 %
Long Canada Bond Forecast (LCBF)	❹	**3.402** %

Step 4: Return on Equity (ROE) forecast

Initial ROE			9.75 %
Change in Long Canada Bond Yield Forecast from September 2009			
LCBF (September 2011) (from Step 3)	④	3.402 %	
Base LCBF		4.250 %	
Difference		-0.848 %	
0.5 X Difference			-0.424 %
Change in A-rated Utility Bond Yield Spread from September 2009			
A-rated Utility Bond Yield Spread (September 2011) (from Step 1)	②	1.605 %	
Base A-rated Utility Bond Yield Spread		1.415 %	
Difference		0.190 %	
0.5 X Difference			0.095 %
Return on Equity based on September 2011 data			**9.42** %

Step 5: Deemed Long-term Debt Rate Forecast

Long Canada Bond Forecast for September 2011 (from Step 3)	④	3.402 %
A-rated Utility Bond Yield Spread September 2011 (from Step 1)	②	1.605 %
Deemed Long-term Debt Rate based on September 2011 data		**5.01** %

References on Calculation Methods:

- **Return on Equity**: Appendix B of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009.
- **Deemed Long-term Debt Rate**: Appendix C of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009.

Ontario Energy Board
Commission de l'Énergie de l'Ontario

Attachment: Cost of Capital Parameter Calculations
(assuming January 1, 2012 effective date for rate changes)

Deemed Short-term Debt Rate

Step 1: Average Annual Spread over Bankers Acceptance

Once a year, in January, Board staff contacts prime Canadian banks to get estimates for the spread of short-term (typically 90-day) debt issuances over Bankers' Acceptance rates. Up to six estimates are provided.

A.	over 90-day Bankers Acceptance		Date of input
Bank 1	85.0	bps	Sept., 2011
Bank 2	87.5	bps	Sept., 2011
Bank 3	100.0	bps	Sept., 2011
Bank 4	85.0	bps	Sept., 2011
Bank 5	100.0	bps	Sept., 2011
Bank 6			

B. Discard high and low estimates
If less than 4 estimates, take average without discarding high and low.

Number of estimates	5	
High estimate	100.0	bps
Low estimate	85.0	bps

C. Average annual Spread	90.833	bps	❶

Step 3: Deemed Short-Term Debt Rate Calculation

Calculate Deemed Short-term debt rate as sum of average annual spread (Step 1) and average 3-month Bankers' Acceptance Rate (Step 2)

Average Annual Spread	0.908	%	①
Average Bankers' Acceptance Rate	1.173	%	②
Deemed Short Term Debt Rate	**2.08**	%	

Step 2: Average 3-month Bankers' Acceptance Rate

Calculation of Average 3-month Bankers' Acceptance Rate during month of September 2011

Month:		**September 2011**
	Day	**Bankers' Acceptance Rate (%) 3-month**
1	1-Sep-11	1.17 %
2	2-Sep-11	1.17 %
3	3-Sep-11	
4	4-Sep-11	
5	5-Sep-11	
6	6-Sep-11	1.17 %
7	7-Sep-11	1.17 %
8	8-Sep-11	1.17 %
9	9-Sep-11	1.17 %
10	10-Sep-11	
11	11-Sep-11	
12	12-Sep-11	1.17 %
13	13-Sep-11	1.17 %
14	14-Sep-11	1.17 %
15	15-Sep-11	1.17 %
16	16-Sep-11	1.17 %
17	17-Sep-11	
18	18-Sep-11	
19	19-Sep-11	1.17 %
20	20-Sep-11	1.18 %
21	21-Sep-11	1.19 %
22	22-Sep-11	1.18 %
23	23-Sep-11	1.18 %
24	24-Sep-11	
25	25-Sep-11	
26	26-Sep-11	1.18 %
27	27-Sep-11	1.17 %
28	28-Sep-11	1.17 %
29	29-Sep-11	1.17 %
30	30-Sep-11	1.17 %
31		
		1.173 % ❷

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Series V39071

Reference on Calculation Method:
• Appendix D of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009.

OVERVIEW OF CALCULATION OF REVENUE DEFICIENCY OR SURPLUS

The information in this Exhibit supports Erie Thames Powerlines' request in this Application for an increase in its 2012 Revenue Requirement. Erie Thames Powerlines requires a distribution revenue requirement of $9,173,991 (proposed revenue of $10,107,049 less other revenue of $933,058) to continue to provide its customers a safe reliable supply of electricity, service its debt and pay its deemed PILS ($517,163).

Erie Thames Powerliness target return on Rate Base is calculated using 40% of Rate Base with a target Return on Rate base of $1,165,091 (based on Equity return of 9.42%). Utilizing current rates and 2012 forecasted customer data Erie Thames Powerlines would expect $8,403,654 in distribution revenue which creates a revenue deficiency of $609,251 (no gross up for tax purposes due to loss carry forwards).

Erie Thames Powerlines's 2010 revenue deficiency is outlined in detail below in the Determination of Net Utility Income Table.

DETERMINATION OF NET UTILITY INCOME

Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates
Revenue Deficiency from Below		$609,251
Distribution Revenue	$8,403,654	$8,564,740
Other Operating Revenue Offsets - net	$933,058	$933,058
Total Revenue	$9,336,712	$10,107,049
Operating Expenses	$7,531,559	$7,531,559
Deemed Interest Expense	$893,236	$893,236
Total Cost and Expenses	$8,424,795	$8,424,795
Utility Income Before Income Taxes	$911,917	$1,682,254
Tax Adjustments to Accounting Income per 2009 PILs	$ -	$ -
Taxable Income	$911,917	$1,682,254
Income Tax Rate	23.41%	23.41%
Income Tax on Taxable Income	$213,463	$393,784
Income Tax Credits	$ -	$ -
Utility Net Income	$698,455	$1,165,091
Utility Rate Base	$30,920,674	$30,920,674
Deemed Equity Portion of Rate Base	$12,368,270	$12,368,270
Income/(Equity Portion of Rate Base)	5.65%	9.42%
Target Return - Equity on Rate Base	9.42%	9.42%
Deficiency/Sufficiency in Return on Equity	-3.77%	0.00%
Indicated Rate of Return	5.15%	6.66%
Requested Rate of Return on Rate Base	6.66%	6.66%
Deficiency/Sufficiency in Rate of Return	-1.51%	0.00%
Target Return on Equity	$1,165,091	$1,165,091
Revenue Deficiency/(Sufficiency)	$466,636	$ -
Gross Revenue Deficiency/(Sufficiency)	$609,251 **(1)**	

COST ALLOCATION OVERVIEW

Introduction:

In a staff discussion paper released on November 28, 2007, Board Staff provided some guidelines on both the allocation of costs and on general fixed-variable rate design.

These guidelines provide for target band-widths for individual customer class revenue-to-cost ratios as well as some guidance on fixed pricing.

Board staff suggested the following generic guidelines starting on page 8 of the Nov. 28 document, note any value below 100% is a subsidization received and anything above 100% is subsidization towards other classes:

- Residential Class
  - Revenue to cost ratios between 85% and 115%
- General Service < 50 kW
  - Revenue to cost ratios between 80% and 120%
- Unmetered Scattered Load
  - Revenue to cost ratios between 80% and 120%
- General Service > 50 to 4,999 kW
  - Revenue to cost ratios between 80% and 180%
- Street Light
  - Revenue to cost ratios between 70% to 120%

Specific Approval Requests:

Erie Thames Powerlines is requesting the following revenue allocations based on allocations from its Cost Allocation Filing with adjustments for the Street Light and Sentinel Light classes:

- Residential Class
  - Revenue Allocation = 56.86%
- General Service < 50 kW
  - Revenue Allocation = 13.60%
- General Service 50 to 999 kW
  - Revenue Allocation = 13.43%
- General Service 1,000 to 4,999 kW
  - Revenue Allocation = 5.10%
- Large User
  - Revenue Allocation = 3.35%
- Street Light
  - Revenue Allocation = 4.39%
- Sentinel Light
  - Revenue Allocation = 0.36%
- Unmetered Scattered Load
  - Revenue Allocation = 0.97%
- Embedded Distributor
  - Revenue Allocation = 1.95%

Erie Thames Powerlines
Rate Design - Revenue to Cost Ratios Existing Rate Classes
Wednesday, April 11, 2012
Verson 1

	Residential	GS < 50	GS>50 to 999 kW	GS>1000 to 2999 kW	GS>3000 kW to 4999 kW	Large Use	Sentinel Lighting	Street Light	Embedded	Unmetered
2012 CA Revenue to Cost %	105.49%	93.69%	85.72%	103.85%	92.93%	119.13%	74.44%	104.03%	69.99%	28.74%
Board Staff Min RC%	85.00%	80.00%	80.00%	80.00%	80.00%	80.00%	70.00%	70.00%	70.00%	80.00%
Board Staff Max RC%	115.00%	120.00%	180.00%	180.00%	180.00%	180.00%	120.00%	120.00%	180.00%	120.00%
2012 DRR Current Rates	4,868,699	1,016,184	926,213	444,668	43,490	349,473	20,837	385,197	114,965	13,889
2012 Misc. Revenue	597,067	130,812	98,451	35,404	3,355	17,262	2,742	31,623	4,399	11,941
2012 Total Revenue Current Rates	5,465,766	1,146,996	1,024,664	480,072	46,845	366,735	23,579	416,820	119,364	25,830
	0.00%	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**51.26%**
Minimum Adjustment										
Current RC%	105.49%	93.69%	85.72%	103.85%	92.93%	119.13%	74.44%	104.03%	69.99%	28.74%
Min RC%	85.00%	80.00%	80.00%	80.00%	80.00%	80.00%	70.00%	70.00%	70.00%	80.00%
Max RC%	115.00%	120.00%	180.00%	180.00%	180.00%	180.00%	120.00%	120.00%	180.00%	120.00%
2006 Total Revenue	5,465,766	1,146,996	1,024,664	480,072	46,845	366,735	23,579	416,820	119,364	25,830
Min Adjustment	-	-	-	-	-			-	-	82,010
2006 Min Adjusted Total Revenue	5,465,766	1,146,996	1,024,664	480,072	46,845	366,735	23,579	416,820	119,364	107,840
Allocation of Balance	(49,308)	(10,347)	(9,244)	(4,331)	(423)	(3,308)	(213)	(3,760)	(1,077)	
2006 Adjusted Total Revenue	5,416,458	1,136,649	1,015,420	475,741	46,422	363,427	23,366	413,060	118,287	107,840
2006 Total Revenue %	59.41%	12.47%	11.14%	5.22%	0.51%	3.99%	0.26%	4.53%	1.30%	1.18%
2012 Total Revenue	6,004,868	1,260,127	1,125,729	527,423	51,465	402,907	25,905	457,932	131,137	119,556
less: 2009 Misc. Rev. Projection	554,353	116,331	103,924	48,690	4,751	37,195	2,391	42,275	12,106	11,037
2009 Min Adustment BRR	5,450,515	1,143,796	1,021,805	478,732	46,714	365,712	23,513	415,657	119,031	108,519
New BRR%	**59.41%**	**12.47%**	**11.14%**	**5.22%**	**0.51%**	**3.99%**	**0.26%**	**4.53%**	**1.30%**	**1.18%**
100% DRR Adjustment										
2012 Total Revenue Current Rates	5,465,766.00	1,146,996.00	1,024,664.00	480,072.00	46,845.00	366,735.00	23,579.00	416,820.00	119,364.00	25,830.00
2012 Total Revenue @ 100% RC	5,181,480.44	1,224,292.90	1,195,309.61	462,292.91	50,410.25	307,835.18	31,677.07	400,669.91	170,536.39	89,867.04
2012 Current Rates Total Revenue %	56.85%	13.43%	13.11%	5.07%	0.55%	3.38%	0.35%	4.40%	1.87%	0.99%
2012 Total Revenue	5,745,813	1,357,635	1,325,495	512,643	55,901	341,363	35,127	444,308	189,110	99,655
less: 2009 Misc. Rev. Projection	554,353	116,331	103,924	48,690	4,751	37,195	2,391	42,275	12,106	11,037
2012 100% RC BRR	5,191,460	1,241,303	1,221,571	463,953	51,149	304,167	32,736	402,033	177,004	88,618
New BRR %	**56.59%**	**13.53%**	**13.32%**	**5.06%**	**0.56%**	**3.32%**	**0.36%**	**4.38%**	**1.93%**	**0.97%**
Actual Applied for RC Ratio	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

As detailed in the above table Erie Thames Powerlines utilized its revenue to cost ratios from its cost allocation model utilizing its existing classes (included with the application) to determine the minimum adjustment required to ensure that each rate class's applied for revenue allocations falls within the bandwidth provided by The Board.

Erie Thames Powerlines is proposing to bring all of its rate classes to 100% of their Cost allocation from the updated Cost allocation model included in this application. Erie Thames Powerlines is also proposing to merge the GS>1,000 to 2,999 and GS>3,000 to 4,999 kW classes and is also providing a Cost allocation model detailing this change within in the application. The resulting RC ratios and revenue allocations from merging these two rate classes are detailed in the following table.

Erie Thames Powerlines
Rate Design - Revenue to Cost Ratios
Wednesday, April 11, 2012
Verson 1

	Residential	GS < 50	GS>50 to 999 kW	GS>1000 to 4999 kW	Large Use	Sentinel Lighting	Street Light	Embedded	Unmetered
2012 CA Revenue to Cost %	105.56%	93.77%	85.45%	85.45%	103.38%	74.36%	103.85%	69.57%	28.70%
Board Staff Min RC%	85.00%	80.00%	80.00%	80.00%	80.00%	70.00%	70.00%	70.00%	80.00%
Board Staff Max RC%	115.00%	120.00%	180.00%	180.00%	180.00%	120.00%	120.00%	180.00%	120.00%
2012 DRR Current Rates	4,868,699	1,016,184	926,213	444,668	349,473	20,837	385,197	114,965	13,889
2012 Misc. Revenue	597,067	130,812	98,451	35,404	17,262	2,742	31,623	4,399	11,941
2012 Total Revenue Current Rates	5,465,766	1,146,996	1,024,664	480,072	366,735	23,579	416,820	119,364	25,830
	0.00%	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**51.30%**
Minimum Adjustment									
Current RC%	105.56%	93.77%	85.45%	85.45%	103.38%	74.36%	103.85%	69.57%	28.70%
Min RC%	85.00%	80.00%	80.00%	80.00%	80.00%	70.00%	70.00%	70.00%	80.00%
Max RC%	115.00%	120.00%	180.00%	180.00%	180.00%	120.00%	120.00%	180.00%	120.00%
2006 Total Revenue	5,465,766	1,146,996	1,024,664	480,072	366,735	23,579	416,820	119,364	25,830
Min Adjustment	-	-	-	-			-	-	82,184
2006 Min Adjusted Total Revenue	5,465,766	1,146,996	1,024,664	480,072	366,735	23,579	416,820	119,364	108,014
Allocation of Balance	(49,668)	(10,423)	(9,311)	(4,362)	(3,333)	(214)	(3,788)	(1,085)	
2006 Adjusted Total Revenue	5,416,098	1,136,573	1,015,353	475,710	363,402	23,365	413,032	118,279	108,014
2006 Total Revenue %	59.72%	12.53%	11.19%	5.24%	4.01%	0.26%	4.55%	1.30%	1.19%
2012 Total Revenue	6,035,482	1,266,551	1,131,468	530,112	404,961	26,037	460,267	131,806	120,366
less: 2009 Misc. Rev. Projection	557,181	116,925	104,454	48,939	37,385	2,404	42,491	12,168	11,112
2009 Min Adustment BRR	5,478,301	1,149,626	1,027,014	481,173	367,576	23,633	417,776	119,638	109,254
New BRR%	**59.72%**	**12.53%**	**11.19%**	**5.24%**	**4.01%**	**0.26%**	**4.55%**	**1.30%**	**1.19%**
100% DRR Adjustment									
2012 Total Revenue Current Rates	5,465,766.00	1,146,996.00	1,024,664.00	480,072.00	366,735.00	23,579.00	416,820.00	119,364.00	25,830.00
2012 Total Revenue @ 100% RC	5,177,777.09	1,223,205.75	1,199,071.84	561,784.95	354,730.01	31,708.07	401,349.36	171,584.96	90,011.34
2012 Current Rates Total Revenue %	56.21%	13.28%	13.02%	6.10%	3.85%	0.34%	4.36%	1.86%	0.98%
2012 Total Revenue	5,681,335	1,342,167	1,315,686	616,421	389,229	34,792	440,382	188,272	98,765
less: 2009 Misc. Rev. Projection	557,181	116,925	104,454	48,939	37,385	2,404	42,491	12,168	11,112
2012 100% RC BRR	5,124,154	1,225,242	1,211,232	567,482	351,844	32,388	397,891	176,104	87,653
New BRR %	**55.86%**	**13.36%**	**13.20%**	**6.19%**	**3.84%**	**0.35%**	**4.34%**	**1.92%**	**0.96%**
Actual Applied for RC Ratio	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

Summary of Results and Proposed Changes

Erie Thames Powerlines Customer Impacts

Class	Consumption kWh	Consumption kW	May 2011 Bill	May 2012 Bill	Difference $	Bill Impact %	Max	Min
Residential	100		$ 26.28	$ 25.66	$ (0.62)	-2.37%	-1.9%	-3.8%
	250		$ 41.80	$ 41.02	$ (0.78)	-1.87%		
	500		$ 67.67	$ 65.73	$ (1.94)	-2.87%		
Average Customer	750		$ 93.55	$ 90.45	$ (3.10)	-3.31%		
	1,000		$ 119.42	$ 115.16	$ (4.26)	-3.57%		
	1,500		$ 171.16	$ 164.58	$ (6.58)	-3.84%		
General Service Less Than 50 kW	1,000		$ 120.00	$ 121.08	$ 1.09	0.9%	0.9%	-0.5%
	1,500		$ 170.74	$ 170.60	$ (0.14)	-0.1%		
Average Customer	2,000		$ 220.64	$ 220.12	$ (0.51)	-0.2%		
	5,000		$ 520.00	$ 517.24	$ (2.76)	-0.5%		
GS>50 to 999 kW	15,000	55	$ 1,159.03	$ 1,072.27	$ (86.76)	-7.5%	-7.5%	-10.9%
	20,000	125	$ 2,094.32	$ 1,875.92	$ (218.40)	-10.4%		
Average Customer	50,000	250	$ 4,169.04	$ 3,715.43	$ (453.61)	-10.9%		
	133,770	376	$ 7,288.11	$ 6,597.03	$ (691.09)	-9.5%		
GS>1000 to 4999 kW	150,000	1,000	$ 16,114.12	$ 16,312.64	$ 198.53	1.2%	1.2%	-0.8%
	200,000	1,250	$ 19,797.00	$ 19,914.76	$ 117.76	0.6%		
Average Customer	500,000	2,500	$ 39,171.43	$ 38,884.98	$ (286.45)	-0.7%		
	833,770	2,900	$ 49,936.33	$ 49,518.87	$ (417.46)	-0.8%		
Large Use	750,000	6,000	$ 126,343.58	$ 115,452.75	$ (10,890.83)	-8.6%	-8.6%	-8.6%
Unmetered Scattered Load - Avg Customer	100		$ 6.66	$ 24.45	$ 17.79	267.1%		
Street Lighting - Avg Customer	25	1	$ 24.83	$ 27.00	$ 2.16	8.7%		
Sentinel	50	1	$ 35.62	$ 10.79	$ (24.83)	-69.7%		
Embedded Distributor	280,000	2,000	$ 115,351.83	$ 117,797.35	$ 2,445.52	2.1%		

Clinton Power Corporation Customer Impacts

Class	Consumption kWh	Consumption kW	May 2011 Bill	May 2012 Bill	Difference $	Bill Impact %	Max	Min
Residential	100		$ 23.38	$ 26.27	$ 2.89	12.36%	12.4%	1.4%
	250		$ 38.33	$ 41.22	$ 2.89	7.54%		
	500		$ 63.36	$ 66.14	$ 2.77	4.37%		
Average Customer	750		$ 88.40	$ 91.05	$ 2.65	3.00%		
	1,000		$ 113.43	$ 115.96	$ 2.53	2.23%		
	1,500		$ 163.49	$ 165.79	$ 2.30	1.40%		
General Service Less Than 50 kW	1,000		$ 123.26	$ 117.36	$ (5.90)	-4.8%	-4.8%	-10.0%
	1,500		$ 183.35	$ 165.02	$ (18.33)	-10.0%		
Average Customer	2,000		$ 236.08	$ 212.68	$ (23.40)	-9.9%		
	5,000		$ 552.44	$ 498.63	$ (53.82)	-9.7%		
GS>50 to 999 kW	15,000	55	$ 864.13	$ 992.36	$ 128.23	14.8%	14.8%	-3.3%
	20,000	125	$ 1,636.01	$ 1,694.30	$ 58.29	3.6%		
Average Customer	50,000	250	$ 3,422.07	$ 3,352.19	$ (69.88)	-2.0%		
	133,770	376	$ 6,258.12	$ 6,050.72	$ (207.40)	-3.3%		
Unmetered Scattered Load - Avg Customer	600		$ 34.66	$ 131.29	$ 96.64	278.8%		
Street Lighting - Avg Customer	25	1	$ 20.89	$ 25.27	$ 4.37	20.9%		
Sentinel	50	1	$ 20.33	$ 11.17	$ (9.15)	-45.0%		

West Perth Power Customer Impacts

Class	Consumption kWh	Consumption kW	May 2011 Bill	May 2012 Bill	Difference $	Bill Impact %	Max	Min
Residential	100		$ 23.93	$ 26.77	$ 2.84	11.89%	11.9%	2.5%
	250		$ 38.06	$ 40.97	$ 2.91	7.63%		
	500		$ 61.52	$ 64.63	$ 3.11	5.06%		
Average Customer	750		$ 84.97	$ 88.29	$ 3.32	3.91%		
	1,000		$ 108.42	$ 111.95	$ 3.53	3.25%		
	1,500		$ 155.33	$ 159.27	$ 3.94	2.54%		
General Service Less Than 50 kW	1,000		$ 110.03	$ 117.28	$ 7.25	6.6%	6.6%	0.0%
	1,500		$ 158.57	$ 164.90	$ 6.33	4.0%		
Average Customer	2,000		$ 207.11	$ 212.52	$ 5.41	2.6%		
	5,000		$ 498.34	$ 498.22	$ (0.12)	0.0%		
GS>50 to 999 kW	15,000	55	$ 843.36	$ 744.47	$ (98.88)	-11.7%	-11.7%	-19.3%
	20,000	125	$ 1,386.06	$ 1,130.93	$ (255.13)	-18.4%		
Average Customer	50,000	250	$ 2,756.96	$ 2,225.45	$ (531.51)	-19.3%		
	133,770	376	$ 5,159.50	$ 4,356.10	$ (803.40)	-15.6%		
Unmetered Scattered Load - Avg Customer	600		$ 64.33	$ 131.52	$ 67.19	104.4%		
Street Lighting - Avg Customer	25	1	$ 26.49	$ 25.32	$ (1.16)	-4.4%		
Sentinel	50	1	$ 12.04	$ 23.23	$ 11.19	93.0%		

RATE DESIGN OVERVIEW - 2012 Rebasing Application

Erie Thames currently has in place rates reflecting the three prior entities, Erie Thames, WPPI and CPC. In this Application, it is proposed that the existing rate classification of Erie Thames be changed to reduce the number of GS classes. Further, Erie Thames is proposing to harmonize distribution rates across the ratepayers. It should be noted that rate riders will still be geographic area specific and as such, the total bill of all residential customers will vary slightly. The purpose of the geographic specific treatment LRAM and deferral and variance accounts to ensure fairness for historical costs and to mitigate the overall impact for customers.

In the November 28, 2007 Staff discussion paper section 4 recommends a range of the floor value equal to the class specific avoided costs and a ceiling value equal to 120% of the minimum system with PLCC adjustment outlined in the 2006 CA informational filing.

Below is a summary of the current and proposed fixed and variable charges for Erie Thames Powerlines. Note, these values include all applicable rate riders (e.g. Smart Meter Adder, Low Voltage Adder)

Customer Class	Current Service Charge	Current Volumetric Rate	Billing Determinant	Proposed Service Charge	Proposed Volumetric Rate	Billing Determinant
Residential	$ 14.19	$ 0.0144	kWh	$ 15.21	$ 0.0168	kWh
GS < 50 kW	$ 19.32	$ 0.0107	kWh	$ 20.94	$ 0.0173	kWh
GS>50 to 999 kW	$ 209.85	$ 5.6219	kW	$ 226.60	$ 4.2217	kW
GS>1000 kW to 4999 kW	$ 2,340.80	$ 3.1214	kW	$ 2,862.06	$ 3.6747	kW
Large Use	$ 9,934.69	$ 1.9245	kW	$ 10,715.28	$ 1.7778	kW
Sentinel Lighting	$ 5.20	$ 14.6906	kW	$ 5.10	$ 18.8735	kW
Street Lights	$ 3.77	$ 11.1243	kW	$ 3.72	$ 15.9885	kW
Unmetered	$ 2.81	$ 0.0135	kWh	$ 2.74	$ 0.1390	kWh
Embedded Distributor	$ 2,254.63	$ 1.6717	kW	$ 1,109.93	$ 5.9806	kW

Erie Thames Powerlines is proposing increases to all of its classes fixed charges to keep the fixed variable split consistent with the historical amounts.

The volumetric charges have been adjusted to account for the remaining changes to the allocated distribution revenue and applied for changes to the LV retail rates.

EXISTING RATE CLASSES

Residential

This classification refers to the supply of electrical energy to customers residing in residential dwelling units.

General Service Less than 50 kW

This classification refers to the supply of electrical energy to General Service Buildings requiring a connection with a connected load less than 50 kW, and, Town Houses and Condominiums described in section 3.1.8 of the distributor's Conditions of Service that require centralized bulk metering. General Service buildings are defined as buildings that are used for purposes other than single-family dwellings.

General Service 50 to 999 kW

This classification refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load or whose average monthly maximum demand used for billing purposes is equal to or greater than 50 kW but less than 1000 kW.

General Service 1000 to 2,999 kW

This classification refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load or whose average monthly maximum demand used for billing purposes is equal to or greater than 1000 kW but less than 3,000 kW.

General Service 3000 to 4,999 kW

This classification refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load or whose average monthly maximum demand used for billing purposes is equal to or greater than 3000 kW but less than 5,000 kW.

Large Use

This classification refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load or whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW.

Unmetered Scattered Load

This classification refers to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

Sentinel Lighting

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light.

Street Lighting

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

Embedded Distributor

This classification refers to an electricity distributor licensed by the Ontario Energy Board that is provided electricity by means of this distributor's facilities. Further servicing details are available in the distributor's Conditions of Service.

EXISTING RATE SCHEDULE

Erie Thames Powerlines Corporation
Tariff of Rates and Charges
Effective May 1, 2011

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

Residential	**UOM**	**Rate**
Service Charge	$	$14.1900
Smart Meter Charge	$	$1.7400
Late Payment Penalty Rate Rider Effective until April 30, 2012	$	$0.2100
Distribution Volumetric Rate	$/kWh	$0.0126
Low Voltage Service Rate	$/kWh	$0.0018
Rate Rider for Global Adjustment Sub-Account effective until April 30 2012	$/kWh	$0.0008
Rate Rider for Deferral/Variance Account Disposition effective until April 30 2012	$/kWh	$0.0012
Rate Rider for Tax Change effective until April 30 2012	$/kWh	-$0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	$0.0088
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	$0.0057
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500
GS<50 kW		
Service Charge	$	$18.9400
Smart Meter Charge	$	$1.7400
Late Payment Penalty Rate Rider Effective until April 30, 2012	$	$0.3800
Distribution Volumetric Rate	$/kWh	$0.0090
Low Voltage Service Rate	$/kWh	$0.0017
Rate Rider for Global Adjustment Sub-Account effective until April 30 2012	$/kWh	$0.0008
Rate Rider for Deferral/Variance Account Disposition effective until April 30 2012	$/kWh	$0.0015
Rate Rider for Tax Change effective until April 30 2012	$/kWh	-$0.0001
Retail Transmission Rate – Network Service Rate	$/kWh	$0.0081
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	$0.0052
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500
GS>50 to 999 kW		
Service Charge	$	$206.0000
Smart Meter Charge	$	$1.7400
Late Payment Penalty Rate Rider Effective until April 30, 2012	$	$3.9500
Distribution Volumetric Rate	$/kW	$1.1531
Low Voltage Service Rate	$/kW	$0.6188
Rate Rider for Global Adjustment Sub-Account effective until April 30 2012	$/kW	$0.1900
Rate Rider for Deferral/Variance Account Disposition effective until April 30 2012	$/kW	$0.4117
Rate Rider for Tax Change effective until April 30 2012	$/kW	-$0.0206
Retail Transmission Rate – Network Service Rate	$/kW	$3.6848
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.8651
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500

GS>1000 to 2999 kW		
Service Charge	$	$2,385.0500
Smart Meter Charge	$	$1.7400
Late Payment Penalty Rate Rider Effective until April 30, 2012	$	$44.2500
Distribution Volumetric Rate	$/kW	$2.4559
Low Voltage Service Rate	$/kW	$0.6655
Rate Rider for Global Adjustment Sub-Account effective until April 30 2012	$/kW	$0.4062
Rate Rider for Deferral/Variance Account Disposition effective until April 30 2012	$/kW	$1.1358
Rate Rider for Tax Change effective until April 30 2012	$/kW	-$0.0362
Retail Transmission Rate – Network Service Rate	$/kW	$4.0022
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$2.0057
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500
GS>3000 to 4999 kW		
Service Charge	$	$1,404.5800
Smart Meter Charge	$	$1.7400
Late Payment Penalty Rate Rider Effective until April 30, 2012	$	$36.0700
Distribution Volumetric Rate	$/kW	$0.8872
Low Voltage Service Rate	$/kW	$0.7102
Rate Rider for Global Adjustment Sub-Account effective until April 30 2012	$/kW	$0.2804
Rate Rider for Deferral/Variance Account Disposition effective until April 30 2012	$/kW	$0.8173
Rate Rider for Tax Change effective until April 30 2012	$/kW	-$0.0149
Retail Transmission Rate – Network Service Rate	$/kW	$4.2197
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$2.1404
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500
Large Use		
Service Charge	$	$9,741.1600
Smart Meter Charge	$	$1.7400
Late Payment Penalty Rate Rider Effective until April 30, 2012	$	$193.5300
Distribution Volumetric Rate	$/kW	$1.9884
Low Voltage Service Rate	$/kW	$0.0639
Rate Rider for Global Adjustment Sub-Account effective until April 30 2012	$/kW	$0.4047
Rate Rider for Deferral/Variance Account Disposition effective until April 30 2012	$/kW	$1.0732
Rate Rider for Tax Change effective until April 30 2012	$/kW	-$0.0208
Retail Transmission Rate – Network Service Rate	$/kW	$4.4368
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$2.2751
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500
Street Lighting		
Service Charge	$	$3.7200
Late Payment Penalty Rate Rider Effective until April 30, 2012	$	$0.0500
Distribution Volumetric Rate	$/kW	$10.6464
Low Voltage Service Rate	$/kW	$0.4779
Rate Rider for Global Adjustment Sub-Account effective until April 30 2012	$/kW	$0.2617
Rate Rider for Deferral/Variance Account Disposition effective until April 30 2012	$/kW	$0.6862
Rate Rider for Tax Change effective until April 30 2012	$/kW	-$0.1891
Retail Transmission Rate – Network Service Rate	$/kW	$2.8456
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$2.3806
Wholesale Market Service Rate	$/kW	$0.0052
Rural Rate Protection Charge	$/kW	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500

Sentinel Lighting		
Service Charge	$	$5.1000
Late Payment Penalty Rate Rider Effective until April 30, 2012	$	$0.1000
Distribution Volumetric Rate	$/kW	$14.2127
Low Voltage Service Rate	$/kW	$0.4779
Rate Rider for Deferral/Variance Account Disposition effective until April 30 2012	$/kW	$0.0457
Rate Rider for Tax Change effective until April 30 2012	$/kW	-$0.2375
Retail Transmission Rate – Network Service Rate	$/kW	$2.8456
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.4404
Wholesale Market Service Rate	$/kW	$0.0052
Rural Rate Protection Charge	$/kW	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500
Embedded Distributor		
Service Charge	$	$2,219.4200
Smart Meter Charge	$	$35.2100
Distribution Volumetric Rate	$/kW	$1.6717
Rate Rider for Global Adjustment Sub-Account effective until April 30 2012	$/kW	$0.1647
Rate Rider for Deferral/Variance Account Disposition effective until April 30 2012	$/kW	$0.5491
Rate Rider for Tax Change effective until April 30 2012	$/kW	-$0.0166
Retail Transmission Rate – Network Service Rate	$/kW	$5.3541
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$2.6450
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500
Unmetered Scattered Load		
Service Charge	$	$2.7400
Late Payment Penalty Rate Rider Effective until April 30, 2012	$	$0.0700
Distribution Volumetric Rate	$/kWh	$0.0118
Low Voltage Service Rate	$/kWh	$0.0017
Rate Rider for Global Adjustment Sub-Account effective until April 30 2012	$/kWh	$0.0008
Rate Rider for Deferral/Variance Account Disposition effective until April 30 2012	$/kWh	$0.0013
Rate Rider for Tax Change effective until April 30 2012	$/kWh	-$0.0001
Retail Transmission Rate – Network Service Rate	$/kWh	$0.0081
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	$0.0052
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500
microFIT Genertator Service Classification		
Service Charge	$	$5.2500
Arrears Certificate	$	15.00
Easement Letter	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank Charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special Meter Reads	$	30.00
Meter dispute charge plus Measurement Canada Fees (if meter found correct)	$	30.00
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
Temporary Service Install & Remove - overhead - no transformer	$	500.00
Temporary Service Install & Remove - underground - no transformer	$	300.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35
Transformer Allowance for Ownership - per kW of billing demand/month	$	(0.60)
Primary Metering allowance for transformer losses - applied to measured demand and energy	%	(1.00)

Once 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)
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
Total Loss Factor -- Secondary Metered Customer < 5,000 kW		1.0427
Total Loss Factor -- Secondary Metered Customer > 5,000 kW		1.0145
Total Loss Factor -- Primary Metered Customer < 5,000 kW		1.0322
Total Loss Factor -- Primary Metered Customer >5,000 kW		1.0045

Clinton Power Corporation

TARIFF OF RATES AND CHARGES
Effective Date December 1st, 2010
Implementation Date January 1st, 2011
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate 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. All customers are single-phase. 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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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	12.30
Smart Meter Funding Adder	$	1.00
Distribution Volumetric Rate	$/kWh	0.0136
Rate Rider Foregone Revenue Recovery Effective Until December 1st, 2011	$/kWh	0.0007
Low Voltage Service Rate	$/kWh	0.0031
Rate Rider for Deferral/Variance Account Disposition Effective Until December 1st, 2012	$/kWh	0.0033
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0013
Late Payment Penalty Rate Rider Effective May 1st, 2011 until April 30th, 2012	$	0.1554

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

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum 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.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	24.17
Smart Meter Funding Adder	$	1.00
Distribution Volumetric Rate	$/kWh	0.0131
Rate Rider Foregone Revenue Recovery Effective Until December 1st, 2011	$/kWh	0.0005
Low Voltage Service Rate	$/kWh	0.0025
Rate Rider for Deferral/Variance Account Disposition Effective Until December 1st, 2012	$/kWh	0.0033
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0012
Late Payment Penalty Rate Rider Effective May 1st, 2011 until April 30th, 2012	$	0.3500

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

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	42.44
Smart Meter Funding Adder	$	1.00
Distribution Volumetric Rate	$/kW	4.6338
Rate Rider Foregone Revenue Recovery Effective Until December 1st, 2011	$/kW	0.1017
Low Voltage Service Rate	$/kW	1.1697
Rate Rider for Deferral/Variance Account Disposition Effective Until December 1st, 2012	$/kW	1.0997
Retail Transmission Rate – Network Service Rate	$/kW	2.0227
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.4787
Late Payment Penalty Rate Rider Effective May 1st, 2011 until April 30th, 2012	$	5.3520

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

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	12.09
Distribution Volumetric Rate	$/kWh	0.0094
Rate Rider Foregone Revenue Recovery Effective Until December 1st, 2011	$/kWh	0.0007
Low Voltage Service Rate	$/kWh	0.0084
Rate Rider for Deferral/Variance Account Disposition Effective Until December 1st, 2012	$/kWh	0.0032
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0013
Late Payment Penalty Rate Rider Effective May 1st, 2011 until April 30th, 2012	$	0.1236

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

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification applies to safety/security lighting with a Residential, General Service or Large Use customer. This is typically exterior lighting, and unmetered. Consumption is estimated based on the equipment rating and estimated hours of use. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	0.2799
Distribution Volumetric Rate	$/kW	0.5405
Rate Rider Foregone Revenue Recovery Effective Until December 1st, 2011	$/kW	0.0357
Low Voltage Service Rate	$/kW	1.4814
Rate Rider for Deferral/Variance Account Disposition Effective Until December 1st, 2012	$/kWh	1.1190
Retail Transmission Rate – Network Service Rate	$/kW	1.5366
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.3778
Late Payment Penalty Rate Rider Effective May 1st, 2011 until April 30th, 2012	$	0.0060

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

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	0.21
Distribution Volumetric Rate	$/kW	21.6340
Rate Rider Foregone Revenue Recovery Effective Until December 1st, 2011	$/kW	1.7878
Low Voltage Service Rate	$/kW	0.8602
Rate Rider for Deferral/Variance Account Disposition Effective Until December 1st, 2012	$/kWh	1.1609
Retail Transmission Rate – Network Service Rate	$/kW	1.5287
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.3701
Late Payment Penalty Rate Rider Effective May 1st, 2011 until April 30th, 2012	$	0.0037

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

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

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

ALLOWANCES

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

SPECIFIC SERVICE CHARGES

APPLICATION

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Customer Administration

Arrears certificate	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	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
Disconnect/Reconnect Charge at meter – during regular hours	$	65.00
Disconnect/Reconnect Charge at meter – after regular hours	$	185.00
Service call – customer-owned equipment	$	30.00
Service call – after regular hours	$	165.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

RETAIL SERVICE CHARGES (if applicable)

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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	1.0554
Total Loss Factor – Secondary Metered Customer > 5,000 kW	NA
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0340
Total Loss Factor – Primary Metered Customer > 5,000 kW	NA

West Perth Power Inc.

TARIFF OF RATES AND CHARGES
Effective Date December 1st, 2010
Implementation Date January 1st, 2011

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

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate 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. All customers are single-phase. Further servicing details are available in the distributor's Conditions of Service.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	13.61
Smart Meter Funding Adder	$	1.00
Distribution Volumetric Rate	$/kWh	0.0098
Rate Rider Foregone Revenue Recovery Effective until December 1st, 2011	$/kWh	0.0002
Low Voltage Service Rate	$/kWh	0.0015
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0046
Late Payment Penalty Rate Rider Effective May 1st, 2011 until April 30th, 2012	$	0.2194

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

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum 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.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	11.95
Smart Meter Funding Adder	$	1.00
Distribution Volumetric Rate	$/kWh	0.0147
Rate Rider Foregone Revenue Recovery Effective until December 1st, 2011	$/kWh	0.0001
Low Voltage Service Rate	$/kWh	0.0010
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Late Payment Penalty Rate Rider Effective May 1st, 2011 until April 30th,	$	0.5428

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

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	204.84
Smart Meter Funding Adder	$	1.00
Distribution Volumetric Rate	$/kW	2.2348
Rate Rider Foregone Revenue Recovery Effective until December 1st, 2011	$/kW	0.0211
Low Voltage Service Rate	$/kW	0.3691
Retail Transmission Rate – Network Service Rate	$/kW	2.0261
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6457
Late Payment Penalty Rate Rider Effective May 1st, 2011 until April 30th,	$	9.1712

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

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor’s Conditions of Service.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	0.67
Distribution Volumetric Rate	$/kWh	0.0258
Rate Rider Foregone Revenue Recovery Effective until December 1st, 2011	$/kWh	0.0020
Low Voltage Service Rate	$/kWh	0.0011
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0023
Late Payment Penalty Rate Rider Effective May 1st, 2011 until April 30th,2012	$	0.0128

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

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification applies to safety/security lighting with a Residential, General Service or Large Use customer. This is typically exterior lighting, and unmetered. Consumption is estimated based on the equipment rating and estimated hours of use. Further servicing details are available in the distributor's Conditions of Service.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	0.00
Distribution Volumetric Rate	$/kW	7.4554
Rate Rider Foregone Revenue Recovery Effective until December 1st, 2011	$/kW	0.5056
Low Voltage Service Rate	$/kW	0.4254
Retail Transmission Rate – Network Service Rate	$/kW	1.5359
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2989
Late Payment Penalty Rate Rider Effective May 1st, 2011 until April 30th, 2012	$	0.0035

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

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	0.31
Distribution Volumetric Rate	$/kW	19.2657
Rate Rider Foregone Revenue Recovery Effective until December 1st, 2011	$/kW	1.5291
Low Voltage Service Rate	$/kW	0.4088
Retail Transmission Rate – Network Service Rate	$/kW	1.5280
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2723
Late Payment Penalty Rate Rider Effective May 1st, 2011 until April 30th, 2012	$	0.0053

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

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

ALLOWANCES

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

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

Customer Administration

Arrears certificate	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00

Non-Payment of Account

Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect Charge at meter – during regular hours	$	65.00
Disconnect/Reconnect Charge at meter – after regular hours	$	185.00
Service call – customer-owned equipment	$	30.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

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	1.0314
Total Loss Factor – Secondary Metered Customer > 5,000 kW	NA
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0211
Total Loss Factor – Primary Metered Customer > 5,000 kW	NA

PROPOSED RATE CLASSES IF DIFFERENT THAN EXISTING

Residential

This classification refers to the supply of electrical energy to customers residing in residential dwelling units.

General Service Less than 50 kW

This classification refers to the supply of electrical energy to General Service Buildings requiring a connection with a connected load less than 50 kW, and, Town Houses and Condominiums described in section 3.1.8 of the distributor's Conditions of Service that require centralized bulk metering. General Service buildings are defined as buildings that are used for purposes other than single-family dwellings.

General Service 50 to 999 kW

This classification refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load or whose average monthly maximum demand used for billing purposes is equal to or greater than 50 kW but less than 1000 kW.

General Service 1000 to 4,999 kW

This classification refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load or whose average monthly maximum demand used for billing purposes is equal to or greater than 1000 kW but less than 5,000 kW.

Large Use

This classification refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load or whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW.

Unmetered Scattered Load

This classification refers to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

Sentinel Lighting

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light.

Street Lighting

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

Embedded Distributor

This classification refers to an electricity distributor licensed by the Ontario Energy Board that is provided electricity by means of this distributor's facilities. Further servicing details are available in the distributor's Conditions of Service.

Erie Thames Powerlines Corporation
Tariff of Rates and Charges
Effective May 1, 2012
Implementation Date To be Determined

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

Residential	**UOM**	**Rate**
Service Charge	$	$15.21
Smart Meter Charge	$	$1.1000
Distribution Volumetric Rate	$/kWh	$0.0143
Low Voltage Service Rate	$/kWh	$0.0021
ETPL Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kWh	$0.0004
CPC Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kWh	$0.0006
WPPI Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kWh	$0.0002
ETPL Rate Rider for Global Adjustment Sub-Account effective One Year from Implementation	$/kWh	$0.0010
ETPL Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kWh	-$0.0009
CPC Rate Rider for Global Adjustment Sub-Account effective Two years from Implementation	$/kWh	-$0.0114
CPC Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kWh	$0.0122
WPPI Rate Rider for Global Adjustment Sub-Account effective One Year from Implementaton	$/kWh	-$0.0029
WPPI Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kWh	-$0.0013
Retail Transmission Rate – Network Service Rate	$/kWh	$0.0059
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	$0.0040
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500
GS<50 kW		
Service Charge	$	$20.95
Smart Meter Charge	$	$1.1000
Distribution Volumetric Rate	$/kWh	$0.0151
Low Voltage Service Rate	$/kWh	$0.0020
ETPL Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kWh	$0.0004
CPC Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kWh	$0.0004
WPPI Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kWh	$0.0002
ETPL Rate Rider for Global Adjustment Sub-Account effective One Year from Implementation	$/kWh	$0.0013
ETPL Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kWh	-$0.0009
CPC Rate Rider for Global Adjustment Sub-Account effective Two years from Implementation	$/kWh	-$0.0115
CPC Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kWh	$0.0081
WPPI Rate Rider for Global Adjustment Sub-Account effective One Year from Implementaton	$/kWh	-$0.0023
WPPI Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kWh	-$0.0010
Retail Transmission Rate – Network Service Rate	$/kWh	$0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	$0.0036
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500
GS>50 to 999 kW		
Service Charge	$	$226.60
Smart Meter Charge	$	$1.1000
Distribution Volumetric Rate	$/kW	$3.4664
Low Voltage Service Rate	$/kW	$0.7099
ETPL Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.2647
CPC Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.3481
WPPI Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.1653
ETPL Rate Rider for Global Adjustment Sub-Account effective One Year from Implementation	$/kW	$2.6824
ETPL Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	-$0.6597
CPC Rate Rider for Global Adjustment Sub-Account effective Two years from Implementation	$/kW	-$4.7823
CPC Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	$6.6561
WPPI Rate Rider for Global Adjustment Sub-Account effective One Year from Implementaton	$/kW	-$2.9573
WPPI Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	-$0.9799
Rate Rider for Tax Change effective until April 30 2012	$/kW	-$0.0206
Retail Transmission Rate – Network Service Rate	$/kW	$2.4575
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.2953
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500

GS>1000 to 4999 kW		
Service Charge	$	$2,862.06
Smart Meter Charge	$	$1.1000
Distribution Volumetric Rate	$/kW	$3.9753
Low Voltage Service Rate	$/kW	$0.7635
ETPL Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.2091
ETPL Rate Rider for Global Adjustment Sub-Account effective One Year from Implementation	$/kW	$2.1192
ETPL Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	-$0.5212
Retail Transmission Rate – Network Service Rate	$/kW	$2.6692
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.3929
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500
Large Use		
Service Charge	$	$10,715.28
Smart Meter Charge	$	$1.1000
Distribution Volumetric Rate	$/kW	$1.9941
Low Voltage Service Rate	$/kW	$0.0733
ETPL Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.2149
ETPL Rate Rider for Global Adjustment Sub-Account effective One Year from Implementation	$/kW	$2.1775
ETPL Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	-$0.5355
Retail Transmission Rate – Network Service Rate	$/kW	$2.9591
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.5800
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500
Street Lighting		
Service Charge	$	$3.80
Distribution Volumetric Rate	$/kW	$14.9986
Low Voltage Service Rate	$/kW	$0.5482
ETPL Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.1093
CPC Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.1936
WPPI Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.0561
ETPL Rate Rider for Global Adjustment Sub-Account effective One Year from Implementation	$/kW	$1.1686
ETPL Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	-$0.2723
CPC Rate Rider for Global Adjustment Sub-Account effective Two years from Implementation	$/kW	-$3.5978
CPC Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	$2.1865
WPPI Rate Rider for Global Adjustment Sub-Account effective One Year from Implementaton	$/kW	-$1.0044
WPPI Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	-$0.3328
Retail Transmission Rate – Network Service Rate	$/kW	$1.8979
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.6533
Wholesale Market Service Rate	$/kW	$0.0052
Rural Rate Protection Charge	$/kW	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500
Sentinel Lighting		
Service Charge	$	$5.25
Distribution Volumetric Rate	$/kW	$17.3901
Low Voltage Service Rate	$/kW	$0.5482
ETPL Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.1373
CPC Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.1143
WPPI Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.1018
ETPL Rate Rider for Global Adjustment Sub-Account effective One Year from Implementation	$/kW	$0.0000
ETPL Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	-$0.3421
CPC Rate Rider for Global Adjustment Sub-Account effective Two years from Implementation	$/kW	-$3.5374
CPC Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	$3.7014
WPPI Rate Rider for Global Adjustment Sub-Account effective One Year from Implementaton	$/kW	-$1.0992
WPPI Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	-$0.6037
Retail Transmission Rate – Network Service Rate	$/kW	$1.8979
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.0003
Wholesale Market Service Rate	$/kW	$0.0052
Rural Rate Protection Charge	$/kW	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500

Service Charge	$	$2,219.86
Smart Meter Charge	$	$1.1000
Distribution Volumetric Rate	$/kW	$4.2434
ETPL Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kW	$0.2744
ETPL Rate Rider for Global Adjustment Sub-Account effective One Year from Implementation	$/kW	$2.7806
ETPL Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kW	-$0.6839
Retail Transmission Rate – Network Service Rate	$/kW	$3.5709
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.8369
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500
Unmetered Scattered Load		
Service Charge	$	$3.00
Distribution Volumetric Rate	$/kWh	$0.1347
Low Voltage Service Rate	$/kWh	$0.0020
ETPL Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kWh	$0.0004
CPC Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kWh	$0.0006
WPPI Rate Rider LRAM and SSM Effective Two Years from Implementation	$/kWh	$0.0000
ETPL Rate Rider for Global Adjustment Sub-Account effective One Year from Implementation	$/kWh	$0.0005
ETPL Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kWh	-$0.0009
CPC Rate Rider for Global Adjustment Sub-Account effective Two years from Implementation	$/kWh	-$0.0123
CPC Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kWh	$0.0113
WPPI Rate Rider for Global Adjustment Sub-Account effective One Year from Implementaton	$/kWh	-$0.0004
WPPI Rate Rider for Deferral/Variance Account Disposition effective One Year from Implementation	$/kWh	-$0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	$0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	$0.0036
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0013
Regulated Price Plan – Administration Charge	$	$0.2500
microFIT Genertator Service Classification		
Service Charge	$	$5.2500
Arrears Certificate	$	15.00
Easement Letter	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank Charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special Meter Reads	$	30.00
Meter dispute charge plus Measurement Canada Fees (if meter found correct)	$	30.00

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
Temporary Service Install & Remove - overhead - no transformer	$	500.00
Temporary Service Install & Remove - underground - no transformer	$	300.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35
Transformer Allowance for Ownership - per kW of billing demand/month	$	(0.60)
Primary Metering allowance for transformer losses - applied to measured demand and energy	%	(1.00)
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)
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
Total Loss Factor -- Secondary Metered Customer < 5,000 kW		1.0483
Total Loss Factor -- Secondary Metered Customer > 5,000 kW		1.0161
Total Loss Factor -- Primary Metered Customer < 5,000 kW		1.0379
Total Loss Factor -- Primary Metered Customer >5,000 kW		1.0060

SUMMARY OF PROPOSED RATE SCHEDULE

The following is a summary of the proposed changes to Erie Thames Powerlines rates for the 2012 test year. The Applicant is forecasting a distribution related delivery deficiency for the 2012 test year of $936,930 including tax implications using existing rates.

The impact on each rate class is described below.

Residential:
The proposed changes to Residential are summarized below.

Erie Thames Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$14.19	$15.21	7%
Distribution Volumetric Rate	$.0144	$0.0168	0.2%

Former WPPI Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$13.61	$15.21	19%
Distribution Volumetric Rate	$.0113	$0.0168	0.5%

Former CPC Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$12.30	$15.21	23%
Distribution Volumetric Rate	$0.0174	$0.0168	0%

In order to adjust the fixed cost recovery through the monthly fixed charge, Erie Thames proposing to increase the monthly customer charge by $1.02 for ETPL, 2.91 for CPC and $2.60 for WPPI in the 2012 test year.

The impact on a typical residential customer is a decrease of 3.0% on total bill for ETPL, and increase of 4.0% for WPPI and an increase of 3% for CPC. The overall bill impact on a typical Residential customer is shown in detail in Exhibit 8, Tab 1, Schedule 8.

The low impact on total bill, compared to the change in the variable charge, is based on the reduction of retail transmission rates (details later in this exhibit). Note, smart meter rate adder is included at $1.10 per metered customer and LV retail rates have been adjusted on explained later in this exhibit.

Due to the relatively low impacts from the changes to network and connection rates, ETPL is proposing to harmonize the rates for this class effective immediately.

GS<50 kW:

The proposed changes to GS<50 kW are summarized below.

	2011 Board Approved	2012 Proposed	% change
Service Charge	$19.32	$20.94	8%
Distribution Volumetric Rate	$0.0107	$0.0173	60%

Former WPPI Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$11.95	$20.94	75%
Distribution Volumetric Rate	$0.0157	$0.0173	9%

Former CPC Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$24.17	$20.94	-13%
Distribution Volumetric Rate	$0.0161	$0.0173	6%

In order to adjust the fixed cost recovery through the monthly fixed charge, Erie Thames Powerlines is proposing to increase the monthly customer charge by $1.62 in the 2012 test year for ETPL, reduce the fixed charge by $3.22 for CPC and increase the fixed charge for WPPI by $9.00 . This proposed fixed charge remains well below the ceiling price detailed in the Cost Allocation Filing included in this application.

The impact on a typical GS<50 kW customer is a decrease of 0.2% on total bill for ETPL, a decrease of 9.9% for CPC and an increase of 2.6% for WPPI customers in the 2012 rate year. The overall bill impact on a typical GS<50 kW customer is shown in detail in Exhibit 8, Tab 1, Schedule 8.

The low impact on total bill, compared to the change in the variable charge, is based on the reduction of retail transmission rates (details later in this exhibit). Note, smart meter rate adder at $1.10 per metered customer and LV retail rates have been adjusted on explained later in this exhibit.

Due to the relatively low impacts from the changes to network and connection rates, ETPL is proposing to harmonize the rates for this class effective immediately.

<u>GS>50 to 999 kW:</u>

The proposed changes to GS>50 to 999 kW are summarized below.

	2011 Board Approved	2012 Proposed	% change
Service Charge	$209.85	$226.6	7.98%
Distribution Volumetric Rate	$5.6219	$4.2217	-24.91%

Former WPPI Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$204.84	$226.6	10%
Distribution Volumetric Rate	$2.6039	$4.2217	60%

Former CPC Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$42.44	$226.6	433%
Distribution Volumetric Rate	$5.9052	$4.2217	-30%

In order to adjust the fixed cost recovery through the monthly fixed charge, Erie Thames is proposing to increase the monthly customer charge by $16.75 in the 2012 test year, increase for CPC customers of $184.16 and increase of $21.76 for WPPI customers, despite the large increase for CPC customers the fixed charge proposed is a value well within the floor and ceiling rates calculated in Cost Allocation filing included in this application..

The impact on a typical GS>50 to 999 kW customer is a decrease of 10.9% on total bill for ETPL customers, a reduction of 19% for West Perth customers and a decrease of 10% for CPC customers. The overall bill impact on a typical GS>50 to 999 kW customer is shown in detail in Exhibit 8, Tab 1, Schedule 8.

The low impact on total bill, compared to the change in the variable charge, is based on the reduction of retail transmission rates (details later in this exhibit). Note, smart meter rate adder at $1.10 per metered customer and LV retail rates have been adjusted on explained later in this exhibit.

Due to the relatively low impacts from the changes to network and connection rates, ETPL is proposing to harmonize the rates for this class effective immediately.

GS>1000 to 4999 kW:

The proposed changes to GS>1000 to 4999 kW are summarized below.

	2011 Board Approved	2012 Proposed	% change
Service Charge	$2,340.80	$2,862.06	22.27%
Distribution Volumetric Rate	$3.1214	$3.6747	17.73%

In order to adjust the fixed cost recovery through the monthly fixed charge, Erie Thames is proposing to increase the monthly customer charge by $521.26 in the 2012 test year, which is a value well within the floor and ceiling rates calculated in Cost Allocation filing included in this application..

The impact on a typical GS>1000 to 4999 kW customer is a decrease of 7.5% on total bill. The overall bill impact on a typical GS>1000 to 4999 kW customer is shown in detail in Exhibit 8, Tab 1, Schedule 8.

The low impact on total bill, compared to the change in the variable charge, is based on the reduction of retail transmission rates (details later in this exhibit). Note, smart meter rate adder at $1.10 per metered customer and LV retail rates have been adjusted on explained later in this exhibit.

Large Use:

The proposed changes to Large Use are summarized below.

	2011 Board Approved	2012 Proposed	% change
Service Charge	$9,934.69	$10,715.28	7.86%
Distribution Volumetric Rate	$1.9245	$1.7778	-7.62%

Former WPPI Service Area

In order to adjust the fixed cost recovery through the monthly fixed charge, Erie Thames is proposing to increase the monthly customer charge by $780.59 in the 2012 test year, which is a value well within the floor and ceiling rates calculated in Cost Allocation filing included in this application..

The impact on a typical Large Use customer is a decrease of 10.0% on total bill. The overall bill impact on a typical Large Use customer is shown in detail in Exhibit 8, Tab 1, Schedule 8.

The low impact on total bill, compared to the change in the variable charge, is based on the reduction of retail transmission rates (details later in this exhibit). Note, smart meter rate adder at $1.10 per metered customer and LV retail rates have been adjusted on explained later in this exhibit.

Street Lighting:

The proposed changes to Street Lighting are summarized below.

Former ETPL Service Territory

	2011 Board Approved	2012 Proposed	% change
Service Charge	$3.77	$3.80	0.80%
Distribution Volumetric Rate	$11.1243	$15.6841	39 %

Former WPPI Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$0.31	$3.80	1125%
Distribution Volumetric Rate	$21.2036	$15.6841	-27%

Former CPC Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$12.09	$3.80	-68%
Distribution Volumetric Rate	$0.0185	$15.6841	kWh to kW

Explanation; In order to adjust the fixed cost recovery through the monthly fixed charge, Erie Thames is proposing to increase the monthly customer charge by $0.03 in the 2012 test year for ETPL customers, decrease by $8.29 for CPC customers and increase by $3.49 for WPPI customers.

The impact on a typical Street Lighting connection is an increase of 9% on total bill for ETPL, a reduction of 4.5% for WPPI customers and an increase of 20% for CPC customers. This large increase for CPC is not a realistic calculation as the variable rate is proposed to change from kWh to kW. The overall bill impact on a typical Street Lighting connection is shown in detail in Exhibit 8, Tab 1, Schedule 8.

Note LV retail rates and RTSR rates have been adjusted and explained later in this exhibit.

Sentinel Lighting:
The proposed changes to Sentinel Lighting are summarized below.

	2011 Board Approved	2012 Proposed	% change
Service Charge	$5.20	$5.25	1%
Distribution Volumetric Rate	$14.6906	$18.8735	22%

Former WPPI Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$0.00	$5.25	100%
Distribution Volumetric Rate	$8.3864	$18.8735	113%

Former CPC Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$0.28	$5.25	95%
Distribution Volumetric Rate	$2.0576	$18.8735	771%

Explanation; In order to adjust the fixed cost recovery through the monthly fixed charge, Erie Thames is proposing to increase the monthly customer charge by $0.05 in the 2012 test year, by $5.25 for WPPI and by $4.97 for CPC.

The impact on a typical Sentinel Lighting connection is a decrease of 69.7% on total bill. An increase of 93% for WPPI customers and a decrease of 45% for CPC customers. The overall bill impact on a typical Sentinel Lighting connection is shown in detail in Exhibit 8, Tab 1, Schedule 8.

Note LV retail rates and RTSR rates have been adjusted on explained later in this exhibit and significantly factor in to this impact.

Unmetered Scattered Load:
The proposed changes to Unmetered Scattered Load are summarized below.

	2011 Board Approved	2012 Proposed	% change
Service Charge	$2.81	$3.00	6.76%
Distribution Volumetric Rate	$0.0135	$0.1384	912%

Former WPPI Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$0.67	$3.00	347%
Distribution Volumetric Rate	$0.0289	$0.1384	373%

Former CPC Service Area

	2011 Board Approved	2012 Proposed	% change
Service Charge	$12.09	$3.00	-75%
Distribution Volumetric Rate	$0.0185	$0.1384	638%

Explanation; In order to adjust the fixed charge Erie Thames Powerlines is proposing to reduce the fixed charge by $0.19 per connection per month for ETPL customers, increase the fixed charge by $2.33 for WPPI customers and decrease the fixed charge by $9.09 for CPC customers.

The impact on a typical Unmetered Scattered Load customer is an increase of 267% on total bill for ETPL, and increase of 104% for WPPI customers and an increase of $278% for CPC customers. This large impact is a direct result of the change in cost allocation, and has been mitigated by the change in RTSR rates. ETPL will consider further rate mitigation steps as the Cost of Service process continues.

The overall bill impact on a typical Unmetered Scattered Load customer is shown in detail in Exhibit 8, Tab 1, Schedule 8.

<u>Embedded Distributor:</u>

The proposed changes to Embedded Distriubtors are summarized below.

	2011 Board Approved	2012 Proposed	% change
Service Charge	$2,254.63	$2,219.86	-1.54%
Distribution Volumetric Rate	$1.6717	$4.2995	157.19%

In order to adjust the fixed cost recovery through the monthly fixed charge, Erie Thames is proposing to decrease the monthly customer charge by $34.77 in the 2012 test year, which is a value well within the floor and ceiling rates calculated in Cost Allocation filing included in this application..

The impact on a typical Embedded Distributor customer is a decrease of 2.2% on total bill. The overall bill impact on a typical Embedded Distributor customer is shown in detail in Exhibit 8, Tab 1, Schedule 8.

The low impact on total bill, compared to the change in the variable charge, is based on the reduction of retail transmission rates (details later in this exhibit). Note, smart meter rate adder at $1.10 per metered customer and LV retail rates have been adjusted on explained later in this exhibit.

RECONCILIATION OF RATE CLASS REVENUE TO TOTAL REVENUE REQUIREMENT

		A	B	A+B		
Revenue Requirement		$ 9,173,990.84	Transformer Allowance Recovery		Low Voltage Revenue	
Residential	55.86%	$ 5,124,154.13	$ -	$ 5,124,154.13	$ 265,980.74	$ 5,390,134.87
GS<50	13.36%	$ 1,225,242.11	$ 6,586.00	$ 1,231,828.11	$ 85,783.13	$ 1,317,611.24
GS>50 to 499 kW	13.20%	$ 1,211,231.63	$ 54,701.00	$ 1,265,932.63	$ 141,037.51	$ 1,406,970.14
GS>1000 to 4999 kW	6.19%	$ 567,482.01	$ 58,140.00	$ 625,622.01	$ 64,486.95	$ 690,108.96
Large Use	3.84%	$ 351,843.80	$ 96,087.00	$ 447,930.80	$ 10,233.33	$ 458,164.13
Unmetered Scattered Load	0.96%	$ 87,653.38		$ 87,653.38	$ 1,051.18	$ 88,704.56
Sentinel Lighting	0.35%	$ 32,388.15		$ 32,388.15	$ 368.94	$ 32,757.09
Embedded Distributor	1.92%	$ 176,104.25	$ 4,667.00	$ 180,771.25	$ -	$ 180,771.25
Street Lighting	4.34%	$ 397,891.38		$ 397,891.38	$ 6,455.00	$ 404,346.37
Total	100.00%	$ 9,173,990.84	$220,181.00	$ 9,394,171.84	$ 575,396.78	$ 9,969,568.62

RATE IMPACTS

This exhibit presents the results of the assessment of customer total bill impacts by level of consumption by customer per rate class and per the total customer class.

Impacts are derived using the applicable November 1, 2011 rates and the proposed 2012 distribution rates.

The total bill impacts are calculated for a range of consumption profiles including the average customer per customer class. The total bill impacts are premised on the distribution rates arising from the new revenue requirements

RATE IMPACTS ERIE THAMES POWERLINES

Residential

100 kWh Consumption [redacted] [redacted]

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				14.19			15.21	1.02	7.2%	4.0%
Smart Meter Funding Adder				1.74			1.10	(0.64)	-36.8%	-2.5%
Distribution	kWh	100	0.0144	1.44	100	0.0164	1.64	0.20	14.0%	0.8%
Sub-Total				**17.37**			**17.95**	**0.58**	**3.3%**	**2.3%**
Regulatory Asset Recovery	kWh	100	0.0008	0.08	100	-0.0009	(0.09)	(0.17)	-216.5%	-0.7%
Regulatory Asset Recovery GA	kWh	100	0.0012	0.12	100	0.0010	0.10	(0.02)	-17.0%	-0.1%
Tax Change Rate Rider	kWh	100	-0.0002	(0.02)	100	0.0000	0.00	0.02	-100.0%	0.1%
Retail Transmission - Network	kWh	104	0.0088	0.92	104	0.0059	0.61	(0.31)	-33.3%	-1.2%
Retail Transmission - Line and Transformation	kWh	104	0.0057	0.59	104	0.0040	0.41	(0.18)	-30.6%	-0.7%
Wholesale Market Service	kWh	104	0.0052	0.54	104	0.0052	0.01	(0.54)	-99.0%	-2.1%
Rural Rate Protection Charge	kWh	104	0.0013	0.14	104	0.0013	0.14	(0.00)	-0.1%	0.0%
Debt Retirement Charge	kWh	100	0.0070	0.70	100	0.0070	0.70	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	104	0.0560	5.84	104	0.0560	5.84	(0.00)	-0.1%	0.0%
Taxes			0.1300	3.40		0.1300	3.32	(0.08)	-2.4%	-0.3%
Total Bill				**26.28**			**25.66**	**(0.62)**	**-2.4%**	**-2.4%**

Residential

250 kWh Consumption [redacted] [redacted]

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				14.19			15.21	1.02	7.2%	4.0%
Smart Meter Funding Adder				1.74			1.10	(0.64)	-36.8%	-2.5%
Distribution	kWh	250	0.0144	3.60	250	0.0164	4.10	0.50	14.0%	2.0%
Sub-Total				**19.53**			**20.41**	**0.88**	**4.5%**	**3.4%**
Regulatory Asset Recovery	kWh	250	0.0008	0.20	250	-0.0009	(0.23)	(0.43)	-216.5%	-1.7%
Regulatory Asset Recovery GA	kWh	250	0.0012	0.30	250	0.0010	0.25	(0.05)	-17.0%	-0.2%
Tax Change Rate Rider	kWh	250	-0.0002	(0.05)	250	0.0000	0.00	0.05	-100.0%	0.2%
Retail Transmission - Network	kWh	261	0.0088	2.29	261	0.0059	1.53	(0.76)	-33.3%	-3.0%
Retail Transmission - Line and Transformation	kWh	261	0.0057	1.49	261	0.0040	1.03	(0.45)	-30.6%	-1.8%
Wholesale Market Service	kWh	261	0.0052	1.36	261	0.0052	1.35	(0.00)	-0.1%	0.0%
Rural Rate Protection Charge	kWh	261	0.0013	0.34	261	0.0013	0.34	(0.00)	-0.1%	0.0%
Debt Retirement Charge	kWh	250	0.0070	1.75	250	0.0070	1.75	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	261	0.0560	14.60	261	0.0560	14.59	(0.01)	-0.1%	0.0%
Taxes			0.1300	5.40		0.1300	5.30	(0.10)	-1.9%	-0.4%
Total Bill				**41.80**			**41.02**	**(0.78)**	**-1.9%**	**-3.0%**

Residential

500 kWh Consumption [redacted] [redacted]

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				14.19			15.21	1.02	7.2%	4.0%
Smart Meter Funding Adder				1.74			1.10	(0.64)	-36.8%	-2.5%
Distribution	kWh	500	0.0144	7.20	500	0.0164	8.21	1.01	14.0%	3.9%
Sub-Total				**23.13**			**24.51**	**1.38**	**6.0%**	**5.4%**
Regulatory Asset Recovery	kWh	500	0.0008	0.40	500	-0.0009	(0.47)	(0.87)	-216.5%	-3.4%
Regulatory Asset Recovery GA	kWh	500	0.0012	0.60	500	0.0010	0.50	(0.10)	-17.0%	-0.4%
Tax Change Rate Rider	kWh	500	-0.0002	(0.10)	500	0.0000	0.00	0.10	-100.0%	0.4%
Retail Transmission - Network	kWh	521	0.0088	4.59	521	0.0059	3.06	(1.53)	-33.3%	-6.0%
Retail Transmission - Line and Transformation	kWh	521	0.0057	2.97	521	0.0040	2.06	(0.91)	-30.6%	-3.5%
Wholesale Market Service	kWh	521	0.0052	2.71	521	0.0052	2.71	(0.00)	-0.1%	0.0%
Rural Rate Protection Charge	kWh	521	0.0013	0.68	521	0.0013	0.68	(0.00)	-0.1%	0.0%
Debt Retirement Charge	kWh	500	0.0070	3.50	500	0.0070	3.50	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	521	0.0560	29.20	521	0.0560	29.18	(0.02)	-0.1%	-0.1%
Taxes			0.1300	8.73		0.1300	8.48	(0.25)	-2.9%	-1.0%
Total Bill				**67.67**			**65.73**	**(1.94)**	**-2.9%**	**-7.6%**

Residential

750 kWh Consumption [redacted] [redacted]

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				14.19			15.21	1.02	7.2%	4.0%
Smart Meter Funding Adder				1.74			1.10	(0.64)	-36.8%	-2.5%
Distribution	kWh	750	0.0144	10.80	750	0.0164	12.31	1.51	14.0%	5.9%
Sub-Total				**26.73**			**28.62**	**1.89**	**7.1%**	**7.4%**
Regulatory Asset Recovery	kWh	750	0.0008	0.60	750	-0.0009	(0.70)	(1.30)	-216.5%	-5.1%
Regulatory Asset Recovery GA	kWh	750	0.0012	0.90	750	0.0010	0.75	(0.15)	-17.0%	-0.6%
Tax Change Rate Rider	kWh	750	-0.0002	(0.15)	750	0.0000	0.00	0.15	-100.0%	0.6%
Retail Transmission - Network	kWh	782	0.0088	6.88	782	0.0059	4.59	(2.29)	-33.3%	-8.9%
Retail Transmission - Line and Transformation	kWh	782	0.0057	4.46	782	0.0040	3.09	(1.36)	-30.6%	-5.3%
Wholesale Market Service	kWh	782	0.0052	4.07	782	0.0052	4.06	(0.00)	-0.1%	0.0%
Rural Rate Protection Charge	kWh	782	0.0013	1.02	782	0.0013	1.02	(0.00)	-0.1%	0.0%
Debt Retirement Charge	kWh	750	0.0070	5.25	750	0.0070	5.25	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	782	0.0560	43.79	782	0.0560	43.77	(0.03)	-0.1%	-0.1%
Taxes			0.1300	12.06		0.1300	11.66	(0.40)	-3.3%	-1.6%
Total Bill				**93.55**			**90.45**	**(3.10)**	**-3.3%**	**-12.1%**

Residential

1,000 kWh Consumption [redacted] [redacted]

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				14.19			15.21	1.02	7.2%	4.0%
Smart Meter Funding Adder				1.74			1.10	(0.64)	-36.8%	-2.5%
Distribution	kWh	1,000	0.0144	14.40	1,000	0.0164	16.41	2.01	14.0%	7.8%
Sub-Total				**30.33**			**32.72**	**2.39**	**7.9%**	**9.3%**
Regulatory Asset Recovery	kWh	1,000	0.0008	0.80	1,000	-0.0009	(0.93)	(1.73)	-216.5%	-6.8%
Regulatory Asset Recovery GA	kWh	1,000	0.0012	1.20	1,000	0.0010	1.00	(0.20)	-17.0%	-0.8%
Tax Change Rate Rider	kWh	1,000	-0.0002	(0.20)	1,000	0.0000	0.00	0.20	-100.0%	0.8%
Retail Transmission - Network	kWh	1,043	0.0088	9.18	1,042	0.0059	6.12	(3.06)	-33.3%	-11.9%
Retail Transmission - Line and Transformation	kWh	1,043	0.0057	5.94	1,042	0.0040	4.13	(1.82)	-30.6%	-7.1%
Wholesale Market Service	kWh	1,043	0.0052	5.42	1,042	0.0052	5.42	(0.00)	-0.1%	0.0%
Rural Rate Protection Charge	kWh	1,043	0.0013	1.36	1,042	0.0013	1.35	(0.00)	-0.1%	0.0%
Debt Retirement Charge	kWh	1,000	0.0070	7.00	1,000	0.0070	7.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,043	0.0560	58.39	1,042	0.0560	58.36	(0.03)	-0.1%	-0.1%
Taxes			0.1300	15.39		0.1300	14.84	(0.55)	-3.6%	-2.2%
Total Bill				**119.42**			**115.16**	**(4.26)**	**-3.6%**	**-16.6%**

Residential

1,500 kWh Consumption [redacted] [redacted]

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				14.19			15.21	1.02	7.2%	4.0%
Smart Meter Funding Adder				1.74			1.10	(0.64)	-36.8%	-2.5%
Distribution	kWh	1,500	0.0144	21.60	1,500	0.0164	24.62	3.02	14.0%	11.8%
Sub-Total				**37.53**			**40.93**	**3.40**	**9.1%**	**13.2%**
Regulatory Asset Recovery	kWh	1,500	0.0008	1.20	1,500	-0.0009	(1.40)	(2.60)	-216.5%	-10.1%
Regulatory Asset Recovery GA	kWh	1,500	0.0012	1.80	1,500	0.0010	1.49	(0.31)	-17.0%	-1.2%
Tax Change Rate Rider	kWh	1,500	-0.0002	(0.30)	1,500	0.0000	0.00	0.30	-100.0%	1.2%
Retail Transmission - Network	kWh	1,564	0.0088	13.76	1,563	0.0059	9.17	(4.59)	-33.3%	-17.9%
Retail Transmission - Line and Transformation	kWh	1,564	0.0057	8.92	1,563	0.0040	6.19	(2.73)	-30.6%	-10.6%
Wholesale Market Service	kWh	1,564	0.0052	8.13	1,563	0.0052	8.13	(0.00)	-0.1%	0.0%
Rural Rate Protection Charge	kWh	1,564	0.0013	2.03	1,563	0.0013	2.03	(0.00)	-0.1%	0.0%
Debt Retirement Charge	kWh	1,500	0.0070	10.50	1,500	0.0070	10.50	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,564	0.0560	87.59	1,563	0.0560	87.54	(0.05)	-0.1%	-0.2%
Taxes			0.1300	22.06		0.1300	21.20	(0.85)	-3.9%	-3.3%
Total Bill				**171.16**			**164.58**	**(6.58)**	**-3.8%**	**-25.6%**

GS < 50 kW

1,000 kWh Consumption [redacted] [redacted]

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				19.32			20.95	1.63	8.4%	6.3%
Smart Meter Funding Adder				1.74			1.10	(0.64)	-36.8%	-2.5%
Distribution	kWh	1,000	0.0107	10.70	1,000	0.0171	17.10	6.40	59.8%	24.9%
Sub-Total				**31.76**			**39.14**	**7.38**	**23.2%**	**28.8%**
Regulatory Asset Recovery	kWh	1,000	0.0008	0.80	1,000	-0.0009	(0.93)	(1.73)	-216.6%	-6.8%
Regulatory Asset Recovery GA	kWh	1,000	0.0015	1.50	1,000	0.0013	1.35	(0.15)	-10.0%	-0.6%
Tax Change Rate Rider	kWh	1,000	-0.0001	(0.10)	1,000	0.0000	0.00	0.10	-100.0%	0.4%
Retail Transmission - Network	kWh	1,043	0.0081	8.45	1,042	0.0054	5.63	(2.82)	-33.3%	-11.0%
Retail Transmission - Line and Transformation	kWh	1,043	0.0052	5.42	1,042	0.0036	3.76	(1.66)	-30.6%	-6.5%
Wholesale Market Service	kWh	1,043	0.0052	5.42	1,042	0.0052	5.42	(0.00)	-0.1%	0.0%
Rural Rate Protection Charge	kWh	1,043	0.0013	1.36	1,042	0.0013	1.35	(0.00)	-0.1%	0.0%
Debt Retirement Charge	kWh	1,000	0.0070	7.00	1,000	0.0070	7.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,043	0.0560	58.39	1,042	0.0560	58.36	(0.03)	-0.1%	-0.1%
Taxes			0.1300	15.42		0.1300	15.57	0.15	1.0%	0.6%
Total Bill				**120.00**			**121.08**	**1.09**	**0.9%**	**4.2%**

GS < 50 kW

1,500 kWh Consumption [redacted] [redacted]

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				19.32			20.95	1.63	8.4%	6.3%
Smart Meter Funding Adder				1.74			1.10	(0.64)	-36.8%	-2.5%
Distribution	kWh	1,500	0.0107	16.05	1,500	0.0171	25.65	9.60	59.8%	37.4%
Sub-Total				**37.11**			**47.69**	**10.58**	**28.5%**	**41.2%**
Regulatory Asset Recovery	kWh	1,500	0.0008	1.20	1,500	-0.0009	(1.40)	(2.60)	-216.6%	-10.1%
Regulatory Asset Recovery GA	kWh	1,500	0.0012	1.80	1,500	0.0013	2.02	0.22	12.5%	0.9%
Tax Change Rate Rider	kWh	1,500	-0.0002	(0.30)	1,500	0.0000	0.00	0.30	-100.0%	1.2%
Retail Transmission - Network	kWh	1,564	0.0088	13.76	1,563	0.0054	8.44	(5.32)	-38.6%	-20.7%
Retail Transmission - Line and Transformation	kWh	1,564	0.0057	8.92	1,563	0.0036	5.64	(3.27)	-36.7%	-12.7%
Wholesale Market Service	kWh	1,564	0.0052	8.13	1,563	0.0052	8.13	(0.00)	-0.1%	0.0%
Rural Rate Protection Charge	kWh	1,564	0.0013	2.03	1,563	0.0013	2.03	(0.00)	-0.1%	0.0%
Debt Retirement Charge	kWh	1,500	0.0070	10.50	1,500	0.0070	10.50	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,564	0.0560	87.59	1,563	0.0560	87.54	(0.05)	-0.1%	-0.2%
Taxes			0.1300	22.00		0.1300	21.92	(0.09)	-0.4%	-0.3%
Total Bill				**170.74**			**170.60**	**(0.14)**	**-0.1%**	**-0.5%**

GS < 50 kW

2,000 kWh Consumption [redacted] [redacted]

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				19.32			20.95	1.63	8.4%	6.3%
Smart Meter Funding Adder				1.74			1.10	(0.64)	-36.8%	-2.5%
Distribution	kWh	2,000	0.0107	21.40	2,000	0.0171	34.19	12.79	59.8%	49.9%
Sub-Total				**42.46**			**56.24**	**13.78**	**32.5%**	**53.7%**
Regulatory Asset Recovery	kWh	2,000	0.0008	1.60	2,000	-0.0009	(1.87)	(3.47)	-216.6%	-13.5%
Regulatory Asset Recovery GA	kWh	2,000	0.0012	2.40	2,000	0.0013	2.70	0.30	12.5%	1.2%
Tax Change Rate Rider	kWh	2,000	-0.0002	(0.40)	2,000	0.0000	0.00	0.40	-100.0%	1.6%
Retail Transmission - Network	kWh	2,085	0.0088	18.35	2,084	0.0054	11.26	(7.09)	-38.6%	-27.6%
Retail Transmission - Line and Transformation	kWh	2,085	0.0057	11.89	2,084	0.0036	7.53	(4.36)	-36.7%	-17.0%
Wholesale Market Service	kWh	2,085	0.0052	10.84	2,084	0.0052	10.84	(0.01)	-0.1%	0.0%
Rural Rate Protection Charge	kWh	2,085	0.0013	2.71	2,084	0.0013	2.71	(0.00)	-0.1%	0.0%
Debt Retirement Charge	kWh	2,000	0.0070	14.00	2,000	0.0070	14.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	2,085	0.0560	116.78	2,084	0.0560	116.72	(0.07)	-0.1%	-0.3%
Taxes			0.1300	28.42		0.1300	28.26	(0.16)	-0.6%	-0.6%
Total Bill				**220.64**			**220.12**	**(0.51)**	**-0.2%**	**-2.0%**

GS < 50 kW

5,000 kWh Consumption [redacted] [redacted]

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				19.32			20.95	1.63	8.4%	6.3%
Smart Meter Funding Adder				1.74			1.10	(0.64)	-36.8%	-2.5%
Distribution	kWh	5,000	0.0107	53.50	5,000	0.0171	85.48	31.98	59.8%	124.7%
Sub-Total				**74.56**			**107.53**	**32.97**	**44.2%**	**128.5%**
Regulatory Asset Recovery	kWh	5,000	0.0008	4.00	5,000	-0.0009	(4.67)	(8.67)	-216.6%	-33.8%
Regulatory Asset Recovery GA	kWh	5,000	0.0012	6.00	5,000	0.0013	6.75	0.75	12.5%	2.9%
Tax Change Rate Rider	kWh	5,000	-0.0002	(1.00)	5,000	0.0000	0.00	1.00	-100.0%	3.9%
Retail Transmission - Network	kWh	5,214	0.0088	45.88	5,211	0.0054	28.15	(17.73)	-38.6%	-69.1%
Retail Transmission - Line and Transformation	kWh	5,214	0.0057	29.72	5,211	0.0036	18.82	(10.90)	-36.7%	-42.5%
Wholesale Market Service	kWh	5,214	0.0052	27.11	5,211	0.0052	27.09	(0.02)	-0.1%	-0.1%
Rural Rate Protection Charge	kWh	5,214	0.0013	6.78	5,211	0.0013	6.77	(0.00)	-0.1%	0.0%
Debt Retirement Charge	kWh	5,000	0.0070	35.00	5,000	0.0070	35.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	5,214	0.0560	291.96	5,211	0.0560	291.79	(0.17)	-0.1%	-0.7%
Taxes			0.1300	66.95		0.1300	66.36	(0.59)	-0.9%	-2.3%
Total Bill				**520.00**			**517.24**	**(2.76)**	**-0.5%**	**-10.8%**

GS>50 to 999 kW

55 kW Consumption
15,000 kWh Consumption

		2011 Bill			2012 Bill			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				209.85			226.60	16.75	8.0%	65.3%
Smart Meter Funding Adder				1.74			1.74	0.00	0.0%	0.0%
Distribution	kW	55	5.6219	309.20	55	4.1763	229.70	(79.51)	-25.7%	-309.9%
Sub-Total				**520.79**			**458.04**	**(62.76)**	**-12.1%**	
Regulatory Asset Recovery	kW	55	0.1900	10.45	55	-0.6597	(36.28)	(46.73)	-447.2%	
Regulatory Asset Recovery GA	kW	55	0.4117	22.64	55	2.6824	147.53	124.89	551.5%	
Tax Change Rate Rider	kW	55	-0.0206	(1.13)	55	0.0000	0.00	1.13	-100.0%	
Retail Transmission - Network	kW	57	3.6848	211.32	57	2.4575	140.86	(70.46)	-33.3%	
Retail Transmission - Line and Transformation	kW	57	1.8651	106.96	57	1.2953	74.24	(32.72)	-30.6%	
Wholesale Market Service	kWh	15,641	0.0052	81.33	15,632	0.0052	81.28	(0.05)	-0.1%	
Rural Rate Protection Charge	kWh	15,641	0.0013	20.33	15,632	0.0013	20.32	(0.01)	-0.1%	
Debt Retirement Charge	kWh	15,000	0.0070	105.00	15,000	0.0070	105.00	0.00	0.0%	
Cost of Power Commodity	kWh	15,641	0.0052	81.33	15,632	0.0052	81.28	(0.05)	-0.1%	
Total Bill				**1,159.03**			**1,072.27**	**(86.76)**	**-7.5%**	

GS>50 to 999 kW

125 kW Consumption
20,000 kWh Consumption

		2011 Bill			2012 Bill			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				209.85			226.60	16.75	8.0%	65.3%
Smart Meter Funding Adder				1.74			1.74	0.00	0.0%	0.0%
Distribution	kW	125	5.6219	702.74	125	4.1763	522.04	(180.70)	-25.7%	-704.3%
Sub-Total				**914.33**			**750.38**	**(163.95)**	**-17.9%**	
Regulatory Asset Recovery	kW	125	0.1900	23.75	125	-0.6597	(82.47)	(106.22)	-447.2%	
Regulatory Asset Recovery GA	kW	125	0.4117	51.46	125	2.6824	335.30	283.84	551.5%	
Tax Change Rate Rider	kW	125	-0.0206	(2.58)	125	0.0000	0.00	2.58	-100.0%	
Retail Transmission - Network	kW	130	3.6848	480.27	130	2.4575	320.13	(160.14)	-33.3%	
Retail Transmission - Line and Transformation	kW	130	1.8651	243.09	130	1.2953	168.72	(74.37)	-30.6%	
Wholesale Market Service	kWh	20,854	0.0052	108.44	20,842	0.0052	108.38	(0.06)	-0.1%	
Rural Rate Protection Charge	kWh	20,854	0.0013	27.11	20,842	0.0013	27.09	(0.02)	-0.1%	
Debt Retirement Charge	kWh	20,000	0.0070	140.00	20,000	0.0070	140.00	0.00	0.0%	
Cost of Power Commodity	kWh	20,854	0.0052	108.44	20,842	0.0052	108.38	(0.06)	-0.1%	
Total Bill				**2,094.32**			**1,875.92**	**(218.40)**	**-10.4%**	

GS>50 to 999 kW

250 kW Consumption
50,000 kWh Consumption

		2011 Bill			2012 Bill			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				209.85			226.60	16.75	8.0%	65.3%
Smart Meter Funding Adder				1.74			1.74	0.00	0.0%	0.0%
Distribution	kW	250	5.6219	1,405.48	250	4.1763	1,044.08	(361.39)	-25.7%	-1408.6%
Sub-Total				**1,617.07**			**1,272.42**	**(344.64)**	**-21.3%**	
Regulatory Asset Recovery	kW	250	0.1900	47.50	250	-0.6597	(164.93)	(212.43)	-447.2%	
Regulatory Asset Recovery GA	kW	250	0.4117	102.93	250	2.6824	670.61	567.68	551.5%	
Tax Change Rate Rider	kW	250	-0.0206	(5.15)	250	0.0000	0.00	5.15	-100.0%	
Retail Transmission - Network	kW	261	3.6848	960.54	261	2.4575	640.25	(320.28)	-33.3%	
Retail Transmission - Line and Transformation	kW	261	1.8651	486.18	261	1.2953	337.45	(148.74)	-30.6%	
Wholesale Market Service	kWh	52,135	0.0052	271.10	52,105	0.0052	270.95	(0.16)	-0.1%	
Rural Rate Protection Charge	kWh	52,135	0.0013	67.78	52,105	0.0013	67.74	(0.04)	-0.1%	
Debt Retirement Charge	kWh	50,000	0.0070	350.00	50,000	0.0070	350.00	0.00	0.0%	
Cost of Power Commodity	kWh	52,135	0.0052	271.10	52,105	0.0052	270.95	(0.16)	-0.1%	
Total Bill				**4,169.04**			**3,715.43**	**(453.61)**	**-10.9%**	

GS>50 to 999 kW

376 kW Consumption
133,770 kWh Consumption

		2011 Bill			2012 Bill			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				209.85			226.60	16.75	8.0%	65.3%
Smart Meter Funding Adder				1.74			1.74	0.00	0.0%	0.0%
Distribution	kW	376	5.6219	2,113.83	376	4.1763	1,570.30	(543.54)	-25.7%	-2118.5%
Sub-Total				**2,325.42**			**1,798.64**	**(526.79)**	**-22.7%**	
Regulatory Asset Recovery	kW	376	0.1900	71.44	376	-0.6597	(248.06)	(319.50)	-447.2%	
Regulatory Asset Recovery GA	kW	376	0.4117	154.80	376	2.6824	1,008.59	853.79	551.5%	
Tax Change Rate Rider	kW	376	-0.0206	(7.75)	376	0.0000	0.00	7.75	-100.0%	
Retail Transmission - Network	kW	392	3.6848	1,444.65	392	2.4575	962.94	(481.70)	-33.3%	
Retail Transmission - Line and Transformation	kW	392	1.8651	731.22	392	1.2953	507.52	(223.70)	-30.6%	
Wholesale Market Service	kWh	139,482	0.0052	725.31	139,402	0.0052	724.89	(0.42)	-0.1%	
Rural Rate Protection Charge	kWh	139,482	0.0013	181.33	139,402	0.0013	181.22	(0.10)	-0.1%	
Debt Retirement Charge	kWh	133,770	0.0070	936.39	133,770	0.0070	936.39	0.00	0.0%	
Cost of Power Commodity	kWh	139,482	0.0052	725.31	139,402	0.0052	724.89	(0.42)	-0.1%	
Total Bill				**7,288.11**			**6,597.03**	**(691.09)**	**-9.5%**	

GS>1000 to 4999 kW

1,000 kW Consumption
150,000 kWh Consumption

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				2,340.80			2,862.06	521.26	22.3%	2031.7%
Smart Meter Funding Adder				1.74			1.74	0.00	0.0%	0.0%
Distribution	kW	1,000	3.1214	3,121.40	1,000	4.7388	4,738.79	1,617.39	51.8%	6304.0%
Sub-Total				**5,463.94**			**7,602.59**	**2,138.65**	**39.1%**	
Regulatory Asset Recovery	kW	1,000	0.4062	406.20	1,000	-0.5212	(521.20)	(927.40)	-228.3%	
Regulatory Asset Recovery GA	kW	1,000	1.1358	1,135.80	1,000	2.1192	2,119.21	983.41	86.6%	
Tax Change Rate Rider	kW	1,000	-0.0362	(36.20)	1,000	0.0000	0.00	36.20	-100.0%	
Retail Transmission - Network	kW	1,043	4.0022	4,173.09	1,042	2.6692	2,781.61	(1,391.48)	-33.3%	
Retail Transmission - Line and Transformation	kW	1,043	2.0057	2,091.34	1,042	1.3929	1,451.55	(639.79)	-30.6%	
Wholesale Market Service	kWh	156,405	0.0052	813.31	156,315	0.0052	812.84	(0.47)	-0.1%	
Rural Rate Protection Charge	kWh	156,405	0.0013	203.33	156,315	0.0013	203.21	(0.12)	-0.1%	
Debt Retirement Charge	kWh	150,000	0.0070	1,050.00	150,000	0.0070	1,050.00	0.00	0.0%	
Cost of Power Commodity	kWh	156,405	0.0052	813.31	156,315	0.0052	812.84	(0.47)	-0.1%	
Total Bill				**16,114.12**			**16,312.64**	**198.53**	**1.2%**	

GS>1000 to 4999 kW

1,250 kW Consumption
200,000 kWh Consumption

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				2,340.80			2,862.06	521.26	22.3%	2031.7%
Smart Meter Funding Adder				1.74			1.74	0.00	0.0%	0.0%
Distribution	kW	1,250	3.1214	3,901.75	1,250	4.7388	5,923.48	2,021.73	51.8%	7880.0%
Sub-Total				**6,244.29**			**8,787.28**	**2,542.99**	**40.7%**	
Regulatory Asset Recovery	kW	1,250	0.4062	507.75	1,250	-0.5212	(651.51)	(1,159.26)	-228.3%	
Regulatory Asset Recovery GA	kW	1,250	1.1358	1,419.75	1,250	2.1192	2,649.01	1,229.26	86.6%	
Tax Change Rate Rider	kW	1,250	-0.0362	(45.25)	1,250	0.0000	0.00	45.25	-100.0%	
Retail Transmission - Network	kW	1,303	4.0022	5,216.37	1,303	2.6692	3,477.01	(1,739.35)	-33.3%	
Retail Transmission - Line and Transformation	kW	1,303	2.0057	2,614.18	1,303	1.3929	1,814.44	(799.74)	-30.6%	
Wholesale Market Service	kWh	208,540	0.0052	1,084.41	208,420	0.0052	1,083.78	(0.62)	-0.1%	
Rural Rate Protection Charge	kWh	208,540	0.0013	271.10	208,420	0.0013	270.95	(0.16)	-0.1%	
Debt Retirement Charge	kWh	200,000	0.0070	1,400.00	200,000	0.0070	1,400.00	0.00	0.0%	
Cost of Power Commodity	kWh	208,540	0.0052	1,084.41	208,420	0.0052	1,083.78	(0.62)	-0.1%	
Total Bill				**19,797.00**			**19,914.76**	**117.76**	**0.6%**	

GS>1000 to 4999 kW

2,500 kW Consumption
500,000 kWh Consumption

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				2,340.80			2,862.06	521.26	22.3%	2031.7%
Smart Meter Funding Adder				1.74			1.74	0.00	0.0%	0.0%
Distribution	kW	2,500	3.1214	7,803.50	2,500	4.7388	11,846.97	4,043.47	51.8%	15760.1%
Sub-Total				**10,146.04**			**14,710.77**	**4,564.73**	**45.0%**	
Regulatory Asset Recovery	kW	2,500	0.4062	1,015.50	2,500	-0.5212	(1,303.01)	(2,318.51)	-228.3%	
Regulatory Asset Recovery GA	kW	2,500	1.1358	2,839.50	2,500	2.1192	5,298.02	2,458.52	86.6%	
Tax Change Rate Rider	kW	2,500	-0.0362	(90.50)	2,500	0.0000	0.00	90.50	-100.0%	
Retail Transmission - Network	kW	2,607	4.0022	10,432.73	2,605	2.6692	6,954.03	(3,478.70)	-33.3%	
Retail Transmission - Line and Transformation	kW	2,607	2.0057	5,228.36	2,605	1.3929	3,628.88	(1,599.47)	-30.6%	
Wholesale Market Service	kWh	521,350	0.0052	2,711.02	521,050	0.0052	2,709.46	(1.56)	-0.1%	
Rural Rate Protection Charge	kWh	521,350	0.0013	677.76	521,050	0.0013	677.37	(0.39)	-0.1%	
Debt Retirement Charge	kWh	500,000	0.0070	3,500.00	500,000	0.0070	3,500.00	0.00	0.0%	
Cost of Power Commodity	kWh	521,350	0.0052	2,711.02	521,050	0.0052	2,709.46	(1.56)	-0.1%	
Total Bill				**39,171.43**			**38,884.98**	**(286.45)**	**-0.7%**	

GS>1000 to 4999 kW

2,900 kW Consumption
833,770 kWh Consumption

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				2,340.80			2,862.06	521.26	22.3%	2031.7%
Smart Meter Funding Adder				1.74			1.74	0.00	0.0%	0.0%
Distribution	kW	2,900	3.1214	9,052.06	2,900	4.7388	13,742.48	4,690.42	51.8%	18281.7%
Sub-Total				**11,394.60**			**16,606.28**	**5,211.68**	**45.7%**	
Regulatory Asset Recovery	kW	2,900	0.4062	1,177.98	2,900	-0.5212	(1,511.49)	(2,689.47)	-228.3%	
Regulatory Asset Recovery GA	kW	2,900	1.1358	3,293.82	2,900	2.1192	6,145.71	2,851.89	86.6%	
Tax Change Rate Rider	kW	2,900	-0.0362	(104.98)	2,900	0.0000	0.00	104.98	-100.0%	
Retail Transmission - Network	kW	3,024	4.0022	12,101.97	3,022	2.6692	8,066.67	(4,035.30)	-33.3%	
Retail Transmission - Line and Transformation	kW	3,024	2.0057	6,064.90	3,022	1.3929	4,209.51	(1,855.39)	-30.6%	
Wholesale Market Service	kWh	869,372	0.0052	4,520.73	868,872	0.0052	4,518.13	(2.60)	-0.1%	
Rural Rate Protection Charge	kWh	869,372	0.0013	1,130.18	868,872	0.0013	1,129.53	(0.65)	-0.1%	
Debt Retirement Charge	kWh	833,770	0.0070	5,836.39	833,770	0.0070	5,836.39	0.00	0.0%	
Cost of Power Commodity	kWh	869,372	0.0052	4,520.73	868,872	0.0052	4,518.13	(2.60)	-0.1%	
Total Bill				**49,936.33**			**49,518.87**	**(417.46)**	**-0.8%**	

Large Use

6,000	kW Consumption
750,000	kWh Consumption

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				9,934.69			10,715.28	780.59	7.9%	3042.5%
Smart Meter Funding Adder				1.74			1.74	0.00	0.0%	0.0%
Distribution	kW	6,000	1.9245	11,547.00	6,000	2.0674	12,404.45	857.45	7.4%	3342.0%
Sub-Total				**21,483.43**			**23,121.47**	**1,638.04**	**7.6%**	
Regulatory Asset Recovery	kW	6,000	0.4047	2,428.20	6,000	-0.5355	(3,213.23)	(5,641.43)	-232.3%	
Regulatory Asset Recovery GA	kW	6,000	1.0732	6,439.20	6,000	2.1775	13,064.94	6,625.74	102.9%	
Tax Change Rate Rider	kW	6,000	-0.0208	(124.80)	6,000	0.0000	0.00	124.80	-100.0%	
Retail Transmission - Network	kW	6,256	4.4368	27,757.51	6,253	2.9591	18,502.01	(9,255.50)	-33.3%	
Retail Transmission - Line and Transformation	kW	6,256	2.2751	14,233.48	6,253	1.5800	9,879.13	(4,354.35)	-30.6%	
Wholesale Market Service	kWh	782,025	0.0052	4,066.53	781,575	0.0052	4,064.19	(2.34)	-0.1%	
Rural Rate Protection Charge	kWh	782,025	0.0013	1,016.63	781,575	0.0013	1,016.05	(0.59)	-0.1%	
Debt Retirement Charge	kWh	750,000	0.0070	5,250.00	750,000	0.0070	5,250.00	0.00	0.0%	
Cost of Power Commodity	kWh	782,025	0.0560	43,793.40	781,575	0.0560	43,768.20	(25.20)	-0.1%	
Total Bill				**126,343.58**			**115,452.75**	**(10,890.83)**	**-8.6%**	

Street Light

1	kW Consumption
25	kWh Consumption

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				3.77			3.80	0.03	0.8%	0.1%
Distribution	kW	1	11.1243	8.34	1	15.5469	11.66	3.32	39.8%	12.3%
Sub-Total				**12.11**			**15.46**	**3.35**	**27.6%**	**12.4%**
Regulatory Asset Recovery	kW	1	0.7588	0.57	1	0.8962	0.67	0.10	18.1%	0.4%
Retail Transmission - Network	kW	1	2.8456	2.20	1	1.8979	1.47	(0.73)	-33.2%	-2.7%
Retail Transmission - Line and Transformation	kW	1	2.3806	1.84	1	1.6533	1.28	(0.56)	-30.5%	-2.1%
Wholesale Market Service	kWh	26	0.0013	0.03	26	0.0013	0.03	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	26	0.2500	6.45	26	0.2500	6.46	0.01	0.1%	0.0%
Debt Retirement Charge	kWh	25	0.0070	0.18	25	0.0070	0.18	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	26	0.0560	1.45	26	0.0560	1.45	0.00	0.1%	0.0%
Total Bill				**24.83**			**27.00**	**2.16**	**8.7%**	**8.0%**

Embedded Distributor

2,000	kW Consumption
280,000	kWh Consumption

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				2,254.63			2,219.86	(34.77)	-1.5%	-135.5%
Smart Meter Funding Adder				0.00			0.00	0.00		0.0%
Distribution	kW	2,000	1.6717	3,343.40	2,000	4.2434	8,486.73	5,143.33	153.8%	20046.9%
Sub-Total				**5,598.03**			**10,706.59**	**5,108.56**	**91.3%**	
Regulatory Asset Recovery	kW	2,000	0.1647	329.40	2,000	-0.6839	(1,367.73)	(1,697.13)	-515.2%	
Regulatory Asset Recovery GA	kW	2,000	0.5491	1,098.20	2,000	2.7806	5,561.17	4,462.97	406.4%	
Tax Change Rate Rider	kW	2,000	-0.0166	(33.20)	2,000	0.0000	0.00	33.20	-100.0%	
Retail Transmission - Network	kW	2,085	5.3541	11,165.44	2,084	3.5709	7,442.42	(3,723.02)	-33.3%	
Retail Transmission - Line and Transformation	kW	2,085	2.6450	5,515.88	2,084	1.8369	3,828.45	(1,687.43)	-30.6%	
Wholesale Market Service	kWh	291,956	0.0013	379.54	291,788	0.0013	379.32	(0.22)	-0.1%	
Rural Rate Protection Charge	kWh	291,956	0.2500	72,989.00	291,788	0.2500	72,947.00	(42.00)	-0.1%	
Debt Retirement Charge	kWh	280,000	0.0070	1,960.00	280,000	0.0070	1,960.00	0.00	0.0%	
Cost of Power Commodity	kWh	291,956	0.0560	16,349.54	291,788	0.0560	16,340.13	(9.41)	-0.1%	
Total Bill				**115,351.83**			**117,797.35**	**2,445.52**	**2.1%**	

Sentinel

0.75	kW Consumption
50	kWh Consumption

	Metric	2000 Volume	2000 Rate $	2000 Charge $	2000 Volume	2000 Rate $	2000 Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				5.20			5.25	0.05	1.0%	0.5%
Distribution	kW	1	14.6906	11.02	0	17.9383	0.00	(11.02)	-100.0%	-102.1%
Sub-Total				**16.22**			**5.25**	**(10.97)**	**-67.6%**	**-101.6%**
Regulatory Asset Recovery	kW	1	-0.1918	(0.14)	1	-0.3421	(0.26)	(0.11)	78.3%	-1.0%
Retail Transmission - Network	kW	1	2.8456	2.23	1	1.8979	1.49	(0.74)	-33.3%	-6.9%
Retail Transmission - Line and Transformation	kW	1	1.4404	1.13	1	1.0003	0.78	(0.34)	-30.5%	-3.2%
Wholesale Market Service	kWh	52	0.2500	13.03	52	0.0052	0.27	(12.76)	-97.9%	-118.2%
Rural Rate Protection Charge	kWh	52	0.0070	0.36	52	0.0013	0.07	(0.30)	-81.4%	-2.8%
Debt Retirement Charge	kWh	50	0.0560	2.80	50	0.0070	0.35	(2.45)	-87.5%	-22.7%
Cost of Power Commodity	kWh	52	0.0000	0.00	52	0.0545	2.84	2.84		26.3%
Total Bill				**35.62**			**10.79**	**(24.83)**	**-69.7%**	**-230.0%**

Unmetered Scattered Load

1 kW Consumption

100 kWh Consumption

	Metric	2000 Volume	2000 Rate $	2000 Charge $	2000 Volume	2000 Rate $	2000 Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				2.81			3.00	0.19	6.8%	0.8%
Distribution	kWh	100	0.0135	1.35	100	0.1367	13.67	12.32	912.3%	50.4%
Sub-Total				**4.16**			**16.67**	**12.51**	**300.6%**	**51.1%**
Regulatory Asset Recovery	kW	100	0.0020	0.20	100	-0.0004	(0.04)	(0.24)	-118.3%	-1.0%
Retail Transmission - Network	kW	100	0.0081	0.81	100	0.0054	0.54	(0.27)	-33.3%	-1.1%
Retail Transmission - Line and Transformation	kW	100	0.0052	0.52	100	0.0036	0.36	(0.16)	-30.6%	-0.6%
Wholesale Market Service	kWh	104	0.0013	0.14	104	0.0052	0.54	0.41	300.3%	1.7%
Rural Rate Protection Charge	kWh	104	0.0013	0.14	104	-0.0001	(0.01)	(0.15)	-107.7%	-0.6%
Debt Retirement Charge	kWh	100	0.0070	0.70	100	0.0070	0.70	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	104	0.0000	0.00	104	0.0545	5.69	5.69		23.3%
Total Bill				**6.66**			**24.45**	**17.79**	**267.1%**	**72.8%**

DETAILED BILL IMPACTS CLINTON POWER CORPORATION

Residential

100 kWh Consumption [redacted] [redacted]

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				12.30			15.21	2.91	23.6%	11.1%
Smart Meter Funding Adder				1.00			1.10	0.10	10.0%	0.4%
Distribution	kWh	100	0.0174	1.74	100	0.0164	1.64	(0.10)	-5.7%	-0.4%
Sub-Total				**15.04**			**17.95**	**2.91**	**19.3%**	**11.1%**
Regulatory Asset Recovery	kWh	100	0.0033	0.33	100	0.0122	1.22	0.89	270.7%	3.4%
Regulatory Asset Recovery	kWh	100	0.0000	0.00	100	-0.0114	(1.14)	(1.14)		-4.3%
Tax Change Rate Rider	kWh	100	0.0000	0.00	100	0.0000	0.00	0.00		0.0%
Retail Transmission - Network	kWh	106	0.0055	0.58	104	0.0059	0.61	0.03	5.4%	0.1%
Retail Transmission - Line and Transformation	kWh	106	0.0013	0.14	104	0.0040	0.41	0.28	200.7%	1.0%
Wholesale Market Service	kWh	106	0.0052	0.55	104	0.0052	0.54	(0.01)	-1.3%	0.0%
Rural Rate Protection Charge	kWh	106	0.0013	0.14	104	0.0013	0.14	(0.00)	-1.3%	0.0%
Debt Retirement Charge	kWh	100	0.0070	0.70	100	0.0070	0.70	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	106	0.0560	5.91	104	0.0560	5.84	(0.07)	-1.3%	-0.3%
Taxes			0.1300	3.04		0.1300	3.56	0.52	17.2%	2.0%
Total Bill				**23.38**			**26.27**	**2.89**	**12.4%**	**11.0%**

Residential

250 kWh Consumption [redacted] [redacted]

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				12.30			15.21	2.91	23.6%	11.1%
Smart Meter Funding Adder				1.00			1.10	0.10	10.0%	0.4%
Distribution	kWh	250	0.0174	4.35	250	0.0164	4.10	(0.25)	-5.7%	-0.9%
Sub-Total				**17.65**			**20.41**	**2.76**	**15.6%**	**10.5%**
Regulatory Asset Recovery	kWh	250	0.0033	0.83	250	0.0122	3.06	2.23	270.7%	8.5%
Regulatory Asset Recovery	kWh	250	0.0000	0.00	250	-0.0114	(2.84)	(2.84)		-10.8%
Tax Change Rate Rider	kWh	250	0.0000	0.00	250	0.0000	0.00	0.00		0.0%
Retail Transmission - Network	kWh	264	0.0055	1.45	261	0.0059	1.53	0.08	5.4%	0.3%
Retail Transmission - Line and Transformation	kWh	264	0.0013	0.34	261	0.0040	1.03	0.69	200.7%	2.6%
Wholesale Market Service	kWh	264	0.0052	1.37	261	0.0052	1.35	(0.02)	-1.3%	-0.1%
Rural Rate Protection Charge	kWh	264	0.0013	0.34	261	0.0013	0.34	(0.00)	-1.3%	0.0%
Debt Retirement Charge	kWh	250	0.0070	1.75	250	0.0070	1.75	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	261	0.0560	14.60	261	0.0560	14.59	(0.01)	-0.1%	0.0%
Taxes			0.1300	4.98		0.1300	5.73	0.74	14.9%	2.8%
Total Bill				**38.33**			**41.22**	**2.89**	**7.5%**	**11.0%**

Residential

500 kWh Consumption [redacted] [redacted]

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				12.30			15.21	2.91	23.6%	11.1%
Smart Meter Funding Adder				1.00			1.10	0.10	10.0%	0.4%
Distribution	kWh	500	0.0174	8.70	500	0.0164	8.21	(0.49)	-5.7%	-1.9%
Sub-Total				**22.00**			**24.51**	**2.51**	**11.4%**	**9.6%**
Regulatory Asset Recovery	kWh	500	0.0033	1.65	500	0.0122	6.12	4.47	270.7%	17.0%
Regulatory Asset Recovery	kWh	500	0.0000	0.00	500	-0.0114	(5.68)	(5.68)		-21.6%
Tax Change Rate Rider	kWh	500	0.0000	0.00	500	0.0000	0.00	0.00		0.0%
Retail Transmission - Network	kWh	528	0.0055	2.90	521	0.0059	3.06	0.16	5.4%	0.6%
Retail Transmission - Line and Transformation	kWh	528	0.0013	0.69	521	0.0040	2.06	1.38	200.7%	5.2%
Wholesale Market Service	kWh	528	0.0052	2.74	521	0.0052	2.71	(0.03)	-1.3%	-0.1%
Rural Rate Protection Charge	kWh	528	0.0013	0.69	521	0.0013	0.68	(0.01)	-1.3%	0.0%
Debt Retirement Charge	kWh	500	0.0070	3.50	500	0.0070	3.50	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	521	0.0560	29.20	521	0.0560	29.18	(0.02)	-0.1%	-0.1%
Taxes			0.1300	8.24		0.1300	9.34	1.10	13.3%	4.2%
Total Bill				**63.36**			**66.14**	**2.77**	**4.4%**	**10.5%**

Residential

750 kWh Consumption [redacted] [redacted]

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				12.30			15.21	2.91	23.6%	11.1%
Smart Meter Funding Adder				1.00			1.10	0.10	10.0%	0.4%
Distribution	kWh	750	0.0174	13.05	750	0.0164	12.31	(0.74)	-5.7%	-2.8%
Sub-Total				**26.35**			**28.62**	**2.27**	**8.6%**	**8.6%**
Regulatory Asset Recovery	kWh	750	0.0033	2.48	750	0.0122	9.17	6.70	270.7%	25.5%
Regulatory Asset Recovery	kWh	750	0.0000	0.00	750	-0.0114	(8.52)	(8.52)		-32.4%
Tax Change Rate Rider	kWh	750	0.0000	0.00	750	0.0000	0.00	0.00		0.0%
Retail Transmission - Network	kWh	792	0.0055	4.35	782	0.0059	4.59	0.23	5.4%	0.9%
Retail Transmission - Line and Transformation	kWh	792	0.0013	1.03	782	0.0040	3.09	2.06	200.7%	7.9%
Wholesale Market Service	kWh	792	0.0052	4.12	782	0.0052	4.06	(0.05)	-1.3%	-0.2%
Rural Rate Protection Charge	kWh	792	0.0013	1.03	782	0.0013	1.02	(0.01)	-1.3%	0.0%
Debt Retirement Charge	kWh	750	0.0070	5.25	750	0.0070	5.25	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	782	0.0560	43.79	782	0.0560	43.77	(0.03)	-0.1%	-0.1%
Taxes			0.1300	11.49		0.1300	12.94	1.45	12.6%	5.5%
Total Bill				**88.40**			**91.05**	**2.65**	**3.0%**	**10.1%**

Residential

1,000 kWh Consumption [redacted] [redacted]

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				12.30			15.21	2.91	23.6%	11.1%
Smart Meter Funding Adder				1.00			1.10	0.10	10.0%	0.4%
Distribution	kWh	1,000	0.0174	17.40	1,000	0.0164	16.41	(0.99)	-5.7%	-3.8%
Sub-Total				**30.70**			**32.72**	**2.02**	**6.6%**	**7.7%**
Regulatory Asset Recovery	kWh	1,000	0.0033	3.30	1,000	0.0122	12.23	8.93	270.7%	34.0%
Regulatory Asset Recovery	kWh	1,000	0.0000	0.00	1,000	-0.0114	(11.36)	(11.36)		-43.3%
Tax Change Rate Rider	kWh	1,000	0.0000	0.00	1,000	0.0000	0.00	0.00		0.0%
Retail Transmission - Network	kWh	1,055	0.0055	5.80	1,042	0.0059	6.12	0.31	5.4%	1.2%
Retail Transmission - Line and Transformation	kWh	1,055	0.0013	1.37	1,042	0.0040	4.13	2.75	200.7%	10.5%
Wholesale Market Service	kWh	1,055	0.0052	5.49	1,042	0.0052	5.42	(0.07)	-1.3%	-0.3%
Rural Rate Protection Charge	kWh	1,055	0.0013	1.37	1,042	0.0013	1.35	(0.02)	-1.3%	-0.1%
Debt Retirement Charge	kWh	1,000	0.0070	7.00	1,000	0.0070	7.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,043	0.0560	58.39	1,042	0.0560	58.36	(0.03)	-0.1%	-0.1%
Taxes			0.1300	14.75		0.1300	16.55	1.81	12.3%	6.9%
Total Bill				**113.43**			**115.96**	**2.53**	**2.2%**	**9.6%**

Residential

1,500 kWh Consumption [redacted] [redacted]

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				12.30			15.21	2.91	23.6%	11.1%
Smart Meter Funding Adder				1.00			1.10	0.10	10.0%	0.4%
Distribution	kWh	1,500	0.0174	26.10	1,500	0.0164	24.62	(1.48)	-5.7%	-5.6%
Sub-Total				**39.40**			**40.93**	**1.53**	**3.9%**	**5.8%**
Regulatory Asset Recovery	kWh	1,500	0.0033	4.95	1,500	0.0122	18.35	13.40	270.7%	51.0%
Regulatory Asset Recovery	kWh	1,500	0.0000	0.00	1,500	-0.0114	(17.05)	(17.05)		-64.9%
Tax Change Rate Rider	kWh	1,500	0.0000	0.00	1,500	0.0000	0.00	0.00		0.0%
Retail Transmission - Network	kWh	1,583	0.0055	8.71	1,563	0.0059	9.17	0.47	5.4%	1.8%
Retail Transmission - Line and Transformation	kWh	1,583	0.0013	2.06	1,563	0.0040	6.19	4.13	200.7%	15.7%
Wholesale Market Service	kWh	1,583	0.0052	8.23	1,563	0.0052	8.13	(0.10)	-1.3%	-0.4%
Rural Rate Protection Charge	kWh	1,583	0.0013	2.06	1,563	0.0013	2.03	(0.03)	-1.3%	-0.1%
Debt Retirement Charge	kWh	1,500	0.0070	10.50	1,500	0.0070	10.50	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,564	0.0560	87.59	1,563	0.0560	87.54	(0.05)	-0.1%	-0.2%
Taxes			0.1300	21.25		0.1300	23.77	2.51	11.8%	9.6%
Total Bill				**163.49**			**165.79**	**2.30**	**1.4%**	**8.7%**

GS < 50 kW

1,000 kWh Consumption [redacted] [redacted]

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				24.17			20.95	(3.22)	-13.3%	-12.3%
Smart Meter Funding Adder				1.00			1.10	0.10	10.0%	0.4%
Distribution	kWh	1,000	0.0161	16.10	1,000	0.0171	17.10	1.00	6.2%	3.8%
Sub-Total				**41.27**			**39.14**	**(2.13)**	**-5.2%**	**-8.1%**
Regulatory Asset Recovery	kWh	1,000	0.0033	3.30	1,000	0.0081	8.15	4.85	146.9%	18.4%
Regulatory Asset Recovery	kWh	1,000	0.0000	0.00	1,000	-0.0115	(11.45)	(11.45)		-43.6%
Tax Change Rate Rider	kWh	1,000	0.0000	0.00	1,000	0.0000	0.00	0.00		0.0%
Retail Transmission - Network	kWh	1,055	0.0049	5.17	1,042	0.0054	5.63	0.46	8.9%	1.7%
Retail Transmission - Line and Transformation	kWh	1,055	0.0012	1.27	1,042	0.0036	3.76	2.50	197.1%	9.5%
Wholesale Market Service	kWh	1,055	0.0052	5.49	1,042	0.0052	5.42	(0.07)	-1.3%	-0.3%
Rural Rate Protection Charge	kWh	1,055	0.0013	1.37	1,042	0.0013	1.35	(0.02)	-1.3%	-0.1%
Debt Retirement Charge	kWh	1,000	0.0070	7.00	1,000	0.0070	7.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,043	0.0560	58.39	1,042	0.0560	58.36	(0.03)	-0.1%	-0.1%
Taxes			0.1300	16.02		0.1300	16.75	0.72	4.5%	2.7%
Total Bill				**123.26**			**117.36**	**(5.90)**	**-4.8%**	**-22.4%**

GS < 50 kW

1,500 kWh Consumption [redacted] [redacted]

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				24.17			20.95	(3.22)	-13.3%	-12.3%
Smart Meter Funding Adder				1.00			1.10	0.10	10.0%	0.4%
Distribution	kWh	1,500	0.0161	24.15	1,500	0.0171	25.65	1.50	6.2%	5.7%
Sub-Total				**49.32**			**47.69**	**(1.63)**	**-3.3%**	**-6.2%**
Regulatory Asset Recovery	kWh	1,500	0.0008	1.20	1,500	0.0081	12.22	11.02	918.3%	41.9%
Regulatory Asset Recovery	kWh	1,500	0.0012	1.80	1,500	-0.0115	(17.18)	(18.98)	-1054.3%	-72.2%
Tax Change Rate Rider	kWh	1,500	-0.0002	(0.30)	1,500	0.0000	0.00	0.30	-100.0%	1.1%
Retail Transmission - Network	kWh	1,583	0.0088	13.93	1,563	0.0054	8.44	(5.49)	-39.4%	-20.9%
Retail Transmission - Line and Transformation	kWh	1,583	0.0057	9.02	1,563	0.0036	5.64	(3.38)	-37.4%	-12.9%
Wholesale Market Service	kWh	1,583	0.0052	8.23	1,563	0.0052	8.13	(0.10)	-1.3%	-0.4%
Rural Rate Protection Charge	kWh	1,583	0.0013	2.06	1,563	0.0013	2.03	(0.03)	-1.3%	-0.1%
Debt Retirement Charge	kWh	1,500	0.0070	10.50	1,500	0.0070	10.50	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,564	0.0560	87.59	1,563	0.0560	87.54	(0.05)	-0.1%	-0.2%
Taxes			0.1300	23.64		0.1300	23.69	0.04	0.2%	0.2%
Total Bill				**183.35**			**165.02**	**(18.33)**	**-10.0%**	**-69.8%**

GS < 50 kW

2,000 kWh Consumption [redacted] [redacted]

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				24.17			20.95	(3.22)	-13.3%	-12.3%
Smart Meter Funding Adder				1.00			1.10	0.10	10.0%	0.4%
Distribution	kWh	2,000	0.0161	32.20	2,000	0.0171	34.19	1.99	6.2%	7.6%
Sub-Total				**57.37**			**56.24**	**(1.13)**	**-2.0%**	**-4.3%**
Regulatory Asset Recovery	kWh	2,000	0.0008	1.60	2,000	0.0081	16.29	14.69	918.3%	55.9%
Regulatory Asset Recovery	kWh	2,000	0.0012	2.40	2,000	-0.0115	(22.90)	(25.30)	-1054.3%	-96.3%
Tax Change Rate Rider	kWh	2,000	-0.0002	(0.40)	2,000	0.0000	0.00	0.40	-100.0%	1.5%
Retail Transmission - Network	kWh	2,111	0.0088	18.58	2,084	0.0054	11.26	(7.32)	-39.4%	-27.8%
Retail Transmission - Line and Transformation	kWh	2,111	0.0057	12.03	2,084	0.0036	7.53	(4.50)	-37.4%	-17.1%
Wholesale Market Service	kWh	2,111	0.0052	10.98	2,084	0.0052	10.84	(0.14)	-1.3%	-0.5%
Rural Rate Protection Charge	kWh	2,111	0.0013	2.74	2,084	0.0013	2.71	(0.03)	-1.3%	-0.1%
Debt Retirement Charge	kWh	2,000	0.0070	14.00	2,000	0.0070	14.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	2,085	0.0560	116.78	2,084	0.0560	116.72	(0.07)	-0.1%	-0.3%
Taxes			0.1300	30.43		0.1300	30.63	0.20	0.6%	0.7%
Total Bill				**236.08**			**212.68**	**(23.40)**	**-9.9%**	**-89.1%**

GS < 50 kW

5,000 kWh Consumption [redacted] [redacted]

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				24.17			20.95	(3.22)	-13.3%	-12.3%
Smart Meter Funding Adder				1.00			1.10	0.10	10.0%	0.4%
Distribution	kWh	5,000	0.0161	80.50	5,000	0.0171	85.48	4.98	6.2%	19.0%
Sub-Total				**105.67**			**107.53**	**1.86**	**1.8%**	**7.1%**
Regulatory Asset Recovery	kWh	5,000	0.0008	4.00	5,000	0.0081	40.73	36.73	918.3%	139.8%
Regulatory Asset Recovery	kWh	5,000	0.0012	6.00	5,000	-0.0115	(57.26)	(63.26)	-1054.3%	-240.8%
Tax Change Rate Rider	kWh	5,000	-0.0002	(1.00)	5,000	0.0000	0.00	1.00	-100.0%	3.8%
Retail Transmission - Network	kWh	5,277	0.0088	46.44	5,211	0.0054	28.15	(18.29)	-39.4%	-69.6%
Retail Transmission - Line and Transformation	kWh	5,277	0.0057	30.08	5,211	0.0036	18.82	(11.26)	-37.4%	-42.9%
Wholesale Market Service	kWh	5,277	0.0052	27.44	5,211	0.0052	27.09	(0.35)	-1.3%	-1.3%
Rural Rate Protection Charge	kWh	5,277	0.0013	6.86	5,211	0.0013	6.77	(0.09)	-1.3%	-0.3%
Debt Retirement Charge	kWh	5,000	0.0070	35.00	5,000	0.0070	35.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	5,214	0.0560	291.96	5,211	0.0560	291.79	(0.17)	-0.1%	-0.6%
Taxes			0.1300	71.17		0.1300	72.27	1.10	1.5%	4.2%
Total Bill				**552.44**			**498.63**	**(53.82)**	**-9.7%**	**-204.8%**

GS>50 to 999 kW

55	kW Consumption
15,000	kWh Consumption

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				42.44			226.60	184.16	433.9%	700.9%
Smart Meter Funding Adder				1.00			1.74	0.74	74.0%	2.8%
Distribution	kW	55	5.9052	324.79	55	4.1763	229.70	(95.09)	-29.3%	-361.9%
Sub-Total				**368.23**			**458.04**	**89.81**	**24.4%**	
Regulatory Asset Recovery	kW	55	1.0997	60.48	55	6.6561	366.09	305.60	505.3%	
Regulatory Asset Recovery	kW	55	0.0000	0.00	55	-4.7823	(263.03)	(263.03)		
Tax Change Rate Rider	kW	55	0.0000	0.00	55	0.0000	0.00	0.00		
Retail Transmission - Network	kW	58	2.0227	117.41	57	2.0227	115.93	(1.48)	-1.3%	
Retail Transmission - Line and Transformation	kW	58	0.4787	27.79	57	0.4787	27.44	(0.35)	-1.3%	
Wholesale Market Service	kWh	15,831	0.0052	82.32	15,632	0.0052	81.28	(1.04)	-1.3%	
Rural Rate Protection Charge	kWh	15,831	0.0013	20.58	15,632	0.0013	20.32	(0.26)	-1.3%	
Debt Retirement Charge	kWh	15,000	0.0070	105.00	15,000	0.0070	105.00	0.00	0.0%	
Cost of Power Commodity	kWh	15,831	0.0052	82.32	15,632	0.0052	81.28	(1.04)	-1.3%	
Total Bill				**864.13**			**992.36**	**128.23**	**14.8%**	

GS>50 to 999 kW

125	kW Consumption
20,000	kWh Consumption

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				42.44			226.60	184.16	433.9%	700.9%
Smart Meter Funding Adder				1.00			1.74	0.74	74.0%	2.8%
Distribution	kW	125	5.9052	738.15	125	4.1763	522.04	(216.11)	-29.3%	-822.5%
Sub-Total				**781.59**			**750.38**	**(31.21)**	**-4.0%**	
Regulatory Asset Recovery	kW	125	1.0997	137.46	125	6.6561	832.02	694.56	505.3%	
Regulatory Asset Recovery	kW	125	0.0000	0.00	125	-4.7823	(597.79)	(597.79)		
Tax Change Rate Rider	kW	125	0.0000	0.00	125	0.0000	0.00	0.00		
Retail Transmission - Network	kW	132	2.0227	266.84	130	2.0227	263.48	(3.36)	-1.3%	
Retail Transmission - Line and Transformation	kW	132	0.4787	63.15	130	0.4787	62.36	(0.80)	-1.3%	
Wholesale Market Service	kWh	21,108	0.0052	109.76	20,842	0.0052	108.38	(1.38)	-1.3%	
Rural Rate Protection Charge	kWh	21,108	0.0013	27.44	20,842	0.0013	27.09	(0.35)	-1.3%	
Debt Retirement Charge	kWh	20,000	0.0070	140.00	20,000	0.0070	140.00	0.00	0.0%	
Cost of Power Commodity	kWh	21,108	0.0052	109.76	20,842	0.0052	108.38	(1.38)	-1.3%	
Total Bill				**1,636.01**			**1,694.30**	**58.29**	**3.6%**	

GS>50 to 999 kW

250	kW Consumption
50,000	kWh Consumption

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				42.44			226.60	184.16	433.9%	700.9%
Smart Meter Funding Adder				1.00			1.74	0.74	74.0%	2.8%
Distribution	kW	250	5.9052	1,476.30	250	4.1763	1,044.08	(432.22)	-29.3%	-1645.1%
Sub-Total				**1,519.74**			**1,272.42**	**(247.32)**	**-16.3%**	
Regulatory Asset Recovery	kW	250	1.0997	274.93	250	6.6561	1,664.04	1,389.11	505.3%	
Regulatory Asset Recovery	kW	250	0.0000	0.00	250	-4.7823	(1,195.57)	(1,195.57)		
Tax Change Rate Rider	kW	250	0.0000	0.00	250	0.0000	0.00	0.00		
Retail Transmission - Network	kW	264	2.0227	533.69	261	2.0227	526.96	(6.73)	-1.3%	
Retail Transmission - Line and Transformation	kW	264	0.4787	126.30	261	0.4787	124.71	(1.59)	-1.3%	
Wholesale Market Service	kWh	52,770	0.0052	274.40	52,105	0.0052	270.95	(3.46)	-1.3%	
Rural Rate Protection Charge	kWh	52,770	0.0013	68.60	52,105	0.0013	67.74	(0.86)	-1.3%	
Debt Retirement Charge	kWh	50,000	0.0070	350.00	50,000	0.0070	350.00	0.00	0.0%	
Cost of Power Commodity	kWh	52,770	0.0052	274.40	52,105	0.0052	270.95	(3.46)	-1.3%	
Total Bill				**3,422.07**			**3,352.19**	**(69.88)**	**-2.0%**	

GS>50 to 999 kW

376	kW Consumption
133,770	kWh Consumption

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				42.44			226.60	184.16	433.9%	700.9%
Smart Meter Funding Adder				1.00			1.74	0.74	74.0%	2.8%
Distribution	kW	376	5.9052	2,220.36	376	4.1763	1,570.30	(650.06)	-29.3%	-2474.2%
Sub-Total				**2,263.80**			**1,798.64**	**(465.16)**	**-20.5%**	
Regulatory Asset Recovery	kW	376	1.0997	413.49	376	6.6561	2,502.71	2,089.22	505.3%	
Regulatory Asset Recovery	kW	376	0.0000	0.00	376	-4.7823	(1,798.14)	(1,798.14)		
Tax Change Rate Rider	kW	376	0.0000	0.00	376	0.0000	0.00	0.00		
Retail Transmission - Network	kW	397	2.0227	802.67	392	2.0227	792.55	(10.12)	-1.3%	
Retail Transmission - Line and Transformation	kW	397	0.4787	189.96	392	0.4787	187.57	(2.39)	-1.3%	
Wholesale Market Service	kWh	141,181	0.0052	734.14	139,402	0.0052	724.89	(9.25)	-1.3%	
Rural Rate Protection Charge	kWh	141,181	0.0013	183.54	139,402	0.0013	181.22	(2.31)	-1.3%	
Debt Retirement Charge	kWh	133,770	0.0070	936.39	133,770	0.0070	936.39	0.00	0.0%	
Cost of Power Commodity	kWh	141,181	0.0052	734.14	139,402	0.0052	724.89	(9.25)	-1.3%	
Total Bill				**6,258.12**			**6,050.72**	**(207.40)**	**-3.3%**	

Street Light

1	kW Consumption
25	kWh Consumption

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				12.09			3.80	(8.29)	-68.6%	-32.8%
Distribution	kW	25	0.0185	0.46	1	15.5469	11.66	11.20	2421.1%	44.3%
Sub-Total				**12.55**			**15.46**	**2.91**	**23.2%**	**11.5%**
Regulatory Asset Recovery	kW	25	0.0032	0.08	1	-1.4114	(1.06)	(1.14)	-1423.2%	-4.5%
Retail Transmission - Network	kW	25	0.0049	0.12	1	1.8979	1.47	1.35	1100.4%	5.3%
Retail Transmission - Line and Transformation	kW	25	0.0013	0.03	1	1.6533	1.28	1.25	3841.6%	4.9%
Wholesale Market Service	kWh	26	0.0013	0.03	26	0.0013	0.03	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	26	0.2500	6.45	26	0.2500	6.46	0.01	0.1%	0.0%
Debt Retirement Charge	kWh	25	0.0070	0.18	25	0.0070	0.18	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	26	0.0560	1.45	26	0.0560	1.45	0.00	0.1%	0.0%
Total Bill				**20.89**			**25.27**	**4.37**	**20.9%**	**17.3%**

Sentinel

0.75	kW Consumption
50	kWh Consumption

	Metric	2000 Volume	2000 Rate $	2000 Charge $	2000 Volume	2000 Rate $	2000 Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				0.28			5.25	4.97	1775.7%	44.5%
Distribution	kW	1	2.0576	1.54	0	17.9383	0.00	(1.54)	-100.0%	-13.8%
Sub-Total				**1.82**			**5.25**	**3.43**	**188.0%**	**30.7%**
Regulatory Asset Recovery	kW	1	1.1190	0.84	1	0.1640	0.12	(0.72)	-85.3%	-6.4%
Retail Transmission - Network	kW	1	1.5366	1.20	1	1.8979	1.49	0.28	23.6%	2.5%
Retail Transmission - Line and Transformation	kW	1	0.3378	0.26	1	1.0003	0.78	0.52	196.4%	4.6%
Wholesale Market Service	kWh	52	0.2500	13.03	52	0.0052	0.27	(12.76)	-97.9%	-114.2%
Rural Rate Protection Charge	kWh	52	0.0070	0.36	52	0.0013	0.07	(0.30)	-81.4%	-2.7%
Debt Retirement Charge	kWh	50	0.0560	2.80	50	0.0070	0.35	(2.45)	-87.5%	-21.9%
Cost of Power Commodity	kWh	52	0.0000	0.00	52	0.0545	2.84	2.84		25.4%
Total Bill				**20.33**			**11.17**	**(9.15)**	**-45.0%**	**-81.9%**

Unmetered Scattered Load

1	kW Consumption
600	kWh Consumption

	Metric	2000 Volume	2000 Rate $	2000 Charge $	2000 Volume	2000 Rate $	2000 Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				12.09			3.00	(9.09)	-75.2%	-6.9%
Distribution	kWh	600	0.0185	11.10	600	0.1367	82.00	70.90	638.7%	54.0%
Sub-Total				**23.19**			**85.00**	**61.81**	**266.5%**	**47.1%**
Regulatory Asset Recovery	kW	600	0.0032	1.92	600	-0.0010	(0.63)	(2.55)	-132.8%	-1.9%
Retail Transmission - Network	kW	600	0.0049	2.94	600	0.0054	3.24	0.30	10.2%	0.2%
Retail Transmission - Line and Transformation	kW	600	0.0013	0.78	600	0.0036	2.17	1.39	177.8%	1.1%
Wholesale Market Service	kWh	626	0.0013	0.81	626	0.0052	3.26	2.44	300.3%	1.9%
Rural Rate Protection Charge	kWh	626	0.0013	0.81	626	-0.0001	(0.06)	(0.88)	-107.7%	-0.7%
Debt Retirement Charge	kWh	600	0.0070	4.20	600	0.0070	4.20	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	626	0.0000	0.00	626	0.0545	34.12	34.12		26.0%
Total Bill				**34.66**			**131.29**	**96.64**	**278.8%**	**73.6%**

DETAILED BILL IMPACTS WEST PERTH POWER

Residential

100 kWh Consumption [redacted] [redacted]

		2011 Bill			2012 Bill			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				13.61			16.21	2.60	19.1%	9.7%
Smart Meter Funding Adder				1.00			1.10	0.10	10.0%	0.4%
Distribution	kWh	100	0.0113	1.13	100	0.0164	1.64	0.51	45.2%	1.9%
Sub-Total				**15.74**			**18.95**	**3.21**	**20.4%**	**12.0%**
Regulatory Asset Recovery	kWh	100	0.0000	0.00	100	-0.0013	(0.13)	(0.13)		-0.5%
Regulatory Asset Recovery	kWh	100	0.0000	0.00	100	-0.0029	(0.29)	(0.29)		-1.1%
Tax Change Rate Rider	kWh	100	0.0000	0.00	100	0.0000	0.00	0.00		0.0%
Retail Transmission - Network	kWh	103	0.0055	0.57	104	0.0059	0.61	0.04	7.8%	0.2%
Retail Transmission - Line and Transformation	kWh	103	0.0046	0.47	104	0.0040	0.41	(0.06)	-13.1%	-0.2%
Wholesale Market Service	kWh	103	0.0052	0.54	104	0.0052	0.54	0.01	1.0%	0.0%
Rural Rate Protection Charge	kWh	103	0.0013	0.13	104	0.0013	0.14	0.00	1.0%	0.0%
Debt Retirement Charge	kWh	100	0.0070	0.70	100	0.0070	0.70	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	103	0.0560	5.78	104	0.0560	5.84	0.06	1.0%	0.2%
Taxes			0.1300	3.11		0.1300	3.52	0.41	13.1%	1.5%
Total Bill				**23.93**			**26.77**	**2.84**	**11.9%**	**10.6%**

Residential

250 kWh Consumption [redacted] [redacted]

		2011 Bill			2012 Bill			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				13.61			16.21	2.60	19.1%	9.7%
Smart Meter Funding Adder				1.00			1.10	0.10	10.0%	0.4%
Distribution	kWh	250	0.0113	2.83	250	0.0164	4.10	1.28	45.2%	4.8%
Sub-Total				**17.44**			**21.41**	**3.98**	**22.8%**	**14.9%**
Regulatory Asset Recovery	kWh	250	0.0000	0.00	250	-0.0013	(0.32)	(0.32)		-1.2%
Regulatory Asset Recovery	kWh	250	0.0000	0.00	250	-0.0029	(0.72)	(0.72)		-2.7%
Tax Change Rate Rider	kWh	250	0.0000	0.00	250	0.0000	0.00	0.00		0.0%
Retail Transmission - Network	kWh	258	0.0055	1.42	261	0.0059	1.53	0.11	7.8%	0.4%
Retail Transmission - Line and Transformation	kWh	258	0.0046	1.19	261	0.0040	1.03	(0.15)	-13.1%	-0.6%
Wholesale Market Service	kWh	258	0.0052	1.34	261	0.0052	1.35	0.01	1.0%	0.1%
Rural Rate Protection Charge	kWh	258	0.0013	0.34	261	0.0013	0.34	0.00	1.0%	0.0%
Debt Retirement Charge	kWh	250	0.0070	1.75	250	0.0070	1.75	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	261	0.0560	14.60	261	0.0560	14.59	(0.01)	-0.1%	0.0%
Taxes			0.1300	4.95		0.1300	5.42	0.47	9.5%	1.8%
Total Bill				**38.06**			**40.97**	**2.91**	**7.6%**	**10.9%**

Residential

500 kWh Consumption [redacted] [redacted]

		2011 Bill			2012 Bill			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				13.61			16.21	2.60	19.1%	9.7%
Smart Meter Funding Adder				1.00			1.10	0.10	10.0%	0.4%
Distribution	kWh	500	0.0113	5.65	500	0.0164	8.21	2.56	45.2%	9.5%
Sub-Total				**20.26**			**25.51**	**5.25**	**25.9%**	**19.6%**
Regulatory Asset Recovery	kWh	500	0.0000	0.00	500	-0.0013	(0.63)	(0.63)		-2.4%
Regulatory Asset Recovery	kWh	500	0.0000	0.00	500	-0.0029	(1.44)	(1.44)		-5.4%
Tax Change Rate Rider	kWh	500	0.0000	0.00	500	0.0000	0.00	0.00		0.0%
Retail Transmission - Network	kWh	516	0.0055	2.84	521	0.0059	3.06	0.22	7.8%	0.8%
Retail Transmission - Line and Transformation	kWh	516	0.0046	2.37	521	0.0040	2.06	(0.31)	-13.1%	-1.2%
Wholesale Market Service	kWh	516	0.0052	2.68	521	0.0052	2.71	0.03	1.0%	0.1%
Rural Rate Protection Charge	kWh	516	0.0013	0.67	521	0.0013	0.68	0.01	1.0%	0.0%
Debt Retirement Charge	kWh	500	0.0070	3.50	500	0.0070	3.50	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	521	0.0560	29.20	521	0.0560	29.18	(0.02)	-0.1%	-0.1%
Taxes			0.1300	8.00		0.1300	8.59	0.59	7.4%	2.2%
Total Bill				**61.52**			**64.63**	**3.11**	**5.1%**	**11.6%**

Residential

750 kWh Consumption [redacted] [redacted]

		2011 Bill			2012 Bill			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				13.61			16.21	2.60	19.1%	9.7%
Smart Meter Funding Adder				1.00			1.10	0.10	10.0%	0.4%
Distribution	kWh	750	0.0113	8.48	750	0.0164	12.31	3.83	45.2%	14.3%
Sub-Total				**23.09**			**29.62**	**6.53**	**28.3%**	**24.4%**
Regulatory Asset Recovery	kWh	750	0.0000	0.00	750	-0.0013	(0.95)	(0.95)		-3.5%
Regulatory Asset Recovery	kWh	750	0.0000	0.00	750	-0.0029	(2.16)	(2.16)		-8.1%
Tax Change Rate Rider	kWh	750	0.0000	0.00	750	0.0000	0.00	0.00		0.0%
Retail Transmission - Network	kWh	774	0.0055	4.25	782	0.0059	4.59	0.33	7.8%	1.2%
Retail Transmission - Line and Transformation	kWh	774	0.0046	3.56	782	0.0040	3.09	(0.46)	-13.1%	-1.7%
Wholesale Market Service	kWh	774	0.0052	4.02	782	0.0052	4.06	0.04	1.0%	0.2%
Rural Rate Protection Charge	kWh	774	0.0013	1.01	782	0.0013	1.02	0.01	1.0%	0.0%
Debt Retirement Charge	kWh	750	0.0070	5.25	750	0.0070	5.25	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	782	0.0560	43.79	782	0.0560	43.77	(0.03)	-0.1%	-0.1%
Taxes			0.1300	11.05		0.1300	11.76	0.71	6.4%	2.7%
Total Bill				**84.97**			**88.29**	**3.32**	**3.9%**	**12.4%**

Residential

1,000 kWh Consumption [redacted] [redacted]

		2011 Bill			2012 Bill			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				13.61			16.21	2.60	19.1%	9.7%
Smart Meter Funding Adder				1.00			1.10	0.10	10.0%	0.4%
Distribution	kWh	1,000	0.0113	11.30	1,000	0.0164	16.41	5.11	45.2%	19.1%
Sub-Total				**25.91**			**33.72**	**7.81**	**30.1%**	**29.2%**
Regulatory Asset Recovery	kWh	1,000	0.0000	0.00	1,000	-0.0013	(1.27)	(1.27)		-4.7%
Regulatory Asset Recovery	kWh	1,000	0.0000	0.00	1,000	-0.0029	(2.88)	(2.88)		-10.8%
Tax Change Rate Rider	kWh	1,000	0.0000	0.00	1,000	0.0000	0.00	0.00		0.0%
Retail Transmission - Network	kWh	1,031	0.0055	5.67	1,042	0.0059	6.12	0.44	7.8%	1.7%
Retail Transmission - Line and Transformation	kWh	1,031	0.0046	4.74	1,042	0.0040	4.13	(0.62)	-13.1%	-2.3%
Wholesale Market Service	kWh	1,031	0.0052	5.36	1,042	0.0052	5.42	0.06	1.0%	0.2%
Rural Rate Protection Charge	kWh	1,031	0.0013	1.34	1,042	0.0013	1.35	0.01	1.0%	0.1%
Debt Retirement Charge	kWh	1,000	0.0070	7.00	1,000	0.0070	7.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,043	0.0560	58.39	1,042	0.0560	58.36	(0.03)	-0.1%	-0.1%
Taxes			0.1300	14.09		0.1300	14.93	0.83	5.9%	3.1%
Total Bill				**108.42**			**111.95**	**3.53**	**3.3%**	**13.2%**

Residential

1,500 kWh Consumption [redacted] [redacted]

		2011 Bill			2012 Bill			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				13.61			16.21	2.60	19.1%	9.7%
Smart Meter Funding Adder				1.00			1.10	0.10	10.0%	0.4%
Distribution	kWh	1,500	0.0113	16.95	1,500	0.0164	24.62	7.67	45.2%	28.6%
Sub-Total				**31.56**			**41.93**	**10.37**	**32.8%**	**38.7%**
Regulatory Asset Recovery	kWh	1,500	0.0000	0.00	1,500	-0.0013	(1.90)	(1.90)		-7.1%
Regulatory Asset Recovery	kWh	1,500	0.0000	0.00	1,500	-0.0029	(4.32)	(4.32)		-16.1%
Tax Change Rate Rider	kWh	1,500	0.0000	0.00	1,500	0.0000	0.00	0.00		0.0%
Retail Transmission - Network	kWh	1,547	0.0055	8.51	1,563	0.0059	9.17	0.67	7.8%	2.5%
Retail Transmission - Line and Transformation	kWh	1,547	0.0046	7.12	1,563	0.0040	6.19	(0.93)	-13.1%	-3.5%
Wholesale Market Service	kWh	1,547	0.0052	8.04	1,563	0.0052	8.13	0.08	1.0%	0.3%
Rural Rate Protection Charge	kWh	1,547	0.0013	2.01	1,563	0.0013	2.03	0.02	1.0%	0.1%
Debt Retirement Charge	kWh	1,500	0.0070	10.50	1,500	0.0070	10.50	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,564	0.0560	87.59	1,563	0.0560	87.54	(0.05)	-0.1%	-0.2%
Taxes			0.1300	20.19		0.1300	21.27	1.07	5.3%	4.0%
Total Bill				**155.33**			**159.27**	**3.94**	**2.5%**	**14.7%**

GS < 50 kW

1,000 kWh Consumption [redacted] [redacted]

		2011 Bill			2012 Bill			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				11.95			20.95	9.00	75.3%	33.6%
Smart Meter Funding Adder				1.00			1.10	0.10	10.0%	0.4%
Distribution	kWh	1,000	0.0157	15.70	1,000	0.0171	17.10	1.40	8.9%	5.2%
Sub-Total				**28.65**			**39.14**	**10.49**	**36.6%**	**39.2%**
Regulatory Asset Recovery	kWh	1,000	0.0000	0.00	1,000	-0.0010	(1.04)	(1.04)		-3.9%
Regulatory Asset Recovery	kWh	1,000	0.0000	0.00	1,000	-0.0023	(2.34)	(2.34)		-8.8%
Tax Change Rate Rider	kWh	1,000	0.0000	0.00	1,000	0.0000	0.00	0.00		0.0%
Retail Transmission - Network	kWh	1,031	0.0049	5.05	1,042	0.0054	5.63	0.58	11.4%	2.2%
Retail Transmission - Line and Transformation	kWh	1,031	0.0041	4.23	1,042	0.0036	3.76	(0.47)	-11.0%	-1.7%
Wholesale Market Service	kWh	1,031	0.0052	5.36	1,042	0.0052	5.42	0.06	1.0%	0.2%
Rural Rate Protection Charge	kWh	1,031	0.0013	1.34	1,042	0.0013	1.35	0.01	1.0%	0.1%
Debt Retirement Charge	kWh	1,000	0.0070	7.00	1,000	0.0070	7.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,043	0.0560	58.39	1,042	0.0560	58.36	(0.03)	-0.1%	-0.1%
Taxes			0.1300	14.30		0.1300	15.55	1.25	8.7%	4.7%
Total Bill				**110.03**			**117.28**	**7.25**	**6.6%**	**27.1%**

GS < 50 kW

1,500 kWh Consumption [redacted] [redacted]

			2011 Bill			2012 Bill			IMPACT	
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				11.95			20.95	9.00	75.3%	33.6%
Smart Meter Funding Adder				1.00			1.10	0.10	10.0%	0.4%
Distribution	kWh	1,500	0.0157	23.55	1,500	0.0171	25.65	2.10	8.9%	7.8%
Sub-Total				**36.50**			**47.69**	**11.19**	**30.7%**	**41.8%**
Regulatory Asset Recovery	kWh	1,500	0.0000	0.00	1,500	-0.0010	(1.57)	(1.57)		-5.8%
Regulatory Asset Recovery	kWh	1,500	0.0000	0.00	1,500	-0.0023	(3.51)	(3.51)		-13.1%
Tax Change Rate Rider	kWh	1,500	0.0000	0.00	1,500	0.0000	0.00	0.00		0.0%
Retail Transmission - Network	kWh	1,547	0.0049	7.58	1,563	0.0054	8.44	0.86	11.4%	3.2%
Retail Transmission - Line and Transformation	kWh	1,547	0.0041	6.34	1,563	0.0036	5.64	(0.70)	-11.0%	-2.6%
Wholesale Market Service	kWh	1,547	0.0052	8.04	1,563	0.0052	8.13	0.08	1.0%	0.3%
Rural Rate Protection Charge	kWh	1,547	0.0013	2.01	1,563	0.0013	2.03	0.02	1.0%	0.1%
Debt Retirement Charge	kWh	1,500	0.0070	10.50	1,500	0.0070	10.50	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,564	0.0560	87.59	1,563	0.0560	87.54	(0.05)	-0.1%	-0.2%
Taxes			0.1300	20.61		0.1300	21.89	1.28	6.2%	4.8%
Total Bill				**158.57**			**164.90**	**6.33**	**4.0%**	**23.7%**

GS < 50 kW

2,000 kWh Consumption [redacted] [redacted]

			2011 Bill			2012 Bill			IMPACT	
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				11.95			20.95	9.00	75.3%	33.6%
Smart Meter Funding Adder				1.00			1.10	0.10	10.0%	0.4%
Distribution	kWh	2,000	0.0157	31.40	2,000	0.0171	34.19	2.79	8.9%	10.4%
Sub-Total				**44.35**			**56.24**	**11.89**	**26.8%**	**44.4%**
Regulatory Asset Recovery	kWh	2,000	0.0000	0.00	2,000	-0.0010	(2.09)	(2.09)		-7.8%
Regulatory Asset Recovery	kWh	2,000	0.0000	0.00	2,000	-0.0023	(4.69)	(4.69)		-17.5%
Tax Change Rate Rider	kWh	2,000	0.0000	0.00	2,000	0.0000	0.00	0.00		0.0%
Retail Transmission - Network	kWh	2,063	0.0049	10.11	2,084	0.0054	11.26	1.15	11.4%	4.3%
Retail Transmission - Line and Transformation	kWh	2,063	0.0041	8.46	2,084	0.0036	7.53	(0.93)	-11.0%	-3.5%
Wholesale Market Service	kWh	2,063	0.0052	10.73	2,084	0.0052	10.84	0.11	1.0%	0.4%
Rural Rate Protection Charge	kWh	2,063	0.0013	2.68	2,084	0.0013	2.71	0.03	1.0%	0.1%
Debt Retirement Charge	kWh	2,000	0.0070	14.00	2,000	0.0070	14.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	2,085	0.0560	116.78	2,084	0.0560	116.72	(0.07)	-0.1%	-0.3%
Taxes			0.1300	26.92		0.1300	28.24	1.31	4.9%	4.9%
Total Bill				**207.11**			**212.52**	**5.41**	**2.6%**	**20.2%**

GS < 50 kW

5,000 kWh Consumption [redacted] [redacted]

			2011 Bill			2012 Bill			IMPACT	
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				11.95			20.95	9.00	75.3%	33.6%
Smart Meter Funding Adder				1.00			1.10	0.10	10.0%	0.4%
Distribution	kWh	5,000	0.0157	78.50	5,000	0.0171	85.48	6.98	8.9%	26.1%
Sub-Total				**91.45**			**107.53**	**16.08**	**17.6%**	**60.1%**
Regulatory Asset Recovery	kWh	5,000	0.0000	0.00	5,000	-0.0010	(5.22)	(5.22)		-19.5%
Regulatory Asset Recovery	kWh	5,000	0.0000	0.00	5,000	-0.0023	(11.71)	(11.71)		-43.8%
Tax Change Rate Rider	kWh	5,000	0.0000	0.00	5,000	0.0000	0.00	0.00		0.0%
Retail Transmission - Network	kWh	5,157	0.0049	25.27	5,211	0.0054	28.15	2.88	11.4%	10.8%
Retail Transmission - Line and Transformation	kWh	5,157	0.0041	21.14	5,211	0.0036	18.82	(2.33)	-11.0%	-8.7%
Wholesale Market Service	kWh	5,157	0.0052	26.82	5,211	0.0052	27.09	0.28	1.0%	1.0%
Rural Rate Protection Charge	kWh	5,157	0.0013	6.70	5,211	0.0013	6.77	0.07	1.0%	0.3%
Debt Retirement Charge	kWh	5,000	0.0070	35.00	5,000	0.0070	35.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	5,214	0.0560	291.96	5,211	0.0560	291.79	(0.17)	-0.1%	-0.6%
Taxes			0.1300	64.78		0.1300	66.29	1.51	2.3%	5.6%
Total Bill				**498.34**			**498.22**	**(0.12)**	**0.0%**	**-0.4%**

GS>50 to 999 kW

55 kW Consumption
15,000 kWh Consumption

			2011 Bill			2012 Bill			IMPACT	
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				204.84			226.60	21.76	10.6%	81.3%
Smart Meter Funding Adder				1.00			1.74	0.74	74.0%	2.8%
Distribution	kW	55	2.6039	143.21	55	4.1763	229.70	86.48	60.4%	323.0%
Sub-Total				**349.05**			**458.04**	**108.98**	**31.2%**	
Regulatory Asset Recovery	kW	55	0.0000	0.00	55	-0.9799	(53.89)	(53.89)		
Regulatory Asset Recovery	kW	55	0.0000	0.00	55	-2.9573	(162.65)	(162.65)		
Tax Change Rate Rider	kW	55	0.0000	0.00	55	0.0000	0.00	0.00		
Retail Transmission - Network	kW	57	2.0261	114.93	57	2.4575	140.86	25.92	22.6%	
Retail Transmission - Line and Transformation	kW	57	1.6457	93.36	57	1.2953	74.24	(19.12)	-20.5%	
Wholesale Market Service	kWh	15,471	0.0052	80.45	15,632	0.0052	81.28	0.83	1.0%	
Rural Rate Protection Charge	kWh	15,471	0.0013	20.11	15,632	0.0013	20.32	0.21	1.0%	
Debt Retirement Charge	kWh	15,000	0.0070	105.00	15,000	0.0070	105.00	0.00	0.0%	
Cost of Power Commodity	kWh	15,471	0.0052	80.45	15,632	0.0052	81.28	0.83	1.0%	
Total Bill				**843.36**			**744.47**	**(98.88)**	**-11.7%**	

GS>50 to 999 kW

125	kW Consumption
20,000	kWh Consumption

		2011 Bill			2012 Bill			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				204.84			226.60	21.76	10.6%	81.3%
Smart Meter Funding Adder				1.00			1.74	0.74	74.0%	2.8%
Distribution	kW	125	2.6039	325.49	125	4.1763	522.04	196.55	60.4%	734.2%
Sub-Total				**531.33**			**750.38**	**219.05**	**41.2%**	
Regulatory Asset Recovery	kW	125	0.0000	0.00	125	-0.9799	(122.49)	(122.49)		
Regulatory Asset Recovery	kW	125	0.0000	0.00	125	-2.9573	(369.66)	(369.66)		
Tax Change Rate Rider	kW	125	0.0000	0.00	125	0.0000	0.00	0.00		
Retail Transmission - Network	kW	129	2.0261	261.21	130	2.4575	320.13	58.91	22.6%	
Retail Transmission - Line and Transformation	kW	129	1.6457	212.17	130	1.2953	168.72	(43.45)	-20.5%	
Wholesale Market Service	kWh	20,628	0.0052	107.27	20,842	0.0052	108.38	1.11	1.0%	
Rural Rate Protection Charge	kWh	20,628	0.0013	26.82	20,842	0.0013	27.09	0.28	1.0%	
Debt Retirement Charge	kWh	20,000	0.0070	140.00	20,000	0.0070	140.00	0.00	0.0%	
Cost of Power Commodity	kWh	20,628	0.0052	107.27	20,842	0.0052	108.38	1.11	1.0%	
Total Bill				**1,386.06**			**1,130.93**	**(255.13)**	**-18.4%**	

GS>50 to 999 kW

250	kW Consumption
50,000	kWh Consumption

		2011 Bill			2012 Bill			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				204.84			226.60	21.76	10.6%	81.3%
Smart Meter Funding Adder				1.00			1.74	0.74	74.0%	2.8%
Distribution	kW	250	2.6039	650.98	250	4.1763	1,044.08	393.11	60.4%	1468.3%
Sub-Total				**856.82**			**1,272.42**	**415.61**	**48.5%**	
Regulatory Asset Recovery	kW	250	0.0000	0.00	250	-0.9799	(244.97)	(244.97)		
Regulatory Asset Recovery	kW	250	0.0000	0.00	250	-2.9573	(739.33)	(739.33)		
Tax Change Rate Rider	kW	250	0.0000	0.00	250	0.0000	0.00	0.00		
Retail Transmission - Network	kW	258	2.0261	522.43	261	2.4575	640.25	117.82	22.6%	
Retail Transmission - Line and Transformation	kW	258	1.6457	424.34	261	1.2953	337.45	(86.89)	-20.5%	
Wholesale Market Service	kWh	51,570	0.0052	268.16	52,105	0.0052	270.95	2.78	1.0%	
Rural Rate Protection Charge	kWh	51,570	0.0013	67.04	52,105	0.0013	67.74	0.70	1.0%	
Debt Retirement Charge	kWh	50,000	0.0070	350.00	50,000	0.0070	350.00	0.00	0.0%	
Cost of Power Commodity	kWh	51,570	0.0052	268.16	52,105	0.0052	270.95	2.78	1.0%	
Total Bill				**2,756.96**			**2,225.45**	**(531.51)**	**-19.3%**	

GS>50 to 999 kW

376	kW Consumption
133,770	kWh Consumption

		2011 Bill			2012 Bill			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				204.84			226.60	21.76	10.6%	81.3%
Smart Meter Funding Adder				1.00			1.74	0.74	74.0%	2.8%
Distribution	kW	376	2.6039	979.07	376	4.1763	1,570.30	591.23	60.4%	2208.4%
Sub-Total				**1,184.91**			**1,798.64**	**613.73**	**51.8%**	
Regulatory Asset Recovery	kW	376	0.0000	0.00	376	-0.9799	(368.44)	(368.44)		
Regulatory Asset Recovery	kW	376	0.0000	0.00	376	-2.9573	(1,111.95)	(1,111.95)		
Tax Change Rate Rider	kW	376	0.0000	0.00	376	0.0000	0.00	0.00		
Retail Transmission - Network	kW	388	2.0261	785.73	392	2.4575	962.94	177.21	22.6%	
Retail Transmission - Line and Transformation	kW	388	1.6457	638.21	392	1.2953	507.52	(130.69)	-20.5%	
Wholesale Market Service	kWh	137,970	0.0052	717.45	139,402	0.0052	724.89	7.44	1.0%	
Rural Rate Protection Charge	kWh	137,970	0.0013	179.36	139,402	0.0013	181.22	1.86	1.0%	
Debt Retirement Charge	kWh	133,770	0.0070	936.39	133,770	0.0070	936.39	0.00	0.0%	
Cost of Power Commodity	kWh	137,970	0.0052	717.45	139,402	0.0052	724.89	7.44	1.0%	
Total Bill				**5,159.50**			**4,356.10**	**(803.40)**	**-15.6%**	

Street Light

1 kW Consumption
25 kWh Consumption

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				0.31			3.80	3.49	1125.8%	13.8%
Distribution	kW	1	21.2036	15.90	1	15.5469	11.66	(4.24)	-26.7%	-16.8%
Sub-Total				**16.21**			**15.46**	**(0.75)**	**-4.6%**	**-3.0%**
Regulatory Asset Recovery	kW	1	0.0000	0.00	1	-1.3372	(1.00)	(1.00)		-4.0%
Retail Transmission - Network	kW	1	1.5280	1.18	1	1.8979	1.47	0.29	24.3%	1.1%
Retail Transmission - Line and Transformation	kW	1	1.2723	0.98	1	1.6533	1.28	0.30	30.1%	1.2%
Wholesale Market Service	kWh	26	0.0013	0.03	26	0.0013	0.03	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	26	0.2500	6.45	26	0.2500	6.46	0.01	0.1%	0.0%
Debt Retirement Charge	kWh	25	0.0070	0.18	25	0.0070	0.18	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	26	0.0560	1.45	26	0.0560	1.45	0.00	0.1%	0.0%
Total Bill				**26.49**			**25.32**	**(1.16)**	**-4.4%**	**-4.6%**

Sentinel

0.75 kW Consumption
50 kWh Consumption

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				0.00			5.25	5.25		22.6%
Distribution	kW	1	8.3864	6.29	1	17.9383	13.45	7.16	113.9%	30.8%
Sub-Total				**6.29**			**18.70**	**12.41**	**197.4%**	**53.4%**
Regulatory Asset Recovery	kW	1	0.0000	0.00	1	-1.7029	(1.28)	(1.28)		-5.5%
Retail Transmission - Network	kW	1	1.5359	1.20	1	1.8979	1.49	0.28	23.7%	1.2%
Retail Transmission - Line and Transformation	kW	1	1.2989	1.02	1	1.0003	0.78	(0.23)	-22.9%	-1.0%
Wholesale Market Service	kWh	52	0.0052	0.27	52	0.0052	0.27	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	52	0.0013	0.07	52	0.0013	0.07	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	50	0.0070	0.35	50	0.0070	0.35	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	52	0.0545	2.84	52	0.0545	2.84	0.00	0.1%	0.0%
Total Bill				**12.04**			**23.23**	**11.19**	**93.0%**	**48.2%**

Unmetered Scattered Load

1 kW Consumption
600 kWh Consumption

	Metric	2011 Bill Volume	2011 Bill Rate $	2011 Bill Charge $	2012 Bill Volume	2012 Bill Rate $	2012 Bill Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				0.67			3.00	2.33	347.8%	1.8%
Distribution	kWh	600	0.0289	17.34	600	0.1367	82.00	64.66	372.9%	49.2%
Sub-Total				**18.01**			**85.00**	**66.99**	**371.9%**	**50.9%**
Regulatory Asset Recovery	kW	600	0.0000	0.00	600	-0.0007	(0.40)	(0.40)		-0.3%
Retail Transmission - Network	kW	600	0.0043	2.58	600	0.0054	3.24	0.66	25.6%	0.5%
Retail Transmission - Line and Transformation	kW	600	0.0023	1.38	600	0.0036	2.17	0.79	57.0%	0.6%
Wholesale Market Service	kWh	626	0.0052	3.25	626	0.0052	3.26	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	626	0.0013	0.81	626	-0.0001	(0.06)	(0.88)	-107.7%	-0.7%
Debt Retirement Charge	kWh	600	0.0070	4.20	600	0.0070	4.20	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	626	0.0545	34.10	626	0.0545	34.12	0.03	0.1%	0.0%
Total Bill				**64.33**			**131.52**	**67.19**	**104.4%**	**51.1%**

PROPOSED CHANGES TO TERMS AND CONDITIONS OF SERVICES

Erie Thames Powerlines is not proposing any changes to our Conditions of Service.

PROPOSED CHANGES TO RETAIL TRANSMISSION RATES

Part of the rebasing application is to provide an updated to the retail transmission rates utilizing the RTSR model provided by Board Staff. ETPL has completed this model and has included it as part of this application. The following rates are produced by the model and result in a decrease to both the Network and Connections rates Erie Thames, West Perth and Erie Thames Powerlines.

Rate Class	Unit	Proposed RTSR Network		Proposed RTSI Connection	
Residential	kWh	$	0.0059	$	0.0040
General Service Less Than 50 kW	kWh	$	0.0054	$	0.0036
General Service 50 to 999 kW	kW	$	2.4575	$	1.2953
General Service 1,000 to 2,999 kW	kW	$	2.6692	$	1.3929
General Service 3,000 to 4,999 kW	kW	$	2.8143	$	1.4865
Large Use	kW	$	2.9591	$	1.5800
Unmetered Scattered Load	kWh	$	0.0054	$	0.0036
Sentinel Lighting	kW	$	1.8979	$	1.0003
Street Lighting	kW	$	1.8979	$	1.6533
Embedded Distributor	kW	$	3.5709	$	1.8369

PROPOSED CHANGES TO LOW VOLTAGE RETAIL RATES

Much like the Retail Transmission Rates above, Erie Thames Powerlines is proposing to adjust approved Low Voltage retail rates (as approved in 2008 Cost of Service for ETPL) to account for Wholesale rate changes and Erie Thames Trend Analysis.

Please see detailed Calculations below.

Trend Analysis

Low Voltage Erie Thames

	2009	2010	2011	Total	
Expenses	303,720	369,391	677,925	1,351,036	
Revenues	466,532	522,558	605,834	1,594,923	
$ Difference	(162,811)	(153,167)	72,091	(243,887)	
% Difference	-53.6%	-41.5%	10.6%	-18.1%	Increase to Retail Rates

No change required for trend analysis as 2011 variance accounts differences reflect the change in LV rates from 2010.

Low Voltage Erie Thames after merger

			2011	Total	
Expenses			481,928	481,928	
Revenues			391,295	391,295	
$ Difference			90,632	90,632	
% Difference			18.8%	18.8%	Increase to Retail Rates

Low Voltage Clinton Power

	2009	2010	2011	Total	
Expenses	91,452	105,082	44,476	241,011	
Revenues	41,312	46,086	29,677	117,075	
$ Difference	50,140	58,997	14,799	123,936	
% Difference	54.8%	56.1%	33.3%	51.4%	Increase to Retail Rates

No change required for trend analysis since moving to ETPL LV rates.

Low Voltage West Perth

	2009	2010	2011	Total	
Expenses	48,490	62,892	30,607	141,988	
Revenues	49,855	51,994	23,093	124,942	
$ Difference	(1,365)	10,897	7,514	17,047	
% Difference	-2.8%	17.3%	24.6%	12.0%	Increase to Retail Rates

No change required for trend analysis since moving to ETPL LV rates.

Retail Rates

	Current Rate	Adjustment	Proposed 2009 Rate	Volumes	Revenues
Residential	$ 0.0018	14.72%	$ 0.0021	147,767,075	$ 305,133.46
GS < 50 kW	$ 0.0017	14.72%	$ 0.0020	50,460,667	$ 98,410.53
GS > 50 to 999 kW	$ 0.6188	14.72%	$ 0.7099	227,921	$ 161,798.43
GS > 1000 to 4999 kW	$ 0.6655	14.72%	$ 0.7635	96,900	$ 73,979.52
Large Use	$ 0.0639	14.72%	$ 0.0733	160,146	$ 11,739.69
Unmetered Load	$ 0.0017	14.72%	$ 0.0020	618,341	$ 1,205.91
Sentinel Lights	$ 0.4779	14.72%	$ 0.5482	772	$ 423.25
Embedded Distributors	$ -	14.72%	$ -	23,768	$ -
Street Light	$ 0.4779	14.72%	$ 0.5482	13,507	$ 7,405.18
Total				199,369,097	$ 660,095.97

Forecasted LV Costs Based on 2011 Actual amounts $ 658,603.58

Difference **$ 1,492.39**

Ex. Tab Schedule Contents of Schedule

9 – Deferral and Variance Accounts

MANAGER'S SUMMARY

Erie Thames Powerlines has included in this Application a request for approval for the disposition of deferral and variance account balances at December 31, 2010 and the forecasted interest through December 31, 2011 for the deferral and Regulatory Settlement Variance Accounts (RSVAs) listed below. The total amount of the variance requested for disposition, including the interest, is $622,859 for Erie Thames Powerlines customers, $499,065 for Clinton Power Corporation customers and ($484,752) for West Perth Power customers. Erie Thames Powerlines corporation proposes that variance accounts be dispositioned in geographic manner to ensure that each customer groups pays (or gets credited) the variances that they have historically been responsible for.

Erie Thames Powerlines recognizes that it is required to file as part of its COS application a disposition of its PILS accounts as per the joint PILS proceeding. Unfortunately, there is very little information available with this regard to this information for both West Perth Power and Clinton Power at this time. Consequently we are not currently in a position to file an accurate representation of the historical PILS issues. Given the complexity of this issue ETPL felt it more appropriate to determine the amounts correctly at a later date and file this information as part of its next IRM application. Therefore Erie Thames Powerlines requests a deferral from filing its PILS information as part of this rate application process.

Erie Thames Powerlines proposes a 1-year disposition period for the above referenced balances. Actual interest has been calculated based on the Board's prescribed rates. Forecasted interest for the period January 1, 2011 to December 31, 2011 is based upon the last Board prescribed rate of 1.47%. The following table details the interest rates used historically.

May 2002 to April 30, 2006	7.25%
Q2 2006	4.14%
Q3 2006 to Q3 2007	4.59%
Q4 2007 to Q1 2008	5.14%
Q2 2008	4.08%
Q3 2008 to Q4 2008	3.35%
Q1 2009	2.45%
Q2 2009	1.00%
Q3 2009 to Q2 2010	0.55%
Q3 2010	0.89%
Q4 2010	1.20%
Q1 2011 to Q1 2012	1.47%

Deferral and RSVAs balances match the 2010 RRR 2.1.7 filing.

- 1508 – Other Regulatory Assets
- 1518 – $RCVA_{Retail}$
- 1521 - Special Purpose Charge Assessment Variance Account
- 1548 – $RCVA_{STR}$
- 1550 – Low Voltage Variance Account
- 1580 – Retail Settlement Variance Account - Wholesale Market Service Charges
- 1584 – Retail Transmission Network Charges
- 1586 – Retail Transmission Connection Charges
- 1588 – Retail Settlement Variance Account – Power
- 1588 – Retail Settlement Variance Account - Power, Sub-account Global Adjustments
- 1592 - PILs and Tax Variances
- 1595-1 Recovery of Regulatory Assets 2008 COS

Erie Thames Powerlines has allocated the balances requested for disposition to the rate classes based on the default cost allocation methodology as set out in the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative, July 31, 2009. In addition to the above deferral and variance accounts requested for disposition, Erie Thames Powerlines is requesting disposition of the balances in the 1555 – Smart Meter Capital (excluding Subaccount- Stranded Meter Cost) and 1556 - Smart Meter OM&A accounts, and inclusion in the rate base. Erie Thames Powerlines is proposing to recover stranded meter costs (1555- subaccount Stranded Meter Costs) through a rate rider over four-year period (see details at Tab 3, Schedule 1 of this Exhibit).

Certification

As Manager of Finance and Regulatory Affairs of Erie Thames Powerlines Corporation, I certify to the best of my knowledge, that the information filed in the regulatory assets claim is consistent with the Board's accounting requirements and procedures in the Accounting Procedures Handbook. The filing is consistent with the requirements of the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative issued July 31, 2009 and Chapter 2 of the filing Requirements for Transmission and Distribution Applications issued June 28, 2010.

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Manager of Finance and Regulatory Affairs

DESCRIPTION OF DEFERRAL AND VARIANCE ACCOUNTS

DEFERRAL AND VARIANCE ACCOUNTS & BALANCES:

This Schedule contains descriptions of Deferral and Variance Accounts ("DVAs") currently used by Clinton Power, Erie Thames Powerlines and West Perth Power, and the status of these accounts as at December 31, 2010.

RSVA/RCVA ACCOUNTS

1588 Retail Settlement Variance Account – Power

Description: This account is used to recover the net difference between the energy amount billed to customers and the energy charge to Clinton Power, Erie Thames Powerlines and West Perth Power using the settlement invoice from the Independent Electricity System Operator ("IESO"). This account will continue on a go forward basis.

1588 Retail Settlement Variance Account - Power, Sub-account Global Adjustments

Description: This is a sub account to the RSVA Power account which is used to recover the net difference between the provincial benefit amount billed to non RPP customers and the global adjustment charge to Clinton Power, Erie Thames Powerlines and West Perth Power for non RPP using the settlement invoice from the IESO. This account will continue on a go forward basis. The main driver of this variance account balance is the difference in the monthly rates between the global adjustment charged by the IESO and the provincial benefit rate charged to the customer. In the month of December 2008, the global adjustment charged on the IESO bill was $13.37 per MWh. The rate charged to non-RPP consumers was $3.90 per MWh. This created a large difference on account at the end of December 31, 2008. As part of the account disposition, Clinton Power, Erie Thames Powerlines and West Perth Power has determined the amount owing to each rate class, based on historical data of customer kWh sales to non-RPP customers (i.e. customers with retailers or on spot pricing).

1580 Retail Settlement Variance Account - Wholesale Market Service Charges

Description: This account is used to record the net of the amount charged by the IESO based on the settlement invoice for the operation of the IESO-administered markets and the operation of the IESO-controlled grid, and the amount billed to customers using the OEB-approved Wholesale Market Service Rate. This account will continue on a go forward basis.

1582 Retail Settlement Variance Account - One-time Wholesale Market Service

Description: This account is used to record the net of non-recurring amounts not included in the Wholesale Market Service Rate charged by the IESO based on the settlement invoice and the amount charged to customers for the same services using the OEB approved rate. This account will continue on a go forward basis.

1584 Retail Settlement Variance Account - Retail Transmission Network Charges

Description: This account is used to record the net of the amount charged by the IESO, based on the settlement invoice for transmission network services, and the amount billed to customers using the OEB-approved Transmission Network Charge. This account will continue on a go forward basis.

1586 Retail Settlement Variance Account - Retail Transmission Connection Charges

Description: This account is used to record the net of the amount charged by the IESO, based on the settlement invoice for transmission connection services, and the amount billed to customers using the OEB-approved Transmission Connection Charge. This account will continue on a go forward basis.

Non RSVA/RCVA Accounts

1508 Other Regulatory Assets

Description: This account includes amounts of regulatory-created assets, not included in other accounts, resulting from the ratemaking actions of the OEB.

1508 Other Regulatory Assets - Sub-account OEB Cost Assessments

Description: This account includes amounts paid for OEB Cost Assessment for the period January 1, 2004 to April 30, 2006 in excess of amounts previously included in rates (1999 OEB costs). This account will come to an end with its proposed disposition.

1508 Other Regulatory Assets - Sub-account Pension Contributions

Description: This account includes amounts paid for OMERS pension expense for the period January 1, 2004 to April 30, 2006 not included in rates. This account will come to an end with its proposed disposition.

1518 RSVA $_{\text{Retail}}$

Description: This account is used to record the net of the revenues derived from certain retailer services, and the incremental costs incurred to provide these services. This account will continue on a go forward basis.

1525 Miscellaneous Deferred Debits

Description: This account includes all debits not elsewhere provided for which will benefit future periods are carried forward and charged to expense over the term of the benefit. At December 31, 2008, there was a balance of $1,145 in this account, representing incremental costs incurred related to the 2010 Cost of Service Rate Application. Within the Cost of Service Rate application, Clinton Power, Erie Thames Powerlines and West Perth Power has requested an increase of $40,000 per year for the next 4 years in our Regulatory Expense account (USOA #5655) to cover the costs of the 2010 Cost of Service Rate Application. The plan is to charge this amount of $1,145 in 2010 to the #5655 account.

1548 RSVA $_{\text{STR}}$

Description: This account is used to record the net of the revenues derived from Service Transaction Request services, and the incremental costs incurred to provide these services. This account will continue on a go forward basis.

1550 Low Voltage (LV) Variance Account

Description: This account is used to record the net of the amount charged by Hydro One for low voltage services, and the amount billed to customers based on Clinton Power, Erie Thames Powerlines and West Perth Power’s approved LV rates. This account will continue on a go forward basis.

1555 Smart Meter Capital and Recovery Offset Variance

Description: This account records the net of the amounts paid for capitalized direct costs1 related to the smart meter program and the amounts charged to customers using the OEB approved smart meter rate rider. This account will continue on a go forward basis.

1556 Smart Meter OM&A Variance

Description: This account records the incremental operating, maintenance, amortization and administrative expenses directly related to smart meters. This account will continue on a go forward basis. There were no costs charged to this account to December 31, 2008.

1562 Deferred Payments in Lieu of Taxes

Description: This account records the amount resulting from the OEB-approved PILs methodology for determining the 2001 deferral account allowance and the PILs proxy amount determined for 2002 and subsequent periods ending April 30, 2006. This account will come to an end based the outcome of the Deferred PILs combined proceedings.

1563 Contra Account -Deferred Payments in Lieu of Taxes

Description: This account was used as a result of Clinton Power, Erie Thames Powerlines and West Perth Power using the third accounting method approved for recording entries in account # 1562. This account will come to an end based the outcome of the Deferred PILs combined proceedings.

1565 CDM Expenditures and Recoveries

Description: This account records the amount spent on Board approved CDM programs and the revenue proxy equivalent to Clinton Power, Erie Thames Powerlines and West Perth Power's third tranche of MARR. Clinton Power, Erie Thames Powerlines and West Perth Power never calculated any carrying charges on this account, even prior to February 28, 2005. This account came to an end at December 31, 2007.

1566 CDM Expenditures and Recoveries Contra

Description: This account is the contra account to Acct 1565. Clinton Power, Erie Thames Powerlines and West Perth Power never calculated any carrying charges on this account, even prior to February 28, 2005. This account came to an end at December 31, 2007.

1590 Recovery of Regulatory Asset Balances

Description: This account records the net of amounts collected from customers from the 2006 EDR Regulatory Asset filing. This Regulatory Asset rate rider was removed from Clinton Power, Erie Thames Powerlines and West Perth Power's Distribution Rates effective May 1, 2008. Separate sub-accounts are maintained for expenses, interest, and recovery amounts.

2405 Other Regulatory Liabilities

Description: Accrued low voltage charges from Hydro One for periods prior to May 1, 2006. The liabilities owing to Hydro One were set up when determined and are billed monthly as a standard charge by Hydro One on their monthly low voltage bills. This balance is owed to Hydro One; not our customers. This account will come to an end when Hydro One has been fully paid in February 2010. A residual will remain at that time requiring disposition.

Calculation of Carrying Charges:

Carrying charges have been applied to all variance accounts, except the CDM accounts (#1565 & #1566). Nor are there any carrying charges on #Acct 1525 Miscellaneous deferred debits, which is a small balance of $1,145 recorded in December 2010. For all other variance accounts, previous to April 30, 2006, Clinton Power, Erie Thames Powerlines and West Perth Power applied a rate of interest equal to its deemed interest rate for debt of 7.25%, as per Chapter 3 of the 2000 Electricity Distribution Handbook. Effective May 1, 2006, the rate of interest being applied is the rate prescribed by the Board for approved deferred and variance accounts. Carrying charges are calculated using simple interest applied to the monthly opening balance in the account (excluding accumulated interest). Another exception to the calculations noted above was for account # 1508 OEB Cost assessment and Pension contributions, which were subject to an annual rate of 3.88% up to April 30, 2006, and the Board prescribed rate thereafter.

TABLE OF INTEREST RATES USED FOR VARIANCE ACCOUNTS

May 2002 to April 30, 2006	7.25%
Q2 2006	4.14%
Q3 2006 to Q3 2007	4.59%
Q4 2007 to Q1 2008	5.14%
Q2 2008	4.08%
Q3 2008 to Q4 2008	3.35%
Q1 2009	2.45%
Q2 2009	1.00%
Q3 2009 to Q2 2010	0.55%
Q3 2010	0.89%
Q4 2010	1.20%
Q1 2011 to Q1 2012	1.47%

CLEARANCE OF DEFFERAL and VARIANCE ACCOUNTS - REQUEST FOR DISPOSITION BY WAY OF A DEFERRAL AND VARIANCE ACCOUNT RATE RIDER

1580 RSVA – Wholesale Market Charge

Disposal of principal balance as at December 31, 2010 of $(433,996) for ETPL, $2,157 for CPC and $8,245 for WPPI and interest owing to April 30, 2012 and forecasted over a one year period is requested. Method of recovery: Allocation to rate classes on basis of 2010 kWh sales.

1582 RSVA – Wholesale Market – One time charges

Disposal of principal balance as at December 31, 2010 of $49,454 for ETPL, $1,338 for CPC and $6,527 for WPPI and interest receivable to April 30, 2012 and projected over a one year period as requested. Method of recovery: Allocation to rate classes on basis of 2010 kWh sales.

1584 RSVA – Retail Transmission Network Charge

Disposal of principal balance as at December 31, 2010 of $14,756 for ETPL, $(41,763) for CPC and $(47,698) for WPPI and interest owing to April 30, 2012 over a one year period is requested. Method of recovery: Allocation to rate classes on basis of 2010 kWh sales.

1586 RSVA – Retail Transmission Connection Charge

Disposal of principal balance as at December 31, 2010 of $(473,329) for ETPL, $(638,688) for CPC and $(1,056,006) for CPC and interest owing to April 30, 2012 of over a one year period is requested. Method of recovery: Allocation to rate classes on basis of 2010 kWh sales.

1588 RSVA – Power – Sub account Global Adjustment

Clinton Power, Erie Thames Powerlines and West Perth Power has segregated the RSVA Power account into two segments for purposes of disposition – sub account global adjustment and remainder of 1588. Clinton Power, Erie Thames Powerlines and West Perth Power is requesting disposal of sub account global adjustment principal balance as at December 31, 2010 of $934,081 for ETPL, $(364,833) for CPC and $(352,362) for WPPI and interest owing to April 30, 2012 over a oneyear period. Method of recovery: Allocation to rate classes on basis of

2010 kWh sales to non –RPP customers. Historical data of kWh sales to non-RPP customers has been used to determine the portion of 2010 forecasted kWh sales which would be sold to each class of non-RPP customers.

1588 RSVA – Power – Remainder after Sub account Global Adjustment

Clinton Power, Erie Thames Powerlines and West Perth Power has segregated the RSVA Power account into two segments for purposes of disposition – sub account global adjustment and remainder of 1588. Clinton Power, Erie Thames Powerlines and West Perth Power is requesting disposal of the remainder, after removal of the sub account global adjustment. Disposal of the remaining principal balance as at December 31, 2010 of $837,496 for ETPL, $951,946 for CPC and $713,716 for WPPI and interest owing to April 30, 2012 over a one year period is requested. Method of recovery: Allocation to rate classes on basis of 2010 kWh sales.

1550 Low Voltage (LV) Variance Account

Disposal of principal balance as at December 31, 2010 of $(318,209) for ETPL, $444,684 for CPC and $114,431 for WPPI and interest receivable to April 30, 2012 over a one year period is requested. Method of recovery: Allocation to rate classes on basis of 2010 kWh sales.

1590 Regulatory Asset Recovery Variance Account

Disposal of principal balance as at December 31, 2012 of $405,734 or ETPL of $36,198 for CPC and $(10,704) for WPPI and interest payable to April 30, 2012 of $111,621 over a one year period is requested. Method of recovery: Allocation to rate classes on basis of 2010 kWh sales.

Accounts Requested for Disposition

Erie Thames Powerlines	*Principal Amount Dec. 2010*	*Interest Amount to Dec. 2010*	*Interest for 2011*	*Interest Jan 2012 to April 2012*	*Total Claim for 2010 Balances*
1550	$ (318,209.36)	$ (923.30)	$ (4,287.87)	$ (1,559.23)	$ (324,979.76)
1580	$ (433,995.96)	$ (74,837.48)	$ (6,379.75)	$ (2,126.58)	$ (517,339.77)
1584	$ 14,755.90	$ (11,282.37)	$ 216.91	$ 72.30	$ 3,762.74
1586	$ (473,329.15)	$ (39,540.30)	$ (6,957.94)	$ (2,319.31)	$ (522,146.70)
1588	$ 837,496.36	$ (184,518.56)	$ 12,311.20	$ 4,103.73	$ 669,392.73
1588	$ 934,081.26	$ 12,818.90	$ 13,730.99	$ 4,577.00	$ 965,208.15
1590	$ 405,734.25	$ (124,291.48)	$ 5,964.29	$ 1,988.10	$ 289,395.16
SubTotal	**$ 966,533.30**	**$ (422,574.59)**	**$ 14,597.83**	**$ 4,736.01**	**$ 563,292.55**
1582	$ 49,454.07	$ 8,156.75	$ 726.97	$ 242.32	$ 58,580.11
1521			$ 739.48	$ 246.49	$ 985.97
SubTotal	**$ 49,454.07**	**$ 8,156.75**	**$ 1,466.45**	**$ 488.81**	**$ 59,566.08**
Grand total	**$ 1,015,987.37**	**$ (414,417.84)**	**$ 16,064.28**	**$ 5,224.82**	**$ 622,858.63**

Clinton Power	*Principal Amount Dec. 2010*	*Interest Amount to Dec. 2010*	*Interest for 2011*	*Interest Jan 2012 to April 2012*	*Total Claim for 2010 Balances*
1550	$ 444,684.47	$ 24,679.94	$ 6,536.86	$ 2,178.95	$ 478,080.22
1580	$ 2,157.33	$ (7,244.75)	$ 31.72	$ 10.57	$ (5,045.13)
1584	$ (41,762.65)	$ (471.20)	$ (613.91)	$ (204.64)	$ (43,052.40)
1586	$ (638,687.99)	$ (45,435.74)	$ (9,388.71)	$ (3,129.57)	$ (696,642.01)
1588	$ 951,946.44	$ 47,919.15	$ 13,993.61	$ 4,664.54	$ 1,018,523.74
1588	$ (364,833.41)	$ (4,267.24)	$ (5,363.05)	$ (1,787.68)	$ (376,251.38)
1590	$ 36,198.59	$ 8,617.29	$ -	$ -	$ 44,815.88
SubTotal	**$ 389,702.78**	**$ 23,797.45**	**$ 5,196.52**	**$ 1,732.17**	**$ 420,428.92**
1508	$ 74,846.00	$ 582.39	$ 1,191.92	$ 366.75	$ 76,987.06
1582	$ 1,338.00	$ 193.59	$ 19.67	$ 6.56	$ 1,557.82
1521		$ -	$ 68.07	$ 22.69	$ 90.76
SubTotal	**$ 76,184.00**	**$ 775.98**	**$ 1,279.66**	**$ 396.00**	**$ 78,635.64**
Grand Total	**$ 465,886.78**	**$ 24,573.43**	**$ 6,476.18**	**$ 2,128.17**	**$ 499,064.56**

West Perth Power	Principal Amount Dec. 2010	Interest Amount to Dec. 2010	Interest for 2011	Interest Jan 2012 to April 2012	Total Claim for 2010 Balances
1550	$ 114,430.72	$ 8,530.45	$ 1,682.13	$ 560.71	$ 125,204.01
1580	$ 8,245.42	$ 27,317.60	$ 121.21	$ 40.40	$ 35,724.63
1584	$ (47,698.07)	$ 1,465.58	$ (701.16)	$ (233.72)	$ (47,167.37)
1586	$ (1,056,006.59)	$ (41,096.27)	$ (15,523.30)	$ (5,174.43)	$ (1,117,800.59)
1588	$ 713,716.35	$ 46,609.57	$ 10,491.63	$ 3,497.21	$ 774,314.76
1588	$ (352,361.60)	$ 5,013.36	$ (5,179.72)	$ (1,726.57)	$ (354,254.53)
1590	$ (10,704.34)	$ (3,689.12)	$ (157.35)	$ (52.45)	$ (14,603.26)
SubTotal	**$ (630,378.11)**	**$ 44,151.17**	**$ (9,266.56)**	**$ (3,088.85)**	**$ (598,582.35)**
1508	$ 80,000.00	$ -	$ 1,176.00	$ 392.00	$ 81,568.00
1508	$ 20,801.15	$ 3,197.29	$ 305.78	$ 101.93	$ 24,406.15
1582	$ 6,527.33	$ 1,050.60	$ 95.95	$ 31.98	$ 7,705.86
1521	$ -	$ -	$ 113.09	$ 37.70	$ 150.79
SubTotal	**$ 107,328.48**	**$ 4,247.89**	**$ 1,690.82**	**$ 563.61**	**$ 113,830.80**
Grand Total	**$ (523,049.63)**	**$ 48,399.06**	**$ (7,575.74)**	**$ (2,525.24)**	**$ (484,751.55)**

Method of Disposition

The following table details the calculations used to determine the proposed regulatory asset rate rider by customer class.

Erie Thames Powerlines						
Request for Disposition	**$ (342,349.52)**	Excluding1588 GA				
					One Year	
			Reg Asset Amnt	***Determinant***	***Rate Rider***	
	Residential	32.59%	$ (111,569.95)	119,707,075	$ (0.0009)	kWh
	GS < 50 kW	10.09%	$ (34,558.56)	37,037,700	$ (0.0009)	kWh
	GS>50 to 999 kW	7.64%	$ (26,156.46)	39,648	$ (0.6597)	kW
	GS>1000 kW to 4999 k	18.82%	$ (64,422.98)	123,604	$ (0.5212)	kW
	Large Use	25.05%	$ (85,764.10)	160,146	$ (0.5355)	kW
	Sentinel Lighting	0.06%	$ (206.43)	603	$ (0.3421)	kW
	Street Lights	0.85%	$ (2,922.26)	10,730	$ (0.2723)	kW
	Embedded	4.75%	$ (16,254.12)	23,768	$ (0.6839)	kW
	Unmetered	0.14%	$ (494.66)	545,982	$ (0.0009)	kWh
	Total	100.00%	**$ (342,349.52)**			
Global Adjustment Disposition			***Reg Asset Amnt***	***Determinant***	***Rate Rider***	
	Residential	12.36%	$ 119,275.91	119,707,075	$ 0.0010	kWh
	GS < 50 kW	5.18%	$ 49,999.05	37,037,700	$ 0.0013	kWh
	GS>50 to 999 kW	11.02%	$ 106,351.73	39,648	$ 2.6824	kW
	GS>1000 kW to 4999 k	27.14%	$ 261,942.74	123,604	$ 2.1192	kW
	Large Use	36.13%	$ 348,715.38	160,146	$ 2.1775	kW
	Sentinel Lighting	0.00%	$ -	603	$ -	kW
	Street Lights	1.30%	$ 12,539.11	10,730	$ 1.1686	kW
	Embedded	6.85%	$ 66,088.99	23,768	$ 2.7806	kW
	Unmetered	0.03%	$ 295.24	545,982	$ 0.0005	kWh
	Total	100.00%	**$ 965,208.15**			
		Non RPP kWh	**Class Allocation**	**Billed KWh**	**Class Allocation**	
	Residential	31,616,674	12.36%	120,247,549	32.59%	
	GS < 50 kW	13,253,336	5.18%	37,246,433	10.09%	
	GS>50 to 999 kW	28,190,839	11.02%	28,190,839	7.64%	
	GS>1000 kW to 4999 k	69,433,617	27.14%	69,433,617	18.82%	
	Large Use	92,434,594	36.13%	92,434,594	25.05%	
	Sentinel Lighting	-	0.00%	222,490	0.06%	
	Street Lights	3,323,762	1.30%	3,149,541	0.85%	
	Embedded	17,518,323	6.85%	17,518,323	4.75%	
	Unmetered	78,260	0.03%	533,136	0.14%	
		255,849,406	**100%**	**368,976,522**	**100%**	

Clinton Power							
Request for Disposition	**$ 875,315.94**	Excluding1588 GA					
					One Year		***Two Year***
			Reg Asset Amnt	***Determinant***	***Rate Rider***		***Rate Rider***
	Residential	32.59%	$ 285,260.96	11,660,000	$ 0.0245	kWh	$ 0.0122
	GS < 50 kW	10.09%	$ 88,359.00	5,422,967	$ 0.0163	kWh	$ 0.0081
	GS>50 to 999 kW	56.26%	$ 492,431.83	36,991	$ 13.3123	kW	$ 6.6561
	Sentinel Lighting	0.06%	$ 527.81	121	$ 4.3729	kW	$ 2.1865
	Street Lights	0.85%	$ 7,471.60	1,009	$ 7.4028	kW	$ 3.7014
	Unmetered	0.14%	$ 1,264.75	56,040	$ 0.0226	kWh	$ 0.0113
	Total	100.00%	**$ 875,315.94**				
							Two Year
Global Adjustment Disposition			***Reg Asset Amnt***	***Determinant***	***Rate Rider***		***Rate Rider***
	Residential	35.22%	$ (132,497.49)	11,660,000	$ (0.0114)	kWh	$ (0.0057)
	GS < 50 kW	16.51%	$ (62,104.17)	5,422,967	$ (0.0115)	kWh	$ (0.0057)
	GS>50 to 999 kW	47.02%	$ (176,900.35)	36,991	$ (4.7823)	kW	$ (2.3911)
	Sentinel Lighting	0.11%	$ (426.96)	121	$ (3.5374)	kW	$ (1.7687)
	Street Lights	0.97%	$ (3,631.30)	1,009	$ (3.5978)	kW	$ (1.7989)
	Unmetered	0.18%	$ (691.12)	56,040	$ (0.0123)	kWh	$ (0.0062)
	Total	100.00%	**$ (376,251.38)**				
		Non RPP kWh	**Class Allocation**	**Billed KWh**	**Class Allocation**		
	Residential	9,127,296.99	35.22%	11,595,218	38.79%		
	GS < 50 kW	4,278,142.83	16.51%	5,392,837	18.04%		
	GS>50 to 999 kW	12,186,057.79	47.02%	12,430,258	41.59%		
	Sentinel Lighting	29,411.97	0.11%	44,498	0.15%		
	Street Lights	250,147.52	0.97%	372,098	1.24%		
	Unmetered	47,608.91	0.18%	56,040	0.19%		
		25,918,666.01	**100%**	**29,890,948**	**100%**		

West Perth Power						
Request for Disposition	**$ (130,497.02)**	Excluding1588 GA				
					One Year	
			Reg Asset Amnt	*Determinant*	*Rate Rider*	
	Residential	27.13%	$ (35,402.58)	27,963,560	$ (0.0013)	kWh
	GS < 50 kW	13.03%	$ (17,007.10)	16,297,712	$ (0.0010)	kWh
	GS>50 to 999 kW	59.04%	$ (77,049.31)	78,630	$ (0.9799)	kW
	Sentinel Lighting	0.03%	$ (38.73)	64	$ (0.6037)	kW
	Street Lights	0.74%	$ (963.79)	2,896	$ (0.3328)	kW
	Unmetered	0.03%	$ (35.51)	166,487	$ (0.0002)	kWh
	Total	100.00%	**$ (130,497.02)**			
Global Adjustment Disposition			*Reg Asset Amnt*	*Determinant*	*Rate Rider*	
	Residential	22.72%	$ (80,487.46)	27,963,560	$ (0.0029)	kWh
	GS < 50 kW	10.78%	$ (38,180.16)	16,297,712	$ (0.0023)	kWh
	GS>50 to 999 kW	65.64%	$ (232,532.80)	78,630	$ (2.9573)	kW
	Sentinel Lighting	0.02%	$ (70.50)	64	$ (1.0992)	kW
	Street Lights	0.82%	$ (2,908.69)	2,896	$ (1.0044)	kW
	Unmetered	0.02%	$ (74.91)	166,487	$ (0.0004)	kWh
	Total	100.00%	**$ (354,254.53)**			
		Non RPP kWh	**Class Allocation**	**Billed KWh**	**Class Allocation**	
	Residential	12,257,684.66	22.72%	16,271,614	27.13%	
	GS < 50 kW	5,814,575.35	10.78%	7,816,746	13.03%	
	GS>50 to 999 kW	35,413,140.45	65.64%	35,413,140	59.04%	
	Sentinel Lighting	10,737.25	0.02%	17,799	0.03%	
	Street Lights	442,973.41	0.82%	442,973	0.74%	
	Unmetered	11,408.30	0.02%	16,319	0.03%	
		53,950,519.42	**100%**	**59,978,592**	**100%**	

Proposed Rates and Bill Impacts

The following table summarizes the proposed Regulatory Asset Recovery rates by class and the impact of those rates. For the rate classes which have been allocated a portion of the non RPP kWh and in turn the credit balance of the Global Adjustment account the impact is a reduction in their rates. For the remaining classes the total annual amount is an immaterial number and will be a minimum cost impact to the customer class.

Erie Thames Powerlines Propsed Rates					
	Units	**Rate Rider**	**Rate Rider GA**	**Impact**	**Impact GA**
Residential	kWh	$ (0.0009)	$ 0.0010	-4.68%	-0.55%
GS<50 kW	kWh	$ (0.0009)	$ 0.0013	-12.47%	1.08%
GS>50 - 999 kW	kW	$ (0.6597)	$ 2.6824	-0.18%	0.49%
GS>1000 - 4999 kW	kW	$ (0.5212)	$ 2.1192	-1.60%	1.70%
Large Use	kW	$ (0.5355)	$ 2.1775	-9.75%	11.45%
Street Lights	kW	$ (0.2723)	$ 1.1686	-0.11%	0.45%
Sentinel Lights	kW	$ (0.3421)	$ -	-1.06%	0.00%
Unmetered Scattered Load	kWh	$ (0.0009)	$ 0.0005	-1.42%	0.33%
Embedded	kW	$ (0.6839)	$ 2.7806	-2.93%	7.71%

West Perth Power DVAD Proposed Rates					
	Units	**Rate Rider**	**Rate Rider GA**	**Impact**	**Impact GA**
Residential	kWh	$ (0.0013)	$ (0.0029)	-3.57%	-8.11%
GS<50 kW	kWh	$ (0.0010)	$ (0.0023)	-7.84%	-17.60%
GS>50 - 999 kW	kW	$ (0.9799)	$ (2.9573)	-0.38%	-0.57%
Street Lights	kW	$ (0.3328)	$ (1.0044)	-0.89%	-2.70%
Sentinel Lights	kW	$ (0.6037)	$ (1.0992)	-2.41%	-7.26%
Unmetered Scattered Load	kWh	$ (0.0002)	$ (0.0004)	-0.08%	-0.23%

Clinton Power DVAD Proposed Rates					
		Two Year			
	Units	**Rate Rider**	**Rate Rider GA**	**Impact**	**Impact GA**
Residential	kWh	$ 0.0122	$ (0.0114)	8.47%	-9.77%
GS<50 kW	kWh	$ 0.0081	$ (0.0115)	41.78%	-65.24%
GS>50 - 999 kW	kW	$ 6.6561	$ (4.7823)	236.00%	-1.85%
Street Lights	kW	$ 2.1865	$ (3.5978)	22.83%	-36.94%
Sentinel Lights	kW	$ 3.7014	$ (3.5374)	3.90%	-9.65%
Unmetered Scattered Load	kWh	$ 0.0113	$ (0.0123)	8.07%	-13.05%

Deferral and Variance Account Continuity Schedule

The following pages contain the continuity schedule for the deferral and variance account of Clinton Power, Erie Thames Powerlines and West Perth Power. The balances being claimed for recovery or refund are as at the year ending balances of December 31st, 2010 plus calculated interest on these balances to April 30th, 2012.

Erie Thames Powerlines Continuity Schedule

Account Descriptions	Account Number	2005 Opening Principal Amounts as of Jan-1-05	Transactions Debit/(Credit) during 2005 excluding interest and adjustments [6]	Board-Approved Disposition during 2005	Adjustments during 2005 - other [3]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec-31-05	Board-Approved Disposition during 2005	Adjustments during 2005 - other [3]	Closing Interest Amounts as of Dec-31-05
Group 1 Accounts											
LV Variance Account	1550					$ -					$ -
RSVA - Wholesale Market Service Charge	1580	$ 772,480	$ 398,913			$ 1,171,393	$ 117,496	$ 66,010			$ 183,506
RSVA - Retail Transmission Network Charge	1584	$ 134,346	$ 55,528			$ 189,874	$ 20,799	$ 5,175			$ 25,975
RSVA - Retail Transmission Connection Charge	1586	$ 1,749	$ 18,120			$ 19,869	$ 8,732	-$ 4,622			$ 4,110
RSVA - Power (excluding Global Adjustment)	1588	$ 2,063,983	$ 1,255,621			$ 3,319,604	$ 258,423	$ 193,830			$ 452,253
RSVA - Power - Sub-Account - Global Adjustment	1588		-$ 567,222			-$ 567,222		-$ 18,271			-$ 18,271
Recovery of Regulatory Asset Balances	1590	-$ 267,744	-$ 846,992			-$ 1,114,737	$ -	-$ 43,959			-$ 43,959
Disposition and Recovery of Regulatory Balances (2008)[10]	1595					$ -					$ -
Disposition and Recovery of Regulatory Balances (2009)[10]	1595					$ -					$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ 2,704,815	$ 313,967	$ -	$ -	$ 3,018,782	$ 405,450	$ 198,163	$ -	$ -	$ 603,613
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ 2,704,815	$ 881,189	$ -	$ -	$ 3,586,004	$ 405,450	$ 216,434	$ -	$ -	$ 621,884
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	-$ 567,222	$ -	$ -	-$ 567,222	$ -	-$ 18,271	$ -	$ -	-$ 18,271
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508					$ -					$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508					$ -					$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508					$ -					$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Other [7]	1508					$ -					$ -
Retail Cost Variance Account - Retail	1518					$ -					$ -
Misc. Deferred Debits	1525					$ -					$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -					$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -					$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -					$ -
Smart Grid Capital Deferral Account	1534					$ -					$ -
Smart Grid OM&A Deferral Account	1535					$ -					$ -
Smart Grid Funding Adder Deferral Account	1536					$ -					$ -
Retail Cost Variance Account - STR	1548					$ -					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555					$ -					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555					$ -					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555					$ -					$ -
Smart Meter OM&A Variance	1556					$ -					$ -
Conservation and Demand Management (CDM) Expenditures and Recoveries	1565					$ -					$ -
CDM Contra	1566					$ -					$ -
Qualifying Transition Costs [5]	1570					$ -					$ -
Pre-market Opening Energy Variance [5]	1571					$ -					$ -
Extra-Ordinary Event Costs	1572					$ -					$ -
Deferred Rate Impact Amounts	1574					$ -					$ -
RSVA - One-time	1582	$ 32,241	*$ 23,604*			$ 55,845	$ 2,443	$ 2,981			$ 5,424
Other Deferred Credits	2425					$ -					$ -
Group 2 Sub-Total		$ 32,241	$ 23,604	$ -	$ -	$ 55,845	$ 2,443	$ 2,981	$ -	$ -	$ 5,424
Deferred Payments in Lieu of Taxes	1562	$ 108,752	*-$ 24,454*			$ 84,298	$ 33,017	$ 6,723			$ 39,740
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592					$ -					$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592					$ -					$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ 2,737,056	$ 337,572	$ -	$ -	$ 3,074,628	$ 407,893	$ 201,144	$ -	$ -	$ 609,037
Special Purpose Charge Assessment Variance Account	**1521**										
Total including Account 1521 [1]		$ 2,737,056	$ 337,572	$ -	$ -	$ 3,074,628	$ 407,893	$ 201,144	$ -	$ -	$ 609,037
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [8]	1563					$ -					$ -
Board-Approved CDM Variance Account	1567										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592					$ -					$ -
Disposition and Recovery of Regulatory Balances[10]	1595					$ -					$ -

2006

Opening Principal Amounts as of Jan-1-06	Transactions Debit/ (Credit) during 2006 excluding interest and adjustments [6]	Board-Approved Disposition during 2006 [2, 2A]	Adjustments during 2006 - other [3]	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec-31-06	Board-Approved Disposition during 2006 [2, 2A]	Adjustments during 2006 - other [3]	Closing Interest Amounts as of Dec-31-06
$ -	$ 342,769			$ 342,769	$ -	$ 5,918			$ 5,918
$ 1,171,393	-$ 500,849			$ 670,544	$ 183,506	$ 49,914			$ 233,420
$ 189,874	-$ 91,841			$ 98,033	$ 25,975	$ 6,936			$ 32,911
$ 19,869	-$ 392,281			-$ 372,412	$ 4,110	-$ 2,802			$ 1,308
$ 3,319,604	-$ 346,034			$ 2,973,570	$ 452,253	$ 148,491			$ 600,744
-$ 567,222	$ 752,671			$ 185,449	-$ 18,271	-$ 6,930			-$ 25,201
-$ 1,114,737	-$ 831,946			-$ 1,946,682	-$ 43,959	-$ 60,513			-$ 104,473
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ 3,018,782	-$ 1,067,511	$ -	$ -	$ 1,951,271	$ 603,613	$ 141,014	$ -	$ -	$ 744,627
$ 3,586,004	-$ 1,820,182	$ -	$ -	$ 1,765,822	$ 621,884	$ 147,944	$ -	$ -	$ 769,828
-$ 567,222	$ 752,671	$ -	$ -	$ 185,449	-$ 18,271	-$ 6,930	$ -	$ -	-$ 25,201
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$ -	-$ 22,207			-$ 22,207	$ -	-$ 485			-$ 485
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$ -				$ -	$ -				$ -
$ 55,845			$ 15,850	$ 71,695	$ 5,424	$ 3,236			$ 8,660
$ -				$ -	$ -				$ -
$ 55,845	-$ 22,207	$ -	$ 15,850	$ 49,488	$ 5,424	$ 2,750	$ -	$ -	$ 8,174
$ 84,298			-$ 44,374	$ 39,924	$ 39,740	$ 4,251			$ 43,991
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ 3,074,628	-$ 1,089,718	$ -	$ 15,850	$ 2,000,759	$ 609,037	$ 143,764	$ -	$ -	$ 752,801
$ 3,074,628	-$ 1,089,718	$ -	$ 15,850	$ 2,000,759	$ 609,037	$ 143,764	$ -	$ -	$ 752,801
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -

2007

Opening Principal Amounts as of Jan-1-07	Transactions Debit/ (Credit) during 2007 excluding interest and adjustments [6]	Board-Approved Disposition during 2007	Adjustments during 2007 - other [3]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec-31-07	Board-Approved Disposition during 2007	Adjustments during 2007 - other [3]	Closing Interest Amounts as of Dec-31-07
$ 342,769	$ 155,399			$ 498,168	$ 5,918	$ 19,838			$ 25,756
$ 670,544	-$ 488,624	$ 541,220		-$ 359,300	$ 233,420	-$ 2,275	$ 192,329		$ 38,815
$ 98,033	$ 75,966	-$ 29,186		$ 203,186	$ 32,911	$ 7,119	$ 32,902		$ 7,128
-$ 372,412	$ 11,969	-$ 185,827		-$ 174,616	$ 1,308	-$ 4,509	$ 44,937		-$ 48,138
$ 2,973,570	$ 548,389	$ 378,587		$ 3,143,372	$ 600,744	$ 138,392	$ 470,411		$ 268,725
$ 185,449	-$ 45,015			$ 140,434	-$ 25,201	$ 2,845			-$ 22,356
-$ 1,946,682	-$ 1,106,969	-$ 3,372,458		$ 318,806	-$ 104,473	-$ 5,480			-$ 109,953
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ 1,951,271	-$ 848,885	-$ 2,667,664	$ -	$ 3,770,050	$ 744,627	$ 155,930	$ 740,579	$ -	$ 159,978
$ 1,765,822	-$ 803,870	-$ 2,667,664	$ -	$ 3,629,616	$ 769,828	$ 153,085	$ 740,579	$ -	$ 182,334
$ 185,449	-$ 45,015	$ -	$ -	$ 140,434	-$ 25,201	$ 2,845	$ -	$ -	-$ 22,356
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-$ 22,207	$ 19,487			-$ 2,720	-$ 485	-$ 2,033			-$ 2,518
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$ -	$ 2,853			$ 2,853	$ -	$ 63			$ 63
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$ 71,695		$ 22,241		$ 49,454	$ 8,660	$ 2,338	$ 5,766		$ 5,232
$ -				$ -	$ -				$ -
$ 49,488	$ 22,340	$ 22,241	$ -	$ 49,587	$ 8,174	$ 369	$ 5,766	$ -	$ 2,777
$ 39,924			-$ 22,107	$ 17,817	$ 43,991	$ 3,945			$ 47,936
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ 2,000,759	-$ 826,545	-$ 2,645,423	$ -	$ 3,819,637	$ 752,801	$ 156,299	$ 746,345	$ -	$ 162,755
$ 2,000,759	-$ 826,545	-$ 2,645,423	$ -	$ 3,819,637	$ 752,801	$ 156,299	$ 746,345	$ -	$ 162,755
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2008

Opening Principal Amounts as of Jan-1-08	Transactions Debit/ (Credit) during 2008 excluding interest and adjustments [6]	Board-Approved Disposition during 2008	Adjustments during 2008 - other [3]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec-31-08	Board-Approved Disposition during 2008	Adjustments during 2008 - other [3]	Closing Interest Amounts as of Dec-31-08
$ 498,168	$ 70,302			$ 568,469	$ 25,756	$ 21,455			$ 47,211
-$ 359,300	-$ 314,813			-$ 674,113	$ 38,815	-$ 17,833			$ 20,982
$ 203,186	-$ 291,780			-$ 88,594	$ 7,128	$ 6,137			$ 13,265
-$ 174,616	-$ 326,797			-$ 501,413	-$ 48,138	-$ 10,387			-$ 58,525
$ 3,143,372	-$ 595,576			$ 2,547,796	$ 268,725	$ 135,362			$ 404,087
$ 140,434	$ 234,565			$ 374,998	-$ 22,356	$ 6,709			-$ 15,647
$ 318,806	-$ 989,101			-$ 670,295	-$ 109,953	-$ 5,730			-$ 115,683
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ 3,770,050	-$ 2,213,200	$ -	$ -	$ 1,556,850	$ 159,978	$ 135,713	$ -	$ -	$ 295,691
$ 3,629,616	-$ 2,447,765	$ -	$ -	$ 1,181,851	$ 182,334	$ 129,004	$ -	$ -	$ 311,338
$ 140,434	$ 234,565	$ -	$ -	$ 374,998	-$ 22,356	$ 6,709	$ -	$ -	-$ 15,647
$ -				$ -	$ -				$ -
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-$ 2,720	-$ 32,379			-$ 35,099	-$ 2,518	-$ 525			-$ 3,043
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ 2,853	$ 6,479			$ 9,331	$ 63	$ 219			$ 283
$ -				$ -	$ -				$ -
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$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ 49,454				$ 49,454	$ 5,232	$ 1,968			$ 7,200
$ -				$ -	$ -				$ -
$ 49,587	-$ 25,901	$ -	$ -	$ 23,686	$ 2,777	$ 1,662	$ -	$ -	$ 4,439
$ 17,817				$ 17,817	$ 47,936	$ 709			$ 48,645
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ 3,819,637	-$ 2,239,101	$ -	$ -	$ 1,580,536	$ 162,755	$ 137,375	$ -	$ -	$ 300,130
$ 3,819,637	-$ 2,239,101	$ -	$ -	$ 1,580,536	$ 162,755	$ 137,375	$ -	$ -	$ 300,130
$ -				$ -	$ -				$ -
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2009

Opening Principal Amounts as of Jan-1-09	Transactions Debit/ (Credit) during 2009 excluding interest and adjustments [6]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [3]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009	Adjustments during 2009 - other [3]	Closing Interest Amounts as of Dec-31-09
$ 568,469	-$ 174,451	$ 342,769		$ 51,249	$ 47,211	$ 3,298	$ 27,995		$ 22,514
-$ 674,113	-$ 75,538			-$ 749,651	$ 20,982	-$ 6,001			$ 14,981
-$ 88,594	-$ 36,867			-$ 125,462	$ 13,265	-$ 96			$ 13,168
-$ 501,413	-$ 254,115			-$ 755,528	-$ 58,525	-$ 5,370			-$ 63,895
$ 2,547,796	-$ 20,115			$ 2,527,682	$ 404,087	$ 41,433			$ 445,521
$ 374,998	$ 752,272			$ 1,127,271	-$ 15,647	$ 10,094			-$ 5,553
-$ 670,295	-$ 177,119			-$ 847,414	-$ 115,683	-$ 8,373			-$ 124,056
$ -				$ -	$ -				$ -
$ -	$ 47,746	-$ 370,764		$ 418,510	$ -	$ 3,645			$ 3,645
$ 1,556,850	$ 61,813	-$ 27,995	$ -	$ 1,646,658	$ 295,691	$ 38,630	$ 27,995	$ -	$ 306,326
$ 1,181,851	-$ 690,459	-$ 27,995	$ -	$ 519,387	$ 311,338	$ 28,536	$ 27,995	$ -	$ 311,879
$ 374,998	$ 752,272	$ -	$ -	$ 1,127,271	-$ 15,647	$ 10,094	$ -	$ -	-$ 5,553
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-$ 35,099	-$ 76,692			-$ 111,791	-$ 3,043	-$ 575			-$ 3,618
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ 9,331	$ 13,182			$ 22,513	$ 283	$ 136			$ 419
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$ -				$ -	$ -				$ -
$ 49,454				$ 49,454	$ 7,200	$ 563			$ 7,762
$ -				$ -	$ -				$ -
$ 23,686	-$ 63,511	$ -	$ -	-$ 39,824	$ 4,439	$ 124	$ -	$ -	$ 4,563
$ 17,817				$ 17,817	$ 48,645	$ 203			$ 48,847
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ 1,580,536	-$ 1,697	-$ 27,995	$ -	$ 1,606,834	$ 300,130	$ 38,754	$ 27,995	$ -	$ 310,889
$ 1,580,536	-$ 1,697	-$ 27,995	$ -	$ 1,606,834	$ 300,130	$ 38,754	$ 27,995	$ -	$ 310,889
$ -				$ -	$ -				$ -
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2010

Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [6]	Board-Approved Disposition during 2010	Other [3] Adjustments during Q1 2010	Other [3] Adjustments during Q2 2010	Other [3] Adjustments during Q3 2010	Other [3] Adjustments during Q4 2010	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other [3]	Closing Interest Amounts as of Dec-31-10
$ 51,249	-$ 143,759	$ 225,700					-$ 318,209	$ 22,514	-$ 1,261	$ 22,176		-$ 923
-$ 749,651	-$ 358,507	-$ 674,162					-$ 433,996	$ 14,981	-$ 2,844	$ 86,974		-$ 74,837
-$ 125,462	$ 114,349	-$ 25,868					$ 14,756	$ 13,168	$ 578	$ 25,029		-$ 11,282
-$ 755,528	-$ 208,870	-$ 491,069					-$ 473,329	-$ 63,895	-$ 3,456	-$ 27,810		-$ 39,540
$ 2,527,682	$ 751,443	$ 2,441,628					$ 837,496	$ 445,521	$ 18,058	$ 648,098		-$ 184,519
$ 1,127,271	$ 181,808	$ 374,998					$ 934,081	-$ 5,553	$ 7,644	-$ 10,728		$ 12,819
-$ 847,414	$ 5,960	-$ 1,247,188					$ 405,734	-$ 124,056	-$ 236			-$ 124,291
$ -							$ -	$ -				$ -
$ 418,510	-$ 436,983	-$ 1,347,778					$ 1,329,305	$ 3,645	$ 5,469			$ 9,114
$ 1,646,658	-$ 94,558	-$ 743,739	$ -	$ -	$ -	$ -	$ 2,295,838	$ 306,326	$ 23,953	$ 743,739	$ -	-$ 413,460
$ 519,387	-$ 276,367	-$ 1,118,737	$ -	$ -	$ -	$ -	$ 1,361,757	$ 311,879	$ 16,309	$ 754,467	$ -	-$ 426,279
$ 1,127,271	$ 181,808	$ 374,998	$ -	$ -	$ -	$ -	$ 934,081	-$ 5,553	$ 7,644	-$ 10,728	$ -	$ 12,819
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-$ 111,791	$ 1,367,252						$ 1,255,461	-$ 3,618	$ 3,598			-$ 20
$ -							$ -	$ -				$ -
$ -							$ -	$ -				$ -
$ 22,513	$ 108,598						$ 131,111	$ 419	$ 656			$ 1,075
$ -							$ -	$ -				$ -
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$ -							$ -	$ -				$ -
$ -							$ -	$ -				$ -
$ -							$ -	$ -				$ -
$ 49,454							$ 49,454	$ 7,762	$ 394			$ 8,157
$ -							$ -	$ -				$ -
-$ 39,824	$ 1,475,850	$ -	$ -	$ -	$ -	$ -	$ 1,436,026	$ 4,563	$ 4,649	$ -	$ -	$ 9,212
$ 17,817							$ 17,817	$ 48,847	$ 142			$ 48,989
$ -							$ -	$ -				$ -
$ -							$ -	$ -				$ -
$ 1,606,834	$ 1,381,291	-$ 743,739	$ -	$ -	$ -	$ -	$ 3,731,864	$ 310,889	$ 28,601	$ 743,739	$ -	-$ 404,248
	$ 50,305						$ 50,305	$ -	$ 676			$ 676
$ 1,606,834	$ 1,431,596	-$ 743,739	$ -	$ -	$ -	$ -	$ 3,782,169	$ 310,889	$ 29,277	$ 743,739	$ -	-$ 403,573
$ -							$ -	$ -				$ -
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2011				Projected Interest on Dec-31-10 Balances			2.1.7 RRR	
Principal Disposition during 2011 - instructed by Board	Interest Disposition during 2011 - instructed by Board	Closing Principal Balances as of Dec 31-10 Adjusted for Dispositions during 2011	Closing Interest Balances as of Dec 31-10 Adjusted during 2011 Disposition	Projected Interest from Jan 1, 2011 to December 31, 2011 on Dec 31 -10 balance adjusted for disposition during 2011 [9]	Projected Interest from January 1, 2012 to April 30, 2012 on Dec 31 -10 balance adjusted for disposition during 2011 [9, 10]	Total Claim	As of Dec 31-10 [4]	Variance RRR vs. 2010 Balance *(Principal + Interest)*
		-$ 318,209	-$ 923	-$ 4,288	-$ 1,559	-$ 324,980	-$ 319,133	$ 0
		-$ 433,996	-$ 74,837	-$ 6,380	-$ 2,127	-$ 517,340	-$ 508,834	-$ 0
		$ 14,756	-$ 11,282	$ 217	$ 72	$ 3,763	$ 3,474	-$ 0
		-$ 473,329	-$ 39,540	-$ 6,958	-$ 2,319	-$ 522,147	-$ 512,870	-$ 0
		$ 837,496	-$ 184,519	$ 12,311	$ 4,104	$ 669,393	$ 652,978	$ -
		$ 934,081	$ 12,819	$ 13,731	$ 4,577	$ 965,208	$ 946,900	-$ 0
		$ 405,734	-$ 124,291	$ 5,964	$ 1,988	$ 289,395	$ 281,443	-$ 0
		$ -	$ -			$ -		$ -
		$ 1,329,305	$ 9,114	$ 8,196	$ 2,732	$ 1,349,348	$ 1,338,419	$ -
$ -	$ -	$ 2,295,838	-$ 413,460	$ 22,794	$ 7,468	$ 1,912,640	$ 1,882,378	-$ 0
$ -	$ -	$ 1,361,757	-$ 426,279	$ 9,063	$ 2,891	$ 947,432	$ 935,477	-$ 0
$ -	$ -	$ 934,081	$ 12,819	$ 13,731	$ 4,577	$ 965,208	$ 946,900	-$ 0
		$ -	$ -			$ -	$ -	$ -
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		$ 1,255,461	-$ 20	$ 18,455	$ 6,152	$ 1,280,048	$ 1,255,441	-$ 0
		$ -	$ -			$ -		$ -
		$ -	$ -			$ -		$ -
		$ 131,111	$ 1,075	$ 1,927	$ 642	$ 134,756	$ 132,186	-$ 0
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		$ -	$ -			$ -		$ -
		$ 49,454	$ 8,157	$ 727	$ 242	$ 58,580	$ 57,611	$ -
		$ -	$ -			$ -		$ -
$ -	$ -	$ 1,436,026	$ 9,212	$ 21,110	$ 7,037	$ 1,473,384	$ 1,445,238	-$ 0
		$ 17,817	$ 48,989	$ 262	$ 87	$ 67,156	$ 66,807	$ -
		$ -	$ -			$ -		$ -
		$ -	$ -			$ -		$ -
$ -	$ -	$ 3,731,864	-$ 404,248	$ 43,904	$ 14,505	$ 3,453,180	$ 3,327,615	
				$ 739	$ 246	$ 51,967	$ 50,981	$ -
$ -	$ -	$ 3,731,864	-$ 404,248	$ 44,643	$ 14,751	$ 3,505,147	$ 3,378,596	$ -
						$ -		$ -
						$ -		$ -
						$ -		$ -
						$ -		$ -

Clinton Power Corporation Continuity

Account Descriptions	Account Number	2005 Opening Principal Amounts as of Jan-1-05	Transactions Debit/ (Credit) during 2005 excluding interest and adjustments [6]	Board-Approved Disposition during 2005	Adjustments during 2005 - other [3]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec-31-05	Board-Approved Disposition during 2005	Adjustments during 2005 - other [3]	Closing Interest Amounts as of Dec-31-05
Group 1 Accounts											
LV Variance Account	1550					$ -					$ -
RSVA - Wholesale Market Service Charge	1580	-$ 14,167	$ 3,741			-$ 10,426	$ 3,804	-$ 1,664			$ 2,140
RSVA - Retail Transmission Network Charge	1584	$ 33,933	$ 13,782			$ 47,715	$ 3,551	$ 3,163			$ 6,714
RSVA - Retail Transmission Connection Charge	1586	-$ 102,602	-$ 96,271			-$ 198,873	-$ 8,982	-$ 10,673			-$ 19,655
RSVA - Power (excluding Global Adjustment)	1588	$ 145,965	$ 120,834			$ 266,799	$ 22,143	$ 14,903			$ 37,046
RSVA - Power - Sub-Account - Global Adjustment	1588		-$ 7,463			-$ 7,463		-$ 126			-$ 126
Recovery of Regulatory Asset Balances	1590	-$ 31,545	-$ 95,295			-$ 126,840	-$ 635	-$ 4,819			-$ 5,454
Disposition and Recovery of Regulatory Balances (2008)[10]	1595					$ -					$ -
Disposition and Recovery of Regulatory Balances (2009)[10]	1595					$ -					$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ 31,584	-$ 60,672	$ -	$ -	-$ 29,088	$ 19,881	$ 785	$ -	$ -	$ 20,666
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ 31,584	-$ 53,209	$ -	$ -	-$ 21,625	$ 19,881	$ 911	$ -	$ -	$ 20,792
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	-$ 7,463	$ -	$ -	-$ 7,463	$ -	-$ 126	$ -	$ -	-$ 126
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508					$ -					$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508					$ -					$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508					$ -					$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Other [7]	1508					$ -					$ -
Retail Cost Variance Account - Retail	1518					$ -					$ -
Misc. Deferred Debits	1525					$ -					$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -					$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -					$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -					$ -
Smart Grid Capital Deferral Account	1534					$ -					$ -
Smart Grid OM&A Deferral Account	1535					$ -					$ -
Smart Grid Funding Adder Deferral Account	1536					$ -					$ -
Retail Cost Variance Account - STR	1548					$ -					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555					$ -					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555					$ -					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555					$ -					$ -
Smart Meter OM&A Variance	1556					$ -					$ -
Conservation and Demand Management (CDM) Expenditures and Recoveries	1565					$ -					$ -
CDM Contra	1566					$ -					$ -
Qualifying Transition Costs [5]	1570					$ -					$ -
Pre-market Opening Energy Variance [5]	1571					$ -					$ -
Extra-Ordinary Event Costs	1572					$ -					$ -
Deferred Rate Impact Amounts	1574					$ -					$ -
RSVA - One-time	1582	$ 4,644	*$ 378*			$ 5,022	$ 378	$ 337			$ 715
Other Deferred Credits	2425					$ -					$ -
Group 2 Sub-Total		$ 4,644	$ 378	$ -	$ -	$ 5,022	$ 378	$ 337	$ -	$ -	$ 715
Deferred Payments in Lieu of Taxes	1562					$ -					$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592					$ -					$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592					$ -					$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ 36,228	-$ 60,294	$ -	$ -	-$ 24,066	$ 20,259	$ 1,122	$ -	$ -	$ 21,381
Special Purpose Charge Assessment Variance Account	**1521**										
Total including Account 1521 [1]		$ 36,228	-$ 60,294	$ -	$ -	-$ 24,066	$ 20,259	$ 1,122	$ -	$ -	$ 21,381
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [8]	1563					$ -					$ -
Board-Approved CDM Variance Account	1567										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592					$ -					$ -
Disposition and Recovery of Regulatory Balances[10]	1595					$ -					$ -

2006

Opening Principal Amounts as of Jan-1-06	Transactions Debit/ (Credit) during 2006 excluding interest and adjustments [6]	Board-Approved Disposition during 2006 [2, 2A]	Adjustments during 2006 - other [3]	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec-31-06	Board-Approved Disposition during 2006 [2, 2A]	Adjustments during 2006 - other [3]	Closing Interest Amounts as of Dec-31-06
$ -	$ 81,290			$ 81,290	$ -	$ 1,011			$ 1,011
-$ 10,426	-$ 27,917	-$ 14,167		-$ 24,176	$ 2,140	-$ 845	$ 2,435		-$ 1,140
$ 47,715	$ 3,971	$ 33,933		$ 17,753	$ 6,714	$ 1,348	$ 6,832		$ 1,230
-$ 198,873	-$ 90,723	-$ 102,603		-$ 186,993	-$ 19,655	-$ 9,252	-$ 18,901		-$ 10,006
$ 266,799	$ 237,942	$ 145,965		$ 358,776	$ 37,046	$ 12,465	$ 36,253		$ 13,258
-$ 7,463	-$ 2,723			-$ 10,186	-$ 126	-$ 720			-$ 846
-$ 126,840	-$ 191,328	-$ 723,020		$ 404,852	-$ 5,454	$ 2,927			-$ 2,527
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
-$ 29,088	$ 10,513	-$ 659,892	$ -	$ 641,317	$ 20,666	$ 6,933	$ 26,619	$ -	$ 980
-$ 21,625	$ 13,235	-$ 659,892	$ -	$ 651,502	$ 20,792	$ 7,653	$ 26,619	$ -	$ 1,826
-$ 7,463	-$ 2,723	$ -	$ -	-$ 10,186	-$ 126	-$ 720	$ -	$ -	-$ 846
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$ 5,022		$ 4,644	$ 960	$ 1,338	$ 715	$ 163	$ 827		$ 51
$ -				$ -	$ -				$ -
$ 5,022	$ -	$ 4,644	$ 960	$ 1,338	$ 715	$ 163	$ 827	$ -	$ 51
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
-$ 24,066	$ 10,513	-$ 655,248	$ 960	$ 642,655	$ 21,381	$ 7,096	$ 27,446	$ -	$ 1,032
-$ 24,066	$ 10,513	-$ 655,248	$ 960	$ 642,655	$ 21,381	$ 7,096	$ 27,446	$ -	$ 1,032
$ -				$ -	$ -				$ -
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$ -				$ -	$ -				$ -

2007

	Opening Principal Amounts as of Jan-1-07	Transactions Debit/ (Credit) during 2007 excluding interest and adjustments [6]	Board-Approved Disposition during 2007	Adjustments during 2007 - other [3]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec-31-07	Board-Approved Disposition during 2007	Adjustments during 2007 - other [3]	Closing Interest Amounts as of Dec-31-07
	$ 81,290	$ 118,716			$ 200,006	$ 1,011	$ 6,397			$ 7,408
	-$ 24,176	-$ 54,884			-$ 79,060	-$ 1,140	-$ 2,595			-$ 3,735
	$ 17,753	-$ 34,399			-$ 16,646	$ 1,230	-$ 230			$ 999
	-$ 186,993	-$ 121,919			-$ 308,912	-$ 10,006	-$ 11,842			-$ 21,848
	$ 358,776	-$ 134,574			$ 224,202	$ 13,258	$ 11,184			$ 24,442
	-$ 10,186	-$ 6,560			-$ 16,745	-$ 846	-$ 823			-$ 1,668
	$ 404,852	-$ 273,293			$ 131,559	-$ 2,527	$ 10,270			$ 7,743
	$ -				$ -	$ -				$ -
	$ -				$ -	$ -				$ -
	$ 641,317	-$ 506,912	$ -	$ -	$ 134,405	$ 980	$ 12,360	$ -	$ -	$ 13,340
	$ 651,502	-$ 500,352	$ -	$ -	$ 151,150	$ 1,826	$ 13,183	$ -	$ -	$ 15,009
	-$ 10,186	-$ 6,560	$ -	$ -	-$ 16,745	-$ 846	-$ 823	$ -	$ -	-$ 1,668
	$ -	$ 9,846			$ 9,846	$ -				$ -
	$ -				$ -	$ -				$ -
	$ -				$ -	$ -				$ -
	$ -				$ -	$ -				$ -
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	$ -				$ -	$ -				$ -
	$ -	-$ 5,398			-$ 5,398	$ -	-$ 128			-$ 128
	$ -				$ -	$ -				$ -
	$ -				$ -	$ -				$ -
	$ -				$ -	$ -				$ -
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	$ -				$ -	$ -				$ -
	$ 1,338				$ 1,338	$ 51	$ 63			$ 114
	$ -				$ -	$ -				$ -
	$ 1,338	$ 4,448	$ -	$ -	$ 5,786	$ 51	-$ 65	$ -	$ -	-$ 13
	$ -				$ -	$ -				$ -
	$ -				$ -	$ -				$ -
	$ -				$ -	$ -				$ -
	$ 642,655	-$ 502,464	$ -	$ -	$ 140,191	$ 1,032	$ 12,296	$ -	$ -	$ 13,327
	$ 642,655	-$ 502,464	$ -	$ -	$ 140,191	$ 1,032	$ 12,296	$ -	$ -	$ 13,327
	$ -				$ -	$ -				$ -
	$ -				$ -	$ -				$ -
	$ -				$ -	$ -				$ -

2008

Opening Principal Amounts as of Jan-1-08	Transactions Debit / (Credit) during 2008 excluding interest and adjustments [6]	Board-Approved Disposition during 2008	Adjustments during 2008 - other [3]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec-31-08	Board-Approved Disposition during 2008	Adjustments during 2008 - other [3]	Closing Interest Amounts as of Dec-31-08
$ 200,006	$ 132,496			$ 332,502	$ 7,408	$ 9,968			$ 17,376
-$ 79,060	-$ 6,983			-$ 86,043	-$ 3,735	-$ 3,237			-$ 6,972
-$ 16,646	-$ 13,496			-$ 30,142	$ 999	-$ 928			$ 71
-$ 308,912	-$ 113,272			-$ 422,184	-$ 21,848	-$ 13,961			-$ 35,809
$ 224,202	$ 147,799			$ 372,001	$ 24,442	$ 10,664			$ 35,105
-$ 16,745	$ 11,542			-$ 5,203	-$ 1,668	-$ 655			-$ 2,323
$ 131,559	-$ 95,361			$ 36,199	$ 7,743	$ 874			$ 8,617
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ 134,405	$ 62,725	$ -	$ -	$ 197,130	$ 13,340	$ 2,726	$ -	$ -	$ 16,066
$ 151,150	$ 51,183	$ -	$ -	$ 202,333	$ 15,009	$ 3,380	$ -	$ -	$ 18,389
-$ 16,745	$ 11,542	$ -	$ -	-$ 5,203	-$ 1,668	-$ 655	$ -	$ -	-$ 2,323
$ 9,846				$ 9,846	$ -	$ 392			$ 392
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
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$ -				$ -	$ -				$ -
$ -	$ 918			$ 918	$ -				$ -
-$ 5,398	-$ 4,977			-$ 10,375	-$ 128	-$ 297			-$ 425
$ -				$ -	$ -				$ -
$ -	$ 32			$ 32	$ -	$ 1			$ 1
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ 1,338				$ 1,338	$ 114	$ 53			$ 168
$ -				$ -	$ -				$ -
$ 5,786	-$ 4,027	$ -	$ -	$ 1,759	-$ 13	$ 148	$ -	$ -	$ 135
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ 140,191	$ 58,698	$ -	$ -	$ 198,888	$ 13,327	$ 2,874	$ -	$ -	$ 16,201
$ 140,191	$ 58,698	$ -	$ -	$ 198,888	$ 13,327	$ 2,874	$ -	$ -	$ 16,201
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -

2009

Opening Principal Amounts as of Jan-1-09	Transactions Debit/ (Credit) during 2009 excluding interest and adjustments [6]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [3]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009	Adjustments during 2009 - other [3]	Closing Interest Amounts as of Dec-31-09
$ 332,502	$ 53,186			$ 385,688	$ 17,376	$ 4,005			$ 21,381
-$ 86,043	$ 89,280			$ 3,237	-$ 6,972	-$ 467			-$ 7,439
-$ 30,142	-$ 12,812			-$ 42,954	$ 71	-$ 276			-$ 205
-$ 422,184	-$ 101,899			-$ 524,083	-$ 35,809	-$ 5,041			-$ 40,850
$ 372,001	$ 283,020			$ 655,021	$ 35,105	$ 5,692			$ 40,797
-$ 5,203	-$ 153,058			-$ 158,261	-$ 2,323	$ 12			-$ 2,311
$ 36,199	$ -			$ 36,199	$ 8,617	$ -			$ 8,617
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ 197,130	$ 157,716	$ -	$ -	$ 354,846	$ 16,066	$ 3,925	$ -	$ -	$ 19,991
$ 202,333	$ 310,774	$ -	$ -	$ 513,107	$ 18,389	$ 3,912	$ -	$ -	$ 22,301
-$ 5,203	-$ 153,058	$ -	$ -	-$ 158,261	-$ 2,323	$ 12	$ -	$ -	-$ 2,311
$ 9,846				$ 9,846	$ 392	$ 112			$ 504
$ -				$ -	$ -				$ -
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$ -				$ -	$ -				$ -
$ 918	-$ 63			$ 855	$ -				$ -
-$ 10,375	-$ 13,803			-$ 24,178	-$ 425	-$ 137			-$ 562
$ -				$ -	$ -				$ -
$ 32	$ 63			$ 95	$ 1	$ 1			$ 1
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$ -				$ -	$ -				$ -
$ 1,338				$ 1,338	$ 168	$ 15			$ 183
$ -				$ -	$ -				$ -
$ 1,759	-$ 13,803	$ -	$ -	-$ 12,044	$ 135	-$ 9	$ -	$ -	$ 125
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ -				$ -	$ -				$ -
$ 198,888	$ 143,914	$ -	$ -	$ 342,802	$ 16,201	$ 3,915	$ -	$ -	$ 20,116
$ 198,888	$ 143,914	$ -	$ -	$ 342,802	$ 16,201	$ 3,915	$ -	$ -	$ 20,116
$ -				$ -	$ -				$ -
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2010

Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [6]	Board-Approved Disposition during 2010	Other [3] Adjustments during Q1 2010	Other [3] Adjustments during Q2 2010	Other [3] Adjustments during Q3 2010	Other [3] Adjustments during Q4 2010	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other [3]	Closing Interest Amounts as of Dec-31-10
$ 385,688	$ 58,997						$ 444,684	$ 21,381	$ 3,299			$ 24,680
$ 3,237	-$ 1,079						$ 2,157	-$ 7,439	$ 194			-$ 7,245
-$ 42,954	$ 1,192						-$ 41,763	-$ 205	-$ 266			-$ 471
-$ 524,083	-$ 114,605						-$ 638,688	-$ 40,850	-$ 4,586			-$ 45,436
$ 655,021	$ 296,926						$ 951,946	$ 40,797	$ 7,122			$ 47,919
-$ 158,261	-$ 206,572						-$ 364,833	-$ 2,311	-$ 1,956			-$ 4,267
$ 36,199	$ -						$ 36,199	$ 8,617	$ -			$ 8,617
$ -							$ -	$ -				$ -
$ -							$ -	$ -				$ -
$ 354,846	$ 34,857	$ -	$ -	$ -	$ -	$ -	$ 389,703	$ 19,991	$ 3,807	$ -	$ -	$ 23,797
$ 513,107	$ 241,429	$ -	$ -	$ -	$ -	$ -	$ 754,536	$ 22,301	$ 5,763	$ -	$ -	$ 28,065
-$ 158,261	-$ 206,572	$ -	$ -	$ -	$ -	$ -	-$ 364,833	-$ 2,311	-$ 1,956	$ -	$ -	-$ 4,267
$ 9,846	$ 65,000						$ 74,846	$ 504	$ 79			$ 582
$ -							$ -	$ -				$ -
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$ 855	$ 138,562						$ 139,417	$ -				$ -
-$ 24,178	-$ 21,243						-$ 45,421	-$ 562	-$ 17			-$ 579
$ -							$ -	$ -				$ -
$ 95	$ 4,844						$ 4,939	$ 1	$ 22			$ 23
$ -							$ -	$ -				$ -
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$ -							$ -	$ -				$ -
$ 1,338							$ 1,338	$ 183	$ 11			$ 194
$ -							$ -	$ -				$ -
-$ 12,044	$ 187,162	$ -	$ -	$ -	$ -	$ -	$ 175,118	$ 125	$ 94	$ -	$ -	$ 220
$ -							$ -	$ -				$ -
$ -							$ -	$ -				$ -
$ -							$ -	$ -				$ -
$ 342,802	$ 222,019	$ -	$ -	$ -	$ -	$ -	$ 564,821	$ 20,116	$ 3,901	$ -	$ -	$ 24,017
	$ 4,631						$ 4,631	$ -	$ 36			$ 36
$ 342,802	$ 226,650	$ -	$ -	$ -	$ -	$ -	$ 569,452	$ 20,116	$ 3,937	$ -	$ -	$ 24,053
$ -							$ -	$ -				$ -
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2011				Projected Interest on Dec-31-10 Balances			2.1.7 RRR	
Principal Disposition during 2011 - instructed by Board	Interest Disposition during 2011 - instructed by Board	Closing Principal Balances as of Dec 31-10 Adjusted for Dispositions during 2011	Closing Interest Balances as of Dec 31-10 Adjusted during 2011 Disposition	Projected Interest from Jan 1, 2011 to December 31, 2011 on Dec 31 -10 balance adjusted for disposition during 2011 [9]	Projected Interest from January 1, 2012 to April 30, 2012 on Dec 31 -10 balance adjusted for disposition during 2011 [9, 10]	Total Claim	As of Dec 31-10 [4]	Variance RRR vs. 2010 Balance *(Principal + Interest)*
		$ 444,684	$ 24,680	$ 6,537	$ 2,179	$ 478,080	$ 469,365	$ 0
		$ 2,157	-$ 7,245	$ 32	$ 11	-$ 5,045	-$ 5,087	$ 0
		-$ 41,763	-$ 471	-$ 614	-$ 205	-$ 43,052	-$ 42,234	-$ 0
		-$ 638,688	-$ 45,436	-$ 9,389	-$ 3,130	-$ 696,642	-$ 684,124	-$ 0
		$ 951,946	$ 47,919	$ 13,994	$ 4,665	$ 1,018,524	$ 999,866	$ 0
		-$ 364,833	-$ 4,267	-$ 5,363	-$ 1,788	-$ 376,251	-$ 369,101	-$ 0
		$ 36,199	$ 8,617	$ -	$ -	$ 44,816	$ 44,816	$ 0
		$ -	$ -			$ -		$ -
		$ -	$ -			$ -		$ -
$ -	$ -	$ 389,703	$ 23,797	$ 5,197	$ 1,732	$ 420,429	$ 413,501	$ 0
$ -	$ -	$ 754,536	$ 28,065	$ 10,560	$ 3,520	$ 796,680	$ 782,601	$ 1
$ -	$ -	-$ 364,833	-$ 4,267	-$ 5,363	-$ 1,788	-$ 376,251	-$ 369,101	-$ 0
		$ 74,846	$ 582	$ 1,192	$ 367	$ 76,987	$ 75,428	$ -
		$ -	$ -			$ -		$ -
		$ -	$ -			$ -		$ -
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						$ -		$ -
		$ -	$ -			$ -		$ -
		$ 139,417	$ -			$ 139,417	$ 139,417	$ -
		-$ 45,421	-$ 579	$ 1,382	$ 461	-$ 44,158	-$ 46,000	$ -
		$ -	$ -			$ -		$ -
		$ 4,939	$ 23	$ 73	$ 24	$ 5,058	$ 4,962	-$ 0
		$ -	$ -			$ -		$ -
		$ -	$ -			$ -		$ -
		$ -	$ -			$ -	$ -	$ -
		$ -	$ -			$ -	$ -	$ -
		$ -	$ -			$ -		$ -
		$ -	$ -			$ -		$ -
		$ 1,338	$ 194	$ 20	$ 7	$ 1,558	$ 1,532	$ 0
		$ -	$ -			$ -		$ -
$ -	$ -	$ 175,118	$ 220	$ 2,666	$ 858	$ 178,862	$ 175,338	$ -
		$ -	$ -			$ -	-$ 10,810	-$ 10,810
		$ -	$ -			$ -		$ -
		$ -	$ -			$ -		$ -
$ -	$ -	$ 564,821	$ 24,017	$ 7,862	$ 2,590	$ 599,291	$ 588,839	
				$ 68	$ 23	$ 4,757	$ 4,666	$ -
$ -	$ -	$ 564,821	$ 24,017	$ 7,931	$ 2,613	$ 604,048	$ 593,505	$ -
						$ -	$ 9,614	$ 9,614
						$ -		$ -
						$ -		$ -
						$ -		$ -

SMART METERS

On October 28, the Ontario Energy Board issued Guideline G-2008-0002 Smart Meter Funding and Cost Recovery. The guideline sets out the Board's filing instructions in relation to the funding of, and the recovery of costs associated with smart meter activities conducted by electricity distributors.

Clinton Power, Erie Thames Powerlines and West Perth Power has been authorized to conduct smart meter activities by virtue of paragraph 8 of Section 1(1) of O. Reg. 427/06, conditional on our meters being acquired pursuant to and in compliance with a Request for Proposal issued by London Hydro Inc. A letter was received from PRP International Fairness Advisory Services regarding the Attestation of the Fairness Commissioner for the London Hydro & Consortium Smart Meter Project as it relates specifically to the two highest ranked proponents for Clinton Power, Erie Thames Powerlines and West Perth Power. Clinton Power, Erie Thames Powerlines and West Perth Power plans have all smart meters fully deployed by May 1, 2011 with a total approximate capital outlay of $325,500. A continuity of the smart meter accounts are provided above as part of the Deferral and Variance Account Continuity Schedule.

As Clinton Power, Erie Thames Powerlines and West Perth Power have completed the installation of smart meters and are on Time of Use Billing in the 2012 rate test year, **Clinton Power, Erie Thames Powerlines and West Perth Power is requesting a Utilitiy Specific smart meter funding adder be approved by the Board as part of the 2012 Cost of Service rate application.**

No disposition of accounts 1555 and 1556 is requested at this time.

The following is the completed Smart Meter Model prepared by Erie Thames Powerlines, that produces a standard Utility Specific Funding adder of $1.10 per customer per month.

OM&A, regardless of whether a distributor has deployments in 2012, distributors should enter the forecasted OM&A for 2012 for all smart meters in service.

Smart Meter Capital Cost and Operational Expense Data

	2006	2007	2008	2009	2010	2011	2012 and later	Total
	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
Smart Meter Installation Plan								
Actual/Planned number of Smart Meters installed during the Calendar Year								
Residential				436	13,890	1,755		16081
General Service < 50 kW				18	1,102	606	54	1780
Actual/Planned number of Smart Meters installed (Residential and GS < 50 kW only)	0	0	0	454	14992	2361	54	17861
Percentage of Residential and GS < 50 kW Smart Meter Installations Completed	0.00%	0.00%	0.00%	2.54%	86.48%	99.70%	100.00%	100.00%
Actual/Planned number of GS > 50 kW meters installed								0
Other (please identify)								0
Total Number of Smart Meters installed or planned to be installed	0	0	0	454	14992	2361	54	17861

1 Capital Costs

1.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	Asset Type Asset type must be selected to enable calculations	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Total
1.1.1 Smart Meters *(may include new meters and modules, etc.)*	Smart Meter				41,572	1,442,596	363,969	23,820	$ 1,871,956
1.1.2 Installation Costs *(may include socket kits, labour, vehicle, benefits, etc.)*	Smart Meter				16,415	708,510	114,526		$ 839,452
1.1.3a Workforce Automation Hardware *(may include fieldwork handhelds, barcode hardware, etc.)*									$ -
1.1.3b Workforce Automation Software *(may include fieldwork handhelds, barcode hardware, etc.)*									$ -
Total Advanced Metering Communications Devices (AMCD)		$ -	$ -	$ -	$ 57,987	$ 2,151,105	$ 478,495	$ 23,820	$ 2,711,407

1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)

	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.2.1 Collectors	Tools & Equipment	8,076	73,227						$ 81,304
1.2.2 Repeaters *(may include radio licence, etc.)*									$ -
1.2.3 Installation *(may include meter seals and rings, collector computer hardware, etc.)*	Tools & Equipment		4,274						$ 4,274
Total Advanced Metering Regional Collector (AMRC) (Includes LAN)		$ 8,076	$ 77,501	$ -	$ -	$ -	$ -	$ -	$ 85,578

1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)

	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.3.1 Computer Hardware	Computer Hardware			23,206				150,000	$ 173,206
1.3.2 Computer Software									$ -
1.3.3 Computer Software Licences & Installation (includes hardware and software) *(may include AS/400 disk space, backup and recovery computer, UPS, etc.)*									$ -
Total Advanced Metering Control Computer (AMCC)		$ -	$ -	$ 23,206	$ -	$ -	$ -	$ 150,000	$ 173,206

1.4 WIDE AREA NETWORK (WAN)

	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.4.1 Activiation Fees									$ -
Total Wide Area Network (WAN)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

1.5 OTHER AMI CAPITAL COSTS RELATED TO MINIMUM FUNCTIONALITY

	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.5.1 Customer Equipment *(including repair of damaged equipment)*									$ -
1.5.2 AMI Interface to CIS									$ -
1.5.3 Professional Fees									$ -
1.5.4 Integration									$ -
1.5.5 Program Management									$ -
1.5.6 Other AMI Capital									$ -
Total Other AMI Capital Costs Related to Minimum Functionality		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Capital Costs Related to Minimum Functionality		$ 8,076	$ 77,501	$ 23,206	$ 57,987	$ 2,151,105	$ 478,495	$ 173,820	$ 2,970,191

	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.6 CAPITAL COSTS BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*									
1.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06	Computer Software								$ -
1.6.2 Costs for deployment of smart meters to customers other than residential and small general service	Applications Software								$ -
1.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.							155,000		$ 155,000
Total Capital Costs Beyond Minimum Functionality		$ -	$ -	$ -	$ -	$ -	$ 155,000	$ -	$ 155,000
Total Smart Meter Capital Costs		$ 8,076	$ 77,501	$ 23,206	$ 57,987	$ 2,151,105	$ 633,495	$ 173,820	$ 3,125,191

2 OM&A Expenses

		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)									
2.1.1 Maintenance *(may include meter reverification costs, etc.)*					6,810	224,880	35,415	810	$ 267,915
2.1.2 Other *(please specifiy)*									$ -
Total Incremental AMCD OM&A Costs		$ -	$ -	$ -	$ 6,810	$ 224,880	$ 35,415	$ 810	$ 267,915
2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)									
2.2.1 Maintenance									$ -
2.2.2 Other *(please specifiy)*									$ -
Total Incremental AMRC OM&A Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)									
2.3.1 Hardware Maintenance *(may include server support, etc.)*									$ -
2.3.2 Software Maintenance *(may include maintenance support, etc.)*									$ -
2.3.2 Other *(please specifiy)*									$ -
Total Incremental AMCC OM&A Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.4 WIDE AREA NETWORK (WAN)									
2.4.1 WAN Maintenance									$ -
2.4.2 Other *(please specifiy)*									$ -
Total Incremental AMRC OM&A Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY									
2.5.1 Business Process Redesign				0	5,625	185,751	29,253	722	$ 221,351
2.5.2 Customer Communication (may include project communication, etc.)									$ -
2.5.3 Program Management					15,000	15,000	15,000	15,000	$ 60,000
2.5.4 Change Management (may include training, etc.)									$ -
2.5.5 Administration Costs					2,000	2,000	2,000	2,000	$ 8,000
2.5.6 Other AMI Expenses *(please specify)*									$ -
Total Other AMI OM&A Costs Related to Minimum Functionality		$ -	$ -	$ -	$ 22,625	$ 202,751	$ 46,253	$ 17,722	$ 289,351
TOTAL OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY		$ -	$ -	$ -	$ 29,435	$ 427,631	$ 81,668	$ 18,532	$ 557,266

		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual		
2.6 OM&A COSTS RELATED TO BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*									
2.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06									$ -
2.6.2 Costs for deployment of smart meters to customers other than residential and small general service									$ -
2.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.									$ -
Total OM&A Costs Beyond Minimum Functionality		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Smart Meter OM&A Costs		$ -	$ -	$ -	$ 29,435	$ 427,631	$ 81,668	$ 18,532	$ 557,266

3 Aggregate Smart Meter Costs by Category

3.1	**Capital**								
3.1.1	Smart Meter	$ -	$ -	$ -	$ 57,987	$ 2,151,105	$ 478,495	$ 23,820	$ 2,711,407
3.1.2	Computer Hardware	$ -	$ -	$ 23,206	$ -	$ -	$ -	$ 150,000	$ 173,206
3.1.3	Computer Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.4	Tools & Equipment	$ 8,076	$ 77,501	$ -	$ -	$ -	$ -	$ -	$ 85,578
3.1.5	Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.6	Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.7	**Total Capital Costs**	**$ 8,076**	**$ 77,501**	**$ 23,206**	**$ 57,987**	**$ 2,151,105**	**$ 478,495**	**$ 173,820**	**$ 2,970,191**
							Error		Error
3.2	**OM&A Costs**								
3.2.1	**Total OM&A Costs**	**$ -**	**$ -**	**$ -**	**$ 29,435**	**$ 427,631**	**$ 81,668**	**$ 18,532**	**$ 557,266**

	2006	2007	2008	2009	2010	2011	2012 and later
Cost of Capital							
Capital Structure[1]							
Deemed Short-term Debt Capitalization			4.0%	4.0%	4.0%	4.0%	4.0%
Deemed Long-term Debt Capitalization	50.0%	50.0%	49.3%	52.7%	56.0%	56.0%	56.0%
Deemed Equity Capitalization	50.0%	50.0%	46.7%	43.3%	40.0%	40.0%	40.0%
Preferred Shares							
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Cost of Capital Parameters							
Deemed Short-term Debt Rate			4.47%	4.47%	4.47%	4.47%	2.08%
Long-term Debt Rate (actual/embedded/deemed)[2]	6.25%	6.25%	5.92%	5.92%	5.92%	5.92%	5.01%
Target Return on Equity (ROE)	9.9%	9.88%	8.57%	8.57%	8.57%	8.57%	9.42%
Return on Preferred Shares							
WACC	8.07%	8.07%	7.10%	7.01%	6.92%	6.92%	6.66%
Working Capital Allowance							
Working Capital Allowance Rate	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
(% of the sum of Cost of Power + controllable expenses)							
Taxes/PILs							
Aggregate Corporate Income Tax Rate	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%
Capital Tax (until July 1st, 2010)	0.30%	0.225%	0.225%	0.225%	0.075%	0.00%	0.00%
Depreciation Rates							
(expressed as expected useful life in years)							
Smart Meters - years	15	15	15	15	15	15	15
- rate (%)	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
Computer Hardware - years	5	5	5	5	5	5	5
- rate (%)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Computer Software - years	5	5	5	5	5	5	5
- rate (%)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Tools & Equipment - years	8	8	8	8	8	8	8
- rate (%)	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Other Equipment - years							
- rate (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CCA Rates							
Smart Meters - CCA Class	8	8	8	8	8	8	8
Smart Meters - CCA Rate	20%	20%	20%	20%	20%	20%	20%
Computer Equipment - CCA Class	46	46	46	46	46	46	46
Computer Equipment - CCA Rate	30%	30%	30%	30%	30%	30%	30%
General Equipment - CCA Class	8	8	8	8	8	8	8
General Equipment - CCA Rate	20%	20%	20%	20%	20%	20%	20%
Applications Software - CCA Class							
Applications Software - CCA Rate							

	2006	2007	2008	2009	2010	2011	2012 and later
Net Fixed Assets - Smart Meters							
Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ 57,987	$ 2,209,092	$ 2,687,587
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ 57,987	$ 2,151,105	$ 478,495	$ 23,820
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ 57,987	$ 2,209,092	$ 2,687,587	$ 2,711,407
Accumulated Depreciation							
Opening Balance		$ -	$ -	$ -	-$ 1,933	-$ 77,502	-$ 240,725
Amortization expense during year	$ -	$ -	$ -	-$ 1,933	-$ 75,569	-$ 163,223	-$ 179,966
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	-$ 1,933	-$ 77,502	-$ 240,725	-$ 420,691
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ 56,054	$ 2,131,590	$ 2,446,863
Closing Balance	$ -	$ -	$ -	$ 56,054	$ 2,131,590	$ 2,446,863	$ 2,290,716
Average Net Book Value	$ -	$ -	$ -	$ 28,027	$ 1,093,822	$ 2,289,226	$ 2,368,789
Net Fixed Assets - Computer Hardware							
Gross Book Value							
Opening Balance		$ -	$ -	$ 23,206	$ 23,206	$ 23,206	$ 23,206
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ 23,206	$ -	$ -	$ -	$ 150,000
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ 23,206	$ 23,206	$ 23,206	$ 23,206	$ 173,206
Accumulated Depreciation							
Opening Balance	$ -	$ -	$ -	-$ 2,321	-$ 6,962	-$ 11,603	-$ 16,244
Amortization expense during year	$ -	$ -	-$ 2,321	-$ 4,641	-$ 4,641	-$ 4,641	-$ 19,641
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	-$ 2,321	-$ 6,962	-$ 11,603	-$ 16,244	-$ 35,886
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ 20,886	$ 16,244	$ 11,603	$ 6,962
Closing Balance	$ -	$ -	$ 20,886	$ 16,244	$ 11,603	$ 6,962	$ 137,321
Average Net Book Value	$ -	$ -	$ 10,443	$ 18,565	$ 13,924	$ 9,283	$ 72,141

Net Fixed Assets - Computer Software (including Applications Software)

Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Net Fixed Assets - Tools and Equipment

Gross Book Value							
Opening Balance		$ 8,076	$ 85,578	$ 85,578	$ 85,578	$ 85,578	$ 85,578
Capital Additions during year (from Smart Meter Costs)	$ 8,076	$ 77,501	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ 8,076	$ 85,578	$ 85,578	$ 85,578	$ 85,578	$ 85,578	$ 85,578
Accumulated Depreciation							
Opening Balance	$ -	-$ 505	-$ 6,358	-$ 17,055	-$ 27,753	-$ 38,450	-$ 49,147
Amortization expense during year	-$ 505	-$ 5,853	-$ 10,697	-$ 10,697	-$ 10,697	-$ 10,697	-$ 10,697
Retirements/Removals (if applicable)							
Closing Balance	-$ 505	-$ 6,358	-$ 17,055	-$ 27,753	-$ 38,450	-$ 49,147	-$ 59,844
Net Book Value							
Opening Balance	$ -	$ 7,571	$ 79,219	$ 68,522	$ 57,825	$ 47,128	$ 36,431
Closing Balance	$ 7,571	$ 79,219	$ 68,522	$ 57,825	$ 47,128	$ 36,431	$ 25,733
Average Net Book Value	$ 3,786	$ 43,395	$ 73,871	$ 63,174	$ 52,476	$ 41,779	$ 31,082

Net Fixed Assets - Other Equipment

Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -

	2006	2007	2008	2009	2010	2011	2012 and Later
erage Net Fixed Asset Values (from Sheet 4)							
Smart Meters	$ -	$ -	$ -	$ 28,027	$ 1,093,822	$ 2,289,226	$ 2,368,789
Computer Hardware	$ -	$ -	$ 10,443	$ 18,565	$ 13,924	$ 9,283	$ 72,141
Computer Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tools & Equipment	$ 3,786	$ 43,395	$ 73,871	$ 63,174	$ 52,476	$ 41,779	$ 31,082
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Net Fixed Assets	**$ 3,786**	**$ 43,395**	**$ 84,314**	**$ 109,766**	**$ 1,160,222**	**$ 2,340,288**	**$ 2,472,012**
orking Capital							
Operating Expenses (from Sheet 2)	$ -	$ -	$ -	$ 29,435	$ 427,631	$ 81,668	$ 18,532
Working Capital Factor (from Sheet 3)	15%	15%	15%	15%	15%	15%	15%
Working Capital Allowance	$ -	$ -	$ -	$ 4,415	$ 64,145	$ 12,250	$ 2,780
cremental Smart Meter Rate Base	**$ 3,786**	**$ 43,395**	**$ 84,314**	**$ 114,181**	**$ 1,224,367**	**$ 2,352,538**	**$ 2,474,792**
turn on Rate Base							
Capital Structure							
Deemed Short Term Debt	$ -	$ -	$ 3,373	$ 4,567	$ 48,975	$ 94,102	$ 98,992
Deemed Long Term Debt	$ 1,893	$ 21,698	$ 41,567	$ 60,173	$ 685,646	$ 1,317,421	$ 1,385,884
Equity	$ 1,893	$ 21,698	$ 39,374	$ 49,440	$ 489,747	$ 941,015	$ 989,917
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Capitalization	$ 3,786	$ 43,395	$ 84,314	$ 114,181	$ 1,224,367	$ 2,352,538	$ 2,474,792
Return on							
Deemed Short Term Debt	$ -	$ -	$ 151	$ 204	$ 2,189	$ 4,206	$ 2,059
Deemed Long Term Debt	$ 118	$ 1,356	$ 2,461	$ 3,563	$ 40,599	$ 78,009	$ 69,433
Equity	$ 187	$ 2,144	$ 3,374	$ 4,237	$ 41,971	$ 80,645	$ 93,250
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Return on Capital	$ 305	$ 3,500	$ 5,986	$ 8,004	$ 84,760	$ 162,861	$ 164,742
erating Expenses	$ -	$ -	$ -	$ 29,435	$ 427,631	$ 81,668	$ 18,532
nortization Expenses (from Sheet 4)							
Smart Meters	$ -	$ -	$ -	$ 1,933	$ 75,569	$ 163,223	$ 179,966
Computer Hardware	$ -	$ -	$ 2,321	$ 4,641	$ 4,641	$ 4,641	$ 19,641
Computer Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tools & Equipment	$ 505	$ 5,853	$ 10,697	$ 10,697	$ 10,697	$ 10,697	$ 10,697
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Amortization Expense in Year	$ 505	$ 5,853	$ 13,018	$ 17,271	$ 90,908	$ 178,561	$ 210,305
cremental Revenue Requirement before Taxes/PILs	$ 810	$ 9,353	$ 19,004	$ 54,711	$ 603,299	$ 423,089	$ 393,579
lculation of Taxable Income							
Incremental Operating Expenses	$ -	$ -	$ -	$ 29,435	$ 427,631	$ 81,668	$ 18,532
Amortization Expense	$ 505	$ 5,853	$ 13,018	$ 17,271	$ 90,908	$ 178,561	$ 210,305
Interest Expense	$ 118	$ 1,356	$ 2,612	$ 3,767	$ 42,789	$ 82,215	$ 71,492
Net Income for Taxes/PILs	$ 187	$ 2,144	$ 3,374	$ 4,237	$ 41,971	$ 80,645	$ 93,250
ossed-up Taxes/PILs (from Sheet 7)	-$ 42.79	-$ 504.10	-$ 908.08	-$ 839.31	-$ 46,197.86	-$ 76,710.10	-$ 47,024.11
venue Requirement, including Grossed-up Taxes/PILs	$ 767	$ 8,849	$ 18,096	$ 53,871	$ 557,101	$ 346,379	$ 346,555

For PILs Calculation

UCC - Smart Meters

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ 52,188.41	$ 1,977,745.48	$ 2,012,841.89
Capital Additions	$ -	$ -	$ -	$ 57,987.12	$ 2,151,105.28	$ 478,495.01	$ 23,819.70
Retirements/Removals (if applicable)							
UCC Before Half Year Rule	$ -	$ -	$ -	$ 57,987.12	$ 2,203,293.69	$ 2,456,240.49	$ 2,036,661.59
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ 28,993.56	$ 1,075,552.64	$ 239,247.51	$ 11,909.85
Reduced UCC	$ -	$ -	$ -	$ 28,993.56	$ 1,127,741.05	$ 2,216,992.98	$ 2,024,751.74
CCA Rate Class	8	8	8	8	8	8	8
CCA Rate	20%	20%	20%	20%	20%	20%	20%
CCA	$ -	$ -	$ -	$ 5,798.71	$ 225,548.21	$ 443,398.60	$ 404,950.35
Closing UCC	$ -	$ -	$ -	$ 52,188.41	$ 1,977,745.48	$ 2,012,841.89	$ 1,631,711.24

UCC - Computer Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ -	$ -	$ 19,725.33	$ 13,807.73	$ 9,665.41	$ 6,765.79
Capital Additions Computer Hardware	$ -	$ -	$ 23,206.27	$ -	$ -	$ -	$ 150,000.00
Capital Additions Computer Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
UCC Before Half Year Rule	$ -	$ -	$ 23,206.27	$ 19,725.33	$ 13,807.73	$ 9,665.41	$ 156,765.79
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ 11,603.14	$ -	$ -	$ -	$ 75,000.00
Reduced UCC	$ -	$ -	$ 11,603.14	$ 19,725.33	$ 13,807.73	$ 9,665.41	$ 81,765.79
CCA Rate Class	46	46	46	46	46	46	46
CCA Rate	30%	30%	30%	30%	30%	30%	30%
CCA	$ -	$ -	$ 3,480.94	$ 5,917.60	$ 4,142.32	$ 2,899.62	$ 24,529.74
Closing UCC	$ -	$ -	$ 19,725.33	$ 13,807.73	$ 9,665.41	$ 6,765.79	$ 132,236.05

UCC - General Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ 7,268.57	$ 75,566.07	$ 60,452.86	$ 48,362.29	$ 38,689.83	$ 30,951.86
Capital Additions Tools & Equipment	$ 8,076.19	$ 77,501.35	$ -	$ -	$ -	$ -	$ -
Capital Additions Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
UCC Before Half Year Rule	$ 8,076.19	$ 84,769.92	$ 75,566.07	$ 60,452.86	$ 48,362.29	$ 38,689.83	$ 30,951.86
Half Year Rule (1/2 Additions - Disposals)	$ 4,038.10	$ 38,750.68	$ -	$ -	$ -	$ -	$ -
Reduced UCC	$ 4,038.10	$ 46,019.25	$ 75,566.07	$ 60,452.86	$ 48,362.29	$ 38,689.83	$ 30,951.86
CCA Rate Class	8	8	8	8	8	8	8
CCA Rate	20%	20%	20%	20%	20%	20%	20%
CCA	$ 807.62	$ 9,203.85	$ 15,113.21	$ 12,090.57	$ 9,672.46	$ 7,737.97	$ 6,190.37
Closing UCC	$ 7,268.57	$ 75,566.07	$ 60,452.86	$ 48,362.29	$ 38,689.83	$ 30,951.86	$ 24,761.49

UCC - Applications Software

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
UCC Before Half Year Rule	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA Rate Class	0	0	0	0	0	0	0
CCA Rate	0%	0%	0%	0%	0%	0%	0%
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -

PILs Calculation

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
INCOME TAX							
Net Income	$ 187.01	$ 2,143.73	$ 3,374.39	$ 4,237.04	$ 41,971.30	$ 80,645.01	$ 93,250.17
Amortization	$ 504.76	$ 5,853.36	$ 13,017.82	$ 17,271.35	$ 90,907.76	$ 178,561.11	$ 210,304.93
CCA - Smart Meters	$ -	$ -	$ -	-$ 5,798.71	-$ 225,548.21	-$ 443,398.60	-$ 404,950.35
CCA - Computers	$ -	$ -	-$ 3,480.94	-$ 5,917.60	-$ 4,142.32	-$ 2,899.62	-$ 24,529.74
CCA - Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA - Other Equipment	-$ 807.62	-$ 9,203.85	-$ 15,113.21	-$ 12,090.57	-$ 9,672.46	-$ 7,737.97	-$ 6,190.37
Change in taxable income	-$ 115.84	-$ 1,206.76	-$ 2,201.94	-$ 2,298.49	-$ 106,483.92	-$ 194,830.07	-$ 132,115.35
Tax Rate (from Sheet 3)	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%
Income Taxes Payable	-$ 41.84	-$ 435.88	-$ 737.65	-$ 758.50	-$ 33,010.02	-$ 55,039.49	-$ 34,680.28
ONTARIO CAPITAL TAX							
Smart Meters	$ -	$ -	$ -	$ 56,054.22	$ 2,131,590.18	$ 2,446,862.53	$ 2,290,715.74
Computer Hardware	$ -	$ -	$ 20,885.64	$ 16,244.39	$ 11,603.14	$ 6,961.88	$ 137,320.63
Computer Software (Including Application Software)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tools & Equipment	$ 7,571.43	$ 79,219.42	$ 68,522.23	$ 57,825.04	$ 47,127.84	$ 36,430.65	$ 25,733.46
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rate Base	$ 7,571.43	$ 79,219.42	$ 89,407.87	$ 130,123.64	$ 2,190,321.16	$ 2,490,255.06	$ 2,453,769.83
Less: Exemption							
Deemed Taxable Capital	$ 7,571.43	$ 79,219.42	$ 89,407.87	$ 130,123.64	$ 2,190,321.16	$ 2,490,255.06	$ 2,453,769.83
Ontario Capital Tax Rate (from Sheet 3)	0.300%	0.225%	0.225%	0.225%	0.075%	0.000%	0.000%
Net Amount (Taxable Capital x Rate)	$ 22.71	$ 178.24	$ 201.17	$ 292.78	$ 1,642.74	$ -	$ -
Change in Income Taxes Payable	-$ 41.84	-$ 435.88	-$ 737.65	-$ 758.50	-$ 33,010.02	-$ 55,039.49	-$ 34,680.28
Change in OCT	$ 22.71	$ 178.24	$ 201.17	$ 292.78	$ 1,642.74	$ -	$ -
PILs	-$ 19.13	-$ 257.64	-$ 536.48	-$ 465.72	-$ 31,367.27	-$ 55,039.49	-$ 34,680.28

Gross Up PILs

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Tax Rate	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%
Change in Income Taxes Payable	-$ 65.50	-$ 682.34	-$ 1,109.25	-$ 1,132.09	-$ 47,840.60	-$ 76,710.10	-$ 47,024.11
Change in OCT	$ 22.71	$ 178.24	$ 201.17	$ 292.78	$ 1,642.74	$ -	$ -
PILs	**-$ 42.79**	**-$ 504.10**	**-$ 908.08**	**-$ 839.31**	**-$ 46,197.86**	**-$ 76,710.10**	**-$ 47,024.11**

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP
2006 Q1		
2006 Q2	4.14%	4.68%
2006 Q3	4.59%	5.05%
2006 Q4	4.59%	4.72%
2007 Q1	4.59%	4.72%
2007 Q2	4.59%	4.72%
2007 Q3	4.59%	5.18%
2007 Q4	5.14%	5.18%
2008 Q1	5.14%	5.18%
2008 Q2	4.08%	5.18%
2008 Q3	3.35%	5.43%
2008 Q4	3.35%	5.43%
2009 Q1	2.45%	6.61%
2009 Q2	1.00%	6.61%
2009 Q3	0.55%	5.67%
2009 Q4	0.55%	4.66%
2010 Q1	0.55%	4.34%
2010 Q2	0.55%	4.34%
2010 Q3	0.89%	4.66%
2010 Q4	1.20%	4.01%
2011 Q1	1.47%	4.29%
2011 Q2	1.47%	4.29%
2011 Q3	1.47%	4.29%
2011 Q4	1.47%	4.29%
2012 Q1	1.47%	4.29%
2012 Q2	1.47%	4.29%
2012 Q3	1.47%	4.29%
2012 Q4	1.47%	4.29%

Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts
Jan-06	*2006*	*Q1*	$ -		0.00%	$ -	$ -	
Feb-06	*2006*	*Q1*	$ -		0.00%	$ -	$ -	
Mar-06	*2006*	*Q1*	$ -		0.00%	$ -	$ -	
Apr-06	*2006*	*Q2*	$ -		4.14%	$ -	$ -	
May-06	*2006*	*Q2*	$ -	$ 3,767.31	4.14%	$ -	$ 3,767.31	
Jun-06	*2006*	*Q2*	$ 3,767.31	$ 3,776.76	4.14%	$ 13.00	$ 7,557.07	
Jul-06	*2006*	*Q3*	$ 7,544.07	$ 3,781.62	4.59%	$ 28.86	$ 11,354.55	
Aug-06	*2006*	*Q3*	$ 11,325.69	$ 3,783.78	4.59%	$ 43.32	$ 15,152.79	
Sep-06	*2006*	*Q3*	$ 15,109.47	$ 3,788.37	4.59%	$ 57.79	$ 18,955.63	
Oct-06	*2006*	*Q4*	$ 18,897.84	$ 3,792.96	4.59%	$ 72.28	$ 22,763.08	
Nov-06	*2006*	*Q4*	$ 22,690.80	$ 3,796.20	4.59%	$ 86.79	$ 26,573.79	
Dec-06	*2006*	*Q4*	$ 26,487.00	$ 3,796.20	4.59%	$ 101.31	$ 30,384.51	$ 30,686.55
Jan-07	*2007*	*Q1*	$ 30,283.20	$ 1,812.51	4.59%	$ 115.83	$ 32,211.54	
Feb-07	*2007*	*Q1*	$ 32,095.71	$ 7,012.54	4.59%	$ 122.77	$ 39,231.02	
Mar-07	*2007*	*Q1*	$ 39,108.25	$ 8,352.39	4.59%	$ 149.59	$ 47,610.22	
Apr-07	*2007*	*Q2*	$ 47,460.63	$ 8,336.04	4.59%	$ 181.54	$ 55,978.22	
May-07	*2007*	*Q2*	$ 55,796.68	$ 8,644.72	4.59%	$ 213.42	$ 64,654.82	
Jun-07	*2007*	*Q2*	$ 64,441.40	$ 5,272.36	4.59%	$ 246.49	$ 69,960.25	
Jul-07	*2007*	*Q3*	$ 69,713.76	$ 4,660.52	4.59%	$ 266.66	$ 74,640.94	
Aug-07	*2007*	*Q3*	$ 74,374.28	$ 4,726.51	4.59%	$ 284.48	$ 79,385.27	
Sep-07	*2007*	*Q3*	$ 79,100.79	$ 4,651.16	4.59%	$ 302.56	$ 84,054.51	
Oct-07	*2007*	*Q4*	$ 83,751.95	$ 4,635.66	5.14%	$ 358.74	$ 88,746.35	
Nov-07	*2007*	*Q4*	$ 88,387.61	$ 4,681.01	5.14%	$ 378.59	$ 93,447.21	
Dec-07	*2007*	*Q4*	$ 93,068.62	$ 4,651.29	5.14%	$ 398.64	$ 98,118.55	$ 70,456.02
Jan-08	*2008*	*Q1*	$ 97,719.91	$ 4,707.92	5.14%	$ 418.57	$ 102,846.40	
Feb-08	*2008*	*Q1*	$ 102,427.83	$ 4,670.77	5.14%	$ 438.73	$ 107,537.33	
Mar-08	*2008*	*Q1*	$ 107,098.60	$ 4,653.99	5.14%	$ 458.74	$ 112,211.33	
Apr-08	*2008*	*Q2*	$ 111,752.59	$ 4,709.41	4.08%	$ 379.96	$ 116,841.96	
May-08	*2008*	*Q2*	$ 116,462.00	$ 4,656.04	4.08%	$ 395.97	$ 121,514.01	
Jun-08	*2008*	*Q2*	$ 121,118.04	$ 4,650.67	4.08%	$ 411.80	$ 126,180.51	
Jul-08	*2008*	*Q3*	$ 125,768.71	$ 4,672.35	3.35%	$ 351.10	$ 130,792.16	

Aug-08	*2008*	*Q3*	$ 130,441.06	$ 4,701.67	3.35%	$ 364.15	$ 135,506.88	
Sep-08	*2008*	*Q3*	$ 135,142.73	$ 4,682.52	3.35%	$ 377.27	$ 140,202.52	
Oct-08	*2008*	*Q4*	$ 139,825.25	$ 4,702.31	3.35%	$ 390.35	$ 144,917.91	
Nov-08	*2008*	*Q4*	$ 144,527.56	$ 4,690.96	3.35%	$ 403.47	$ 149,621.99	
Dec-08	*2008*	*Q4*	$ 149,218.52	$ 4,618.62	3.35%	$ 416.57	$ 154,253.71	$ 60,923.91
Jan-09	*2009*	*Q1*	$ 153,837.14	$ 4,416.44	2.45%	$ 314.08	$ 158,567.66	
Feb-09	*2009*	*Q1*	$ 158,253.58	$ 4,497.52	2.45%	$ 323.10	$ 163,074.20	
Mar-09	*2009*	*Q1*	$ 162,751.10	$ 4,601.80	2.45%	$ 332.28	$ 167,685.18	
Apr-09	*2009*	*Q2*	$ 167,352.90	$ 4,598.73	1.00%	$ 139.46	$ 172,091.09	
May-09	*2009*	*Q2*	$ 171,951.63	$ 5,584.12	1.00%	$ 143.29	$ 177,679.04	
Jun-09	*2009*	*Q2*	$ 177,535.75	$ 14,055.87	1.00%	$ 147.95	$ 191,739.57	
Jul-09	*2009*	*Q3*	$ 191,591.62	$ 16,289.71	0.55%	$ 87.81	$ 207,969.14	
Aug-09	*2009*	*Q3*	$ 207,881.33	$ 15,713.33	0.55%	$ 95.28	$ 223,689.94	
Sep-09	*2009*	*Q3*	$ 223,594.66	$ 16,092.25	0.55%	$ 102.48	$ 239,789.39	
Oct-09	*2009*	*Q4*	$ 239,686.91	$ 16,015.23	0.55%	$ 109.86	$ 255,812.00	
Nov-09	*2009*	*Q4*	$ 255,702.14	$ 16,104.85	0.55%	$ 117.20	$ 271,924.19	
Dec-09	*2009*	*Q4*	$ 271,806.99	$ 17,368.09	0.55%	$ 124.58	$ 289,299.66	$ 137,375.31
Jan-10	*2010*	*Q1*	$ 289,175.08	$ 17,857.28	0.55%	$ 132.54	$ 307,164.90	
Feb-10	*2010*	*Q1*	$ 307,032.36	$ 17,731.40	0.55%	$ 140.72	$ 324,904.48	
Mar-10	*2010*	*Q1*	$ 324,763.76	$ 19,493.57	0.55%	$ 148.85	$ 344,406.18	
Apr-10	*2010*	*Q2*	$ 344,257.33	$ 15,960.93	0.55%	$ 157.78	$ 360,376.04	
May-10	*2010*	*Q2*	$ 360,218.26	$ 17,499.69	0.55%	$ 165.10	$ 377,883.05	
Jun-10	*2010*	*Q2*	$ 377,717.95	$ 17,667.95	0.55%	$ 173.12	$ 395,559.02	
Jul-10	*2010*	*Q3*	$ 395,385.90	$ 17,947.67	0.89%	$ 293.24	$ 413,626.81	
Aug-10	*2010*	*Q3*	$ 413,333.57	$ 17,558.97	0.89%	$ 306.56	$ 431,199.10	
Sep-10	*2010*	*Q3*	$ 430,892.54	$ 17,804.41	0.89%	$ 319.58	$ 449,016.53	
Oct-10	*2010*	*Q4*	$ 448,696.95	$ 17,649.76	1.20%	$ 448.70	$ 466,795.41	
Nov-10	*2010*	*Q4*	$ 466,346.71	$ 17,701.65	1.20%	$ 466.35	$ 484,514.71	
Dec-10	*2010*	*Q4*	$ 484,048.36	$ 17,885.78	1.20%	$ 484.05	$ 502,418.19	$ 215,995.65
Jan-11	*2011*	*Q1*	$ 501,934.14	$ 14,029.89	1.47%	$ 614.87	$ 516,578.90	
Feb-11	*2011*	*Q1*	$ 515,964.03	$ 14,222.62	1.47%	$ 632.06	$ 530,818.71	
Mar-11	*2011*	*Q1*	$ 530,186.65	$ 14,089.15	1.47%	$ 649.48	$ 544,925.28	
Apr-11	*2011*	*Q2*	$ 544,275.80	$ 14,137.23	1.47%	$ 666.74	$ 559,079.77	
May-11	*2011*	*Q2*	$ 558,413.03	$ 15,133.98	1.47%	$ 684.06	$ 574,231.07	
Jun-11	*2011*	*Q2*	$ 573,547.01	$ 27,429.68	1.47%	$ 702.60	$ 601,679.29	
Jul-11	*2011*	*Q3*	$ 600,976.69	$ 29,126.33	1.47%	$ 736.20	$ 630,839.22	
Aug-11	*2011*	*Q3*	$ 630,103.02	$ 28,946.34	1.47%	$ 771.88	$ 659,821.24	
Sep-11	*2011*	*Q3*	$ 659,049.36	$ 29,344.89	1.47%	$ 807.34	$ 689,201.59	
Oct-11	*2011*	*Q4*	$ 688,394.25	$ 28,607.18	1.47%	$ 843.28	$ 717,844.71	
Nov-11	*2011*	*Q4*	$ 717,001.43	$ 28,927.37	1.47%	$ 878.33	$ 746,807.13	
Dec-11	*2011*	*Q4*	$ 745,928.80	$ 27,822.86	1.47%	$ 913.76	$ 774,665.42	$ 280,718.12
Jan-12	*2012*	*Q1*	$ 773,751.66	$ 27,133.16	1.47%	$ 947.85	$ 801,832.67	
Feb-12	*2012*	*Q1*	$ 800,884.82	$ 29,707.53	1.47%	$ 981.08	$ 831,573.43	
Mar-12	*2012*	*Q1*	$ 830,592.35	$ 28,316.79	1.47%	$ 1,017.48	$ 859,926.62	
Apr-12	*2012*	*Q2*	$ 858,909.14		1.47%	$ 1,052.16	$ 859,961.30	
May-12	*2012*	*Q2*	$ 858,909.14		1.47%	$ 1,052.16	$ 859,961.30	
Jun-12	*2012*	*Q2*	$ 858,909.14		1.47%	$ 1,052.16	$ 859,961.30	
Jul-12	*2012*	*Q3*	$ 858,909.14		1.47%	$ 1,052.16	$ 859,961.30	
Aug-12	*2012*	*Q3*	$ 858,909.14		1.47%	$ 1,052.16	$ 859,961.30	
Sep-12	*2012*	*Q3*	$ 858,909.14		1.47%	$ 1,052.16	$ 859,961.30	
Oct-12	*2012*	*Q4*	$ 858,909.14		1.47%	$ 1,052.16	$ 859,961.30	
Nov-12	*2012*	*Q4*	$ 858,909.14		1.47%	$ 1,052.16	$ 859,961.30	
Dec-12	*2012*	*Q4*	$ 858,909.14		1.47%	$ 1,052.16	$ 859,961.30	$ 97,573.33
Total Funding Adder Revenues Collected				**$ 858,909.14**		**$ 34,819.75**	**$ 893,728.89**	**$ 893,728.89**

Account 1556 - Sub-accounts Operating Expenses, Amortization Expenses, Carrying Charges

Prescribed Interest Rates	Approved Deferral and Variance Accounts	CWIP
2006 Q1	0.00%	0.00%
2006 Q2	4.14%	4.68%
2006 Q3	4.59%	5.05%
2006 Q4	4.59%	4.72%
2007 Q1	4.59%	4.72%
2007 Q2	4.59%	4.72%
2007 Q3	4.59%	5.18%
2007 Q4	5.14%	5.18%
2008 Q1	5.14%	5.18%
2008 Q2	4.08%	5.18%
2008 Q3	3.35%	5.43%
2008 Q4	3.35%	5.43%
2009 Q1	2.45%	6.61%
2009 Q2	1.00%	6.61%
2009 Q3	0.55%	5.67%
2009 Q4	0.55%	4.66%
2010 Q1	0.55%	4.34%
2010 Q2	0.55%	4.34%
2010 Q3	0.89%	4.66%
2010 Q4	1.20%	4.01%
2011 Q1	1.47%	4.29%
2011 Q2	1.47%	4.29%
2011 Q3	1.47%	4.29%
2011 Q4	1.47%	4.29%
2012 Q1	1.47%	4.29%
2012 Q2	1.47%	4.29%
2012 Q3	1.47%	4.29%
2012 Q4	1.47%	4.29%

Date	Year	Quarter	Opening Balance (Principal)	OM&A Expenses	Amortization / Depreciation Expense	Closing Balance (Principal)	(Annual) Interest Rate	Interest (on opening balance)	Cumulative Interest
Jan-06	2006	Q1	$ -			-	0.00%	-	-
Feb-06	2006	Q1	-			-	0.00%	-	-
Mar-06	2006	Q1	-			-	0.00%	-	-
Apr-06	2006	Q2	-			-	4.14%	-	-
May-06	2006	Q2	-			-	4.14%	-	-
Jun-06	2006	Q2	-			-	4.14%	-	-
Jul-06	2006	Q3	-			-	4.59%	-	-
Aug-06	2006	Q3	-			-	4.59%	-	-
Sep-06	2006	Q3	-			-	4.59%	-	-
Oct-06	2006	Q4	-			-	4.59%	-	-
Nov-06	2006	Q4	-			-	4.59%	-	-
Dec-06	2006	Q4	-			-	4.59%	-	-
Jan-07	2007	Q1	-	$ 237.72		237.72	4.59%	-	-
Feb-07	2007	Q1	237.72	$ 237.72		475.44	4.59%	0.91	0.91
Mar-07	2007	Q1	475.44	$ 237.72		713.16	4.59%	1.82	2.73
Apr-07	2007	Q2	713.16	$ 237.72		950.88	4.59%	2.73	5.46
May-07	2007	Q2	950.88	$ 237.72		1,188.60	4.59%	3.64	9.09
Jun-07	2007	Q2	1,188.60	$ 237.72		1,426.32	4.59%	4.55	13.64
Jul-07	2007	Q3	1,426.32	$ 237.72		1,664.04	4.59%	5.46	19.09
Aug-07	2007	Q3	1,664.04	$ 237.72		1,901.76	4.59%	6.36	25.46
Sep-07	2007	Q3	1,901.76	$ 237.72		2,139.48	4.59%	7.27	32.73
Oct-07	2007	Q4	2,139.48	$ 237.72		2,377.20	5.14%	9.16	41.90
Nov-07	2007	Q4	2,377.20	$ 237.72		2,614.92	5.14%	10.18	52.08
Dec-07	2007	Q4	2,614.92	$ 237.72		2,852.64	5.14%	11.20	63.28
Jan-08	2008	Q1	2,852.64	$ 539.89		3,392.53	5.14%	12.22	75.50
Feb-08	2008	Q1	3,392.53	$ 539.89		3,932.42	5.14%	14.53	90.03
Mar-08	2008	Q1	3,932.42	$ 539.89		4,472.31	5.14%	16.84	106.88
Apr-08	2008	Q2	4,472.31	$ 539.89		5,012.20	4.08%	15.21	122.08
May-08	2008	Q2	5,012.20	$ 539.89		5,552.09	4.08%	17.04	139.12
Jun-08	2008	Q2	5,552.09	$ 539.89		6,091.98	4.08%	18.88	158.00
Jul-08	2008	Q3	6,091.98	$ 539.89		6,631.87	3.35%	17.01	175.01
Aug-08	2008	Q3	6,631.87	$ 539.89		7,171.76	3.35%	18.51	193.52
Sep-08	2008	Q3	7,171.76	$ 539.89		7,711.65	3.35%	20.02	213.54

Oct-08	*2008*	*Q4*	7,711.65	$	539.89		8,251.54	3.35%	21.53	235.07
Nov-08	*2008*	*Q4*	8,251.54	$	539.89		8,791.43	3.35%	23.04	258.11
Dec-08	*2008*	*Q4*	8,791.43	$	539.89		9,331.32	3.35%	24.54	282.65
Jan-09	*2009*	*Q1*	9,331.32	$	765.43		10,096.75	2.45%	19.05	301.70
Feb-09	*2009*	*Q1*	10,096.75	$	765.43		10,862.18	2.45%	20.61	322.31
Mar-09	*2009*	*Q1*	10,862.18	$	765.43		11,627.61	2.45%	22.18	344.49
Apr-09	*2009*	*Q2*	11,627.61	$	765.43		12,393.04	1.00%	9.69	354.18
May-09	*2009*	*Q2*	12,393.04	$	765.43		13,158.47	1.00%	10.33	364.51
Jun-09	*2009*	*Q2*	13,158.47	$	765.43		13,923.90	1.00%	10.97	375.47
Jul-09	*2009*	*Q3*	13,923.90	$	765.43		14,689.33	0.55%	6.38	381.86
Aug-09	*2009*	*Q3*	14,689.33	$	765.43		15,454.76	0.55%	6.73	388.59
Sep-09	*2009*	*Q3*	15,454.76	$	765.43		16,220.19	0.55%	7.08	395.67
Oct-09	*2009*	*Q4*	16,220.19	$	765.43		16,985.62	0.55%	7.43	403.11
Nov-09	*2009*	*Q4*	16,985.62	$	765.43		17,751.05	0.55%	7.79	410.89
Dec-09	*2009*	*Q4*	17,751.05	$	4,762.11		22,513.16	0.55%	8.14	419.03
Jan-10	*2010*	*Q1*	22,513.16	$	5,371.65		27,884.81	0.55%	10.32	429.34
Feb-10	*2010*	*Q1*	27,884.81	$	5,371.66		33,256.47	0.55%	12.78	442.13
Mar-10	*2010*	*Q1*	33,256.47	$	10,494.13		43,750.60	0.55%	15.24	457.37
Apr-10	*2010*	*Q2*	43,750.60	$	6,164.44		49,915.04	0.55%	20.05	477.42
May-10	*2010*	*Q2*	49,915.04	$	11,117.97		61,033.01	0.55%	22.88	500.30
Jun-10	*2010*	*Q2*	61,033.01	$	22,405.38		83,438.39	0.55%	27.97	528.27
Jul-10	*2010*	*Q3*	83,438.39	$	5,701.17		89,139.56	0.89%	61.88	590.15
Aug-10	*2010*	*Q3*	89,139.56	$	9,871.66		99,011.22	0.89%	66.11	656.27
Sep-10	*2010*	*Q3*	99,011.22	$	8,049.35		107,060.57	0.89%	73.43	729.70
Oct-10	*2010*	*Q4*	107,060.57	$	6,681.64		113,742.21	1.20%	107.06	836.76
Nov-10	*2010*	*Q4*	113,742.21	$	10,838.56		124,580.77	1.20%	113.74	950.50
Dec-10	*2010*	*Q4*	124,580.77	$	6,529.96		131,110.73	1.20%	124.58	1,075.08
Jan-11	*2011*	*Q1*	131,110.73	$	11,198.97		142,309.70	1.47%	160.61	1,235.69
Feb-11	*2011*	*Q1*	142,309.70	$	21,336.06		163,645.76	1.47%	174.33	1,410.02
Mar-11	*2011*	*Q1*	163,645.76	$	17,821.03		181,466.79	1.47%	200.47	1,610.49
Apr-11	*2011*	*Q2*	181,466.79	$	16,747.30		198,214.09	1.47%	222.30	1,832.79
May-11	*2011*	*Q2*	198,214.09	$	16,606.43		214,820.52	1.47%	242.81	2,075.60
Jun-11	*2011*	*Q2*	214,820.52	$	35,917.39		250,737.91	1.47%	263.16	2,338.75
Jul-11	*2011*	*Q3*	250,737.91	$	9,544.03		260,281.94	1.47%	307.15	2,645.91
Aug-11	*2011*	*Q3*	260,281.94	$	22,748.34		283,030.28	1.47%	318.85	2,964.75
Sep-11	*2011*	*Q3*	283,030.28	$	13,855.04		296,885.32	1.47%	346.71	3,311.47
Oct-11	*2011*	*Q4*	296,885.32	$	32,338.49		329,223.81	1.47%	363.68	3,675.15
Nov-11	*2011*	*Q4*	329,223.81	$	13,855.04		343,078.85	1.47%	403.30	4,078.45
Dec-11	*2011*	*Q4*	343,078.85	$	21,579.49		364,658.34	1.47%	420.27	4,498.72

Jan-12	*2012*	*Q1*	364,658.34	$ 13,855.04		378,513.38	1.47%	446.71	4,945.43
Feb-12	*2012*	*Q1*	378,513.38	$ 21,579.49		400,092.87	1.47%	463.68	5,409.11
Mar-12	*2012*	*Q1*	400,092.87	$ 13,855.04		413,947.91	1.47%	490.11	5,899.22
Apr-12	*2012*	*Q2*	413,947.91	$ 21,579.49		435,527.40	1.47%	507.09	6,406.31
May-12	*2012*	*Q2*	435,527.40	$ 13,855.04		449,382.44	1.47%	533.52	6,939.83
Jun-12	*2012*	*Q2*	449,382.44	$ 21,579.49		470,961.93	1.47%	550.49	7,490.32
Jul-12	*2012*	*Q3*	470,961.93	$ 13,855.04		484,816.97	1.47%	576.93	8,067.25
Aug-12	*2012*	*Q3*	484,816.97	$ 21,579.49		506,396.46	1.47%	593.90	8,661.15
Sep-12	*2012*	*Q3*	506,396.46	$ 13,855.04		520,251.50	1.47%	620.34	9,281.49
Oct-12	*2012*	*Q4*	520,251.50	$ 21,579.49		541,830.99	1.47%	637.31	9,918.79
Nov-12	*2012*	*Q4*	541,830.99	$ 13,855.04		555,686.03	1.47%	663.74	10,582.54
Dec-12	*2012*	*Q4*	555,686.03	$ 21,579.49		577,265.52	1.47%	680.72	11,263.25
				$ 577,265.52	$ -	$ 577,265.52			

Year	**OM&A (from Sheet 5)**	**Amortization Expense (from Sheet 5)**	**Cumulative OM&A and Amortization Expense**	**Average Cumulative OM&A and Amortization Expense**	**Average Annual Prescribed Interest Rate for Deferral and Variance Accounts (from Sheets 8A and 8B)**	**Simple Interest on OM&A and Amortization Expenses**
2006	$ -	$ 504.76	$ 504.76	$ 252.38	4.37%	$ 11.02
2007	$ -	$ 5,853.36	$ 6,358.12	$ 3,431.44	4.73%	$ 162.22
2008	$ -	$ 13,017.82	$ 19,375.94	$ 12,867.03	3.98%	$ 512.11
2009	$ 29,435.06	$ 17,271.35	$ 66,082.35	$ 42,729.14	1.14%	$ 486.04
2010	$ 427,630.88	$ 90,907.76	$ 584,620.99	$ 325,351.67	0.80%	$ 2,594.68
2011	$ 81,667.79	$ 178,561.11	$ 844,849.89	$ 714,735.44	1.47%	$ 10,506.61
2012	$ 18,532.06	$ 210,304.93	$ 1,073,686.88	$ 959,268.39	1.47%	$ 14,101.25
Cumulative Interest to 2011						$ 14,272.68
Cumulative Interest to 2012						$ 28,373.93

Check if applicable

X	Smart Meter Funding Adder (SMFA)	
	Smart Meter Disposition Rider (SMDR)	**The SMDR is calculated based on costs to December 31, 2011**
	Smart Meter Incremental Revenue Requirement Rate Rider (SMIRR)	**The SMIRR is calculated based on the incremental revenue requirement associated with the recovery of capital related costs to December 31, 2012 and associated OM&A.**

UPDATE WORKSHEET

	2006	2007	2008	2009	2010	2011	2012 and later	Total
Deferred and forecasted Smart Meter Incremental Revenue Requirement (from Sheet 5)	$ 767.29	$ 8,849.10	$ 18,096.19	$ 53,871.37	$ 557,100.74	$ 346,379.31	$ 346,554.85	$ 1,331,618.85
Interest on Deferred and forecasted OM&A and Amortization Expense (Sheet 8A/8B) (Check **one** of the boxes below)	$ -	$ 63.28	$ 219.37	$ 136.38	$ 656.06	$ 3,423.64		$ 4,498.72
X Sheet 8A (Interest calculated on monthly balances)	$ -	$ 63.28	$ 219.37	$ 136.38	$ 656.06	$ 3,423.64		$ 4,498.72
Sheet 8B (Interest calculated on average annual balances)								$ -
SMFA Revenues (from Sheet 8)	$ 30,283.20	$ 67,436.71	$ 56,117.23	$ 135,337.94	$ 212,759.06	$ 271,817.52	$ 85,157.48	$ 858,909.14
SMFA Interest (from Sheet 8)	$ 403.35	$ 3,019.31	$ 4,806.68	$ 2,037.37	$ 3,236.59	$ 8,900.60	$ 12,415.85	$ 34,819.75
Net Deferred Revenue Requirement	-$ 29,919.26	-$ 61,543.64	-$ 42,608.35	-$ 83,367.56	$ 341,761.14	$ 69,084.83	$ 248,981.52	$ 442,388.68
Number of Metered Customers (average for 2012 test year)							18904	

Calculation of Smart Meter Funding Adder (per metered customer per month)

Net Deferred Revenues from 2006 to April 30, 2012		$ 442,388.68
SMFA	May 1, 2012 to April 30, 2013	$ 1.10
Check: Forecasted SMFA Revenues for 2012 test year		$ 249,532.80

Exhibit Tab Schedule

10 –LRAMand SSM

LRAM/SSM Request

Overview

Erie Thames has engaged in CDM efforts and is seeking to recover certain amounts as specified herein. During the 2008 rebasing for Erie Thames, the prospective results of CDM programs were not included in the forecast. Further, because of the nature of the settlement agreement with WPPI and CPC, no CDM results were included in those proceeding as well.

Erie Thames' CDM efforts have been successful, and as a result, kWh consumption and kW demand have decreased causing Erie Thames to experience distribution revenue losses. The overall consumption and demand utilized in the forecast for this Application includes historic CDM programs and incorporates the loss/reductions resulting from the large customers that have left the system or made significant changes in their consumption. The recovery sought in this Application is not related to the loss or reduced demand of those large customers.

The Board has authorized distributors to apply for Lost Revenue Adjustment Mechanism "LRAM" and Shared Savings Mechanism "SSM" adjustments. The authorization to apply for LRAM and SSM adjustments is derived from the Board's December 2004 Decision on the Pollution Probe motion (RP-2004-0203); the OEB's May 2005 Report on the 2006 Electricity Distribution Rate Handbook ("the Report", Board File No. RP-2004-0188); and the Guidelines for Electricity Distributor Conservation and Demand Management (EB-2008-0037), issued on March 28, 2008. At page 107 of the May 2005 Report on the 2006 EDR Handbook, the Board addressed LRAM recoveries, stating:

> *"In its December 2004 Decision (RP-2004-0203), the Board concluded that an LRAM was appropriate and that it should apply to 3rd tranche expenditures. The Board indicated, at that time, that the LRAM formula would be established as part of the 2006 proceeding. The Board continues to believe that an LRAM is appropriate and concludes that it will be retrospective, not prospective. At this time, greater accuracy will be achieved if the LRAM is calculated after-the-fact, based on actual results. Accordingly, a distributor will be expected to calculate the energy savings by customer class and to value those energy savings by the Board-Approved distribution charge appropriate to that class. The resulting amount may be claimed in a subsequent rate year as compensation for lost revenue".*

With respect to SSM, at page 110 of the Report, the OEB wrote:

> *"The Board, in its (RP-2004-0203) Decision, found that a distributor shareholder*

*incentive was an appropriate way to encourage distributors to pursue CDM programs. The Board continues to be of this view. Distributors should be rewarded with 5 percent*7 *of the net savings established by the TRC test. The Board recognizes that it will be essential to establish certain inputs and to define avoided costs. Accordingly, the Board's Conservation Manual will address these matters. This will allow parties to screen CDM programs and calculate the relevant incentives."*

1 At page 111 of the Report, the OEB wrote:

"The SSM will apply to TRC benefits achieved by 3rd tranche expenditures as well as any incremental expenditures that are approved in 2006. However, as in the case of the Board's Decision with respect to 2005, the incentive will not apply to utility-side activities. Since the SSM will be retrospective, no claims for a shareholder incentive should be made in the 2006 Rate Applications. There has been considerable discussion in this proceeding as to whether CDM expenditures on the utility side should be differentiated from customer-side expenditures. The Board recognizes that conservation programs should have a balance between the two. It is important to recall however, the Board's earlier finding that the SSM incentive does not apply to utility-side investments. The Board previously ruled with respect to the 2005 SSM that the inclusion of capitalized assets into rate base provides sufficient incentives. The Board continues to hold that view."

The Guidelines for Electricity Distributor CDM state:

"5.1 Eligible LRAM programs
LRAM is available regardless of whether the programs are funded by the OPA or through distribution rates. The LRAM applies to programs implemented by the distributor, within its licensed service area, including programs delivered by the distributor itself and/or programs delivered for the distributor by a third party (under contract with the distributor, either in relation to rate-funded programs, or where the distributor has contracted with the OPA but has outsourced CDM program delivery to a third party)."

And further:

"6.1 Eligible SSM programs
The SSM is available for customer focused initiatives that are funded through distribution rates and where the costs of the initiatives are expensed, such as efficiency improvements in the use of electricity. The SSM is not available for utility-side expenditures or programs that are not funded through distribution rates, such as those funded by the OPA. Where a program is initially funded through distribution rates, but is subsequently funded by the OPA, SSM will only

> *be available for the period in which the program was funded through distribution rates."*

In accordance with the Report and the Guidelines for Electricity Distributor Conservation and Demand Management, Erie Thames Powerlines' LRAM request includes OPA funded as well as distribution rate funded programs, while the SSM request includes 1 programs funded through distribution rates. Erie Thames Powerlines has calculated energy savings by customer class and valued those savings by the Board-approved distribution charge appropriate to each class, as required by the Board.

Furthermore, Erie Thames Powerlines submits to the Board that Erie Thames Powerlines has complied with the independent third party review requirements for LRAM and SSM recoveries as laid out on page 28 of the Guidelines for Electricity Distributor Conservation and Demand Management (EB-2008-0037), which states:

> *"Where a distributor is making a claim for LRAM in relation to programs funded by the OPA, or where the distributors making a claim for LRAM and/or SSM in relation to programs funded through distribution rates, distributors should engage an independent third party. This independent third party review applies to LRAM or SSM claims made in relation to programs funded in 2007 and beyond."*

The presence of third party data verification should provide the OEB with reassurance that the amounts claimed by Erie Thames Powerlines for SSM and LRAM are reasonable and serve to maintain the interests of the rate payers. Please refer to Exhibit 10, Tab 1, Schedule 6, Appendix A for Indeco, Strategic Solutions for a Changing World review of Erie Thames Powerlines' CDM programs, program results and LRAM and SSM submission. Embedded in this review is a summary by year and rate class of both Erie Thames Powerlines's distribution rate funded conservation programs, as well as OPA contracted programs.

SUMMARY of LRAM & SSM:

The purpose of the LRAM adjustment is to remove any disincentive a utility may have towards CDM programs, by compensating a local distribution company (LDC) with a portion of lost revenues. The LRAM is determined by calculating the energy savings by customer class and valuing those energy savings by multiplying these quantities against the Board-approved variable distribution rate corresponding to the appropriate class, excluding any regulatory Asset Recovery rate riders.

The reduction in distribution revenue is calculated on the foregone volumes resulting from CDM activities by class and at the variable distribution rates applicable to the years 2007, 2008, 2009 and 2010. As the amounts are up to and including 2010 they pre-date the amalgamation of WPPI, CPC and Erie Thames. As such, Erie Thames has approached the Application with the intent of recovering through a geographic specific rate rider in recognition of this fact.

The total LRAM requested for recovery is $333,514, comprised of $40,993 for the service area of the former WPPI, $40,299 from the former service are of CPC; and $252,222 from former area of Erie Thames. The total SSM claim included in this application is $31,035 which is the sum of $3,034 from West Perth, $5,476 for Clinton Power, and $22,525 for Erie Thames Powerlines.

Erie Thames Powerlines is proposing that all three of the rate riders recover these amounts over a two year period to limit the impacts to the customer and that they be allocated to rate classes based on the percentage of the billed kWh per class.

Erie Thames Powerlines Propsed LRAM Rates

	Units	Rate Rider
Residential	kWh	$ 0.0004
GS<50 kW	kWh	$ 0.0004
GS>50 - 999 kW	kW	$ 0.2647
GS>1000 - 4999 kW	kW	$ 0.2091
Large Use	kW	$ 0.2149
Street Lights	kW	$ 0.1093
Sentinel Lights	kW	$ 0.1373
Unmetered Scattered Load	kWh	$ 0.0004
Embedded	kW	$ 0.2744

Erie Thames Powerlines	*Principal Amount Dec. 2010*	
LRAM claim	$ 252,222.00	
SSM Claim	$ 22,525.00	
SubTotal	**$ -**	
Grand total	**$ 274,747.00**	
Erie Thames Powerlines		
Request for Disposition	**$ 274,747.00**	Excluding1588 GA

		LRAM Recovery	Determinant		Two Year Rate Rider
Residential	32.59%	$ 89,538.63	119,707,075	kWh	$ 0.0004
GS < 50 kW	10.09%	$ 27,734.41	37,037,700	kWh	$ 0.0004
GS>50 to 999 kW	7.64%	$ 20,991.44	39,648	kW	$ 0.2647
GS>1000 kW to 4999 k	18.82%	$ 51,701.60	123,604	kW	$ 0.2091
Large Use	25.05%	$ 68,828.57	160,146	kW	$ 0.2149
Sentinel Lighting	0.06%	$ 165.67	603	kW	$ 0.1373
Street Lights	0.85%	$ 2,345.21	10,730	kW	$ 0.1093
Embedded	4.75%	$ 13,044.48	23,768	kW	$ 0.2744
Unmetered	0.14%	$ 396.98	545,982	kWh	$ 0.0004
Total	100.00%	**$ 274,747.00**			

	Billed KWh	Class Allocation
Residential	120,247,549	32.59%
GS < 50 kW	37,246,433	10.09%
GS>50 to 999 kW	28,190,839	7.64%
GS>1000 kW to 4999 k	69,433,617	18.82%
Large Use	92,434,594	25.05%
Sentinel Lighting	222,490	0.06%
Street Lights	3,149,541	0.85%
Embedded	17,518,323	4.75%
Unmetered	533,136	0.14%
	368,976,522	**100%**

Clinton Power LRAM Proposed Rates						
	Units	**Rate Rider**				
Residential	kWh	$ 0.0006				
GS<50 kW	kWh	$ 0.0004				
GS>50 - 999 kW	kW	$ 0.3481				
Street Lights	kW	$ 0.1936				
Sentinel Lights	kW	$ 0.1143				
Unmetered Scattered Load	kWh	$ 0.0006				
Clinton Power	***Principal Amount Dec. 2010***					
LRAM claim	$ 40,299.00					
SSM Claim	$ 5,476.00					
SubTotal	**$ -**					
Grand Total	**$ 45,775.00**					
Clinton Power						
Request for Disposition	**$ 45,775.00**					
						Two Year
			Reg Asset Amnt	***Determinant***		***Rate Rider***
	Residential	32.59%	$ 14,917.84	11,660,000	kWh	$ 0.0006
	GS < 50 kW	10.09%	$ 4,620.77	5,422,967	kWh	$ 0.0004
	GS>50 to 999 kW	56.26%	$ 25,751.92	36,991	kW	$ 0.3481
	Sentinel Lighting	0.06%	$ 27.60	121	kW	$ 0.1143
	Street Lights	0.85%	$ 390.73	1,009	kW	$ 0.1936
	Unmetered	0.14%	$ 66.14	56,040	kWh	$ 0.0006
	Total	100.00%	**$ 45,775.00**			
		Billed KWh	**Class Allocation**			
	Residential	11,595,218	38.79%			
	GS < 50 kW	5,392,837	18.04%			
	GS>50 to 999 kW	12,430,258	41.59%			
	Sentinel Lighting	44,498	0.15%			
	Street Lights	372,098	1.24%			
	Unmetered	56,040	0.19%			
		29,890,948	**100%**			

West Perth Power LRAM Proposed Rates

	Units	Rate Rider
Residential	kWh	$ 0.0002
GS<50 kW	kWh	$ 0.0002
GS>50 - 999 kW	kW	$ 0.1653
Street Lights	kW	$ 0.0561
Sentinel Lights	kW	$ 0.1018
Unmetered Scattered Load	kWh	$ 0.0000

West Perth Power	***Principal Amount Dec. 2010***
LRAM claim	$ 40,993.00
SSM Claim	$ 3,034.00
Grand Total	**$ 44,027.00**
West Perth Powe	
Request for Disposition	**$ 44,027.00**

		Reg Asset Amnt	***Determinant***		***Two Year Rate Rider***
Residential	27.13%	$ 11,944.10	27,963,560	kWh	$ 0.0002
GS < 50 kW	13.03%	$ 5,737.85	16,297,712	kWh	$ 0.0002
GS>50 to 999 kW	59.04%	$ 25,994.85	78,630	kW	$ 0.1653
Sentinel Lighting	0.03%	$ 13.07	64	kW	$ 0.1018
Street Lights	0.74%	$ 325.16	2,896	kW	$ 0.0561
Unmetered	0.03%	$ 11.98	166,487	kWh	$ 0.0000
Total	100.00%	**$ 44,027.00**			

	Billed KWh	**Class Allocation**
Residential	16,271,614	27.13%
GS < 50 kW	7,816,746	13.03%
GS>50 to 999 kW	35,413,140	59.04%
Sentinel Lighting	17,799	0.03%
Street Lights	442,973	0.74%
Unmetered	16,319	0.03%
	59,978,592	**100%**

BILL IMPACTS:

Erie Thames Powerlines proposes that the LRAM and SSM amounts be recovered over 2 years through rate riders. Table 6 below provides a summary of the impacts of the proposed LRAM and SSM adjustments for the average customer in each affected rate class.

Table 6 Summary of Impacts

Customer Classs	Consumption		Dollar Impact ETPL	Dollar Impact CPC	Dollar Impact WPPI	Total Bill ETPL	Total Bill CPC	Total Bill WPPI
Residential	750	kWh	$ 0.28	$ 0.32	$ 0.16	0.3075%	0.1744%	0.0035%
GS<50 kW	1500	kWh	$ 0.56	$ 0.64	$ 0.26	0.3272%	0.1590%	0.0020%
GS>50 - 999 kW	125	kW	$ 33.09	$ 43.51	$ 20.66	1.7483%	1.0916%	0.0009%
GS>1000 - 4999 kW	1250	kW	$ 261.43	$ -	$ -	1.4035%		
Large Use	6000	kW	$ 1,289.36	$ -	$ -	1.1318%		
Umetered	100	kWh	$ 0.04	$ 0.06	$ 0.00	0.1467%	0.0027%	0.0059%
Sentinel	0.75	kW	$ 0.10	$ 0.09	$ 0.08	0.9537%	0.6836%	0.0399%
Street Lighting	0.75	kW	$ 0.08	$ 0.15	$ 0.06	0.2982%	0.2180%	0.0116%
Embedded Distributor	2000	kW	$ 548.83	$ -	$ -	0.4645%		

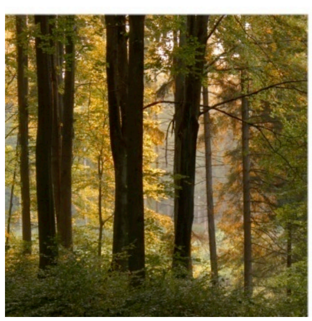
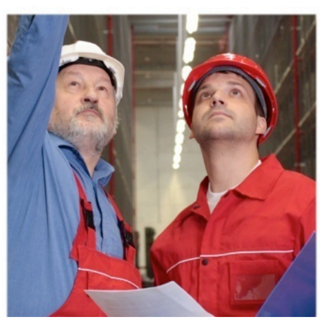
Erie Thames Powerlines submits that the recovery of the LRAM and SSM over 2 years satisfactorily mitigates the rate impact to customers, and that further mitigation is not required.

Strategic Solutions for a Changing World™

Erie Thames Powerlines Corp. LRAM/SSM






Third party review:

Erie Thames Powerlines Corporation
LRAM and SSM claims

IndEco

This document was prepared for Erie Thames Powerlines by IndEco Strategic Consulting Inc.

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IndEco report B1667

23 September 2011

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Executive summary

A third party review of the Conservation and Demand Management (CDM) programs run by Erie Thames Powerlines (ETP) was required as part of its application to the Ontario Energy Board (OEB) for collection of Lost Revenue Adjustment Mechanism (LRAM) and Shared Savings Mechanism (SSM) claims.

IndEco Strategic Consulting Inc. (IndEco) acted as third party reviewer by examining the participant rates, program costs, equipment specifications, and calculations that enter into the energy savings and Total Resource Costs (TRC) submitted by ETP to the OEB. The review was completed as detailed in the OEB *Guidelines for Electricity Distributor Conservation and Demand Management*.

The third party review included ETP's CDM activities in 2005, 2006, 2007, 2008 and 2009 and 2010 supported through Third Tranche of Market Adjustment Revenue Requirement (MARR) funding, and Ontario Power Authority (OPA) funding.

Net benefits, calculated using the TRC test, used OEB recommended inputs. For prescriptive programs, inputs were taken from the OEB *Total Resource Cost Guide*, or program evaluations provided by the OPA. TRC inputs for custom programs also relied upon manufacturer specifications and ETP's evaluations. Net TRC benefits totalled over $450,000.

Lost revenues are calculated using estimated energy savings or monthly peak demand savings using the best available and most current input assumptions. Energy savings for prescriptive programs originally reported in Erie Thames Powerlines's annual filings have been updated to reflect new assumptions available since then. In the span of the LRAM claim, these savings totalled over 13 GWh in the Residential rate class and 5 GWh in the GS < 50 kW rate class. Savings in the GS 50 to 999 kW rate class totalled approximately 700 kW-months.

IndEco concludes that ETP's electricity rates should be adjusted to reflect LRAM and SSM claims of $252,222 and $22,525 respectively.

Introduction

Lost Revenue Adjustment Mechanism and Shared Savings Mechanism claims can benefit a local distribution company (LDC) by removing the disincentive for energy conservation, and by providing it with a portion of net economic benefits from conservation and demand management activities, respectively.

What is the lost revenue adjustment mechanism (LRAM)

LRAM is designed to ensure that the LDC does not have a disincentive to promote energy efficiency and energy conservation by compensating the LDC for revenues lost as a result of its conservation initiatives. It requires the calculation of electricity savings over the period between the last rate application, and the time of the application. In turn, this calculation requires information on what the electricity use would have been in the absence of the LDC initiatives, and what it was with the LDC initiative. Some of the inputs to the calculation include: hours the equipment is used, wattage rating of the old and new equipment, and lifetime of the equipment if it is less than the period over which the LRAM is being claimed. Also required are the number of participants, or pieces of equipment installed, and an estimate of the free-rider rate, which is the fraction of the savings that would have occurred anyway, in the absence of the program. These savings are estimated by rate class, and revenue losses are determined by multiplying those losses by the cost of distribution per unit for each rate class. Carrying charges are calculated using deferral and variance account interest rates prescribed by the OEB.[1]

What is the shared savings mechanism (SSM)?

The SSM rewards the LDC for its CDM initiatives by sharing a percentage of the net economic benefits that result from the initiatives over their lifetime. For CDM activities by Ontario electricity distributors, that percentage has been set at five percent by the Ontario Energy Board (OEB). Key inputs to the calculation of SSM include all of the LRAM inputs, and in addition, the total lifetime of each technology installed, equipment costs, program costs, projected electricity costs (and water and natural gas if relevant) over that lifetime.

[1] For prescribed interest rates, see http://www.oeb.gov.on.ca/OEB/Industry/Rules+and+Requirements/Rules+Codes+Guidelines+and+Forms/Prescribed+Interest+Rates

Sources of information

Although these input data requirements are sometimes measured, they sometimes use values from published sources, or assumptions provided by the Ontario Energy Board, or other reputable agencies. Collectively all these data are sometimes referred to as “TRC inputs” after the Total Resource Cost test that is used to calculate total economic costs and benefits to society. For some types of programs, such as large scale distribution of compact fluorescent bulbs, it would be impractical to measure the hours each bulb is used, for example, and therefore these published sources provide an average value that is typical for this equipment type.

In some cases, estimated values for a particular component of the calculation are available from multiple sources. In these cases, information is taken from the sources highest in the information hierarchy. The information hierarchy (from greatest to least confidence) for LRAM calculations is:

1. Information or results from an OPA conducted or sponsored evaluation of the specific program (e.g. OPA 2010)
2. Information or results from a third-party evaluation of the specific program
3. Information or results from a site-specific assessment of the application of the technology, including on-site measurement or survey of the specific customer (e.g. ETP 2007)
4. Manufacturer specifications for energy use/demand of the specific technology installed
5. Information from the OPA’s most current measures and assumptions lists (OPA 2011a, OPA 2011b)
6. Information from earlier OPA measures and assumptions lists
7. Information from the OEB’s TRC guide list of measures and assumptions (OEB 2008b).

In principal, we might have consulted values from the literature and adopted these if they could be shown to be more current, specific or otherwise suitable than the values from sources 4 through 7. However, this was not necessary in this case.

In the span of the LRAM claim, these savings totalled over 13 GWh in the Residential rate class and 5 GWh in the GS < 50 kW rate class. Savings in the GS 50 to 999 kW rate class totalled approximately 700 kW-months.

Net TRC benefits totalled over $450,000.

Scope

This review examines the measures, energy savings, program costs and net TRC benefits for the programs in ETP's third tranche CDM portfolio. These programs ran in 2005, 2006, and 2007. It also includes programs run under contract to the Ontario Power Authority (OPA) in 2006, 2007, 2008, 2009 and 2010. Lost revenues associated with these programs are estimated through April 30, 2012. Since this LRAM claim is being filed as part of a Cost of Service application, all energy savings post-April 30 2012 associated with CDM programs up to and including programs run in 2010 should be captured in the load forecast.

In the TRC calculation, benefits and costs are reported in current dollars, which requires a discount rate for future dollars. Even though these activities are at the margin, OEB has dictated that the discount rate to be used is the weighted average cost of capital (WACC). The WACC provided by ETP is as follows:

- 2005: 10%
- 2006: 8.13%
- 2007: 8.13%

Because the WACC is only used to calculate present values for TRC calculations for the SSM, it is only required for 2005-2007 since these are the years for which an SSM amount is being claimed.

TRC inputs, and requested SSM and LRAM amounts

TRC inputs

Inputs used to calculate energy savings, TRC costs and TRC benefits for each prescriptive and custom measure were reviewed to ensure accuracy and suitability.

IndEco finds that appropriate measure specifications were used to calculate program energy savings and net TRC benefits. For the calculation of LRAM claims, prescriptive measures used values provided by the 2011 OPA Measures and Assumptions lists (OPA 2011a and OPA 2011b). For the calculation of SSM claims, the best available information at the beginning of the year the program was launched was used. This is consistent with the guidance in section 7.3 of the *OEB Guidelines for Electricity CDM* (OEB 2008a). Custom measures were substantiated through program-specific documentation and calculations.

Exceptions to the sources of prescriptive measure input assumptions used in the calculation of LRAM claims are as follows:

- The '2006-2009 Final OPA CDM results. Erie Thames Powerlines' and the '2010 Final CDM Results summary Erie Thames' were used as sources of inputs for OPA-evaluated programs. These evaluated results have been adopted in accordance with Board recommendations that "The Board would consider an evaluation by the OPA or a third party designated by the OPA to be sufficient."[2] OPA advises that these estimates are prepared in a manner consistent with OPA current practice, and are the same values used to report progress against provincial conservation targets
- The 2005, 2006 and 2007 LED and Traffic Light Conversion programs used savings estimates derived from site-specific data on existing and efficient lighting technologies and annual operating hours.

A summary list of the assumption sources used for the calculation of the LRAM claim is provided in Table 1.

The measure inputs used to calculate SSM and LRAM claims can be found in Table 8 and Table 9 in Appendix A, respectively.

Requested SSM amounts

Equipment costs and benefits were calculated by entering the measure assumptions found in Tables 8 and 9 of Appendix A into IndEco's TRC calculator.

[2] OEB 2008a. Guidelines for Electricity Distributor Conservation and Demand Management. p.28

SSM amounts were calculated for all third tranche programs, including the 2006 and 2007 EKC programs, for which ETP played a central role, and funded its contribution from third tranche funds.

The EKC program design was changed in 2008 and ETP's participation was not integral to the program. Therefore no SSM is claimed on net benefits from the 2008, 2009 or 2010 programs.

SSM amounts and TRC benefits net of free riders for all applicable programs are shown in Table 3.

Requested LRAM amounts

LRAM calculations are to be completed with the best information available at the time of the third party review. As such, the energy savings indicated in ETP's annual reports for programs in ETP's CDM portfolio were recalculated with the assumptions found in Table 9 in Appendix A. As the 2005 and 2006 LED Christmas Light Exchange programs were the only third tranche prescriptive programs in ETP's CDM portfolio, they were the only programs impacted by this update.

Energy savings for measures installed between 2005 and 31 December 2010 were calculated to April 30, 2012.

Tables 3 and 4 show the net and gross energy savings or demand reductions of each program by rate class. OPA program energy savings in Tables 3 and 4 were acquired directly from spreadsheets provided by the OPA.

Energy savings were converted to LRAM values by using ETP distribution rates. Distribution rates are in Table 5.

The requested LRAM is presented in Table 6.

Table 1 – Source of information used for the calculation of the LRAM/SSM claim

Funding source	Rate class	Program	Source of LRAM inputs
OPA	Residential	2006 Secondary Refrigerator Retirement Pilot	OPA 2010
OPA	Residential	2006 Cool & Hot Savings Rebate	OPA 2010
OPA	Residential	2007 Great Refrigerator Roundup	OPA 2010
OPA	Residential	2007 Cool & Hot Savings Rebate	OPA 2010
OPA	Residential	2007 Summer Savings	OPA 2010
OPA	Residential	2007 Social Housing Pilot	OPA 2010
OPA	Residential	2008 Great Refrigerator Roundup	OPA 2010
OPA	Residential	2008 Cool Savings Rebate	OPA 2010
OPA	Residential	2008 Every Kilowatt Counts Power Savings Event	OPA 2010
OPA	Residential	2008 Summer Sweepstakes	OPA 2010
OPA	Residential	2009 Great Refrigerator Roundup	OPA 2010
OPA	Residential	2009 Cool Savings Rebate	OPA 2010
OPA	Residential	2009 Every Kilowatt Counts Power Savings Event	OPA 2010
OPA	Residential	2010 Cool Savings Rebate	OPA 2011c
OPA	Residential	2010 Every Kilowatt Counts Power Savings Event	OPA 2011c
OPA	Residential	2010 Great Refrigerator Roundup	OPA 2011c
OPA	Residential	2010 peaksaver® consumer	OPA 2011c
OPA	Residential, GS < 50 kW	2008 peaksaver®	OPA 2010
OPA	Residential, GS < 50 kW	2009 peaksaver®	OPA 2010
OPA	Residential, GS < 50 kW	2007 peaksaver®	OPA 2010
OPA	GS < 50 kW	2008 High Performance New Construction	OPA 2010
OPA	GS < 50 kW	2008 Power Savings Blitz	OPA 2010
OPA	GS < 50 kW	2009 High Performance New Construction	OPA 2010
OPA	GS < 50 kW	2009 Power Savings Blitz	OPA 2010
OPA	GS < 50 kW	2010 High Performance New Construction	OPA 2011c
OPA	GS < 50 kW	2010 peaksaver® business	OPA 2011c
OPA	GS < 50 kW	2010 Power Savings Blitz	OPA 2011c
OPA	GS < 50 kW	2010 Multifamily Energy Efficiency Rebates	OPA 2011c
OPA	GS < 50 kW, GS 50-999 kW	2007 Electricity Retrofit Incentive	OPA 2010
OPA	GS < 50 kW, GS 50-999 kW	2008 Electricity Retrofit Incentive	OPA 2010
OPA	GS < 50 kW, GS 50-999 kW	2009 Electricity Retrofit Incentive	OPA 2010
OPA	GS < 50 kW, GS 50-999 kW	2010 Electricity Retrofit Incentive program	OPA 2011c

Funding source	Rate class	Program	Source of LRAM inputs
Third Tranche	Residential	2006 Every Kilowatt Counts	OPA 2010
Third Tranche	Residential	2007 Every Kilowatt Counts	OPA 2010
Third Tranche	Residential	2005 LED Christmas Light Exchange program	ETP 2006
Third Tranche	Residential	2006 Conservation Advertising Campaign	ETP 2007
Third Tranche	Residential	2006 LED Christmas Light Exchange program	ETP 2007
Third Tranche	Residential	2006 Residential CDM website	ETP 2007
Third Tranche	GS < 50 kW	2005 LED Traffic Light Retrofit Incentive Program	ETP 2006
Third Tranche	GS < 50 kW	2006 LED Traffic Light Retrofit Incentive Program	ETP 2007
Third Tranche	GS < 50 kW	2006 Street light conversions	ETP 2007
Third Tranche	GS < 50 kW	2007 LED Traffic Light Retrofit Incentive Program	ETP 2008
Third Tranche	GS < 50 kW	2007 Street light conversions	ETP 2008
Third Tranche	Large use (GS 5,000+)	2006 Large User Energy Avoidance Audit	ETP 2007
Third Tranche	All GS classes	2006 C&I Energy Management	ETP 2007
Third Tranche	All GS classes	2007 C&I Energy Management	ETP 2008

1. The sources of SSM inputs were the best available at the onset of the program.

Table 2 – Summary of Net TRC benefits and SSM entitlement

Program	Year	Residential	GS < 50 kW	GS 50-999 kW	Large use (GS 5,000+)	Net TRC	SSM amount
C&I Energy Management	2006		-$1,962	-$5,885		-$7,847	-$392
	2007		-$863	-$2,588		-$3,450	-$173
Conservation Advertising Campaign	2006	-$333				-$333	-$17
Every Kilowatt Counts	2006	$299,409				$299,409	$14,970
	2007	$138,900				$138,900	$6,945
Large User Energy Avoidance Audit	2006				-$2,756	-$2,756	-$138
LED Christmas Light Exchange program	2005	$3,246				$3,246	$162
	2006	$573				$573	$29
LED Traffic Light Retrofit Incentive Program	2005		$14,621			$14,621	$731
	2006		$9,863			$9,863	$493
	2007		$19,811			$19,811	$991
Residential CDM website	2006	-$22,454				-$22,454	-$1,123
Street light conversions	2006		-$2,797			-$2,797	-$140
	2007		$3,711			$3,711	$186
Total		**$419,341**	**$42,384**	**-$8,473**	**-$2,756**	**$450,496**	**$22,525**

Table 3 – Cumulative net program energy savings and peak demand savings by rate class through April 30, 2012

Funding source	Program	Program year	Residential (kWh)	GS < 50 kW (kWh)	GS 50-999 kW (kW-mo)
OPA	Cool & Hot Savings Rebate	2006	251,925		
		2007	328,304		
	Cool Savings Rebate	2008	288,396		
		2009	272,801		
		2010	273,000		
	Electricity Retrofit Incentive	2007		3,004	3
		2008		482,058	245
		2009		1,111,659	424
		2010		172,200	97
	Every Kilowatt Counts Power Savings Event	2008	1,442,115		
		2009	460,745		
		2010	126,000		
	Great Refrigerator Roundup	2007	361,284		
		2008	696,672		
		2009	488,357		
		2010	343,000		
	High Performance New Construction	2008		4,276	
		2009		104,434	
		2010		249,667	
	Multifamily Energy Efficiency Rebates	2010		21,000	
	peaksaver®	2007	0	0	
		2008	8,728	178	
		2009	4,235	86	
	peaksaver® business	2010		19.20438 957	
	peaksaver® consumer	2010	924		
	Power Savings Blitz	2008		22,380	
		2009		2,134,511	
		2010		515,667	
	Secondary Refrigerator Retirement Pilot	2006	96,681		
	Social Housing Pilot	2007	179,397		
	Summer Savings	2007	351,439		
	Summer Sweepstakes	2008	1,422,856		
OPA subtotal			**7,396,859**	**4,821,140**	**769**
Third Tranche	C&I Energy Management	2006			
		2007			
	Conservation Advertising Campaign	2006	0		
	Every Kilowatt Counts	2006	4,439,045		
		2007	1,950,067		

Funding source	Program	Program year	Residential (kWh)	GS < 50 kW (kWh)	GS 50-999 kW (kW-mo)
	Large User Energy Avoidance Audit	2006			
	LED Christmas Light Exchange program	2005	24,857		
		2006	14,914		
	LED Traffic Light Retrofit Incentive Program	2005		235,908	
		2006		157,890	
		2007		214,860	
	Residential CDM website	2006			
	Street light conversions	2006		113,267	
Third Tranche subtotal			**6,428,884**	**721,925**	**0**
Total			**13,825,743**	**5,543,065**	**769**

1. Rates for general service rate class of customers rated at greater than 50 kW are on a monthly demand basis (kW), not an energy one (kWh). Lost revenue results when the customer's monthly peak demand is lower than it otherwise would be as a result of the CDM initiatives. These are measured in kW-month, which is the reduction within one month of the peak kilowatt demand. Excluded are peak demand reductions associated with demand response programs, which are not anticipated to impact on revenues.

Table 4 – Cumulative gross program energy savings and peak demand savings by rate class through April 30, 2012

Funding source	Program	Program year	Residential (kWh)	GS < 50 kW (kWh)	GS 50-999 kW (kW-mo)
OPA	Cool & Hot Savings Rebate	2006	319,143		
		2007	640,526		
	Cool Savings Rebate	2008	502,048		
		2009	638,618		
		2010	641,667		
	Electricity Retrofit Incentive	2007		3,338	3
		2008		921,717	468
		2009		1,522,821	580
		2010		336,747	190
	Every Kilowatt Counts Power Savings Event	2008	3,572,948		
		2009	1,206,746		
		2010	273,000		
	Great Refrigerator Roundup	2007	895,230		
		2008	1,284,864		
		2009	915,588		
		2010	646,333		
	High Performance New Construction	2008		6,109	
		2009		149,192	
		2010		357,000	
	Multifamily Energy Efficiency Rebates	2010		28,000	
	peaksaver®	2007	0	0	
		2008	9,698	198	
		2009	4,705	96	
	peaksaver® business	2010		19.20438 957	
	peaksaver® consumer	2010	1,016		
	Power Savings Blitz	2008		24,065	
		2009		2,246,854	
		2010		518,000	
	Secondary Refrigerator Retirement Pilot	2006	107,424		
	Social Housing Pilot	2007	179,397		
	Summer Savings	2007	2,928,658		
	Summer Sweepstakes	2008	1,833,908		
OPA subtotal			16,601,516	6,114,155	1,242
Third Tranche	C&I Energy Management	2006			
		2007			
	Conservation Advertising Campaign	2006	0		
	Every Kilowatt Counts	2006	4,932,273		
		2007	2,647,674		

Funding source	Program	Program year	Residential (kWh)	GS < 50 kW (kWh)	GS 50-999 kW (kW-mo)
	Large User Energy Avoidance Audit	2006			
	LED Christmas Light Exchange program	2005	35,510		
		2006	21,306		
	LED Traffic Light Retrofit Incentive Program	2005		235,908	
		2006		157,890	
		2007		214,860	
	Residential CDM website	2006			
	Street light conversions	2006		113,267	
Third Tranche subtotal			**7,636,763**	**721,925**	**0**
Total			**24,238,279**	**6,836,080**	**1242**

Table 5 – Distribution rates per rate class

Rate Class	Units	2005	2006	2007	2008	2009	2010	2011
Residential	$/kWh	0.0077	0.0124	0.0136	0.0143	0.0144	0.0126	0.0126
GS < 50 kW	$/kWh	0.0099	0.0142	0.0162	0.0106	0.0107	0.009	0.009
GS 50-999 kW	$/kW	1.0166	2.3266	1.9807	1.7632	1.7757	1.1533	1.1531

Table 6 – Summary of requested LRAM amounts in 2012$[1]

Funding	Program	Year	Residential	GS < 50 kW	GS 50-999 kW	Total LRAM
OPA	Cool & Hot Savings Rebate	2006	$3,555	$0	$0	$3,555
		2007	$4,621	$0	$0	$4,621
	Cool Savings Rebate	2008	$3,991	$0	$0	$3,991
		2009	$3,666	$0	$0	$3,666
		2010	$3,500	$0	$0	$3,500
	Electricity Retrofit Incentive	2008	$0	$4,859	$371	$5,230
		2009	$0	$10,812	$596	$11,408
		2007	$0	$35	$5	$40
	Electricity Retrofit Incentive program	2010	$0	$1,577	$118	$1,695
	Every Kilowatt Counts Power Savings Event	2008	$19,981	$0	$0	$19,981
		2009	$6,199	$0	$0	$6,199
		2010	$1,616	$0	$0	$1,616
	Great Refrigerator Roundup	2007	$5,085	$0	$0	$5,085
		2008	$9,642	$0	$0	$9,642
		2009	$6,562	$0	$0	$6,562
		2010	$4,398	$0	$0	$4,398
	High Performance New Construction	2008	$0	$43	$0	$43
		2009	$0	$1,016	$0	$1,016
		2010	$0	$2,287	$0	$2,287
	Multifamily Energy Efficiency Rebates	2010	$0	$192	$0	$192
	peaksaver®	2008	$121	$2	$0	$123
		2009	$57	$1	$0	$58
		2007	$0	$0	$0	$0
	peaksaver® business	2010	$0	$0	$0	$0
	peaksaver® consumer	2010	$12	$0	$0	$12
	Power Savings Blitz	2008	$0	$227	$0	$227
		2009	$0	$20,760	$0	$20,760
		2010	$0	$4,723	$0	$4,723
	Secondary Refrigerator Retirement Pilot	2006	$1,372	$0	$0	$1,372
	Social Housing Pilot	2007	$2,525	$0	$0	$2,525
	Summer Savings	2007	$5,215	$0	$0	$5,215
	Summer Sweepstakes	2008	$19,693	$0	$0	$19,693
OPA subtotal			**$101,811**	**$46,533**	**$1,090**	**$149,434**
Third Tranche	C&I Energy Management	2006	$0	$0	$0	$0
		2007	$0	$0	$0	$0
	Conservation Advertising Campaign	2006	$0	$0	$0	$0
	Every Kilowatt Counts	2006	$65,353	$0	$0	$65,353
		2007	$27,453	$0	$0	$27,453

Funding	Program	Year	Residential	GS < 50 kW	GS 50-999 kW	Total LRAM
	Large User Energy Avoidance Audit	2006	$0	$0	$0	$0
	LED Christmas Light Exchange program	2005	$350	$0	$0	$350
		2006	$213	$0	$0	$213
	LED Traffic Light Retrofit Incentive Program	2005	$0	$2,850	$0	$2,850
		2006	$0	$1,854	$0	$1,854
		2007	$0	$2,302	$0	$2,302
	Residential CDM website	2006	$0	$0	$0	$0
	Street light conversions	2006	$0	$1,404	$0	$1,404
		2007	$0	$1,007	$0	$1,007
Third tranche subtotal			**$93,370**	**$9,418**	**$0**	**$102,788**
Total			**$195,181**	**$55,950**	**$1,090**	**$252,222**

1. LRAM amounts by program and program year, and program totals are for energy (or demand) reductions for the years 2005 through April 30, 2012.

Findings

The third-tranche programs in ETP's CDM portfolio were completed as of December 31, 2007. Although the OEB guidance for this report asks for comments on future program evaluation and improvements to program performance, this expectation is not relevant for these programs that have ended and are not expected to be reinitiated.

IndEco has reviewed the input values and custom project justifications used to calculate the energy savings and net TRC benefits resulting from ETP's portfolio as well as those associated with 2006, 2007, 2008, 2009, and 2010 OPA-funded programs.

IndEco has concluded that sufficient detail and documentation exists to recommend increasing Erie Thames Powerlines's distribution rates in order to collect $252,222 in LRAM and $22,525 in SSM amounts, allocated by rate class as shown in Table 7.

Table 7 – LRAM and SSM amounts by rate class in 2012$

Rate class	LRAM	SSM
Residential	$195,181	$20,967
General Service < 50 kW	$55,950	$2,119
General Service 50-999 kW	$1,090	($424)
GS 1,000-2,999 kW	$0	$0
GS 3,000-4,999	$0	$0
Large use (GS 5,000+)	$0	($138)
Total	**$252,222**	**$22,525**

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Appendix A. Inputs used for TRC and energy savings calculations

Table 8 - SSM inputs and contribution to the total SSM for all measures.

Program	Energy Efficient Measure	Units	Measure life	SSM Free Ridership	Energy savings (kW/a)	Equipment cost	Contribution to SSM	Assumption Source
2006 Every Kilowatt Counts	Energy Star® Compact Fluorescent Light Bulb - Spring Campaign	3,854	4	10%	104	$2.5	$4,055	OPA 2010
2006 Every Kilowatt Counts	Electric Timers - Spring Campaign	108	20	10%	183	$12.5	$664	OPA 2010
2006 Every Kilowatt Counts	Programmable Thermostats - Spring Campaign	47	15	10%	216	$65.0	$234	OPA 2010
2006 Every Kilowatt Counts	Energy Star® Ceiling Fans - Spring Campaign	36	20	10%	141	$25.0	$158	OPA 2010
2006 Every Kilowatt Counts	Energy Star® Compact Fluorescent Light Bulb - Autumn Campaign	5,714	4	10%	104	$1.6	$6,239	OPA 2010
2006 Every Kilowatt Counts	Seasonal Light Emitting Diode Light String - Autumn Campaign	1,375	30	10%	31	$8.7	$1,191	OPA 2010
2006 Every Kilowatt Counts	Programmable Thermostats - Autumn Campaign	91	18	10%	522	$25.0	$1,992	OPA 2010
2006 Every Kilowatt Counts	Dimmers - Autumn Campaign	72	10	10%	139	$13.0	$184	OPA 2010
2006 Every Kilowatt Counts	Indoor Motion Sensors - Autumn Campaign	26	20	10%	209	$20.0	$174	OPA 2010
2006 Every Kilowatt Counts	Programmable Baseboard Thermostats - Autumn Campaign	5	18	10%	1,466	$25.0	$272	OPA 2010
2007 Every Kilowatt Counts	15 W CFL	6,716	8	22%	43	$2.0	$4,609	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	SSM Free Ridership	Energy savings (kW/a)	Equipment cost	Contribution to SSM	Assumption Source
2007 Every Kilowatt Counts	20+ W CFL	1,093	8	22%	62	$0.9	$1,171	OPA 2010
2007 Every Kilowatt Counts	Energy Star® Light Fixture	26	16	45%	123	$24.0	$51	OPA 2010
2007 Every Kilowatt Counts	T8 Fluorescent Tube	51	18	23%	37	$20.0	$21	OPA 2010
2007 Every Kilowatt Counts	Seasonal LED Light String	1,779	5	51%	14	$8.7	($185)	OPA 2010
2007 Every Kilowatt Counts	Project Porchlight CFL	1,413	8	24%	43	$2.0	$945	OPA 2010
2007 Every Kilowatt Counts	Solar Light	862	5	87%	5	$4.8	($19)	OPA 2010
2007 Every Kilowatt Counts	Energy Star® Ceiling Fan	54	10	45%	90	$47.0	$2	OPA 2010
2007 Every Kilowatt Counts	Furnace Filter	218	1	45%	38	$12.0	($57)	OPA 2010
2007 Every Kilowatt Counts	Power Bar with Timer	24	10	23%	72	$25.0	$14	OPA 2010
2007 Every Kilowatt Counts	Lighting Control Device	276	10	45%	72	$20.8	$193	OPA 2010
2007 Every Kilowatt Counts	Outdoor Motion Sensor	86	10	45%	160	$16.2	$157	OPA 2010
2007 Every Kilowatt Counts	Dimmer Switch	55	10	45%	24	$13.0	($0)	OPA 2010
2007 Every Kilowatt Counts	Programmable Thermostat	53	15	45%	75	$25.0	$42	OPA 2010
2005 LED Traffic Light Retrofit Incentive	10 W LED bulbs	48	10	0%	548	$80.6	$542	ETP 2006
2005 LED Traffic Light Retrofit Incentive	6 W LED bulbs	16	10	0%	377	$80.6	$189	ETP 2006
2005 LED Christmas Light Exchange	LED Christmas lights	500	30	10%	0	$2.0	$296	OEB 2008b

Program	Energy Efficient Measure	Units	Measure life	SSM Free Ridership	Energy savings (kW/a)	Equipment cost	Contribution to SSM	Assumption Source
2006 LED Christmas Light Exchange	LED Christmas lights	300	30	10%	0	$2.0	$206	OEB 2008b
2006 LED Traffic Light Retrofit Incentive	10 W LED bulbs	32	10	0%	548	$143.3	$297	ETP 2007
2006 LED Traffic Light Retrofit Incentive	6 W LED bulbs	20	10	0%	377	$143.3	$196	ETP 2007
2006 Street light conversions	100 Watt	62	5	0%	328	$100.0	$30	ETP 2007
2006 Street light conversions	150 Watt	18	5	0%	109	$100.0	($57)	ETP 2007
2007 LED Traffic Light Retrofit Incentive	10 W LED bulbs	52	10	0%	548	$74.0	$698	ETP 2008
2007 LED Traffic Light Retrofit Incentive	6 W LED bulbs	32	10	0%	377	$74.0	$292	ETP 2008
2007 Street light conversions	100 Watt	56	5	0%	328	$50.0	$186	ETP 2008

The net TRC benefits are the total technology benefits less the total technology costs (net of free riders) less the total program costs. The total net technology benefits and costs are $597,682 and $98,028. The total program cost for all programs is $49,159. Net TRC benefits are thus $450,495. The SSM incentive is 5% of these net TRC benefits, or $22,525.

Table 9 – LRAM inputs and contribution to the total LRAM for all measures.

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Energy savings (kW/a)	Contribution to LRAM (2012$)	Assumption Source
2006 Secondary Refrigerator Retirement Pilot	Refrigerator Retirement	14	6	10%	1,200	$1,329	OPA 2010
2006 Secondary Refrigerator Retirement Pilot	Freezer Retirement	1	6	10%	900	$43	OPA 2010
2006 Cool & Hot Savings Rebate	Energy Star® Central Air Conditioner - Cool Savings	41	14	10%	390	$1,300	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Energy savings (kW/a)	Contribution to LRAM (2012$)	Assumption Source
2006 Cool & Hot Savings Rebate	Programmable Thermostat - Cool Savings	32	18	10%	177	$449	OPA 2010
2006 Cool & Hot Savings Rebate	Central Air Conditioner Tune-ups - Cool Savings	28	8	10%	410	$932	OPA 2010
2006 Cool & Hot Savings Rebate	Energy Star® Central Air Conditioner - Hot Savings	8	18	43%	155	$67	OPA 2010
2006 Cool & Hot Savings Rebate	Efficient Furnace with ECM - Hot Savings	18	15	41%	837	$785	OPA 2010
2006 Cool & Hot Savings Rebate	Programmable Thermostat - Hot Savings	16	15	73%	54	$22	OPA 2010
2006 Every Kilowatt Counts	Energy Star® Compact Fluorescent Light Bulb - Spring Campaign	3,854	4	10%	104	$21,533	OPA 2010
2006 Every Kilowatt Counts	Electric Timers - Spring Campaign	108	20	10%	183	$1,591	OPA 2010
2006 Every Kilowatt Counts	Programmable Thermostats - Spring Campaign	47	15	10%	216	$817	OPA 2010
2006 Every Kilowatt Counts	Energy Star® Ceiling Fans - Spring Campaign	36	20	10%	141	$406	OPA 2010
2006 Every Kilowatt Counts	Energy Star® Compact Fluorescent Light Bulb - Autumn Campaign	5,714	4	10%	104	$31,927	OPA 2010
2006 Every Kilowatt Counts	Seasonal Light Emitting Diode Light String - Autumn Campaign	1,375	30	10%	31	$3,402	OPA 2010
2006 Every Kilowatt Counts	Programmable Thermostats - Autumn Campaign	91	18	10%	522	$3,808	OPA 2010
2006 Every Kilowatt Counts	Dimmers - Autumn Campaign	72	10	10%	139	$802	OPA 2010
2006 Every Kilowatt Counts	Indoor Motion Sensors - Autumn Campaign	26	20	10%	209	$433	OPA 2010
2006 Every Kilowatt Counts	Programmable Baseboard Thermostats - Autumn Campaign	5	18	10%	1,466	$637	OPA 2010
2007 Great Refrigerator Roundup	Bottom Freezer Fridge	2	9	27%	1,064	$96	OPA 2010
2007 Great Refrigerator Roundup	Chest Freezer	38	8	54%	471	$618	OPA 2010
2007 Great Refrigerator Roundup	Side by Side Fridge-Freezer	14	9	61%	900	$359	OPA 2010
2007 Great Refrigerator Roundup	Single Door Fridge	38	9	61%	721	$797	OPA 2010
2007 Great Refrigerator Roundup	Small Freezer (under 10 cubic feet)	1	8	70%	339	$11	OPA 2010
2007 Great Refrigerator Roundup	Small Fridge (under 10 cubic feet)	3	9	70%	490	$33	OPA 2010
2007 Great Refrigerator Roundup	Top Freezer Fridge	136	9	61%	732	$2,929	OPA 2010
2007 Great Refrigerator Roundup	Upright Freezer	7	8	54%	743	$188	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Energy savings (kW/a)	Contribution to LRAM (2012$)	Assumption Source
2007 Great Refrigerator Roundup	Window Air Conditioner	8	5	57%	240	$54	OPA 2010
2007 Cool & Hot Savings Rebate	Energy Star® Central Air Conditioner - Hot Savings	8	18	43%	155	$55	OPA 2010
2007 Cool & Hot Savings Rebate	Efficient Furnace with ECM - Hot Savings	17	15	41%	837	$647	OPA 2010
2007 Cool & Hot Savings Rebate	Programmable Thermostat - Hot Savings	16	15	73%	54	$18	OPA 2010
2007 Cool & Hot Savings Rebate	Energy Star® Central Air Conditioner, Tier 2 - Cool Savings	64	18	43%	155	$429	OPA 2010
2007 Cool & Hot Savings Rebate	Medium Efficiency Furnace with ECM - Cool Savings	86	15	41%	837	$3,177	OPA 2010
2007 Cool & Hot Savings Rebate	Programmable Thermostat - Cool Savings	80	15	73%	54	$88	OPA 2010
2007 Cool & Hot Savings Rebate	Central Air Conditioner Tune-ups - Cool Savings	79	5	84%	235	$207	OPA 2010
2007 Every Kilowatt Counts	15 W CFL	6,716	8	22%	43	$16,907	OPA 2010
2007 Every Kilowatt Counts	20+ W CFL	1,093	8	22%	62	$3,975	OPA 2010
2007 Every Kilowatt Counts	Energy Star® Light Fixture	26	16	45%	123	$132	OPA 2010
2007 Every Kilowatt Counts	T8 Fluorescent Tube	51	18	23%	37	$110	OPA 2010
2007 Every Kilowatt Counts	Seasonal LED Light String	1,779	5	51%	14	$846	OPA 2010
2007 Every Kilowatt Counts	Project Porchlight CFL	1,413	8	24%	43	$3,467	OPA 2010
2007 Every Kilowatt Counts	Solar Light	862	5	87%	5	$38	OPA 2010
2007 Every Kilowatt Counts	Energy Star® Ceiling Fan	54	10	45%	90	$201	OPA 2010
2007 Every Kilowatt Counts	Furnace Filter	218	1	45%	38	$68	OPA 2010
2007 Every Kilowatt Counts	Power Bar with Timer	24	10	23%	72	$100	OPA 2010
2007 Every Kilowatt Counts	Lighting Control Device	276	10	45%	72	$823	OPA 2010
2007 Every Kilowatt Counts	Outdoor Motion Sensor	86	10	45%	160	$569	OPA 2010
2007 Every Kilowatt Counts	Dimmer Switch	55	10	45%	24	$54	OPA 2010
2007 Every Kilowatt Counts	Programmable Thermostat	53	15	45%	75	$163	OPA 2010
2007 Summer Savings	Households, Change in Behaviour Only - Behaviour Related	134	1	88%	5,453	$1,318	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Energy savings (kW/a)	Contribution to LRAM (2012$)	Assumption Source
2007 Summer Savings	Households, Combination of Change in Behaviour and "Pulled Forward" Equipment - Behaviour Related	134	1	88%	2,919	$706	OPA 2010
2007 Summer Savings	Households, Combination of Change in Behaviour and "Pulled Forward" Equipment - Equipment Related	134	2	88%	1,662	$807	OPA 2010
2007 Summer Savings	Households, Combination of Change in Behaviour and "Pulled Forward" Equipment - Compact Fluorescent Light Bulb Related	134	8	88%	171	$206	OPA 2010
2007 Summer Savings	Households, Change in Behaviour and Incremental Equipment (With Full Equipment Life) - Behaviour Related	134	1	88%	4,822	$1,166	OPA 2010
2007 Summer Savings	Households, Change in Behaviour and Incremental Equipment (With Full Equipment Life) - Equipment Related	134	14	88%	643	$774	OPA 2010
2007 Summer Savings	Households, Change in Behaviour and Incremental Equipment (With Full Equipment Life) - Compact Fluorescent Light Bulb Related	134	8	88%	199	$239	OPA 2010
2007 Social Housing Pilot	All projects	1	10	0%	33,637	$2,525	OPA 2010
2007 Electricity Retrofit Incentive	All projects	1	5	10%	814	$40	OPA 2010
2008 Great Refrigerator Roundup	Bottom Freezer Fridge	3	9	45%	775	$68	OPA 2010
2008 Great Refrigerator Roundup	Chest Freezer	64	8	48%	740	$1,472	OPA 2010
2008 Great Refrigerator Roundup	Side by Side Fridge-Freezer	25	9	45%	775	$639	OPA 2010
2008 Great Refrigerator Roundup	Single Door Fridge	49	9	45%	775	$1,241	OPA 2010
2008 Great Refrigerator Roundup	Small Freezer (under 10 cubic feet)	1	8	48%	740	$17	OPA 2010
2008 Great Refrigerator Roundup	Small Fridge (under 10 cubic feet)	1	9	45%	775	$37	OPA 2010
2008 Great Refrigerator Roundup	Top Freezer Fridge	227	9	45%	775	$5,812	OPA 2010
2008 Great Refrigerator Roundup	Upright Freezer	12	8	48%	740	$288	OPA 2010
2008 Great Refrigerator Roundup	Window Air Conditioner	16	5	64%	197	$68	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Energy savings (kW/a)	Contribution to LRAM (2012$)	Assumption Source
2008 Cool Savings Rebate	2007 Energy Star® Central Air Conditioner, Tier 2	13	18	43%	155	$68	OPA 2010
2008 Cool Savings Rebate	2007 Medium Efficiency Furnace with ECM	27	15	41%	837	$790	OPA 2010
2008 Cool Savings Rebate	2007 Programmable Thermostat	21	15	73%	54	$18	OPA 2010
2008 Cool Savings Rebate	2008 Energy Star® Central Air Conditioner, Tier 2	63	18	43%	125	$272	OPA 2010
2008 Cool Savings Rebate	2008 Efficient Furnace with ECM	95	18	41%	819	$2,771	OPA 2010
2008 Cool Savings Rebate	2008 Programmable Thermostat	81	18	73%	54	$72	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Energy Star® Qualified Compact Fluorescent Light Bulbs	2,570	8	48%	53	$4,266	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Energy Star® Qualified Dimmable CFLs	280	6	62%	98	$618	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Energy Star® Qualified Decorative CFLs	4,342	4	61%	30	$2,836	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Energy Star® Qualified Compact Fluorescent Floods (Indoor & Outdoor)	1,205	7	63%	88	$2,373	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Energy Star® Qualified Light Fixtures	1,871	16	67%	133	$4,998	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	T8 Fluorescent Fixtures	340	16	67%	37	$249	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Lighting Control Devices	366	10	55%	102	$1,018	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Power Bars with Timers	20	10	59%	53	$26	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Heavy Duty Timers	42	10	67%	301	$254	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Programmable Thermostats - Baseboard	118	15	53%	64	$210	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Air Conditioner/Furnace Filters	111	1	65%	38	$22	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Pipe Wrap	2,398	6	53%	38	$2,558	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Energy savings (kW/a)	Contribution to LRAM (2012$)	Assumption Source
2008 Every Kilowatt Counts Power Savings Event	Keep Cool Pilot – Dehumidifier	1	12	65%	500	$8	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Keep Cool Pilot – Room Air Conditioner	1	9	58%	141	$3	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Rewards for Recycling – Dehumidifier	22	12	56%	500	$296	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Rewards for Recycling – Room Air Conditioner	24	9	56%	141	$90	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Rewards for Recycling – Halogen Lamp	19	16	52%	275	$153	OPA 2010
2008 peaksaver®	Residential Air Conditioner - Thermostat	132	13	10%	17	$123	OPA 2010
2008 Summer Sweepstakes	Registered qualified active households	184	5	22%	421	$3,608	OPA 2010
2008 Summer Sweepstakes	Registered unqualified active households	276	5	22%	421	$5,411	OPA 2010
2008 Summer Sweepstakes	Registered qualified inactive households	18	5	22%	421	$361	OPA 2010
2008 Summer Sweepstakes	Registered unqualified inactive households	69	5	22%	421	$1,357	OPA 2010
2008 Summer Sweepstakes	Non-registered active households	8,970	5	22%	21	$8,956	OPA 2010
2008 Electricity Retrofit Incentive	Custom Project	1	15	48%	259,395	$5,230	OPA 2010
2008 High Performance New Construction	Custom Project	1	14	30%	1,410	$43	OPA 2010
2008 Power Savings Blitz	T8 Fixture With Electronic Ballast	35	15	7%	151	$215	OPA 2010
2008 Power Savings Blitz	Energy Star® rated CLF	3	2	7%	191	$12	OPA 2010
2009 Great Refrigerator Roundup	Bottom Freezer Fridge - Not Replaced - Running Part Time (38% of the time)	0	5	46%	674	$1	OPA 2010
2009 Great Refrigerator Roundup	Bottom Freezer Fridge - Standard Efficiency Unit Replacement - Running Part Time (38% of the time)	0	5	46%	454	$0	OPA 2010
2009 Great Refrigerator Roundup	Bottom Freezer Fridge - Energy Star Unit Replacement - Running Part Time (38% of the time)	0	5	46%	498	$2	OPA 2010
2009 Great Refrigerator Roundup	Bottom Freezer Fridge - Not Replaced - Running All Time (100% of time)	1	5	46%	1,769	$22	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Energy savings (kW/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Great Refrigerator Roundup	Bottom Freezer Fridge - Standard Efficiency Unit Replacement - Running All Time (100% of time)	0	5	46%	1,193	$6	OPA 2010
2009 Great Refrigerator Roundup	Bottom Freezer Fridge - Energy Star Unit Replacement - Running All Time (100% of time)	1	5	46%	1,308	$32	OPA 2010
2009 Great Refrigerator Roundup	Chest Freezer - Not Replaced - Running Part Time (26% of the time)	2	4	48%	282	$16	OPA 2010
2009 Great Refrigerator Roundup	Chest Freezer - Standard Efficiency Unit Replacement - Running Part Time (26% of the time)	1	4	48%	247	$4	OPA 2010
2009 Great Refrigerator Roundup	Chest Freezer - Energy Star Unit Replacement - Running Part Time (26% of the time)	3	4	48%	261	$18	OPA 2010
2009 Great Refrigerator Roundup	Chest Freezer - Not Replaced - Running All Time (100% of time)	24	4	48%	1,096	$612	OPA 2010
2009 Great Refrigerator Roundup	Chest Freezer - Standard Efficiency Unit Replacement - Running All Time (100% of time)	7	4	48%	959	$148	OPA 2010
2009 Great Refrigerator Roundup	Chest Freezer - Energy Star Unit Replacement - Running All Time (100% of time)	30	4	48%	1,012	$713	OPA 2010
2009 Great Refrigerator Roundup	Side by Side Fridge-Freezer - Not Replaced - Running Part Time (38% of the time)	1	5	46%	507	$9	OPA 2010
2009 Great Refrigerator Roundup	Side by Side Fridge-Freezer - Standard Efficiency Unit Replacement - Running Part Time (38% of the time)	0	5	46%	260	$2	OPA 2010
2009 Great Refrigerator Roundup	Side by Side Fridge-Freezer - Energy Star Unit Replacement - Running Part Time (38% of the time)	1	5	46%	309	$10	OPA 2010
2009 Great Refrigerator Roundup	Side by Side Fridge-Freezer - Not Replaced - Running All Time (100% of time)	5	5	46%	1,331	$166	OPA 2010
2009 Great Refrigerator Roundup	Side by Side Fridge-Freezer - Standard Efficiency Unit Replacement - Running All Time (100% of time)	2	5	46%	682	$32	OPA 2010
2009 Great Refrigerator Roundup	Side by Side Fridge-Freezer - Energy Star Unit Replacement - Running All Time (100% of time)	10	5	46%	812	$197	OPA 2010
2009 Great Refrigerator Roundup	Single Door Fridge - Not Replaced - Running Part Time (38% of the time)	1	5	46%	418	$13	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Energy savings (kW/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Great Refrigerator Roundup	Single Door Fridge - Standard Efficiency Unit Replacement - Running Part Time (38% of the time)	0	5	46%	237	$3	OPA 2010
2009 Great Refrigerator Roundup	Single Door Fridge - Energy Star Unit Replacement - Running Part Time (38% of the time)	2	5	46%	273	$17	OPA 2010
2009 Great Refrigerator Roundup	Single Door Fridge - Not Replaced - Running All Time (100% of time)	9	5	46%	1,097	$247	OPA 2010
2009 Great Refrigerator Roundup	Single Door Fridge - Standard Efficiency Unit Replacement - Running All Time (100% of time)	3	5	46%	623	$52	OPA 2010
2009 Great Refrigerator Roundup	Single Door Fridge - Energy Star Unit Replacement - Running All Time (100% of time)	18	5	46%	718	$315	OPA 2010
2009 Great Refrigerator Roundup	Top Freezer Fridge - Not Replaced - Running Part Time (38% of the time)	7	5	46%	470	$77	OPA 2010
2009 Great Refrigerator Roundup	Top Freezer Fridge - Standard Efficiency Unit Replacement - Running Part Time (38% of the time)	2	5	46%	252	$15	OPA 2010
2009 Great Refrigerator Roundup	Top Freezer Fridge - Energy Star Unit Replacement - Running Part Time (38% of the time)	13	5	46%	295	$94	OPA 2010
2009 Great Refrigerator Roundup	Top Freezer Fridge - Not Replaced - Running All Time (100% of time)	49	5	46%	1,234	$1,454	OPA 2010
2009 Great Refrigerator Roundup	Top Freezer Fridge - Standard Efficiency Unit Replacement - Running All Time (100% of time)	18	5	46%	661	$289	OPA 2010
2009 Great Refrigerator Roundup	Top Freezer Fridge - Energy Star Unit Replacement - Running All Time (100% of time)	94	5	46%	776	$1,778	OPA 2010
2009 Great Refrigerator Roundup	Upright Freezer - Not Replaced - Running Part Time (26% of the time)	0	4	48%	365	$2	OPA 2010
2009 Great Refrigerator Roundup	Upright Freezer - Standard Efficiency Unit Replacement - Running Part Time (26% of the time)	0	4	48%	180	$0	OPA 2010
2009 Great Refrigerator Roundup	Upright Freezer - Energy Star Unit Replacement - Running Part Time (26% of the time)	0	4	48%	189	$2	OPA 2010
2009 Great Refrigerator Roundup	Upright Freezer - Not Replaced - Running All Time (100% of time)	3	4	48%	1,416	$90	OPA 2010
2009 Great Refrigerator Roundup	Upright Freezer - Standard Efficiency Unit Replacement - Running All Time (100% of time)	1	4	48%	697	$12	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Energy savings (kW/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Great Refrigerator Roundup	Upright Freezer - Energy Star Unit Replacement - Running All Time (100% of time)	3	4	48%	736	$59	OPA 2010
2009 Great Refrigerator Roundup	Dehumidifier - Not Replaced - Running All Time (100% of time)	1	4	64%	960	$14	OPA 2010
2009 Great Refrigerator Roundup	Dehumidifier - Standard Efficiency Unit Replacement - Running All Time (100% of time)	1	4	64%	540	$5	OPA 2010
2009 Great Refrigerator Roundup	Dehumidifier - Energy Star Unit Replacement - Running All Time (100% of time)	2	4	64%	463	$12	OPA 2010
2009 Great Refrigerator Roundup	Window Air Conditioner - Not Replaced - Running All Time (100% of time)	4	3	64%	371	$20	OPA 2010
2009 Great Refrigerator Roundup	Window Air Conditioner - Standard Efficiency Unit Replacement - Running All Time (100% of time)	0	3	64%	118	$1	OPA 2010
2009 Great Refrigerator Roundup	Window Air Conditioner - Energy Star Unit Replacement - Running All Time (100% of time)	2	3	64%	141	$4	OPA 2010
2009 Cool Savings Rebate	Energy Star® 14.5 SEER (Tier 1) Central Air Conditioner (CAC)	28	18	42%	113	$81	OPA 2010
2009 Cool Savings Rebate	Energy Star® 14.5 SEER (Tier 1) Central Air Conditioner (CAC) with change in behavior	4	18	42%	317	$36	OPA 2010
2009 Cool Savings Rebate	Energy Star® 15.0 SEER (Tier 2) Central Air Conditioner (CAC)	73	18	42%	177	$334	OPA 2010
2009 Cool Savings Rebate	Energy Star® 15.0 SEER (Tier 2) Central Air Conditioner (CAC) with change in behaviour	11	18	42%	366	$108	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, AHRI Matched CAC & Furnace, Continuous Fan, No change	6	19	60%	2,773	$306	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, AHRI Matched CAC & Furnace, Non-continuous Fan, No change	25	19	60%	324	$147	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Energy savings (kW/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, AHRI Matched CAC & Furnace, Continuous Fan, Change from non-continuous	2	19	60%	91	$3	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, Unmatched CAC & Furnace, Continuous Fan, No change	11	19	60%	2,823	$550	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, Unmatched CAC & Furnace, Non-continuous Fan, No change	45	19	60%	373	$299	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, Unmatched CAC & Furnace, Continuous Fan, Change from non-continuous	4	19	60%	140	$9	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, Heating only, Continuous Fan, No change	2	19	60%	1,535	$49	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, Heating only, Non-continuous Fan, No change	7	19	60%	324	$42	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, Heating only, Continuous Fan, Change from non-continuous	1	19	60%	192	$2	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, AHRI Matched CAC & Furnace, Continuous Fan, No change	7	19	60%	2,867	$371	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, AHRI Matched CAC & Furnace, Non-continuous Fan, No change	30	19	60%	207	$110	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Energy savings (kW/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, AHRI Matched CAC & Furnace, Continuous Fan, Change from non-continuous	2	19	60%	(49)	($2)	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, Unmatched CAC & Furnace, Continuous Fan, No change	13	19	60%	2,927	$669	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, Unmatched CAC & Furnace, Non-continuous Fan, No change	53	19	60%	267	$251	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, Unmatched CAC & Furnace, Continuous Fan, Change from non-continuous	4	19	60%	11	$1	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, Heating only, Continuous Fan, No change	2	19	60%	1,570	$59	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, Heating only, Non-continuous Fan, No change	9	19	60%	207	$32	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, Heating only, Continuous Fan, Change from non-continuous	1	19	60%	76	$1	OPA 2010
2009 Cool Savings Rebate	Programmable Thermostat - Central Air Conditioning (CAC) & Gas heating	58	15	61%	30	$31	OPA 2010
2009 Cool Savings Rebate	Programmable Thermostat - Energy Star® Central Air Conditioning (CAC) & Gas Heating	78	15	61%	26	$35	OPA 2010
2009 Cool Savings Rebate	Programmable Thermostat - Gas Heating only	17	15	61%	9	$3	OPA 2010
2009 Cool Savings Rebate	Participant Spillover - Lighting	8	5	0%	40	$14	OPA 2010
2009 Cool Savings Rebate	Participant Spillover - Cooling or Heating	3	3	0%	100	$12	OPA 2010
2009 Cool Savings Rebate	Participant Spillover - Water heating	4	10	0%	141	$25	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Energy savings (kW/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Cool Savings Rebate	Participant Spillover - Appliances	6	4	0%	76	$19	OPA 2010
2009 Cool Savings Rebate	Participant Spillover - Insulation of other weatherization	8	10	0%	75	$27	OPA 2010
2009 Cool Savings Rebate	Participant Spillover - Windows	6	10	0%	100	$28	OPA 2010
2009 Cool Savings Rebate	Participant Spillover - Roof products	3	15	0%	50	$7	OPA 2010
2009 Cool Savings Rebate	Participant Spillover - Other products	3	5	0%	50	$8	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Compact Fluorescent - Spring Campaign - Participant Rebated	306	8	31%	23	$218	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Decorative CFLs - Spring Campaign - Participant Rebated	726	6	23%	26	$647	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Fixtures - Spring Campaign - Participant Rebated	59	16	47%	116	$163	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Ceiling Fans - Spring Campaign - Participant Rebated	25	10	24%	71	$62	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Heavy Duty Pool and Spa Timers - Spring Campaign - Participant Rebated	10	10	24%	454	$148	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Clotheslines - Spring Campaign - Participant Rebated	25	10	45%	77	$47	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Pipe Wrap - Spring Campaign - Participant Rebated	20	6	22%	8	$6	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Water Blanket - Spring Campaign - Participant Rebated	3	10	20%	52	$5	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Window Air Conditioner - Spring Campaign - Participant Promoted	25	12	33%	96	$73	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Dehumidifiers - Spring Campaign - Participant Promoted	24	12	32%	284	$207	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Programmable Thermostat - Spring Campaign - Participant Promoted	59	15	55%	138	$164	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Solar Power Products - Spring Campaign - Participant Promoted	153	5	40%	5	$20	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Energy savings (kW/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Every Kilowatt Counts Power Savings Event	Control Products - Spring Campaign - Participant Promoted	76	10	47%	72	$131	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Reduce power to electronics (Behavioural) - Spring Campaign - Participant Spillover	32	1	85%	21	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Installed CFLs - Spring Campaign - Participant Spillover	28	8	87%	101	$17	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Washed in Cold Laundry (Behavioural) - Spring Campaign - Participant Spillover	28	1	86%	30	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Turned off/Reduced lights (Behavioural) - Spring Campaign - Participant Spillover	26	1	88%	263	$12	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Dried clothes outside or on rack (Behavioural) - Spring Campaign - Participant Spillover	23	1	89%	74	$3	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Installed a new energy efficient appliance - Refrigerator - Spring Campaign - Participant Spillover	20	14	86%	65	$8	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Unplugged devices usually left plugged in (Behavioural) - Spring Campaign - Participant Spillover	19	1	80%	70	$4	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Installed a new energy efficient appliance - Clothes washing machine - Spring Campaign - Participant Spillover	12	14	88%	122	$8	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Added ceiling/attic/wall/basement insulation - Spring Campaign - Participant Spillover	12	20	88%	394	$25	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Installed Programmable Thermostat - Spring Campaign - Participant Spillover	12	15	87%	308	$21	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Compact Fluorescent - Spring Campaign - Non-Participant Rebated	233	8	65%	22	$81	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Decorative CFLs - Spring Campaign - Non-Participant Rebated	116	6	60%	26	$54	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Fixtures - Spring Campaign - Non-Participant Rebated	109	16	59%	68	$134	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Energy savings (kW/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Ceiling Fans - Spring Campaign - Non-Participant Rebated	32	10	86%	71	$14	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Heavy Duty Pool and Spa Timers - Spring Campaign - Non-Participant Rebated	20	10	86%	454	$55	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Clotheslines - Spring Campaign - Non-Participant Rebated	74	10	86%	77	$35	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Pipe Wrap - Spring Campaign - Non-Participant Rebated	171	6	86%	8	$8	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Water Blanket - Spring Campaign - Non-Participant Rebated	25	10	86%	52	$8	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Window Air Conditioner - Spring Campaign - Non-Participant Promoted	42	12	57%	96	$78	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Dehumidifiers - Spring Campaign - Non-Participant Promoted	50	12	56%	284	$281	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Programmable Thermostat - Spring Campaign - Non-Participant Promoted	79	15	71%	138	$142	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Solar Power Products - Spring Campaign - Non-Participant Promoted	512	5	61%	5	$43	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Control Products - Spring Campaign - Non-Participant Promoted	176	10	66%	72	$196	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Compact Fluorescent - Autumn Campaign - Participant Rebated	1,386	8	31%	25	$1,098	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Specialty CFLs - Autumn Campaign - Participant Rebated	560	6	29%	21	$373	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Fixtures - Autumn Campaign - Participant Rebated	67	16	30%	119	$250	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Weather-stripping - adhesive foam or V-strip - Autumn Campaign - Participant Rebated	62	15	43%	15	$24	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Weather-stripping - door frame kits - Autumn Campaign - Participant Rebated	41	15	47%	17	$17	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Programmable Thermostat - Autumn Campaign - Participant Rebated	27	15	33%	32	$26	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Energy savings (kW/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Every Kilowatt Counts Power Savings Event	Pipe Wrap - Autumn Campaign - Participant Rebated	23	6	55%	7	$3	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Water Blanket - Autumn Campaign - Participant Rebated	5	10	37%	56	$8	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Lighting/Appliance Controls - Autumn Campaign - Participant Rebated	47	17	28%	21	$32	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Holiday LED Lights - Autumn Campaign - Participant Promoted	165	5	41%	14	$60	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Dimmer Switches - Autumn Campaign - Participant Promoted	70	10	50%	24	$37	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Solar Powered Products - Autumn Campaign - Participant Promoted	135	4	48%	6	$18	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Washed laundry with cold water - Autumn Campaign - Participant Spillover	49	1	83%	30	$4	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Turned off / reduced use of power to electronics - Autumn Campaign - Participant Spillover	45	1	81%	21	$3	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Turned off / reduced use of lights - Autumn Campaign - Participant Spillover	42	1	83%	263	$27	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Dried clothes outside or inside on a rack - Autumn Campaign - Participant Spillover	30	1	87%	74	$4	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Turned down the thermostat setting on my furnace - Autumn Campaign - Participant Spillover	30	1	81%	270	$22	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Unplugged devices usually plugged into outlet - Autumn Campaign - Participant Spillover	28	1	82%	70	$5	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Installed a new energy efficient appliance – Refrigerator - Autumn Campaign - Participant Spillover	28	14	75%	65	$20	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Added ceiling/attic/wall/basement insulation - Autumn Campaign - Participant Spillover	22	20	78%	394	$87	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Replaced my old furnace with a high efficiency furnace - Autumn Campaign - Participant Spillover	20	15	80%	352	$62	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Energy savings (kW/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Every Kilowatt Counts Power Savings Event	Installed a new energy efficient appliance - Clothes washing machine - Autumn Campaign - Participant Spillover	18	15	81%	142	$23	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Compact Fluorescent - Autumn Campaign - Non-Participant Rebated	1,262	8	86%	24	$184	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Specialty CFLs - Autumn Campaign - Non-Participant Rebated	401	6	85%	30	$81	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Fixtures - Autumn Campaign - Non-Participant Rebated	112	16	76%	36	$44	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Weather-stripping - adhesive foam or V-strip - Autumn Campaign - Non-Participant Rebated	435	15	93%	15	$21	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Weather-stripping - door frame kits - Autumn Campaign - Non-Participant Rebated	332	15	94%	17	$16	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Programmable Thermostat - Autumn Campaign - Non-Participant Rebated	66	15	83%	83	$43	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Pipe Wrap - Autumn Campaign - Non-Participant Rebated	308	6	89%	6	$9	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Water Blanket - Autumn Campaign - Non-Participant Rebated	38	10	78%	40	$15	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Lighting/Appliance Controls - Autumn Campaign - Non-Participant Rebated	329	17	90%	42	$63	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Holiday LED Lights - Autumn Campaign - Non-Participant Promoted	539	5	65%	14	$116	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Dimmer Switches - Autumn Campaign - Non-Participant Promoted	170	10	73%	24	$49	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Solar Powered Products - Autumn Campaign - Non-Participant Promoted	272	4	58%	5	$24	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Working Room Air Conditioner Retirement - Rewards for Recycling Campaign - Incented	13	6	62%	32	$7	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Working Room Dehumidifier Retirement - Rewards for Recycling Campaign - Incented	12	8	53%	300	$75	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Energy savings (kW/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Every Kilowatt Counts Power Savings Event	Working Halogen Torchiere Retirement - Rewards for Recycling Campaign - Incented	4	10	49%	58	$5	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Recycled Second Refrigerator - Rewards for Recycling Campaign - Spillover	3	14	64%	1,238	$55	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Recycled Additional Room Air Conditioner - Rewards for Recycling Campaign - Spillover	2	6	64%	30	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Recycled Central Air Conditioner - Rewards for Recycling Campaign - Spillover	2	18	64%	72	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Recycled Additional Room Dehumidifier - Rewards for Recycling Campaign - Spillover	2	8	64%	309	$12	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Installed Energy Star® Windows - Rewards for Recycling Campaign - Spillover	4	20	82%	1,530	$48	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Installed Energy Star® CFL Bulbs - Rewards for Recycling Campaign - Spillover	13	8	82%	45	$5	OPA 2010
2009 peaksaver®	Residential Air Conditioner - Thermostat	249	13	10%	6	$56	OPA 2010
2009 peaksaver®	Commercial Air Conditioner - Thermostat	6	13	10%	6	$1	OPA 2010
2009 Electricity Retrofit Incentive	Custom Project	1	9	27%	557,130	$11,408	OPA 2010
2009 High Performance New Construction	Custom Project	1	20	30%	44,758	$1,016	OPA 2010
2009 Power Savings Blitz	All projects	1	9	5%	674,056	$20,760	OPA 2010
2010 Cool Savings Rebate	Rebates	510	2	57%	539	$3,500	OPA 2011c
2010 Every Kilowatt Counts Power Savings Event	Products purchased	1,738	2	54%	67	$1,616	OPA 2011c
2010 Great Refrigerator Roundup	Appliances	254	2	47%	1,091	$4,398	OPA 2011c
2010 peaksaver® consumer	Devices installed	179	2	9%	2	$12	OPA 2011c
2010 Electricity Retrofit Incentive program	Projects	1	2	49%	176,000	$1,695	OPA 2011c
2010 High Performance New Construction	Projects	1	2	30%	153,000	$2,287	OPA 2011c
2010 peaksaver® business	Devices installed	1	2	0%	8	$0	OPA 2011c

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Energy savings (kW/a)	Contribution to LRAM (2012$)	Assumption Source
2010 Power Savings Blitz	Projects	83	2	0%	2,675	$4,723	OPA 2011c
2010 Multifamily Energy Efficiency Rebates	Projects	0	2	25%	75,155	$192	OPA 2011c
2005 LED Traffic Light Retrofit Incentive Program	10 W LED bulbs	48	7	0%	548	$2,318	ETP 2006
2005 LED Traffic Light Retrofit Incentive Program	6 W LED bulbs	16	7	0%	377	$532	ETP 2006
2005 LED Christmas Light Exchange program	LED Christmas lights	500	5	30%	14	$350	OPA 2011a
2006 LED Christmas Light Exchange program	LED Christmas lights	300	5	30%	14	$213	OPA 2011a
2006 LED Traffic Light Retrofit Incentive Program	10 W LED bulbs	32	6	0%	548	$1,297	ETP 2007
2006 LED Traffic Light Retrofit Incentive Program	6 W LED bulbs	20	6	0%	377	$558	ETP 2007
2006 Street light conversions	100 Watt	62	5	0%	328	$1,280	ETP 2007
2006 Street light conversions	150 Watt	18	5	0%	109	$124	ETP 2007
2007 LED Traffic Light Retrofit Incentive Program	10 W LED bulbs	52	5	0%	548	$1,618	ETP 2008
2007 LED Traffic Light Retrofit Incentive Program	6 W LED bulbs	32	5	0%	377	$685	ETP 2008
2007 Street light conversions	100 Watt	56	5	0%	328	$1,007	ETP 2008
Total						$252,222	

Table 10 –LRAM contributions and carrying charges.

Funding	Program	Year	LRAM	Carrying charges	Total
OPA	Cool & Hot Savings Rebate	2006	$3,345	$210	$3,555
		2007	$4,414	$207	$4,621
	Cool Savings Rebate	2008	$3,867	$125	$3,991
		2009	$3,585	$81	$3,666
		2010	$3,440	$60	$3,500
	Electricity Retrofit Incentive	2008	$5,065	$165	$5,230
		2009	$11,154	$254	$11,408
		2007	$38	$2	$40
	Electricity Retrofit Incentive program	2010	$1,666	$29	$1,695
	Every Kilowatt Counts Power Savings Event	2008	$19,350	$631	$19,981
		2009	$6,062	$138	$6,199
		2010	$1,588	$28	$1,616
	Great Refrigerator Roundup	2007	$4,858	$228	$5,085
		2008	$9,341	$301	$9,642
		2009	$6,417	$145	$6,562
		2010	$4,322	$76	$4,398
	High Performance New Construction	2008	$42	$1	$43
		2009	$993	$23	$1,016
		2010	$2,247	$40	$2,287
	Multifamily Energy Efficiency Rebates	2010	$189	$3	$192
	peaksaver®	2008	$119	$4	$123
		2009	$56	$1	$58
	peaksaver® business	2010	$0	$0	$0
	peaksaver® consumer	2010	$12	$0	$12
	Power Savings Blitz	2008	$219	$7	$227
		2009	$20,299	$461	$20,760
		2010	$4,641	$82	$4,723
	Secondary Refrigerator Retirement Pilot	2006	$1,287	$85	$1,372
	Social Housing Pilot	2007	$2,412	$113	$2,525
	Summer Savings	2007	$4,785	$431	$5,215
	Summer Sweepstakes	2008	$19,077	$615	$19,693
Third Tranche	Every Kilowatt Counts	2006	$60,370	$4,983	$65,353
		2007	$26,220	$1,233	$27,453
	LED Christmas Light Exchange program	2005	$322	$28	$350
		2006	$201	$12	$213
	LED Traffic Light Retrofit Incentive Program	2005	$2,645	$205	$2,850
		2006	$1,749	$105	$1,854
		2007	$2,213	$89	$2,302
	Street light conversions	2006	$1,312	$92	$1,404
		2007	$966	$40	$1,007
Total			**$240,889**	**$11,333**	**$252,222**

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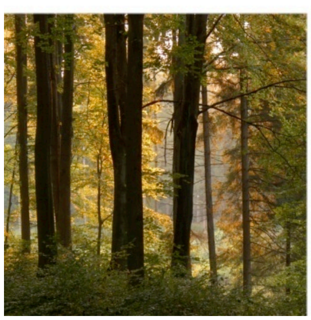
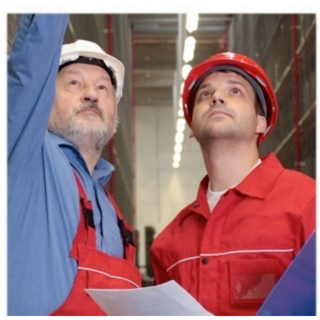
Clinton Power Corporation LRAM/SSM






Third party review:

Clinton Power Corporation LRAM and SSM claims

This document was prepared for Clinton Power Corporation by IndEco Strategic Consulting Inc.

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IndEco report B1667

26 September 2011

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Executive summary

A third party review of the Conservation and Demand Management (CDM) programs run by Clinton Power Corporation (CPC) was required as part of its application to the Ontario Energy Board (OEB) for collection of Lost Revenue Adjustment Mechanism (LRAM) and Shared Savings Mechanism (SSM) claims.

IndEco Strategic Consulting Inc. (IndEco) acted as third party reviewer by examining the participant rates, program costs, equipment specifications, and calculations that enter into the energy savings and Total Resource Costs (TRC) submitted by CPC to the OEB. The review was completed as detailed in the OEB *Guidelines for Electricity Distributor Conservation and Demand Management*.

The third party review included CPC's CDM activities in 2006, 2007, 2008 and 2009 and 2010 supported through Third Tranche of Market Adjustment Revenue Requirement (MARR) funding, and Ontario Power Authority (OPA) funding.

Net benefits, calculated using the TRC test, used OEB recommended inputs. For prescriptive programs, inputs were taken from the OEB *Total Resource Cost Guide*, or program evaluations provided by the OPA. TRC inputs for custom programs relied upon CPC's evaluations. Net TRC benefits totalled over $100,000.

Lost revenues are calculated using estimated energy savings or monthly peak demand savings using the best available and most current input assumptions. Energy savings for prescriptive programs originally reported in Clinton Power Corporation's annual filings have been updated to reflect new assumptions available since then. In the span of the LRAM claim, these savings totalled over 2.1 GWh in the Residential rate class and 1.0 GWh in the GS < 50 kW rate class.

IndEco concludes that CPC's electricity rates should be adjusted to reflect LRAM and SSM claims of $40,299 and $5,476 respectively.

Introduction

Lost Revenue Adjustment Mechanism and Shared Savings Mechanism claims can benefit a local distribution company (LDC) by removing the disincentive for energy conservation, and by providing it with a portion of net economic benefits from conservation and demand management activities, respectively.

What is the lost revenue adjustment mechanism (LRAM)

LRAM is designed to ensure that the LDC does not have a disincentive to promote energy efficiency and energy conservation by compensating the LDC for revenues lost as a result of its conservation initiatives. It requires the calculation of electricity savings over the period between the last rate application, and the time of the application. In turn, this calculation requires information on what the electricity use would have been in the absence of the LDC initiatives, and what it was with the LDC initiative. Some of the inputs to the calculation include: hours the equipment is used, wattage rating of the old and new equipment, and lifetime of the equipment if it is less than the period over which the LRAM is being claimed. Also required are the number of participants, or pieces of equipment installed, and an estimate of the free-rider rate, which is the fraction of the savings that would have occurred anyway, in the absence of the program. These savings are estimated by rate class, and revenue losses are determined by multiplying those losses by the cost of distribution per unit for each rate class. Carrying charges are calculated using deferral and variance account interest rates prescribed by the OEB.[1]

What is the shared savings mechanism (SSM)?

The SSM rewards the LDC for its CDM initiatives by sharing a percentage of the net economic benefits that result from the initiatives over their lifetime. For CDM activities by Ontario electricity distributors, that percentage has been set at five percent by the Ontario Energy Board (OEB). Key inputs to the calculation of SSM include all of the LRAM inputs, and in addition, the total lifetime of each technology installed, equipment costs, program costs, projected electricity costs (and water and natural gas if relevant) over that lifetime.

Sources of information

Although these input data requirements are sometimes measured, they sometimes use values from published sources, or assumptions provided by the Ontario Energy Board, or other reputable agencies. Collectively

[1] For prescribed interest rates, see http://www.oeb.gov.on.ca/OEB/Industry/Rules+and+Requirements/Rules+Codes+Guidelines+and+Forms/Prescribed+Interest+Rates

all these data are sometimes referred to as "TRC inputs" after the Total Resource Cost test that is used to calculate total economic costs and benefits to society. For some types of programs, such as large scale distribution of compact fluorescent bulbs, it would be impractical to measure the hours each bulb is used, for example, and therefore these published sources provide an average value that is typical for this equipment type.

In some cases, estimated values for a particular component of the calculation are available from multiple sources. In these cases, information is taken from the sources highest in the information hierarchy. The information hierarchy (from greatest to least confidence) for LRAM calculations is:

1 Information or results from an OPA conducted or sponsored evaluation of the specific program (e.g. OPA 2010)
2 Information or results from a third-party evaluation of the specific program
3 Information or results from a site-specific assessment of the application of the technology, including on-site measurement or survey of the specific customer
4 Manufacturer specifications for energy use/demand of the specific technology installed
5 Information from the OPA's most current measures and assumptions lists (OPA 2011a, OPA 2011b)
6 Information from earlier OPA measures and assumptions lists
7 Information from the OEB's TRC guide list of measures and assumptions (OEB 2008b).

In principal, we might have consulted values from the literature and adopted these if they could be shown to be more current, specific or otherwise suitable than the values from sources 4 through 7. However, this was not necessary in this case.

In the span of the LRAM claim, these savings totalled over 2.1 GWh in the Residential rate class and 1.0 GWh in the GS < 50 kW rate class.

Net TRC benefits totalled over $100,000.

Scope

This review examines the measures, energy savings, program costs and net TRC benefits for the programs in CPC's third tranche CDM portfolio. It also includes programs run under contract to the Ontario Power Authority (OPA) in 2006, 2007, 2008, 2009 and 2010. Lost revenues associated with these programs are estimated through April 30, 2012. Since this LRAM claim is being filed as part of a Cost of Service application, all energy savings post-April 30 2012 associated with CDM programs up to and including programs run in 2010 should be captured in the load forecast.

In the TRC calculation, benefits and costs are reported in current dollars, which requires a discount rate for future dollars. Even though these activities are at the margin, OEB has dictated that the discount rate to be used is the weighted average cost of capital (WACC). The WACC provided by CPC is as follows:

- 2006: 8%

The WACC is only used to calculate present values for TRC calculations used for the determination of SSM. Therefore, it is only required for 2006 since it is the only year for which an SSM amount is being claimed.

TRC inputs, and requested SSM and LRAM amounts

TRC inputs

Inputs used to calculate energy savings, TRC costs, and TRC benefits for each prescriptive and custom measure were reviewed to ensure accuracy and suitability.

IndEco finds that appropriate measure specifications were used to calculate program energy savings and net TRC benefits. For the calculation of LRAM claims, prescriptive measures used values provided by the 2011 OPA Measures and Assumptions lists (OPA 2011a and OPA 2011b). For the calculation of SSM claims, the best available information at the beginning of the year the program was launched was used. This is consistent with the guidance in section 7.3 of the *OEB Guidelines for Electricity CDM* (OEB 2008a). Custom measures were substantiated through program-specific documentation and calculations.

Exceptions to the sources of prescriptive measure input assumptions used in the calculation of LRAM claims are as follows:

- The '2006-2009 Final OPA CDM results. Clinton Power Corporation' and the '2010 Final CDM Results summary Clinton Power Corporation' were used as sources of inputs for OPA-evaluated programs. These evaluated results have been adopted in accordance with Board recommendations that "The Board would consider an evaluation by the OPA or a third party designated by the OPA to be sufficient."[2] OPA advises that these estimates are prepared in a manner consistent with OPA current practice, and are the same values used to report progress against provincial conservation targets
- The 2006 Seasonal Lighting Upgrade program used savings estimates derived from program-specific data on existing and efficient lighting technologies and annual operating hours of the pole-mounted seasonal lights being replaced.

A summary list of the assumption sources used for the calculation of the LRAM claim is provided in Table 1.

The measure inputs used to calculate SSM and LRAM claims can be found in Table 8 and Table 9 in Appendix A, respectively.

Requested SSM amounts

Equipment TRC costs and benefits were calculated by entering the measure assumptions found in Table 8 of Appendix A into IndEco's TRC calculator.

[2] OEB 2008a. Guidelines for Electricity Distributor Conservation and Demand Management. p.28

SSM amounts were calculated for all third tranche programs, including the 2006 and 2007 EKC programs, for which CPC played a central role, and funded its contribution from third tranche funds.

The EKC program design was changed in 2008 and CPC's participation was not integral to the program. Therefore no SSM is claimed on net benefits from the 2008, 2009 or 2010 programs.

SSM amounts and TRC benefits net of free riders for all applicable programs are shown in Table 3.

Requested LRAM amounts

LRAM calculations are to be completed with the best information available at the time of the third party review. As such, the energy savings indicated in CPC's annual reports for programs in CPC's CDM portfolio were recalculated with the assumptions found in Table 9 in Appendix A. As the 2006 Residential Conservation Kits program was the only prescriptive third tranche program in CPC's CDM portfolio, it was the only program impacted by this update.

Energy savings for measures installed between 2006 and 31 December 2010 were calculated to April 30, 2012.

Tables 3 and 4 show the net and gross energy savings or demand reductions of each program by rate class. OPA program energy savings in Tables 3 and 4 were acquired directly from spreadsheets provided by the OPA.

Energy savings were converted to LRAM values by using CPC distribution rates. Distribution rates are in Table 5.

The requested LRAM is presented in Table 6.

Table 1 – Source of information used for the calculation of the LRAM/SSM claim

Funding	Rate class	Program	Source
OPA	Residential	2006 Cool & Hot Savings Rebate	OPA 2010
OPA	Residential	2006 Secondary Refrigerator Retirement Pilot	OPA 2010
OPA	Residential	2007 Cool & Hot Savings Rebate	OPA 2010
OPA	Residential	2007 Great Refrigerator Roundup	OPA 2010
OPA	Residential	2007 Social Housing Pilot	OPA 2010
OPA	Residential	2007 Summer Savings	OPA 2010
OPA	Residential	2008 Cool Savings Rebate	OPA 2010
OPA	Residential	2008 Every Kilowatt Counts Power Savings Event	OPA 2010
OPA	Residential	2008 Great Refrigerator Roundup	OPA 2010
OPA	Residential	2008 Summer Sweepstakes	OPA 2010
OPA	Residential	2009 Cool Savings Rebate	OPA 2010
OPA	Residential	2009 Every Kilowatt Counts Power Savings Event	OPA 2010
OPA	Residential	2009 Great Refrigerator Roundup	OPA 2010
OPA	Residential	2010 Cool Savings Rebate	OPA 2011c
OPA	Residential	2010 Every Kilowatt Counts Power Savings Event	OPA 2011c
OPA	Residential	2010 Great Refrigerator Roundup	OPA 2011c
OPA	Residential	2010 peaksaver® consumer	OPA 2011c
OPA	Residential, GS < 50 kW	2007 peaksaver®	OPA 2010
OPA	Residential, GS < 50 kW	2008 peaksaver®	OPA 2010
OPA	Residential, GS < 50 kW	2009 peaksaver®	OPA 2010
OPA	GS < 50 kW	2008 Electricity Retrofit Incentive	OPA 2010
OPA	GS < 50 kW	2008 High Performance New Construction	OPA 2010
OPA	GS < 50 kW	2009 High Performance New Construction	OPA 2010
OPA	GS < 50 kW	2009 Power Savings Blitz	OPA 2010
OPA	GS < 50 kW	2010 Electricity Retrofit Incentive	OPA 2011c
OPA	GS < 50 kW	2010 High Performance New Construction	OPA 2011c
OPA	GS < 50 kW	2010 Multifamily energy efficiency rebates	OPA 2011c
OPA	GS < 50 kW	2010 Power Savings Blitz	OPA 2011c
Third Tranche	Residential	2006 Every Kilowatt Counts	OPA 2010
Third Tranche	Residential	2006 Residential Conservation Kits	OPA 2011a (LRAM) OEB 2008b (SSM)
Third Tranche	Residential	2007 Every Kilowatt Counts	OPA 2010
Third Tranche	GS < 50 kW	2006 Seasonal Lighting Upgrade	CPC 2009

1. The sources of SSM inputs were the best available at the onset of the program.

Table 2 – Summary of Net TRC benefits and SSM entitlements

Program	Year	Residential	GS < 50 kW	Net TRC	SSM amount
Every Kilowatt Counts	2006	$33,209		$33,209	$1,660
	2007	$15,080		$15,080	$754
Residential Conservation Kits	2006	$34,434		$34,434	$1,722
Seasonal Lighting Upgrade	2006		$13,637	$13,637	$682
Seasonal Lighting Upgrade - Christmas Tree	2006		$13,160	$13,160	$658
Total		**$82,723**	**$26,797**	**$109,521**	**$5,476**

Table 3 – Cumulative net program energy savings and peak demand savings by rate class through April 30, 2012

Funding source	Program	Program year	Residential (kWh)	GS < 50 kW (kWh)
OPA	Cool & Hot Savings Rebate	2006	27,100	
		2007	34,836	
	Cool Savings Rebate	2008	30,631	
		2009	27,649	
		2010	18,000	
	Electricity Retrofit Incentive	2008		84,606
		2010		42,750
	Every Kilowatt Counts Power Savings Event	2008	153,597	
		2009	46,709	
		2010	11,250	
	Great Refrigerator Roundup	2007	38,637	
		2008	83,985	
		2009	302,088	
		2010	47,250	
	High Performance New Construction	2008		273
		2009		6,302
		2010		15,750
	Multifamily energy efficiency rebates	2010		58,500
	peaksaver®	2007		
		2008	343	120
		2009	391	137
	peaksaver® consumer	2010	40	
	Power Savings Blitz	2009		554,973
		2010		22,500
	Secondary Refrigerator Retirement Pilot	2006	10,539	
	Social Housing Pilot	2007	19,022	
	Summer Savings	2007	28,351	
	Summer Sweepstakes	2008	196,082	
OPA subtotal			**1,076,501**	**785,911**
Third Tranche	Every Kilowatt Counts	2006	482,674	
		2007	206,888	
	Residential Conservation Kits	2006	336,148	
	Seasonal Lighting Upgrade	2006		117,970
	Seasonal Lighting Upgrade - Christmas Tree	2006		140,071
Third tranche subtotal			**1,025,710**	**258,041**
Total			**2,102,211**	**1,043,952**

Table 4 – Cumulative gross program energy savings and peak demand savings by rate class through April 30, 2012

Funding source	Program	Program year	Residential (kWh)	GS < 50 kW (kWh)
OPA	Cool & Hot Savings Rebate	2006	34,331	
		2007	68,075	
	Cool Savings Rebate	2008	53,324	
		2009	64,723	
		2010	45,000	
	Electricity Retrofit Incentive	2008		161,771
		2010		83,250
	Every Kilowatt Counts Power Savings Event	2008	380,599	
		2009	122,394	
		2010	27,000	
	Great Refrigerator Roundup	2007	96,272	
		2008	154,993	
		2009	568,414	
		2010	87,750	
	High Performance New Construction	2008		389
		2009		9,003
		2010		22,500
	Multifamily energy efficiency rebates	2010		78,750
	peaksaver®	2007		
		2008	381	134
		2009	435	153
	peaksaver® consumer	2010	44	
	Power Savings Blitz	2009		584,182
		2010		22,500
	Secondary Refrigerator Retirement Pilot	2006	11,710	
	Social Housing Pilot	2007	19,022	
	Summer Savings	2007	236,256	
	Summer Sweepstakes	2008	252,729	
OPA subtotal			**2,223,450**	**962,631**
Third Tranche	Every Kilowatt Counts	2006	536,304	
		2007	281,000	
	Residential Conservation Kits	2006	480,212	
	Seasonal Lighting Upgrade	2006		117,970
	Seasonal Lighting Upgrade - Christmas Tree	2006		140,071
Third tranche subtotal			**1,297,516**	**258,041**
Total			**3,520,966**	**1,220,672**

Table 5 – Distribution rates per rate class

Rate Class	Units	2006	2007	2008	2009	2010	2011
Residential	$/kWh	0.0112	0.0112	0.0113	0.0114	0.0136	0.0136
GS < 50	$/kWh	0.0108	0.0108	0.0109	0.011	0.0131	0.0131

Table 6 – Summary of requested LRAM amounts in 2012$[1]

Funding	Program	Year	Residential	GS < 50	LRAM
OPA	Cool & Hot Savings Rebate	2006	$348	$0	*$348*
		2007	$447	$0	*$447*
	Cool Savings Rebate	2008	$396	$0	*$396*
		2009	$365	$0	*$365*
		2010	$249	$0	*$249*
	Electricity Retrofit Incentive	2008	$0	$1,054	*$1,054*
		2010	$0	$570	*$570*
	Every Kilowatt Counts Power Savings Event	2008	$1,984	$0	*$1,984*
		2009	$616	$0	*$616*
		2010	$156	$0	*$156*
	Great Refrigerator Roundup	2007	$496	$0	*$496*
		2008	$1,085	$0	*$1,085*
		2009	$3,990	$0	*$3,990*
		2010	$654	$0	*$654*
	High Performance New Construction	2008	$0	$3	*$3*
		2009	$0	$80	*$80*
		2010	$0	$210	*$210*
	Multifamily energy efficiency rebates	2010	$0	$780	*$780*
	peaksaver®	2008	$4	$2	*$6*
		2009	$5	$2	*$7*
		2007	$0	$0	*$0*
	peaksaver® consumer	2010	$1	$0	*$1*
	Power Savings Blitz	2009	$0	$7,064	*$7,064*
		2010	$0	$300	*$300*
	Secondary Refrigerator Retirement Pilot	2006	$135	$0	*$135*
	Social Housing Pilot	2007	$244	$0	*$244*
	Summer Savings	2007	$354	$0	*$354*
	Summer Sweepstakes	2008	$2,534	$0	*$2,534*
OPA subtotal			**$14,063**	**$10,065**	***$24,128***
Third Tranche	Every Kilowatt Counts	2006	$5,979	$0	*$5,979*
		2007	$2,653	$0	*$2,653*
	Residential Conservation Kits	2006	$4,332	$0	*$4,332*
	Seasonal Lighting Upgrade	2006	$0	$1,466	*$1,466*
	Seasonal Lighting Upgrade - Christmas Tree	2006	$0	$1,740	*$1,740*
Third Tranche subtotal			**$12,965**	**$3,206**	***$16,171***
Total			**$27,028**	**$13,271**	**$40,299**

1. LRAM amounts are for energy (or demand) reductions from the year the program started until April 30, 2012.

Findings

The third-tranche programs in CPC's CDM portfolio were completed as of December 31, 2008. Although the OEB guidance for this report asks for comments on future program evaluation and improvements to program performance, this expectation is not relevant for these programs that have ended and are not expected to be reinitiated.

IndEco has reviewed the input values and custom project justifications used to calculate the energy savings and net TRC benefits resulting from CPC's portfolio as well as those associated with 2006, 2007, 2008, 2009, and 2010 OPA-funded programs.

IndEco has concluded that sufficient detail and documentation exists to recommend increasing Clinton Power Corporation's distribution rates in order to collect $40,299 in LRAM and $5,476 in SSM amounts, allocated by rate class as shown in Table 7.

Table 7 – LRAM and SSM amounts by rate class in 2012$

Rate class	LRAM	SSM
Residential	$27,028	$4,136
GS < 50 kW	$13,271	$1,340
Total	**$40,299**	**$5,476**

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Appendix A.Inputs used for TRC and energy savings calculations

Table 8 - SSM inputs and contribution to the total SSM for all measures.

Program	Energy Efficient Measure	Units	Measure life	SSM Free ridership	Annual energy savings (kWh/a)	Contribution to SSM (2012$)	Assumption Source
2006 Every Kilowatt Counts	Energy Star® Compact Fluorescent Light Bulb - Spring Campaign	420	4	10%	104	$443	OPA 2010
2006 Every Kilowatt Counts	Electric Timers - Spring Campaign	12	20	10%	183	$73	OPA 2010
2006 Every Kilowatt Counts	Programmable Thermostats - Spring Campaign	5	15	10%	216	$26	OPA 2010
2006 Every Kilowatt Counts	Energy Star® Ceiling Fans - Spring Campaign	4	20	10%	141	$17	OPA 2010
2006 Every Kilowatt Counts	Energy Star® Compact Fluorescent Light Bulb - Autumn Campaign	623	4	10%	104	$681	OPA 2010
2006 Every Kilowatt Counts	Seasonal Light Emitting Diode Light String - Autumn Campaign	150	30	10%	31	$132	OPA 2010
2006 Every Kilowatt Counts	Programmable Thermostats - Autumn Campaign	10	18	10%	522	$219	OPA 2010
2006 Every Kilowatt Counts	Dimmers - Autumn Campaign	8	10	10%	139	$20	OPA 2010
2006 Every Kilowatt Counts	Indoor Motion Sensors - Autumn Campaign	3	20	10%	209	$19	OPA 2010
2006 Every Kilowatt Counts	Programmable Baseboard Thermostats - Autumn Campaign	1	18	10%	1,466	$30	OPA 2010
2007 Every Kilowatt Counts	15 W CFL	723	8	22%	43	$499	OPA 2010
2007 Every Kilowatt Counts	20+ W CFL	118	8	22%	62	$127	OPA 2010
2007 Every Kilowatt Counts	Energy Star® Light Fixture	3	16	45%	123	$6	OPA 2010
2007 Every Kilowatt Counts	T8 Fluorescent Tube	6	18	23%	37	$2	OPA 2010
2007 Every Kilowatt Counts	Seasonal LED Light String	192	5	51%	14	($20)	OPA 2010
2007 Every Kilowatt Counts	Project Porchlight CFL	152	8	24%	43	$102	OPA 2010
2007 Every Kilowatt Counts	Solar Light	93	5	87%	5	($2)	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	SSM Free ridership	Annual energy savings (kWh/a)	Contribution to SSM (2012$)	Assumption Source
2007 Every Kilowatt Counts	Energy Star® Ceiling Fan	6	10	45%	90	$0	OPA 2010
2007 Every Kilowatt Counts	Furnace Filter	24	1	45%	38	($6)	OPA 2010
2007 Every Kilowatt Counts	Power Bar with Timer	3	10	23%	72	$2	OPA 2010
2007 Every Kilowatt Counts	Lighting Control Device	30	10	45%	72	$21	OPA 2010
2007 Every Kilowatt Counts	Outdoor Motion Sensor	9	10	45%	160	$19	OPA 2010
2007 Every Kilowatt Counts	Dimmer Switch	6	10	45%	24	$0	OPA 2010
2007 Every Kilowatt Counts	Programmable Thermostat	6	15	45%	75	$5	OPA 2010
2006 Residential Conservation Kits	15 W CFL	1,300	4	10%	0	$1,499	OEB 2008b
2006 Residential Conservation Kits	Weatherstripping	1,300	25	10%	0	$745	OEB 2008b
2006 Seasonal Lighting Upgrade	Seasonal pole mounted fixtures upgrade	52	20	0%	365	$835	CPC 2009
2006 Seasonal Lighting Upgrade - Christmas Tree	Christmas tree lighting upgrades	95	20	0%	237	$937	CPC 2009
Total equipment contribution to SSM						**$6,430**	

The net TRC benefits are the total technology benefits less the total technology costs (net of free riders) less the total program costs. The total net technology benefits and costs are $145,877 and $17,286. The total program cost for all programs is $19,070. Net TRC benefits are thus $109,521. The SSM incentive is 5% of these net TRC benefits, or $5,476.

Table 9 – LRAM inputs and contribution to the total LRAM for all measures.

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2006 Secondary Refrigerator Retirement Pilot	Refrigerator Retirement	2	6	10%	1,200	$131	OPA 2010
2006 Secondary Refrigerator	Freezer Retirement	0	6	10%	900	$4	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
Retirement Pilot							
2006 Cool & Hot Savings Rebate	Energy Star® Central Air Conditioner - Cool Savings	5	14	10%	390	$127	OPA 2010
2006 Cool & Hot Savings Rebate	Programmable Thermostat - Cool Savings	3	18	10%	177	$44	OPA 2010
2006 Cool & Hot Savings Rebate	Central Air Conditioner Tune-ups - Cool Savings	3	8	10%	410	$91	OPA 2010
2006 Cool & Hot Savings Rebate	Energy Star® Central Air Conditioner - Hot Savings	1	18	43%	155	$7	OPA 2010
2006 Cool & Hot Savings Rebate	Efficient Furnace with ECM - Hot Savings	2	15	41%	837	$77	OPA 2010
2006 Cool & Hot Savings Rebate	Programmable Thermostat - Hot Savings	2	15	73%	54	$2	OPA 2010
2006 Every Kilowatt Counts	Energy Star® Compact Fluorescent Light Bulb - Spring Campaign	420	4	10%	104	$1,939	OPA 2010
2006 Every Kilowatt Counts	Electric Timers - Spring Campaign	12	20	10%	183	$156	OPA 2010
2006 Every Kilowatt Counts	Programmable Thermostats - Spring Campaign	5	15	10%	216	$80	OPA 2010
2006 Every Kilowatt Counts	Energy Star® Ceiling Fans - Spring Campaign	4	20	10%	141	$40	OPA 2010
2006 Every Kilowatt Counts	Energy Star® Compact Fluorescent Light Bulb - Autumn Campaign	623	4	10%	104	$2,876	OPA 2010
2006 Every Kilowatt Counts	Seasonal Light Emitting Diode Light String - Autumn Campaign	150	30	10%	31	$333	OPA 2010
2006 Every Kilowatt Counts	Programmable Thermostats - Autumn Campaign	10	18	10%	522	$373	OPA 2010
2006 Every Kilowatt Counts	Dimmers - Autumn Campaign	8	10	10%	139	$78	OPA 2010
2006 Every Kilowatt Counts	Indoor Motion Sensors - Autumn Campaign	3	20	10%	209	$42	OPA 2010
2006 Every Kilowatt Counts	Programmable Baseboard Thermostats - Autumn Campaign	1	18	10%	1,466	$62	OPA 2010
2007 Great Refrigerator	Bottom Freezer Fridge	0	9	27%	1,064	$10	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
Roundup							
2007 Great Refrigerator Roundup	Chest Freezer	3	8	54%	471	$47	OPA 2010
2007 Great Refrigerator Roundup	Side by Side Fridge-Freezer	2	9	61%	900	$37	OPA 2010
2007 Great Refrigerator Roundup	Single Door Fridge	4	9	61%	721	$82	OPA 2010
2007 Great Refrigerator Roundup	Small Freezer (under 10 cubic feet)	0	8	70%	339	$1	OPA 2010
2007 Great Refrigerator Roundup	Small Fridge (under 10 cubic feet)	0	9	70%	490	$3	OPA 2010
2007 Great Refrigerator Roundup	Top Freezer Fridge	16	9	61%	732	$301	OPA 2010
2007 Great Refrigerator Roundup	Upright Freezer	1	8	54%	743	$14	OPA 2010
2007 Cool & Hot Savings Rebate	Energy Star® Central Air Conditioner - Hot Savings	1	18	43%	155	$5	OPA 2010
2007 Cool & Hot Savings Rebate	Efficient Furnace with ECM - Hot Savings	2	15	41%	837	$63	OPA 2010
2007 Cool & Hot Savings Rebate	Programmable Thermostat - Hot Savings	2	15	73%	54	$2	OPA 2010
2007 Cool & Hot Savings Rebate	Energy Star® Central Air Conditioner, Tier 2 - Cool Savings	7	18	43%	155	$41	OPA 2010
2007 Cool & Hot Savings Rebate	Medium Efficiency Furnace with ECM - Cool Savings	9	15	41%	837	$307	OPA 2010
2007 Cool & Hot Savings Rebate	Programmable Thermostat - Cool Savings	9	15	73%	54	$9	OPA 2010
2007 Cool & Hot Savings Rebate	Central Air Conditioner Tune-ups - Cool Savings	9	5	84%	235	$20	OPA 2010
2007 Every Kilowatt Counts	15 W CFL	723	8	22%	43	$1,634	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2007 Every Kilowatt Counts	20+ W CFL	118	8	22%	62	$384	OPA 2010
2007 Every Kilowatt Counts	Energy Star® Light Fixture	3	16	45%	123	$13	OPA 2010
2007 Every Kilowatt Counts	T8 Fluorescent Tube	6	18	23%	37	$11	OPA 2010
2007 Every Kilowatt Counts	Seasonal LED Light String	192	5	51%	14	$82	OPA 2010
2007 Every Kilowatt Counts	Project Porchlight CFL	152	8	24%	43	$335	OPA 2010
2007 Every Kilowatt Counts	Solar Light	93	5	87%	5	$4	OPA 2010
2007 Every Kilowatt Counts	Energy Star® Ceiling Fan	6	10	45%	90	$19	OPA 2010
2007 Every Kilowatt Counts	Furnace Filter	24	1	45%	38	$6	OPA 2010
2007 Every Kilowatt Counts	Power Bar with Timer	3	10	23%	72	$10	OPA 2010
2007 Every Kilowatt Counts	Lighting Control Device	30	10	45%	72	$80	OPA 2010
2007 Every Kilowatt Counts	Outdoor Motion Sensor	9	10	45%	160	$55	OPA 2010
2007 Every Kilowatt Counts	Dimmer Switch	6	10	45%	24	$5	OPA 2010
2007 Every Kilowatt Counts	Programmable Thermostat	6	15	45%	75	$16	OPA 2010
2007 Summer Savings	Households, Change in Behaviour Only - Behaviour Related	11	1	88%	5,453	$88	OPA 2010
2007 Summer Savings	Households, Combination of Change in Behaviour and "Pulled Forward" Equipment - Behaviour Related	11	1	88%	2,919	$47	OPA 2010
2007 Summer Savings	Households, Combination of Change in Behaviour and "Pulled Forward" Equipment - Equipment Related	11	2	88%	1,662	$53	OPA 2010
2007 Summer Savings	Households, Combination of Change in Behaviour and "Pulled Forward" Equipment - Compact Fluorescent Light Bulb Related	11	8	88%	171	$15	OPA 2010
2007 Summer Savings	Households, Change in Behaviour and Incremental Equipment (With Full Equipment Life) - Behaviour Related	11	1	88%	4,822	$78	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2007 Summer Savings	Households, Change in Behaviour and Incremental Equipment (With Full Equipment Life) - Equipment Related	11	14	88%	643	$56	OPA 2010
2007 Summer Savings	Households, Change in Behaviour and Incremental Equipment (With Full Equipment Life) - Compact Fluorescent Light Bulb Related	11	8	88%	199	$17	OPA 2010
2007 Social Housing Pilot	Custom Retrofit Projects	1	10	0%	3,623	$244	OPA 2010
2008 Great Refrigerator Roundup	Bottom Freezer Fridge	0	9	45%	775	$8	OPA 2010
2008 Great Refrigerator Roundup	Chest Freezer	8	8	48%	740	$175	OPA 2010
2008 Great Refrigerator Roundup	Side by Side Fridge-Freezer	3	9	45%	775	$71	OPA 2010
2008 Great Refrigerator Roundup	Single Door Fridge	6	9	45%	775	$138	OPA 2010
2008 Great Refrigerator Roundup	Small Freezer (under 10 cubic feet)	0	8	48%	740	$2	OPA 2010
2008 Great Refrigerator Roundup	Small Fridge (under 10 cubic feet)	0	9	45%	775	$4	OPA 2010
2008 Great Refrigerator Roundup	Top Freezer Fridge	28	9	45%	775	$646	OPA 2010
2008 Great Refrigerator Roundup	Upright Freezer	2	8	48%	740	$34	OPA 2010
2008 Great Refrigerator Roundup	Window Air Conditioner	2	5	64%	197	$8	OPA 2010
2008 Cool Savings Rebate	2007 Energy Star® Central Air Conditioner, Tier 2	1	18	43%	155	$7	OPA 2010
2008 Cool Savings Rebate	2007 Medium Efficiency Furnace with ECM	3	15	41%	837	$78	OPA 2010
2008 Cool Savings Rebate	2007 Programmable Thermostat	2	15	73%	54	$2	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2008 Cool Savings Rebate	2008 Energy Star® Central Air Conditioner, Tier 2	7	18	43%	125	$27	OPA 2010
2008 Cool Savings Rebate	2008 Efficient Furnace with ECM	10	18	41%	819	$275	OPA 2010
2008 Cool Savings Rebate	2008 Programmable Thermostat	9	18	73%	54	$7	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Energy Star® Qualified Compact Fluorescent Light Bulbs	278	8	48%	53	$423	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Energy Star® Qualified Dimmable CFLs	30	6	62%	98	$61	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Energy Star® Qualified Decorative CFLs	470	4	61%	30	$284	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Energy Star® Qualified Compact Fluorescent Floods (Indoor & Outdoor)	131	7	63%	88	$235	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Energy Star® Qualified Light Fixtures	203	16	67%	133	$496	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	T8 Fluorescent Fixtures	37	16	67%	37	$25	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Lighting Control Devices	40	10	55%	102	$101	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Power Bars with Timers	2	10	59%	53	$3	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Heavy Duty Timers	5	10	67%	301	$25	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Programmable Thermostats - Baseboard	13	15	53%	64	$21	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Air Conditioner/Furnace Filters	12	1	65%	38	$2	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Pipe Wrap	260	6	53%	38	$254	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Keep Cool Pilot – Dehumidifier	0	12	65%	500	$1	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2008 Every Kilowatt Counts Power Savings Event	Keep Cool Pilot – Room Air Conditioner	0	9	58%	141	$0	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Rewards for Recycling – Dehumidifier	2	12	56%	500	$29	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Rewards for Recycling – Room Air Conditioner	3	9	56%	141	$9	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Rewards for Recycling – Halogen Lamp	2	16	52%	275	$15	OPA 2010
2008 peaksaver®	Residential Air Conditioner - Thermostat	7	13	10%	17	$6	OPA 2010
2008 Summer Sweepstakes	Registered qualified active households	26	5	22%	421	$464	OPA 2010
2008 Summer Sweepstakes	Registered unqualified active households	39	5	22%	421	$696	OPA 2010
2008 Summer Sweepstakes	Registered qualified inactive households	3	5	22%	421	$46	OPA 2010
2008 Summer Sweepstakes	Registered unqualified inactive households	10	5	22%	421	$175	OPA 2010
2008 Summer Sweepstakes	Non-registered active households	1,260	5	22%	21	$1,152	OPA 2010
2008 Electricity Retrofit Incentive	All projects	1	15	48%	38,064	$1,054	OPA 2010
2008 High Performance New Construction	Custom Project	1	14	30%	92	$3	OPA 2010
2009 Great Refrigerator Roundup	Bottom Freezer Fridge - Not Replaced - Running Part Time (38% of the time)	0	5	46%	674	$1	OPA 2010
2009 Great Refrigerator Roundup	Bottom Freezer Fridge - Standard Efficiency Unit Replacement - Running Part Time (38% of the time)	0	5	46%	454	$0	OPA 2010
2009 Great Refrigerator Roundup	Bottom Freezer Fridge - Energy Star Unit Replacement - Running Part Time (38% of the time)	0	5	46%	498	$1	OPA 2010
2009 Great Refrigerator Roundup	Bottom Freezer Fridge - Not Replaced - Running All Time (100% of time)	0	5	46%	1,769	$11	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Great Refrigerator Roundup	Bottom Freezer Fridge - Standard Efficiency Unit Replacement - Running All Time (100% of time)	0	5	46%	1,193	$3	OPA 2010
2009 Great Refrigerator Roundup	Bottom Freezer Fridge - Energy Star Unit Replacement - Running All Time (100% of time)	1	5	46%	1,308	$15	OPA 2010
2009 Great Refrigerator Roundup	Chest Freezer - Not Replaced - Running Part Time (26% of the time)	1	4	48%	282	$7	OPA 2010
2009 Great Refrigerator Roundup	Chest Freezer - Standard Efficiency Unit Replacement - Running Part Time (26% of the time)	0	4	48%	247	$2	OPA 2010
2009 Great Refrigerator Roundup	Chest Freezer - Energy Star Unit Replacement - Running Part Time (26% of the time)	1	4	48%	261	$9	OPA 2010
2009 Great Refrigerator Roundup	Chest Freezer - Not Replaced - Running All Time (100% of time)	12	4	48%	1,096	$285	OPA 2010
2009 Great Refrigerator Roundup	Chest Freezer - Standard Efficiency Unit Replacement - Running All Time (100% of time)	3	4	48%	959	$69	OPA 2010
2009 Great Refrigerator Roundup	Chest Freezer - Energy Star Unit Replacement - Running All Time (100% of time)	15	4	48%	1,012	$332	OPA 2010
2009 Great Refrigerator Roundup	Side by Side Fridge-Freezer - Not Replaced - Running Part Time (38% of the time)	0	5	46%	507	$5	OPA 2010
2009 Great Refrigerator Roundup	Side by Side Fridge-Freezer - Standard Efficiency Unit Replacement - Running Part Time (38% of the time)	0	5	46%	260	$1	OPA 2010
2009 Great Refrigerator Roundup	Side by Side Fridge-Freezer - Energy Star Unit Replacement - Running Part Time (38% of the time)	1	5	46%	309	$6	OPA 2010
2009 Great Refrigerator Roundup	Side by Side Fridge-Freezer - Not Replaced - Running All Time (100% of time)	3	5	46%	1,331	$96	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Great Refrigerator Roundup	Side by Side Fridge-Freezer - Standard Efficiency Unit Replacement - Running All Time (100% of time)	1	5	46%	682	$18	OPA 2010
2009 Great Refrigerator Roundup	Side by Side Fridge-Freezer - Energy Star Unit Replacement - Running All Time (100% of time)	6	5	46%	812	$113	OPA 2010
2009 Great Refrigerator Roundup	Single Door Fridge - Not Replaced - Running Part Time (38% of the time)	1	5	46%	418	$9	OPA 2010
2009 Great Refrigerator Roundup	Single Door Fridge - Standard Efficiency Unit Replacement - Running Part Time (38% of the time)	0	5	46%	237	$2	OPA 2010
2009 Great Refrigerator Roundup	Single Door Fridge - Energy Star Unit Replacement - Running Part Time (38% of the time)	2	5	46%	273	$11	OPA 2010
2009 Great Refrigerator Roundup	Single Door Fridge - Not Replaced - Running All Time (100% of time)	7	5	46%	1,097	$171	OPA 2010
2009 Great Refrigerator Roundup	Single Door Fridge - Standard Efficiency Unit Replacement - Running All Time (100% of time)	2	5	46%	623	$36	OPA 2010
2009 Great Refrigerator Roundup	Single Door Fridge - Energy Star Unit Replacement - Running All Time (100% of time)	13	5	46%	718	$218	OPA 2010
2009 Great Refrigerator Roundup	Top Freezer Fridge - Not Replaced - Running Part Time (38% of the time)	4	5	46%	470	$46	OPA 2010
2009 Great Refrigerator Roundup	Top Freezer Fridge - Standard Efficiency Unit Replacement - Running Part Time (38% of the time)	2	5	46%	252	$9	OPA 2010
2009 Great Refrigerator Roundup	Top Freezer Fridge - Energy Star Unit Replacement - Running Part Time (38% of the time)	8	5	46%	295	$57	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Great Refrigerator Roundup	Top Freezer Fridge - Not Replaced - Running All Time (100% of time)	31	5	46%	1,234	$880	OPA 2010
2009 Great Refrigerator Roundup	Top Freezer Fridge - Standard Efficiency Unit Replacement - Running All Time (100% of time)	11	5	46%	661	$175	OPA 2010
2009 Great Refrigerator Roundup	Top Freezer Fridge - Energy Star Unit Replacement - Running All Time (100% of time)	60	5	46%	776	$1,077	OPA 2010
2009 Great Refrigerator Roundup	Upright Freezer - Not Replaced - Running Part Time (26% of the time)	0	4	48%	365	$4	OPA 2010
2009 Great Refrigerator Roundup	Upright Freezer - Standard Efficiency Unit Replacement - Running Part Time (26% of the time)	0	4	48%	180	$0	OPA 2010
2009 Great Refrigerator Roundup	Upright Freezer - Energy Star Unit Replacement - Running Part Time (26% of the time)	1	4	48%	189	$2	OPA 2010
2009 Great Refrigerator Roundup	Upright Freezer - Not Replaced - Running All Time (100% of time)	4	4	48%	1,416	$140	OPA 2010
2009 Great Refrigerator Roundup	Upright Freezer - Standard Efficiency Unit Replacement - Running All Time (100% of time)	1	4	48%	697	$19	OPA 2010
2009 Great Refrigerator Roundup	Upright Freezer - Energy Star Unit Replacement - Running All Time (100% of time)	6	4	48%	736	$92	OPA 2010
2009 Great Refrigerator Roundup	Dehumidifier - Not Replaced - Running All Time (100% of time)	2	4	64%	960	$32	OPA 2010
2009 Great Refrigerator Roundup	Dehumidifier - Standard Efficiency Unit Replacement - Running All Time (100% of time)	1	4	64%	540	$10	OPA 2010
2009 Great Refrigerator Roundup	Dehumidifier - Energy Star Unit Replacement - Running All Time (100% of time)	4	4	64%	463	$26	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Cool Savings Rebate	Energy Star® 14.5 SEER (Tier 1) Central Air Conditioner (CAC)	3	18	42%	113	$8	OPA 2010
2009 Cool Savings Rebate	Energy Star® 14.5 SEER (Tier 1) Central Air Conditioner (CAC) with change in behaviour	0	18	42%	317	$4	OPA 2010
2009 Cool Savings Rebate	Energy Star® 15.0 SEER (Tier 2) Central Air Conditioner (CAC)	8	18	42%	177	$33	OPA 2010
2009 Cool Savings Rebate	Energy Star® 15.0 SEER (Tier 2) Central Air Conditioner (CAC) with change in behaviour	1	18	42%	366	$11	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, AHRI Matched CAC & Furnace, Continuous Fan, No change	1	19	60%	2,773	$30	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, AHRI Matched CAC & Furnace, Non-continuous Fan, No change	3	19	60%	324	$15	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, AHRI Matched CAC & Furnace, Continuous Fan, Change from non-continuous	0	19	60%	91	$0	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, Unmatched CAC & Furnace, Continuous Fan, No change	1	19	60%	2,823	$55	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, Unmatched CAC & Furnace, Non-continuous Fan, No change	5	19	60%	373	$30	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, Unmatched CAC & Furnace, Continuous Fan,	0	19	60%	140	$1	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
	Change from non-continuous						
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, Heating only, Continuous Fan, No change	0	19	60%	1,535	$5	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, Heating only, Non-continuous Fan, No change	1	19	60%	324	$4	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, Heating only, Continuous Fan, Change from non-continuous	0	19	60%	192	$0	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, AHRI Matched CAC & Furnace, Continuous Fan, No change	1	19	60%	2,867	$37	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, AHRI Matched CAC & Furnace, Non-continuous Fan, No change	3	19	60%	207	$11	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, AHRI Matched CAC & Furnace, Continuous Fan, Change from non-continuous	0	19	60%	(49)	($0)	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, Unmatched CAC & Furnace, Continuous Fan, No change	1	19	60%	2,927	$67	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, Unmatched CAC & Furnace, Non-continuous	5	19	60%	267	$25	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
	Fan, No change						
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, Unmatched CAC & Furnace, Continuous Fan, Change from non-continuous	0	19	60%	11	$0	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, Heating only, Continuous Fan, No change	0	19	60%	1,570	$6	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, Heating only, Non-continuous Fan, No change	1	19	60%	207	$3	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, Heating only, Continuous Fan, Change from non-continuous	0	19	60%	76	$0	OPA 2010
2009 Cool Savings Rebate	Programmable Thermostat - Central Air Conditioning (CAC) & Gas heating	6	15	61%	30	$3	OPA 2010
2009 Cool Savings Rebate	Programmable Thermostat - Energy Star® Central Air Conditioning (CAC) & Gas Heating	8	15	61%	26	$3	OPA 2010
2009 Cool Savings Rebate	Programmable Thermostat - Gas Heating only	2	15	61%	9	$0	OPA 2010
2009 Cool Savings Rebate	Participant Spillover - Lighting	1	5	0%	40	$1	OPA 2010
2009 Cool Savings Rebate	Participant Spillover - Cooling or Heating	0	3	0%	100	$1	OPA 2010
2009 Cool Savings Rebate	Participant Spillover - Water heating	0	10	0%	141	$2	OPA 2010
2009 Cool Savings Rebate	Participant Spillover - Appliances	1	4	0%	76	$2	OPA 2010
2009 Cool Savings Rebate	Participant Spillover - Insulation of other weatherization	1	10	0%	75	$3	OPA 2010
2009 Cool Savings Rebate	Participant Spillover - Windows	1	10	0%	100	$3	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Cool Savings Rebate	Participant Spillover - Roof products	0	15	0%	50	$1	OPA 2010
2009 Cool Savings Rebate	Participant Spillover - Other products	0	5	0%	50	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Compact Fluorescent - Spring Campaign - Participant Rebated	32	8	31%	23	$22	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Decorative CFLs - Spring Campaign - Participant Rebated	75	6	23%	26	$64	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Fixtures - Spring Campaign - Participant Rebated	6	16	47%	116	$16	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Ceiling Fans - Spring Campaign - Participant Rebated	3	10	24%	71	$6	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Heavy Duty Pool and Spa Timers - Spring Campaign - Participant Rebated	1	10	24%	454	$15	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Clotheslines - Spring Campaign - Participant Rebated	3	10	45%	77	$5	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Pipe Wrap - Spring Campaign - Participant Rebated	2	6	22%	8	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Water Blanket - Spring Campaign - Participant Rebated	0	10	20%	52	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Window Air Conditioner - Spring Campaign - Participant Promoted	3	12	33%	96	$7	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Dehumidifiers - Spring Campaign - Participant Promoted	2	12	32%	284	$21	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Programmable Thermostat - Spring Campaign - Participant Promoted	6	15	55%	138	$16	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Solar Power Products - Spring Campaign - Participant Promoted	16	5	40%	5	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Control Products - Spring Campaign - Participant Promoted	8	10	47%	72	$13	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Reduce power to electronics (Behavioural) - Spring Campaign - Participant Spillover	3	1	85%	21	$0	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Every Kilowatt Counts Power Savings Event	Installed CFLs - Spring Campaign - Participant Spillover	3	8	87%	101	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Washed in Cold Laundry (Behavioural) - Spring Campaign - Participant Spillover	3	1	86%	30	$0	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Turned off/Reduced lights (Behavioural) - Spring Campaign - Participant Spillover	3	1	88%	263	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Dried clothes outside or on rack (Behavioural) - Spring Campaign - Participant Spillover	2	1	89%	74	$0	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Installed a new energy efficient appliance - Refrigerator - Spring Campaign - Participant Spillover	2	14	86%	65	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Unplugged devices usually left plugged in (Behavioural) - Spring Campaign - Participant Spillover	2	1	80%	70	$0	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Installed a new energy efficient appliance - Clothes washing machine - Spring Campaign - Participant Spillover	1	14	88%	122	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Added ceiling/attic/wall/basement insulation - Spring Campaign - Participant Spillover	1	20	88%	394	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Installed Programmable Thermostat - Spring Campaign - Participant Spillover	1	15	87%	308	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Compact Fluorescent - Spring Campaign - Non-Participant Rebated	24	8	65%	22	$8	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Decorative CFLs - Spring Campaign - Non-Participant Rebated	12	6	60%	26	$5	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Fixtures - Spring Campaign - Non-Participant Rebated	11	16	59%	68	$13	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Ceiling Fans - Spring Campaign - Non-Participant Rebated	3	10	86%	71	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Heavy Duty Pool and Spa Timers - Spring Campaign - Non-Participant Rebated	2	10	86%	454	$6	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Every Kilowatt Counts Power Savings Event	Clotheslines - Spring Campaign - Non-Participant Rebated	8	10	86%	77	$3	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Pipe Wrap - Spring Campaign - Non-Participant Rebated	18	6	86%	8	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Water Blanket - Spring Campaign - Non-Participant Rebated	3	10	86%	52	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Window Air Conditioner - Spring Campaign - Non-Participant Promoted	4	12	57%	96	$8	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Dehumidifiers - Spring Campaign - Non-Participant Promoted	5	12	56%	284	$28	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Programmable Thermostat - Spring Campaign - Non-Participant Promoted	8	15	71%	138	$14	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Solar Power Products - Spring Campaign - Non-Participant Promoted	53	5	61%	5	$4	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Control Products - Spring Campaign - Non-Participant Promoted	18	10	66%	72	$20	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Compact Fluorescent - Autumn Campaign - Participant Rebated	144	8	31%	25	$109	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Specialty CFLs - Autumn Campaign - Participant Rebated	58	6	29%	21	$37	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Fixtures - Autumn Campaign - Participant Rebated	7	16	30%	119	$25	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Weatherstripping - adhesive foam or V-strip - Autumn Campaign - Participant Rebated	6	15	43%	15	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Weatherstripping - door frame kits - Autumn Campaign - Participant Rebated	4	15	47%	17	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Programmable Thermostat - Autumn Campaign - Participant Rebated	3	15	33%	32	$3	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Pipe Wrap - Autumn Campaign - Participant Rebated	2	6	55%	7	$0	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Every Kilowatt Counts Power Savings Event	Water Blanket - Autumn Campaign - Participant Rebated	1	10	37%	56	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Lighting/Appliance Controls - Autumn Campaign - Participant Rebated	5	17	28%	21	$3	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Holiday LED Lights - Autumn Campaign - Participant Promoted	17	5	41%	14	$6	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Dimmer Switches - Autumn Campaign - Participant Promoted	7	10	50%	24	$4	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Solar Powered Products - Autumn Campaign - Participant Promoted	14	4	48%	6	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Washed laundry with cold water - Autumn Campaign - Participant Spillover	5	1	83%	30	$0	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Turned off / reduced use of power to electronics - Autumn Campaign - Participant Spillover	5	1	81%	21	$0	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Turned off / reduced use of lights - Autumn Campaign - Participant Spillover	4	1	83%	263	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Dried clothes outside or inside on a rack - Autumn Campaign - Participant Spillover	3	1	87%	74	$0	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Turned down the thermostat setting on my furnace - Autumn Campaign - Participant Spillover	3	1	81%	270	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Unplugged devices usually plugged into outlet - Autumn Campaign - Participant Spillover	3	1	82%	70	$0	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Installed a new energy efficient appliance – Refrigerator - Autumn Campaign - Participant Spillover	3	14	75%	65	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Added ceiling/attic/wall/basement insulation - Autumn Campaign - Participant Spillover	2	20	78%	394	$9	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Replaced my old furnace with a high efficiency furnace - Autumn Campaign -	2	15	80%	352	$6	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
	Participant Spillover						
2009 Every Kilowatt Counts Power Savings Event	Installed a new energy efficient appliance - Clothes washing machine - Autumn Campaign - Participant Spillover	2	15	81%	142	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Compact Fluorescent - Autumn Campaign - Non-Participant Rebated	131	8	86%	24	$18	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Specialty CFLs - Autumn Campaign - Non-Participant Rebated	42	6	85%	30	$8	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Fixtures - Autumn Campaign - Non-Participant Rebated	12	16	76%	36	$4	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Weatherstripping - adhesive foam or V-strip - Autumn Campaign - Non-Participant Rebated	45	15	93%	15	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Weatherstripping - door frame kits - Autumn Campaign - Non-Participant Rebated	34	15	94%	17	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Programmable Thermostat - Autumn Campaign - Non-Participant Rebated	7	15	83%	83	$4	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Pipe Wrap - Autumn Campaign - Non-Participant Rebated	32	6	89%	6	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Water Blanket - Autumn Campaign - Non-Participant Rebated	4	10	78%	40	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Lighting/Appliance Controls - Autumn Campaign - Non-Participant Rebated	34	17	90%	42	$6	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Holiday LED Lights - Autumn Campaign - Non-Participant Promoted	56	5	65%	14	$12	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Dimmer Switches - Autumn Campaign - Non-Participant Promoted	18	10	73%	24	$5	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Solar Powered Products - Autumn Campaign - Non-Participant Promoted	28	4	58%	5	$2	OPA 2010
2009 Every Kilowatt Counts	Working Room Air Conditioner Retirement -	1	6	62%	32	$1	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
Power Savings Event	Rewards for Recycling Campaign - Incented						
2009 Every Kilowatt Counts Power Savings Event	Working Room Dehumidifier Retirement - Rewards for Recycling Campaign - Incented	1	8	53%	300	$7	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Working Halogen Torchiere Retirement - Rewards for Recycling Campaign - Incented	0	10	49%	58	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Recycled Second Refrigerator - Rewards for Recycling Campaign - Spillover	0	14	64%	1,238	$5	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Recycled Additional Room Air Conditioner - Rewards for Recycling Campaign - Spillover	0	6	64%	30	$0	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Recycled Central Air Conditioner - Rewards for Recycling Campaign - Spillover	0	18	64%	72	$0	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Recycled Additional Room Dehumidifier - Rewards for Recycling Campaign - Spillover	0	8	64%	309	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Installed Energy Star® Windows - Rewards for Recycling Campaign - Spillover	0	20	82%	1,530	$5	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Installed Energy Star® CFL Bulbs - Rewards for Recycling Campaign - Spillover	1	8	82%	45	$0	OPA 2010
2009 peaksaver®	Residential Air Conditioner - Thermostat	29	13	10%	6	$6	OPA 2010
2009 peaksaver®	Commercial Air Conditioner - Thermostat	3	13	10%	6	$1	OPA 2010
2009 High Performance New Construction	Custom Project	1	20	30%	2,770	$80	OPA 2010
2009 Power Savings Blitz	All measures	1	9	5%	179,748	$7,064	OPA 2010
2010 Cool Savings Rebate	Rebates	33	2	60%	606	$249	OPA 2011c
2010 Every Kilowatt Counts Power Savings Event	Products purchased	175	2	58%	69	$156	OPA 2011c
2010 Great Refrigerator Roundup	Appliances	36	2	46%	1,083	$654	OPA 2011c
2010 peaksaver® consumer	Devices installed	8	2	9%	2	$1	OPA 2011c
2010 Electricity Retrofit	Projects	0	2	49%	143,753	$570	OPA 2011c

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
Incentive							
2010 High Performance New Construction	Projects	0	2	30%	146,000	$210	OPA 2011c
2010 Multifamily energy efficiency rebates	Projects	0	2	26%	75,155	$780	OPA 2011c
2010 Power Savings Blitz	Projects	4	2	0%	2,500	$300	OPA 2011c
2006 Residential Conservation Kits	15 W CFL	1,300	4	30%	44	$3,238	OPA 2011a
2006 Residential Conservation Kits	Weatherstripping	1,300	6	30%	15	$1,094	OPA 2011 Resource planning tool
2006 Seasonal Lighting Upgrade	Seasonal pole mounted fixtures upgrade	52	20	0%	365	$1,466	CPC 2009
2006 Seasonal Lighting Upgrade - Christmas Tree	Christmas tree lighting upgrades	95	20	0%	237	$1,740	CPC 2009
Total						**$40,299**	

Table 10 –LRAM contributions and carrying charges.

Funding	Program	Year	LRAM	Carrying charges	Total
OPA	Cool & Hot Savings Rebate	2006	$328	$20	$348
		2007	$428	$19	$447
	Cool Savings Rebate	2008	$384	$12	$396
		2009	$357	$8	$365
		2010	$245	$4	$249
	Electricity Retrofit Incentive	2008	$1,023	$31	$1,054
		2010	$560	$10	$570
	Every Kilowatt Counts Power Savings Event	2008	$1,925	$59	$1,984
		2009	$603	$13	$616
		2010	$153	$3	$156
	Great Refrigerator Roundup	2007	$475	$21	$496
		2008	$1,053	$32	$1,085
		2009	$3,904	$86	$3,990
		2010	$643	$12	$654
	High Performance New Construction	2008	$3	$0	$3
		2009	$78	$2	$80
		2010	$206	$4	$210
	Multifamily energy efficiency rebates	2010	$766	$14	$780
	peaksaver®	2008	$6	$0	$6
		2009	$7	$0	$7
	peaksaver® consumer	2010	$1	$0	$1
	Power Savings Blitz	2009	$6,912	$152	$7,064
		2010	$295	$5	$300
	Secondary Refrigerator Retirement Pilot	2006	$127	$8	$135
	Social Housing Pilot	2007	$234	$10	$244
	Summer Savings	2007	$325	$29	$354
	Summer Sweepstakes	2008	$2,459	$75	$2,534
Third Tranche	Every Kilowatt Counts	2006	$5,518	$461	$5,979
		2007	$2,541	$113	$2,653
	Residential Conservation Kits	2006	$4,134	$198	$4,332
	Seasonal Lighting Upgrade	2006	$1,398	$67	$1,466
	Seasonal Lighting Upgrade - Christmas Tree	2006	$1,660	$80	$1,740
Total			**$38,750**	**$1,549**	**$40,299**

1. Carrying charges are calculated quarterly, at the measure (not program) level to capture different carrying charge interest rates by quarter, program ramp up, and measure life.

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West Perth Power Inc.
LRAM/SSM

Third party review:

West Perth Power Inc. LRAM and SSM claims

This document was prepared for West Perth Power Inc. by IndEco Strategic Consulting Inc.

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IndEco report B1667

23 September 2011

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Executive summary

A third party review of the Conservation and Demand Management (CDM) programs run by West Perth Power Inc. (WPPI) was required as part of its application to the Ontario Energy Board (OEB) for collection of Lost Revenue Adjustment Mechanism (LRAM) and Shared Savings Mechanism (SSM) claims.

IndEco Strategic Consulting Inc. (IndEco) acted as third party reviewer by examining the participant rates, program costs, equipment specifications, and calculations that enter into the energy savings and Total Resource Costs (TRC) submitted by WPPI to the OEB. The review was completed as detailed in the OEB *Guidelines for Electricity Distributor Conservation and Demand Management*.

The third party review included WPPI's CDM activities in 2006, 2007, 2008 and 2009 and 2010 supported through Third Tranche of Market Adjustment Revenue Requirement (MARR) funding, and Ontario Power Authority (OPA) funding.

Net benefits, calculated using the TRC test, used OEB recommended inputs. For prescriptive programs, inputs were taken from the OEB *Total Resource Cost Guide*, or program evaluations provided by the OPA. TRC inputs for custom programs upon WPPI's evaluations. Net TRC benefits totalled over $60,000.

Lost revenues are calculated using estimated energy savings or monthly peak demand savings using the best available and most current input assumptions. Energy savings for prescriptive programs originally reported in West Perth Power Inc.'s annual filings have been updated to reflect new assumptions available since then. In the span of the LRAM claim, these savings totalled over 1.8 GWh in the Residential rate class and 1.4 GWh in the GS < 50 kW rate class. Savings in the unmetered scattered load rate class totalled over 72,000 kWh.

IndEco concludes that WPPI's electricity rates should be adjusted to reflect LRAM and SSM claims of $40,993 and $3,034 respectively.

Introduction

Lost Revenue Adjustment Mechanism and Shared Savings Mechanism claims can benefit a local distribution company (LDC) by removing the disincentive for energy conservation, and by providing it with a portion of net economic benefits from conservation and demand management activities, respectively.

What is the lost revenue adjustment mechanism (LRAM)

LRAM is designed to ensure that the LDC does not have a disincentive to promote energy efficiency and energy conservation by compensating the LDC for revenues lost as a result of its conservation initiatives. It requires the calculation of electricity savings over the period between the last rate application, and the time of the application. In turn, this calculation requires information on what the electricity use would have been in the absence of the LDC initiatives, and what it was with the LDC initiative. Some of the inputs to the calculation include: hours the equipment is used, wattage rating of the old and new equipment, and lifetime of the equipment if it is less than the period over which the LRAM is being claimed. Also required are the number of participants, or pieces of equipment installed, and an estimate of the free-rider rate, which is the fraction of the savings that would have occurred anyway, in the absence of the program. These savings are estimated by rate class, and revenue losses are determined by multiplying those losses by the cost of distribution per unit for each rate class. Carrying charges are calculated using deferral and variance account interest rates prescribed by the OEB.[1]

What is the shared savings mechanism (SSM)?

The SSM rewards the LDC for its CDM initiatives by sharing a percentage of the net economic benefits that result from the initiatives over their lifetime. For CDM activities by Ontario electricity distributors, that percentage has been set at five percent by the Ontario Energy Board (OEB). Key inputs to the calculation of SSM include all of the LRAM inputs, and in addition, the total lifetime of each technology installed, equipment costs, program costs, projected electricity costs (and water and natural gas if relevant) over that lifetime.

Sources of information

Although these input data requirements are sometimes measured, they sometimes use values from published sources, or assumptions provided by the Ontario Energy Board, or other reputable agencies. Collectively

[1] For prescribed interest rates, see http://www.oeb.gov.on.ca/OEB/Industry/Rules+and+Requirements/Rules+Codes+Guidelines+and+Forms/Prescribed+Interest+Rates

all these data are sometimes referred to as “TRC inputs” after the Total Resource Cost test that is used to calculate total economic costs and benefits to society. For some types of programs, such as large scale distribution of compact fluorescent bulbs, it would be impractical to measure the hours each bulb is used, for example, and therefore these published sources provide an average value that is typical for this equipment type.

In some cases, estimated values for a particular component of the calculation are available from multiple sources. In these cases, information is taken from the sources highest in the information hierarchy. The information hierarchy (from greatest to least confidence) for LRAM calculations is:

1 Information or results from an OPA conducted or sponsored evaluation of the specific program (e.g. OPA 2010)
2 Information or results from a third-party evaluation of the specific program
3 Information or results from a site-specific assessment of the application of the technology, including on-site measurement or survey of the specific customer
4 Manufacturer specifications for energy use/demand of the specific technology installed
5 Information from the OPA’s most current measures and assumptions lists (OPA 2011a, OPA 2011b)
6 Information from earlier OPA measures and assumptions lists
7 Information from the OEB’s TRC guide list of measures and assumptions (OEB 2008b).

In principal, we might have consulted values from the literature and adopted these if they could be shown to be more current, specific or otherwise suitable than the values from sources 4 through 7. However, this was not necessary in this case.

In the span of the LRAM claim, these savings totalled over 1.8 GWh in the Residential rate class and 1.4 GWh in the GS < 50 kW rate class. Savings in the unmetered scattered load rate class totalled over 72,000 kWh.

Net TRC benefits totalled over $60,000.

Scope

This review examines the measures, energy savings, program costs and net TRC benefits for the programs in WPPI's third tranche CDM portfolio. It also includes programs run under contract to the Ontario Power Authority (OPA) in 2006, 2007, 2008, 2009 and 2010. Lost revenues associated with these programs are estimated through April 30, 2012. Since this LRAM claim is being filed as part of a Cost of Service application, all energy savings post-April 30 2012 associated with CDM programs up to and including programs run in 2010 should be captured in the load forecast.

In the TRC calculation, benefits and costs are reported in current dollars, which requires a discount rate for future dollars. Even though these activities are at the margin, OEB has dictated that the discount rate to be used is the weighted average cost of capital (WACC). The WACC provided by WPPI is as follows:

- 2008: 8%

Because the WACC is only used to calculate present values for TRC calculations for the SSM, it is only required for 2008 since is the only year for which an SSM amount is being claimed.

TRC inputs, and requested SSM and LRAM amounts

TRC inputs

Inputs used to calculate energy savings, TRC costs and TRC benefits for each prescriptive and custom measure were reviewed to ensure accuracy and suitability.

IndEco finds that appropriate measure specifications were used to calculate program energy savings and net TRC benefits. For the calculation of LRAM claims, prescriptive measures used values provided by the 2011 OPA Measures and Assumptions lists (OPA 2011a and OPA 2011b). For the calculation of SSM claims, the best available information at the beginning of the year the program was launched was used. This is consistent with the guidance in section 7.3 of the *OEB Guidelines for Electricity CDM* (OEB 2008a). Custom measures were substantiated through program-specific documentation and calculations.

Exceptions to the sources of prescriptive measure input assumptions used in the calculation of LRAM claims are as follows:

- The '2006-2009 Final OPA CDM results. West Perth Power Inc.' and the '2010 Final CDM Results summary West Perth' were used as sources of inputs for OPA-evaluated programs. These evaluated results have been adopted in accordance with Board recommendations that "The Board would consider an evaluation by the OPA or a third party designated by the OPA to be sufficient."[2] OPA advises that these estimates are prepared in a manner consistent with OPA current practice, and are the same values used to report progress against provincial conservation targets
- The 2008 Seasonal Lighting program used savings estimates derived from program-specific data on existing and efficient lighting technologies and annual operating hours of the pole-mounted seasonal lights being replaced.

A summary list of the assumption sources used for the calculation of the LRAM claim is provided in Table 1.

The measure inputs used to calculate SSM and LRAM claims can be found in Table 8 and Table 9 in Appendix A, respectively.

Requested SSM amounts

Equipment costs and benefits were calculated by entering the measure assumptions found in Tables 8 and 9 of Appendix A into IndEco's TRC calculator.

[2] OEB 2008a. Guidelines for Electricity Distributor Conservation and Demand Management. p.28

SSM amounts were calculated for all third tranche programs, including the 2006 and 2007 EKC programs, for which WPPI played a central role, and funded its contribution from third tranche funds.

The EKC program design was changed in 2008 and WPPI's participation was not integral to the program. Therefore no SSM is claimed on net benefits from the 2008, 2009 or 2010 programs.

SSM amounts and TRC benefits net of free riders for all applicable programs are shown in Table 3.

Requested LRAM amounts

LRAM calculations are to be completed with the best information available at the time of the third party review. As such, the energy savings indicated in WPPI's annual reports for programs in WPPI's CDM portfolio were recalculated with the assumptions found in Table 9 in Appendix A. As the 2008 Residential Seasonal Light Exchange program was the only third tranche prescriptive program in WPPI's CDM portfolio, it was the only program impacted by this update.

Energy savings for measures installed between 2006 and 31 December 2010 were calculated to April 30, 2012.

Tables 3 and 4 show the net and gross energy savings or demand reductions of each program by rate class. OPA program energy savings in Tables 3 and 4 were acquired directly from spreadsheets provided by the OPA.

Energy savings were converted to LRAM values by using WPPI distribution rates. Distribution rates are in Table 5.

The requested LRAM is presented in Table 6.

Table 1 – Source of information used for the calculation of the LRAM/SSM claim

Funding	Rate class	Program	Source
OPA	Residential	2006 Secondary Fridge Retirement Pilot	OPA 2010
OPA	Residential	2006 Cool & Hot Savings Rebate	OPA 2010
OPA	Residential	2007 Great Refrigerator Roundup	OPA 2010
OPA	Residential	2007 Cool & Hot Savings Rebate	OPA 2010
OPA	Residential	2007 Social Housing Pilot	OPA 2010
OPA	Residential	2008 Great Refrigerator Roundup	OPA 2010
OPA	Residential	2008 Cool Savings Rebate	OPA 2010
OPA	Residential	2008 EKC Power Savings Event	OPA 2010
OPA	Residential	2008 Summer Sweepstakes	OPA 2010
OPA	Residential	2009 Great Refrigerator Roundup	OPA 2010
OPA	Residential	2009 Cool Savings Rebate	OPA 2010
OPA	Residential	2009 EKC Power Savings Event	OPA 2010
OPA	Residential	2010 Cool Savings Rebate	OPA 2011c
OPA	Residential	2010 EKC Power Savings Event	OPA 2011c
OPA	Residential	2010 Great Refrigerator Roundup	OPA 2011c
OPA	Residential	2010 peaksaver® consumer	OPA 2011c
OPA	Residential, GS < 50 kW	2007 peaksaver®	OPA 2010
OPA	Residential, GS < 50 kW	2008 peaksaver®	OPA 2010
OPA	Residential, GS < 50 kW	2009 peaksaver®	OPA 2010
OPA	GS < 50 kW	2008 Electricity Retrofit Incentive	OPA 2010
OPA	GS < 50 kW	2008 High Performance New Construction	OPA 2010
OPA	GS < 50 kW	2008 Power Savings Blitz	OPA 2010
OPA	GS < 50 kW	2009 Electricity Retrofit Incentive	OPA 2010
OPA	GS < 50 kW	2009 High Performance New Construction	OPA 2010
OPA	GS < 50 kW	2009 Power Savings Blitz	OPA 2010
OPA	GS < 50 kW	2010 Power Savings Blitz	OPA 2011c
OPA	GS < 50 kW	2010 High Performance New Construction	OPA 2011c
OPA	GS < 50 kW	2010 Multifamily Energy Efficiency Rebates	OPA 2011c
Third Tranche	Residential	2006 Every Kilowatt Counts	OPA 2010
Third Tranche	Residential	2007 Every Kilowatt Counts	OPA 2010
Third Tranche	Residential	2008 Residential Seasonal Light Exchange	OPA 2011a (LRAM), OEB 2008b (SSM)
Third Tranche	Unmetered scattered load	2008 Seasonal Lighting Upgrade	WPP 2009

1. The sources of SSM inputs were the best available at the onset of the program.

Table 2 – Summary of Net TRC benefits and SSM entitlements

Program	Year	Residential	Unmetered scattered load	Net TRC	SSM amount
Every Kilowatt Counts	2006	$40,585		$40,585	$2,029
	2007	$18,624		$18,624	$931
Residential Seasonal Light Exchange	2008	$4,104		$4,104	$205
Seasonal Lighting Upgrade	2008		-$2,627	-$2,627	-$131
Total		**$63,313**	**-$2,627**	**$60,686**	**$3,034**

Table 3 – Cumulative net program energy savings and peak demand savings by rate class through April 30, 2012

Funding source	Program	Program year	Residential (kWh)	GS < 50 kW (kWh)	Unmetered scattered load (kWh)
OPA	Cool & Hot Savings Rebate	2006	33,119		
		2007	43,025		
	Cool Savings Rebate	2008	37,832		
		2009	36,684		
		2010	31,500		
	Electricity Retrofit Incentive	2008		109,475	
		2009		440,597	
	Every Kilowatt Counts Power Savings Event	2008	189,704		
		2009	61,972		
		2010	18,000		
	Great Refrigerator Roundup	2007	42,924		
		2008	102,151		
		2009	85,637		
		2010	65,250		
	High Performance New Construction	2008		694	
		2009		14,972	
		2010		35,916	
	Multifamily Energy Efficiency Rebates	2010		1,185	
	peaksaver®	2007			
		2008	543	119	
		2009	542	119	
	peaksaver® consumer	2010	81		
	Power Savings Blitz	2008		51,131	
		2009		650,359	
		2010		101,250	
	Secondary Refrigerator Retirement Pilot	2006	12,879		
	Social Housing Pilot	2007	23,494		
	Summer Sweepstakes	2008	173,163		
OPA subtotal			**958,500**	**1,405,817**	**0**
Third Tranche	Every Kilowatt Counts	2006	589,871		
		2007	255,522		
	Residential Seasonal Light Exchange	2008	24,806		
	Seasonal Lighting Upgrade	2008			72,394
Third tranche subtotal			**870,200**	**0**	**72,394**
Total			**1,828,700**	**1,405,817**	**72,394**

Table 4 – Cumulative gross program energy savings and peak demand savings by rate class through April 30, 2012

Funding source	Program	Program year	Residential (kWh)	GS < 50 kW (kWh)	Unmetered scattered load (kWh)
OPA	Cool & Hot Savings Rebate	2006	41,955		
		2007	84,078		
	Cool Savings Rebate	2008	65,859		
		2009	85,871		
		2010	72,000		
	Electricity Retrofit Incentive	2008		209,322	
		2009		603,557	
	Every Kilowatt Counts Power Savings Event	2008	470,069		
		2009	162,386		
		2010	38,250		
	Great Refrigerator Roundup	2007	106,728		
		2008	187,391		
		2009	160,851		
		2010	123,750		
	High Performance New Construction	2008		991	
		2009		21,388	
		2010		53,874	
	Multifamily Energy Efficiency Rebates	2010		4,500	
	peaksaver®	2007			
		2008	603	132	
		2009	602	132	
	peaksaver® consumer	2010	89		
	Power Savings Blitz	2008		54,980	
		2009		684,588	
		2010		101,250	
	Secondary Refrigerator Retirement Pilot	2006	14,310		
	Social Housing Pilot	2007	23,494		
	Summer Sweepstakes	2008	223,189		
OPA subtotal			**1,861,475**	**1,734,715**	**0**
Third Tranche	Every Kilowatt Counts	2006	655,413		
		2007	347,056		
	Residential Seasonal Light Exchange	2008	35,438		
	Seasonal Lighting Upgrade	2008			72,394
Third tranche subtotal			**1,037,906**	**0**	**72,394**
Total			**2,899,381**	**1,734,715**	**72,394**

Table 5 – Distribution rates per rate class

Rate Class	Units	2006	2007	2008	2009	2010	2011
Residential	$/kWh	0.0098	0.0099	0.01	0.01	0.0101	0.0098
GS < 50 kW	$/kWh	0.0139	0.014	0.0141	0.0141	0.0142	0.0147
GS > 50 kW	$/kW	2.2685	2.2889	2.3072	2.3072	2.3256	2.2348
Unmetered scattered load	$/kW	1.4794	1.4927	1.5046	1.5406	NA	NA
Unmetered scattered load	$/kWh	NA	NA	NA	NA	0.0258	0.0258

Table 6 – Summary of requested LRAM amounts in 2012$[1]

Funding source	Program	Program year	Residential (kWh)	GS < 50 kW (kWh)	Unmetered scattered load (kWh)	LRAM
OPA	Cool & Hot Savings Rebate	2006	$350	$0	0	$350
		2007	$448	$0	0	$448
	Cool Savings Rebate	2008	$389	$0	0	$389
		2009	$373	$0	0	$373
		2010	$319	$0	0	$319
	Electricity Retrofit Incentive	2008	$0	$1,615	0	$1,615
		2009	$0	$6,469	0	$6,469
	Every Kilowatt Counts Power Savings Event	2008	$1,952	$0	0	$1,952
		2009	$631	$0	0	$631
		2010	$182	$0	0	$182
	Great Refrigerator Roundup	2007	$447	$0	0	$447
		2008	$1,050	$0	0	$1,050
		2009	$872	$0	0	$872
		2010	$660	$0	0	$660
	High Performance New Construction	2008	$0	$10	0	$10
		2009	$0	$220	0	$220
		2010	$0	$529	0	$529
	Multifamily Energy Efficiency Rebates	2010	$0	$17	0	$17
	peaksaver®	2007	$6	$2	0	$7
		2008	$6	$2	0	$7
		2009	$0	$0	0	$0
	peaksaver®	2010	$1	$0	0	$1
	Power Savings Blitz	2008	$0	$754	0	$754
		2009	$0	$9,550	0	$9,550
		2010	$0	$1,492	0	$1,492
	Secondary Fridge Retirement Pilot	2006	$136	$0	0	$136
	Social Housing Pilot	2007	$245	$0	0	$245
	Summer Sweepstakes	2008	$1,781	$0	0	$1,781
OPA subtotal			**$9,846**	**$20,661**	**$0**	**$30,507**
Third Tranche	Every Kilowatt Counts	2006	$6,349	$0	$0	$6,349
		2007	$2,662	$0	$0	$2,662
	Res Seasonal Light Exchange	2008	$253	$0	$0	$253
	Seasonal Lighting Upgrade	2008	$0	$0	$1,222	$1,222
Third tranche subtotal			**$9,264**	**$0**	**$1,222**	**$10,486**
Total			**$19,110**	**$20,661**	**$1,222**	**$40,993**

1. LRAM amounts by program and program year, and program totals are for energy (or demand) reductions for the years 2005 through April 30, 2012.

Findings

The third-tranche programs in WPPI's CDM portfolio were completed as of December 31, 2008. Although the OEB guidance for this report asks for comments on future program evaluation and improvements to program performance, this expectation is not relevant for these programs that have ended and are not expected to be reinitiated.

IndEco has reviewed the input values and custom project justifications used to calculate the energy savings and net TRC benefits resulting from WPPI's portfolio as well as those associated with 2006, 2007, 2008, 2009, and 2010 OPA-funded programs.

IndEco has concluded that sufficient detail and documentation exists to recommend increasing West Perth Power Inc.'s distribution rates in order to collect $40,993 in LRAM and $3,034 in SSM amounts, allocated by rate class as shown in Table 7.

Table 7 – LRAM and SSM amounts by rate class in 2012$

Rate class	LRAM	SSM
Residential	$19,110	$3,166
GS < 50 kW	$20,661	$0
GS > 50 kW	$0	$0
Unmetered scattered load	$1,222	($131)
Total	**$40,993**	**$3,034**

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Appendix A.Inputs used for TRC and energy savings calculations

Table 8 - SSM inputs and contribution to the total SSM for all measures.

Program	Energy Efficient Measure	Units	Measure life	SSM Free ridership	Annual energy savings (kWh/a)	Contribution to SSM	Assumption Source
2006 Every Kilowatt Counts	Energy Star® Compact Fluorescent Light Bulb - Spring Campaign	513	4	10%	104	$541	OPA 2010
2006 Every Kilowatt Counts	Electric Timers - Spring Campaign	14	20	10%	183	$89	OPA 2010
2006 Every Kilowatt Counts	Programmable Thermostats - Spring Campaign	6	15	10%	216	$32	OPA 2010
2006 Every Kilowatt Counts	Energy Star® Ceiling Fans - Spring Campaign	5	20	10%	141	$21	OPA 2010
2006 Every Kilowatt Counts	Energy Star® Compact Fluorescent Light Bulb - Autumn Campaign	761	4	10%	104	$833	OPA 2010
2006 Every Kilowatt Counts	Seasonal Light Emitting Diode Light String - Autumn Campaign	183	30	10%	31	$161	OPA 2010
2006 Every Kilowatt Counts	Programmable Thermostats - Autumn Campaign	12	18	10%	522	$268	OPA 2010
2006 Every Kilowatt Counts	Dimmers - Autumn Campaign	10	10	10%	139	$25	OPA 2010
2006 Every Kilowatt Counts	Indoor Motion Sensors - Autumn Campaign	3	20	10%	209	$23	OPA 2010
2006 Every Kilowatt Counts	Programmable Baseboard Thermostats - Autumn Campaign	1	18	10%	1,466	$37	OPA 2010
2007 Every Kilowatt Counts	15 W CFL	894	8	22%	43	$616	OPA 2010
2007 Every Kilowatt Counts	20+ W CFL	145	8	22%	62	$156	OPA 2010
2007 Every Kilowatt Counts	Energy Star® Light Fixture	3	16	45%	123	$7	OPA 2010
2007 Every Kilowatt Counts	T8 Fluorescent Tube	7	18	23%	37	$3	OPA 2010
2007 Every Kilowatt Counts	Seasonal LED Light String	237	5	51%	14	($25)	OPA 2010
2007 Every Kilowatt Counts	Project Porchlight CFL	188	8	24%	43	$126	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	SSM Free ridership	Annual energy savings (kWh/a)	Contribution to SSM	Assumption Source
2007 Every Kilowatt Counts	Solar Light	115	5	87%	5	($3)	OPA 2010
2007 Every Kilowatt Counts	Energy Star® Ceiling Fan	7	10	45%	90	$0	OPA 2010
2007 Every Kilowatt Counts	Furnace Filter	29	1	45%	38	($8)	OPA 2010
2007 Every Kilowatt Counts	Power Bar with Timer	3	10	23%	72	$2	OPA 2010
2007 Every Kilowatt Counts	Lighting Control Device	37	10	45%	72	$26	OPA 2010
2007 Every Kilowatt Counts	Outdoor Motion Sensor	11	10	45%	160	$24	OPA 2010
2007 Every Kilowatt Counts	Dimmer Switch	7	10	45%	24	$0	OPA 2010
2007 Every Kilowatt Counts	Programmable Thermostat	7	15	45%	75	$6	OPA 2010
2008 Residential Seasonal Light Exchange	LED seasonal lights	600	0	10%	0	$443	OEB 2008b
2008 Seasonal Lighting Upgrade	LED seasonal pole mounted fixtures	44	0	0%	0	($131)	WPPI 2009

The net TRC benefits are the total technology benefits less the total technology costs (net of free riders) less the total program costs. The total net technology benefits and costs are $94,685 and $29,244. The total program cost for all programs is $4,755. Net TRC benefits are thus $60,686. The SSM incentive is 5% of these net TRC benefits, or $3,034.

Table 9 – LRAM inputs and contribution to the total LRAM for all measures.

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2006 Secondary Refrigerator Retirement Pilot	Refrigerator Retirement	2	6	10%	1,200	$132	OPA 2010
2006 Secondary Refrigerator Retirement Pilot	Freezer Retirement	0	6	10%	900	$4	OPA 2010
2006 Cool & Hot Savings Rebate	Energy Star® Central Air Conditioner – Cool Savings	6	14	10%	390	$128	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2006 Cool & Hot Savings Rebate	Programmable Thermostat – Cool Savings	4	18	10%	177	$44	OPA 2010
2006 Cool & Hot Savings Rebate	Central Air Conditioner Tune-ups – Cool Savings	4	8	10%	410	$92	OPA 2010
2006 Cool & Hot Savings Rebate	Energy Star® Central Air Conditioner – Hot Savings	1	18	43%	155	$7	OPA 2010
2006 Cool & Hot Savings Rebate	Efficient Furnace with ECM – Hot Savings	2	15	41%	837	$77	OPA 2010
2006 Cool & Hot Savings Rebate	Programmable Thermostat – Hot Savings	2	15	73%	54	$2	OPA 2010
2006 Every Kilowatt Counts	Energy Star® Compact Fluorescent Light Bulb – Spring Campaign	513	4	10%	104	$2,086	OPA 2010
2006 Every Kilowatt Counts	Electric Timers – Spring Campaign	14	20	10%	183	$156	OPA 2010
2006 Every Kilowatt Counts	Programmable Thermostats – Spring Campaign	6	15	10%	216	$80	OPA 2010
2006 Every Kilowatt Counts	Energy Star® Ceiling Fans – Spring Campaign	5	20	10%	141	$40	OPA 2010
2006 Every Kilowatt Counts	Energy Star® Compact Fluorescent Light Bulb – Autumn Campaign	761	4	10%	104	$3,093	OPA 2010
2006 Every Kilowatt Counts	Seasonal Light Emitting Diode Light String – Autumn Campaign	183	30	10%	31	$335	OPA 2010
2006 Every Kilowatt Counts	Programmable Thermostats – Autumn Campaign	12	18	10%	522	$375	OPA 2010
2006 Every Kilowatt Counts	Dimmers – Autumn Campaign	10	10	10%	139	$79	OPA 2010
2006 Every Kilowatt Counts	Indoor Motion Sensors – Autumn Campaign	3	20	10%	209	$43	OPA 2010
2006 Every Kilowatt Counts	Programmable Baseboard Thermostats – Autumn Campaign	1	18	10%	1,466	$63	OPA 2010
2007 Great Refrigerator Roundup	Bottom Freezer Fridge	0	9	27%	1,064	$9	OPA 2010
2007 Great Refrigerator Roundup	Chest Freezer	4	8	54%	471	$48	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2007 Great Refrigerator Roundup	Side by Side Fridge-Freezer	2	9	61%	900	$33	OPA 2010
2007 Great Refrigerator Roundup	Single Door Fridge	5	9	61%	721	$73	OPA 2010
2007 Great Refrigerator Roundup	Small Freezer (under 10 cubic feet)	0	8	70%	339	$1	OPA 2010
2007 Great Refrigerator Roundup	Small Fridge (under 10 cubic feet)	0	9	70%	490	$3	OPA 2010
2007 Great Refrigerator Roundup	Top Freezer Fridge	17	9	61%	732	$267	OPA 2010
2007 Great Refrigerator Roundup	Upright Freezer	1	8	54%	743	$15	OPA 2010
2007 Cool & Hot Savings Rebate	Energy Star® Central Air Conditioner – Hot Savings	1	18	43%	155	$5	OPA 2010
2007 Cool & Hot Savings Rebate	Efficient Furnace with ECM – Hot Savings	2	15	41%	837	$63	OPA 2010
2007 Cool & Hot Savings Rebate	Programmable Thermostat – Hot Savings	2	15	73%	54	$2	OPA 2010
2007 Cool & Hot Savings Rebate	Energy Star® Central Air Conditioner, Tier 2 – Cool Savings	9	18	43%	155	$42	OPA 2010
2007 Cool & Hot Savings Rebate	Medium Efficiency Furnace with ECM – Cool Savings	11	15	41%	837	$308	OPA 2010
2007 Cool & Hot Savings Rebate	Programmable Thermostat – Cool Savings	11	15	73%	54	$9	OPA 2010
2007 Cool & Hot Savings Rebate	Central Air Conditioner Tune-ups – Cool Savings	11	5	84%	235	$20	OPA 2010
2007 Every Kilowatt Counts	15 W CFL	894	8	22%	43	$1,639	OPA 2010
2007 Every Kilowatt Counts	20+ W CFL	145	8	22%	62	$385	OPA 2010
2007 Every Kilowatt Counts	Energy Star® Light Fixture	3	16	45%	123	$13	OPA 2010
2007 Every Kilowatt Counts	T8 Fluorescent Tube	7	18	23%	37	$11	OPA 2010
2007 Every Kilowatt Counts	Seasonal LED Light String	237	5	51%	14	$83	OPA 2010
2007 Every Kilowatt Counts	Project Porchlight CFL	188	8	24%	43	$336	OPA 2010
2007 Every Kilowatt Counts	Solar Light	115	5	87%	5	$4	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2007 Every Kilowatt Counts	Energy Star® Ceiling Fan	7	10	45%	90	$19	OPA 2010
2007 Every Kilowatt Counts	Furnace Filter	29	1	45%	38	$7	OPA 2010
2007 Every Kilowatt Counts	Power Bar with Timer	3	10	23%	72	$10	OPA 2010
2007 Every Kilowatt Counts	Lighting Control Device	37	10	45%	72	$80	OPA 2010
2007 Every Kilowatt Counts	Outdoor Motion Sensor	11	10	45%	160	$55	OPA 2010
2007 Every Kilowatt Counts	Dimmer Switch	7	10	45%	24	$5	OPA 2010
2007 Every Kilowatt Counts	Programmable Thermostat	7	15	45%	75	$16	OPA 2010
2007 Social Housing Pilot	Custom Retrofit Projects	1	10	0%	4,475	$245	OPA 2010
2008 Great Refrigerator Roundup	Bottom Freezer Fridge	0	9	45%	775	$8	OPA 2010
2008 Great Refrigerator Roundup	Chest Freezer	7	8	48%	740	$111	OPA 2010
2008 Great Refrigerator Roundup	Side by Side Fridge-Freezer	4	9	45%	775	$75	OPA 2010
2008 Great Refrigerator Roundup	Single Door Fridge	8	9	45%	775	$145	OPA 2010
2008 Great Refrigerator Roundup	Small Freezer (under 10 cubic feet)	0	8	48%	740	$1	OPA 2010
2008 Great Refrigerator Roundup	Small Fridge (under 10 cubic feet)	0	9	45%	775	$4	OPA 2010
2008 Great Refrigerator Roundup	Top Freezer Fridge	37	9	45%	775	$680	OPA 2010
2008 Great Refrigerator Roundup	Upright Freezer	1	8	48%	740	$22	OPA 2010
2008 Great Refrigerator Roundup	Window Air Conditioner	1	5	64%	197	$3	OPA 2010
2008 Cool Savings Rebate	2007 Energy Star® Central Air Conditioner, Tier 2	2	18	43%	155	$7	OPA 2010
2008 Cool Savings Rebate	2007 Medium Efficiency Furnace with ECM	4	15	41%	837	$77	OPA 2010
2008 Cool Savings Rebate	2007 Programmable Thermostat	3	15	73%	54	$2	OPA 2010
2008 Cool Savings Rebate	2008 Energy Star® Central Air Conditioner, Tier 2	8	18	43%	125	$26	OPA 2010
2008 Cool Savings Rebate	2008 Efficient Furnace with ECM	13	18	41%	819	$270	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2008 Cool Savings Rebate	2008 Programmable Thermostat	11	18	73%	54	$7	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Energy Star® Qualified Compact Fluorescent Light Bulbs	344	8	48%	53	$416	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Energy Star® Qualified Dimmable CFLs	37	6	62%	98	$60	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Energy Star® Qualified Decorative CFLs	581	4	61%	30	$281	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Energy Star® Qualified Compact Fluorescent Floods (Indoor & Outdoor)	161	7	63%	88	$231	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Energy Star® Qualified Light Fixtures	250	16	67%	133	$487	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	T8 Fluorescent Fixtures	46	16	67%	37	$24	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Lighting Control Devices	49	10	55%	102	$99	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Power Bars with Timers	3	10	59%	53	$3	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Heavy Duty Timers	6	10	67%	301	$25	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Programmable Thermostats – Baseboard	16	15	53%	64	$20	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Air Conditioner/Furnace Filters	15	1	65%	38	$2	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Pipe Wrap	321	6	53%	38	$249	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Keep Cool Pilot – Dehumidifier	0	12	65%	500	$1	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Keep Cool Pilot – Room Air Conditioner	0	9	58%	141	$0	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Rewards for Recycling – Dehumidifier	3	12	56%	500	$29	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2008 Every Kilowatt Counts Power Savings Event	Rewards for Recycling – Room Air Conditioner	3	9	56%	141	$9	OPA 2010
2008 Every Kilowatt Counts Power Savings Event	Rewards for Recycling – Halogen Lamp	3	16	52%	275	$15	OPA 2010
2008 peaksaver®	Residential Air Conditioner – Thermostat	10	13	10%	17	$7	OPA 2010
2008 Summer Sweepstakes	Registered qualified active households	23	5	22%	421	$326	OPA 2010
2008 Summer Sweepstakes	Registered unqualified active households	34	5	22%	421	$489	OPA 2010
2008 Summer Sweepstakes	Registered qualified inactive households	2	5	22%	421	$33	OPA 2010
2008 Summer Sweepstakes	Registered unqualified inactive households	9	5	22%	421	$123	OPA 2010
2008 Summer Sweepstakes	Non-registered active households	1,113	5	22%	21	$810	OPA 2010
2008 Electricity Retrofit Incentive	All projects	1	15	48%	49,252	$1,615	OPA 2010
2008 High Performance New Construction	Custom Project	1	14	30%	233	$10	OPA 2010
2008 Power Savings Blitz	T8 Fixture With Electronic Ballast	62	15	7%	151	$546	OPA 2010
2008 Power Savings Blitz	Energy Star® rated CLF	30	2	7%	191	$157	OPA 2010
2008 Power Savings Blitz	Electric Water Heater Tank Wrap	2	7	7%	436	$51	OPA 2010
2009 Great Refrigerator Roundup	Bottom Freezer Fridge – Not Replaced - Running Part Time (38% of the time)	0	5	46%	674	$0	OPA 2010
2009 Great Refrigerator Roundup	Bottom Freezer Fridge – Standard Efficiency Unit Replacement – Running Part Time (38% of the time)	0	5	46%	454	$0	OPA 2010
2009 Great Refrigerator Roundup	Bottom Freezer Fridge – Energy Star Unit Replacement – Running Part Time (38% of the time)	0	5	46%	498	$1	OPA 2010
2009 Great Refrigerator Roundup	Bottom Freezer Fridge – Not Replaced -			46%	1,769	$8	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
	Running All Time (100% of time)						
2009 Great Refrigerator Roundup	Bottom Freezer Fridge – Standard Efficiency Unit Replacement – Running All Time (100% of time)	0	5	46%	1,193	$2	OPA 2010
2009 Great Refrigerator Roundup	Bottom Freezer Fridge – Energy Star Unit Replacement – Running All Time (100% of time)	1	5	46%	1,308	$12	OPA 2010
2009 Great Refrigerator Roundup	Chest Freezer – Not Replaced - Running Part Time (26% of the time)	0	4	48%	282	$2	OPA 2010
2009 Great Refrigerator Roundup	Chest Freezer – Standard Efficiency Unit Replacement – Running Part Time (26% of the time)	0	4	48%	247	$0	OPA 2010
2009 Great Refrigerator Roundup	Chest Freezer – Energy Star Unit Replacement – Running Part Time (26% of the time)	1	4	48%	261	$2	OPA 2010
2009 Great Refrigerator Roundup	Chest Freezer – Not Replaced - Running All Time (100% of time)	4	4	48%	1,096	$77	OPA 2010
2009 Great Refrigerator Roundup	Chest Freezer – Standard Efficiency Unit Replacement – Running All Time (100% of time)	1	4	48%	959	$19	OPA 2010
2009 Great Refrigerator Roundup	Chest Freezer – Energy Star Unit Replacement – Running All Time (100% of time)	5	4	48%	1,012	$90	OPA 2010
2009 Great Refrigerator Roundup	Side by Side Fridge-Freezer – Not Replaced - Running Part Time (38% of the time)	0	5	46%	507	$2	OPA 2010
2009 Great Refrigerator Roundup	Side by Side Fridge-Freezer – Standard Efficiency Unit Replacement – Running Part Time (38% of the time)	0	5	46%	260	$0	OPA 2010
2009 Great Refrigerator Roundup	Side by Side Fridge-Freezer – Energy Star Unit Replacement – Running Part	0	5	46%	309	$3	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
	Time (38% of the time)						
2009 Great Refrigerator Roundup	Side by Side Fridge-Freezer – Not Replaced - Running All Time (100% of time)	2	5	46%	1,331	$43	OPA 2010
2009 Great Refrigerator Roundup	Side by Side Fridge-Freezer – Standard Efficiency Unit Replacement – Running All Time (100% of time)	1	5	46%	682	$8	OPA 2010
2009 Great Refrigerator Roundup	Side by Side Fridge-Freezer – Energy Star Unit Replacement – Running All Time (100% of time)	4	5	46%	812	$51	OPA 2010
2009 Great Refrigerator Roundup	Single Door Fridge – Not Replaced - Running Part Time (38% of the time)	0	5	46%	418	$3	OPA 2010
2009 Great Refrigerator Roundup	Single Door Fridge – Standard Efficiency Unit Replacement – Running Part Time (38% of the time)	0	5	46%	237	$1	OPA 2010
2009 Great Refrigerator Roundup	Single Door Fridge – Energy Star Unit Replacement – Running Part Time (38% of the time)	1	5	46%	273	$3	OPA 2010
2009 Great Refrigerator Roundup	Single Door Fridge – Not Replaced - Running All Time (100% of time)	3	5	46%	1,097	$51	OPA 2010
2009 Great Refrigerator Roundup	Single Door Fridge – Standard Efficiency Unit Replacement – Running All Time (100% of time)	1	5	46%	623	$11	OPA 2010
2009 Great Refrigerator Roundup	Single Door Fridge – Energy Star Unit Replacement – Running All Time (100% of time)	5	5	46%	718	$65	OPA 2010
2009 Great Refrigerator Roundup	Top Freezer Fridge – Not Replaced - Running Part Time (38% of the time)	1	5	46%	470	$8	OPA 2010
2009 Great Refrigerator Roundup	Top Freezer Fridge – Standard Efficiency Unit Replacement – Running Part Time (38% of the time)	0	5	46%	252	$2	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Great Refrigerator Roundup	Top Freezer Fridge – Energy Star Unit Replacement – Running Part Time (38% of the time)	2	5	46%	295	$9	OPA 2010
2009 Great Refrigerator Roundup	Top Freezer Fridge – Not Replaced - Running All Time (100% of time)	7	5	46%	1,234	$148	OPA 2010
2009 Great Refrigerator Roundup	Top Freezer Fridge – Standard Efficiency Unit Replacement – Running All Time (100% of time)	2	5	46%	661	$29	OPA 2010
2009 Great Refrigerator Roundup	Top Freezer Fridge – Energy Star Unit Replacement – Running All Time (100% of time)	13	5	46%	776	$180	OPA 2010
2009 Great Refrigerator Roundup	Upright Freezer – Not Replaced - Running Part Time (26% of the time)	0	4	48%	365	$0	OPA 2010
2009 Great Refrigerator Roundup	Upright Freezer – Standard Efficiency Unit Replacement – Running Part Time (26% of the time)	0	4	48%	180	$0	OPA 2010
2009 Great Refrigerator Roundup	Upright Freezer – Energy Star Unit Replacement – Running Part Time (26% of the time)	0	4	48%	189	$0	OPA 2010
2009 Great Refrigerator Roundup	Upright Freezer – Not Replaced - Running All Time (100% of time)	1	4	48%	1,416	$17	OPA 2010
2009 Great Refrigerator Roundup	Upright Freezer – Standard Efficiency Unit Replacement – Running All Time (100% of time)	0	4	48%	697	$2	OPA 2010
2009 Great Refrigerator Roundup	Upright Freezer – Energy Star Unit Replacement – Running All Time (100% of time)	1	4	48%	736	$11	OPA 2010
2009 Great Refrigerator Roundup	Dehumidifier – Not Replaced - Running All Time (100% of time)	0	4	64%	960	$4	OPA 2010
2009 Great Refrigerator Roundup	Dehumidifier – Standard Efficiency Unit Replacement – Running All Time (100%	0	4	64%	540	$1	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
	of time)						
2009 Great Refrigerator Roundup	Dehumidifier – Energy Star Unit Replacement – Running All Time (100% of time)	1	4	64%	463	$3	OPA 2010
2009 Great Refrigerator Roundup	Window Air Conditioner – Not Replaced - Running All Time (100% of time)	1	3	64%	371	$3	OPA 2010
2009 Great Refrigerator Roundup	Window Air Conditioner – Standard Efficiency Unit Replacement – Running All Time (100% of time)	0	3	64%	118	$0	OPA 2010
2009 Great Refrigerator Roundup	Window Air Conditioner – Energy Star Unit Replacement – Running All Time (100% of time)	0	3	64%	141	$0	OPA 2010
2009 Cool Savings Rebate	Energy Star® 14.5 SEER (Tier 1) Central Air Conditioner (CAC)	4	18	42%	113	$8	OPA 2010
2009 Cool Savings Rebate	Energy Star® 14.5 SEER (Tier 1) Central Air Conditioner (CAC) with change in behaviour	1	18	42%	317	$4	OPA 2010
2009 Cool Savings Rebate	Energy Star® 15.0 SEER (Tier 2) Central Air Conditioner (CAC)	10	18	42%	177	$34	OPA 2010
2009 Cool Savings Rebate	Energy Star® 15.0 SEER (Tier 2) Central Air Conditioner (CAC) with change in behaviour	2	18	42%	366	$11	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, AHRI Matched CAC & Furnace, Continuous Fan, No change	1	19	60%	2,773	$31	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, AHRI	4	19	60%	324	$15	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
	Matched CAC & Furnace, Non-continuous Fan, No change						
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, AHRI Matched CAC & Furnace, Continuous Fan, Change from non-continuous	0	19	60%	91	$0	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, Unmatched CAC & Furnace, Continuous Fan, No change	2	19	60%	2,823	$56	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, Unmatched CAC & Furnace, Non-continuous Fan, No change	6	19	60%	373	$30	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, Unmatched CAC & Furnace, Continuous Fan, Change from non-continuous	0	19	60%	140	$1	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, Heating only, Continuous Fan, No change	0	19	60%	1,535	$5	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed before 1980, Heating only, Non-continuous Fan, No change	1	19	60%	324	$4	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically	0	19	60%	192	$0	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
	Commutated Motor (ECM), Home constructed before 1980, Heating only, Continuous Fan, Change from non-continuous						
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, AHRI Matched CAC & Furnace, Continuous Fan, No change	1	19	60%	2,867	$38	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, AHRI Matched CAC & Furnace, Non-continuous Fan, No change	4	19	60%	207	$11	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, AHRI Matched CAC & Furnace, Continuous Fan, Change from non-continuous	0	19	60%	(49)	($0)	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, Unmatched CAC & Furnace, Continuous Fan, No change	2	19	60%	2,927	$68	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, Unmatched CAC & Furnace, Non-continuous Fan, No change	7	19	60%	267	$26	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home	1	19	60%	11	$0	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
	constructed after 1980, Unmatched CAC & Furnace, Continuous Fan, Change from non-continuous						
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, Heating only, Continuous Fan, No change	0	19	60%	1,570	$6	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, Heating only, Non-continuous Fan, No change	1	19	60%	207	$3	OPA 2010
2009 Cool Savings Rebate	Furnace with Electronically Commutated Motor (ECM), Home constructed after 1980, Heating only, Continuous Fan, Change from non-continuous	0	19	60%	76	$0	OPA 2010
2009 Cool Savings Rebate	Programmable Thermostat – Central Air Conditioning (CAC) & Gas heating	8	15	61%	30	$3	OPA 2010
2009 Cool Savings Rebate	Programmable Thermostat – Energy Star® Central Air Conditioning (CAC) & Gas Heating	11	15	61%	26	$4	OPA 2010
2009 Cool Savings Rebate	Programmable Thermostat – Gas Heating only	2	15	61%	9	$0	OPA 2010
2009 Cool Savings Rebate	Participant Spillover – Lighting	1	5	0%	40	$1	OPA 2010
2009 Cool Savings Rebate	Participant Spillover – Cooling or Heating	0	3	0%	100	$1	OPA 2010
2009 Cool Savings Rebate	Participant Spillover – Water heating	1	10	0%	141	$3	OPA 2010
2009 Cool Savings Rebate	Participant Spillover – Appliances	1	4	0%	76	$2	OPA 2010
2009 Cool Savings Rebate	Participant Spillover – Insulation of other weatherization	1	10	0%	75	$3	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Cool Savings Rebate	Participant Spillover – Windows	1	10	0%	100	$3	OPA 2010
2009 Cool Savings Rebate	Participant Spillover – Roof products	0	15	0%	50	$1	OPA 2010
2009 Cool Savings Rebate	Participant Spillover – Other products	0	5	0%	50	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Compact Fluorescent - Spring Campaign – Participant Rebated	42	8	31%	23	$22	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Decorative CFLs – Spring Campaign – Participant Rebated	100	6	23%	26	$66	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Fixtures – Spring Campaign – Participant Rebated	8	16	47%	116	$17	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Ceiling Fans – Spring Campaign – Participant Rebated	4	10	24%	71	$6	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Heavy Duty Pool and Spa Timers – Spring Campaign – Participant Rebated	1	10	24%	454	$15	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Clotheslines – Spring Campaign – Participant Rebated	3	10	45%	77	$5	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Pipe Wrap – Spring Campaign – Participant Rebated	3	6	22%	8	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Water Blanket – Spring Campaign – Participant Rebated	0	10	20%	52	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Window Air Conditioner – Spring Campaign – Participant Promoted	3	12	33%	96	$7	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Dehumidifiers – Spring Campaign – Participant Promoted	3	12	32%	284	$21	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Programmable Thermostat – Spring Campaign – Participant Promoted	8	15	55%	138	$17	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Solar Power Products – Spring Campaign – Participant Promoted	21	5	40%	5	$2	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Every Kilowatt Counts Power Savings Event	Control Products – Spring Campaign – Participant Promoted	10	10	47%	72	$13	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Reduce power to electronics (Behavioural) – Spring Campaign – Participant Spillover	4	1	85%	21	$0	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Installed CFLs – Spring Campaign – Participant Spillover	4	8	87%	101	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Washed in Cold Laundry (Behavioural) – Spring Campaign – Participant Spillover	4	1	86%	30	$0	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Turned off/Reduced lights (Behavioural) – Spring Campaign – Participant Spillover	4	1	88%	263	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Dried clothes outside or on rack (Behavioural) – Spring Campaign – Participant Spillover	3	1	89%	74	$0	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Installed a new energy efficient appliance – Refrigerator – Spring Campaign – Participant Spillover	3	14	86%	65	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Unplugged devices usually left plugged in (Behavioural) – Spring Campaign – Participant Spillover	3	1	80%	70	$0	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Installed a new energy efficient appliance – Clothes washing machine – Spring Campaign – Participant Spillover	2	14	88%	122	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Added ceiling/attic/wall/basement insulation – Spring Campaign – Participant Spillover	2	20	88%	394	$3	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Installed Programmable Thermostat – Spring Campaign – Participant Spillover	2	15	87%	308	$2	OPA 2010
2009 Every Kilowatt Counts Power	Energy Star Qualified Compact	32	8	65%	22	$8	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
Savings Event	Fluorescent - Spring Campaign – Non-Participant Rebated						
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Decorative CFLs – Spring Campaign – Non-Participant Rebated	16	6	60%	26	$6	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Fixtures – Spring Campaign – Non-Participant Rebated	15	16	59%	68	$14	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Ceiling Fans – Spring Campaign – Non-Participant Rebated	4	10	86%	71	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Heavy Duty Pool and Spa Timers – Spring Campaign – Non-Participant Rebated	3	10	86%	454	$6	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Clotheslines – Spring Campaign – Non-Participant Rebated	10	10	86%	77	$4	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Pipe Wrap – Spring Campaign – Non-Participant Rebated	24	6	86%	8	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Water Blanket – Spring Campaign – Non-Participant Rebated	3	10	86%	52	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Window Air Conditioner – Spring Campaign – Non-Participant Promoted	6	12	57%	96	$8	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Dehumidifiers – Spring Campaign – Non-Participant Promoted	7	12	56%	284	$29	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Programmable Thermostat – Spring Campaign – Non-Participant Promoted	11	15	71%	138	$14	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Solar Power Products – Spring Campaign – Non-Participant Promoted	71	5	61%	5	$4	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Control Products – Spring Campaign – Non-Participant Promoted	24	10	66%	72	$20	OPA 2010
2009 Every Kilowatt Counts Power	Energy Star Qualified Compact	191	8	31%	25	$112	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
Savings Event	Fluorescent - Autumn Campaign – Participant Rebated						
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Specialty CFLs – Autumn Campaign – Participant Rebated	77	6	29%	21	$38	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Fixtures – Autumn Campaign – Participant Rebated	9	16	30%	119	$25	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Weatherstripping – adhesive foam or V-strip – Autumn Campaign – Participant Rebated	9	15	43%	15	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Weatherstripping – door frame kits – Autumn Campaign – Participant Rebated	6	15	47%	17	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Programmable Thermostat – Autumn Campaign – Participant Rebated	4	15	33%	32	$3	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Pipe Wrap – Autumn Campaign – Participant Rebated	3	6	55%	7	$0	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Water Blanket – Autumn Campaign – Participant Rebated	1	10	37%	56	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Lighting/Appliance Controls – Autumn Campaign – Participant Rebated	6	17	28%	21	$3	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Holiday LED Lights – Autumn Campaign – Participant Promoted	23	5	41%	14	$6	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Dimmer Switches – Autumn Campaign – Participant Promoted	10	10	50%	24	$4	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Solar Powered Products – Autumn Campaign – Participant Promoted	19	4	48%	6	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Washed laundry with cold water – Autumn Campaign – Participant Spillover	7	1	83%	30	$0	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Every Kilowatt Counts Power Savings Event	Turned off / reduced use of power to electronics – Autumn Campaign – Participant Spillover	6	1	81%	21	$0	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Turned off / reduced use of lights – Autumn Campaign – Participant Spillover	6	1	83%	263	$3	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Dried clothes outside or inside on a rack – Autumn Campaign – Participant Spillover	4	1	87%	74	$0	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Turned down the thermostat setting on my furnace – Autumn Campaign – Participant Spillover	4	1	81%	270	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Unplugged devices usually plugged into outlet – Autumn Campaign – Participant Spillover	4	1	82%	70	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Installed a new energy efficient appliance – Refrigerator – Autumn Campaign – Participant Spillover	4	14	75%	65	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Added ceiling/attic/wall/basement insulation – Autumn Campaign – Participant Spillover	3	20	78%	394	$9	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Replaced my old furnace with a high efficiency furnace – Autumn Campaign – Participant Spillover	3	15	80%	352	$6	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Installed a new energy efficient appliance – Clothes washing machine – Autumn Campaign – Participant Spillover	3	15	81%	142	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Compact Fluorescent - Autumn Campaign – Non-Participant Rebated	174	8	86%	24	$19	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Specialty CFLs – Autumn Campaign – Non-Participant Rebated	55	6	85%	30	$8	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	ENERGY STAR Fixtures – Autumn Campaign – Non-Participant Rebated	15	16	76%	36	$4	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Weatherstripping – adhesive foam or V-strip – Autumn Campaign – Non-Participant Rebated	60	15	93%	15	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Weatherstripping – door frame kits – Autumn Campaign – Non-Participant Rebated	46	15	94%	17	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Programmable Thermostat – Autumn Campaign – Non-Participant Rebated	9	15	83%	83	$4	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Pipe Wrap – Autumn Campaign – Non-Participant Rebated	42	6	89%	6	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Water Blanket – Autumn Campaign – Non-Participant Rebated	5	10	78%	40	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Lighting/Appliance Controls – Autumn Campaign – Non-Participant Rebated	45	17	90%	42	$6	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Energy Star Qualified Holiday LED Lights – Autumn Campaign – Non-Participant Promoted	74	5	65%	14	$12	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Dimmer Switches – Autumn Campaign – Non-Participant Promoted	23	10	73%	24	$5	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Solar Powered Products – Autumn Campaign – Non-Participant Promoted	38	4	58%	5	$2	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Working Room Air Conditioner Retirement – Rewards for Recycling Campaign – Incented	2	6	62%	32	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Working Room Dehumidifier Retirement – Rewards for Recycling	2	8	53%	300	$8	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
	Campaign – Incented						
2009 Every Kilowatt Counts Power Savings Event	Working Halogen Torchiere Retirement – Rewards for Recycling Campaign – Incented	1	10	49%	58	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Recycled Second Refrigerator – Rewards for Recycling Campaign – Spillover	0	14	64%	1,238	$6	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Recycled Additional Room Air Conditioner – Rewards for Recycling Campaign – Spillover	0	6	64%	30	$0	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Recycled Central Air Conditioner – Rewards for Recycling Campaign – Spillover	0	18	64%	72	$0	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Recycled Additional Room Dehumidifier – Rewards for Recycling Campaign – Spillover	0	8	64%	309	$1	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Installed Energy Star® Windows – Rewards for Recycling Campaign – Spillover	1	20	82%	1,530	$5	OPA 2010
2009 Every Kilowatt Counts Power Savings Event	Installed Energy Star® CFL Bulbs – Rewards for Recycling Campaign – Spillover	2	8	82%	45	$0	OPA 2010
2009 peaksaver®	Residential Air Conditioner – Thermostat	33	13	10%	6	$6	OPA 2010
2009 peaksaver®	Commercial Air Conditioner – Thermostat	7	13	10%	6	$1	OPA 2010
2009 Electricity Retrofit Incentive	All projects	1	9	27%	185,710	$6,469	OPA 2010
2009 High Performance New Construction	Custom Project	1	20	30%	6,581	$220	OPA 2010
2009 Power Savings Blitz	All projects	1	9	5%	210,643	$9,550	OPA 2010

Program	Energy Efficient Measure	Units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Contribution to LRAM (2012$)	Assumption Source
2010 Cool Savings Rebate	Rebates	62	2	56%	516	$319	OPA 2011c
2010 Every Kilowatt Counts Power Savings Event	Products purchased	245	2	53%	69	$182	OPA 2011c
2010 Great Refrigerator Roundup	Appliances	51	2	47%	1,078	$660	OPA 2011c
2010 peaksaver® consumer	Devices installed	16	2	9%	2	$1	OPA 2011c
2010 Power Savings Blitz	Projects	17	2	0%	2,647	$1,492	OPA 2011c
2010 High Performance New Construction	Projects	0	2	33%	146,000	$529	OPA 2011c
2010 Multifamily Energy Efficiency Rebates	Projects	0	2	74%	75,155	$17	OPA 2011c
2008 Residential Seasonal Light Exchange	LED seasonal lights	600	0	30%	14	$253	OPA 2011a
2008 Seasonal Lighting Upgrade	LED seasonal pole mounted fixtures	44	0	0%	390	$1,222	WPPI 2009
Total						$40,993	

Table 10 –LRAM contributions and carrying charges.

Funding	Program	Year	LRAM	Carrying charge	Total
OPA	Cool & Hot Savings Rebate	2006	$329	$21	$350
		2007	$428	$20	$448
	Cool Savings Rebate	2008	$377	$12	$389
		2009	$365	$8	$373
		2010	$313	$6	$319
	Electricity Retrofit Incentive	2008	$1,565	$49	$1,615
		2009	$6,328	$142	$6,469
	Every Kilowatt Counts Power Savings Event	2008	$1,891	$61	$1,952
		2009	$617	$14	$631
		2010	$179	$3	$182
	Great Refrigerator Roundup	2007	$427	$20	$447
		2008	$1,018	$33	$1,050
		2009	$852	$19	$872
		2010	$648	$12	$660
	High Performance New Construction	2008	$10	$0	$10
		2009	$215	$5	$220
		2010	$520	$9	$529
	Multifamily Energy Efficiency Rebates	2010	$17	$0	$17
	peaksaver®	2008	$7	$0	$7
		2009	$7	$0	$7
	peaksaver® consumer	2010	$1	$0	$1
	Power Savings Blitz	2008	$729	$25	$754
		2009	$9,340	$209	$9,550
		2010	$1,466	$26	$1,492
	Secondary Refrigerator Retirement Pilot	2006	$128	$8	$136
	Social Housing Pilot	2007	$234	$11	$245
	Summer Sweepstakes	2008	$1,726	$55	$1,781
Third Tranche	Every Kilowatt Counts	2006	$5,855	$495	$6,349
		2007	$2,543	$119	$2,662
	Residential Seasonal Light Exchange	2008	$247	$6	$253
	Seasonal Lighting Upgrade	2008	$1,204	$18	$1,222
Total			**$39,585**	**$1,408**	**$40,993**

1. Carrying charges are calculated quarterly, at the measure (not program) level to capture different carrying charge interest rates by quarter, program ramp up, and measure life.

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