INDEX

ONTARIO ENERGY BOARD

IN THE MATTER OF the Ontario Energy Board Act, 1998, being Schedule B to the Energy Competition Act, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an Application by (“LDC Name”) to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2008.

APPLICATION

The Applicant is ERIE THAMES POWERLINES CORPORATION Corporation (ETPL). ETPL is an Ontario corporation with its office in the Town of Aylmer Ontario. ETPL carries on the business of distributing electricity within the town/cities of Aylmer, Beachville, Belmont, Burgessville, Embro, Ingersoll, Norwich, Otterville, Port Stanley, Tavistock and Thamesford.

ETPL hereby applies to the Ontario Energy Board (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, 2008.

Except where specifically identified in the Application, ETPL followed Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated November 14, 2006 (the “Filing Requirements”) in order to prepare this application

The Schedule of Rates and Charges proposed in this Application is identified in Exhibit 9; Tab 1; Schedule 6 attached to this Summary.

ETPL requests that the OEB make its Rate Order effective May 1, 2008 in accordance with the Filing Requirements.

ETPL submits the proposed distribution rates contained in this Application are just and reasonable on the following grounds:

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

(ii) the proposed adjusted rates are necessary to meet ETPL’s Market Based Rate of Return and PILs requirements;

(iii) 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 ETPL; and

(iv) other grounds as may be set out in the material accompanying this Application Summary.

ETPL applies for an Order or Orders approving the proposed distribution rates and other charges set out in this Application to be effective May 1, 2008, or as soon as possible thereafter. ETPL submits these rates and charges are just and reasonable pursuant to section 78 of the Ontario Energy Board Act, 1998 being Schedule B to the Energy Competition Act, 1998, S.O. 1998, c.15,

The address of service for ETPL is: 280 Elm St., Aylmer, ON, N5H 3G3

DATED at Aylmer Ontario, this 14th day of September, 2007.

Chris White
Vice President & General Manager
Erie Thames Powerlines Corporation

Original Signed

Jeffrey Pettit, CMA
President & CEO
Erie Thames Power Corporation

Original Signed

Electricity Distribution License

See Appendix A

ERIE THAMES POWERLINES
CORPORATION

CONTACT INFORMATION

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SPECIFIC APPROVALS REQUESTED

- Approval to charge rates effective May 1, 2008 to recover a revenue sufficiency of $317,071 (Exhibit 7, Tab 1, Schedule 1,)

- Approval of ETPL's proposed change in capital structure, decreasing ETPL's deemed common equity component from 50% to 46.67% (Exhibit 6, Tab 1, Schedule 2,) consistent with Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors dated December 20, 2006

- Approval to continue the following deferral/variance accounts on May 1, 2008 (Exhibit , Tab, Schedule):

  - 1550 LV Variance Account
  - 1580 RSVA-Wholesale Market Service Charge
  - 1582 RSVA-One-time Wholesale Market Service
  - 1584 RSVA-Retail Transmission Network Charge
  - 1586 RSVA-Retail Transmission Connection Charge
  - 1588 RSVA-Power
  - 1562 Deferred Payments in Lieu of Taxes

- Approval of the proposed loss factor of 4.36% Exhibit 4, Tab 2, Schedule 9.

DRAFT ISSUES LIST

1. Smart Metering

Erie Thames Powerlines has not included any costs with respect to smart metering in this rate application. In its current rates ETPL has approval for $0.26 per customer per month to cover the costs for Smart Metering. ETPL was unsure of how these costs were to be handled in this rate process and requests that the Board approve the appropriate change in rates for this initiative.

PROCEDURAL ORDERS/MOTIONS/NOTICES

To be included when received

ACCOUNTING ORDERS REQUESTED

ETPL requests an accounting order to disposition it regulatory account balances as at December 31st, 2006. Details of the balance can be found in Exhibit 5, Tab 1, Schedules 1, 2 and 3.

NON-COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS

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

MAP OF DISTRIBUTION SYSTEM

Distribution System Maps are in pdf format and are hyperlinked for electronic submission. Printed copies are located in Appendix B.

The Distribution System Maps are listed as follows:

1. ETP-MAP-Aylmer 22x34L (1).pdf
2. ETP-MAP-Beachville 22x34P WM (1).pdf
3. ETP-MAP-Belmont Layout1-28 x 40L (1).pdf
4. ETP-MAP-Burgessville 22x34P WM (1).pdf
5. ETP-MAP-Embro 28 x 40P WM (1).pdf
6. ETP-MAP-Ingersoll 28 x 40L (1).pdf
7. ETP-MAP-Norwich 28 x 40L WM (1).pdf
8. ETP-MAP-Otterville 22x34L WM (1).pdf
9. ETP-MAP-PtStanley 28 x 40L WM (1).pdf
10. ETP-MAP-Tavistock 34 x 44P WM (1).pdf
11. ETP-MAP-Thamesford 28 x 40L WM (1).pdf

LIST OF NEIGHBORING UTILITIES

LIST OF ADJACENT DISTRIBUTORS

London Hydro 111 Horton Street London, ON N6A 4J8	Direct line: Direct Fax: Website:	519-661-5503 519-661-5838 www.londonhydro.com
Festival Hydro 187 Erie Street Stratford, ON N5A 6T5	Direct line: Direct Fax: Website:	519-271-4700 519-271-7204 www.festivalhydro.com
Woodstock Hydro 16 Graham Street Woodstock, ON N4S 7X4	Direct line: Direct Fax: Website:	519-537-3488 519-537-5081 www.woodstockhydro.com
St. Thomas Energy Inc 135 Edward Street St. Thomas, ON N5P 4A8	Direct line: Direct Fax: Website:	519-631-5550 519-631-5193 www.sttenergy.com
Tillsonburg Hydro Inc. 200 Broadway Tillsonburg, ON N4G 5A7	Direct line: Direct Fax: Website:	519-842-6428 519-842-9431 www.town.tillsonburg.on.ca
Hydro One Networks Inc. 483 Bay St. Toronto, ON M5G 2P5	Direct line: Direct Fax: Website:	416-345-5000 www.HydroOne.com

DESCRIPTION OF DISTRIBUTOR

COMMUNITIES SERVED:	Aylmer, Beachville, Belmont, Burgessville, Embro, Ingersoll, Norwich, Otterville, Port Stanley, Tavistock, and Thamesford
TOTAL SERVICE AREA	46 sq km
RURAL SERVICE AREA	0 sq km
DISTRIBUTION TYPE	Directly connected and embedded with Hydro One Networks
SERVICE AREA POPULATION	32,542
MUNICIPAL POPULATION	62,569
BOUNDARIES	West: Refer to Schedule 1 of distribution License App. A
	North: Refer to Schedule 1 of distribution License App. A
	East: Refer to Schedule 1 of distribution License App. A
	South: Refer to Schedule 1 of distribution License App. A

EXPLANATION OF HOST AND EMBEDDED UTILITIES

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

UTILITY ORGANIZATIONAL CHART

See Appendix C

CORPORATE ENTITIES RELATIONSHIP CHARTS

See Appendix D

PLANNED CHANGES IN CORPORATE AND OPERATIONAL STRUCTURE

Erie Thames Power group of companies is currently reviewing its corporate and operational structure. However, this review is in its early stages and at the time of this application there has been no decision regarding any change.

STATUS REPORT ON BOARD DIRECTIVES

Erie Thames Powerlines Corporation has no Board Directives at this time.

CONDITIONS OF SERVICE

See Appendix E

PLANNED CHANGES IN CONDITIONS OF SERVICE AND SERVICE CHARGES

Erie Thames Powerlines reviews its Conditions of Service periodically as required by the Distribution System Code.

Erie Thames Powerlines 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

PURPOSE AND NEED

ETPL estimates that its present rates will produce a sufficiency in distribution revenue of $317,071 for the 2008 Test Year. Excluded from this estimate is the impact of energy costs. ETPL 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 ETPL sees them, are discussed below.

Through this Application, ETPL seeks:

- To recover:
  - Revenue Sufficiency arising from changes in OM&A, Amortization, Rate of Return and PILS
  - Deferral and Variance account balances

- To change:
  - Distribution Loss Factor

- 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 ETPL's forecasted results for its 2008 Test Year. With the rates presently in effect, ETPL estimates that its revenue for 2008 would not be sufficient to provide a reasonable return. ETPL is also presenting the historical actual information for fiscal 2006, information for the current approved test year and six months actual and six months forecast for the fiscal 2007 bridge year.

TIMING

The financial information supporting the test Year for this Application will be ETPL's fiscal year ending December 31, 2008 (the "2008 Test Year"). However, this information will be used to set rates for the period May 1, 2008 to April 30, 2009. The Test Year revenue requirement is that forecast by ETPL as needed to enable it to earn a reasonable return for fiscal 2008. For the required revenues to match and appropriately offset the expected costs of service for the Test Year, revised rates reflecting the Board's decision must be effective for volumes consumed on and after May 1, 2008.

CUSTOMER IMPACT

Erie Thames Powerlines will not have unacceptable impacts on the total distribution portion of the customer's bill and therefore ETPL is not proposing any rate mitigation measures.

Residential	Units	2007	2008	% Change
Service Charge	$	$14.0600	$14.8300	5.48%
Distribution Volumetric Rate	$/kWh	$0.0137	$0.0149	8.76%
Deferred Revenue Recovery Rate Rider	$/kWh	$0.0016	$0.0016	0.00%
Regulatory Asset Recovery	$/kWh	$0.0047	$0.0005	-89.36%
Retail Transmission Rate – Network Service Rate	$/kWh	$0.0047	$0.0038	-19.15%
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	$0.0050	$0.0047	-6.00%
Wholesale Market Service Rate	$/kWh	$0.0052	$0.0052	0.00%
Rural Rate Protection Charge	$/kWh	$0.0010	$0.0010	0.00%
Regulated Price Plan – Administration Charge	$	$0.2500	$0.2500	0.00%

In order to adjust the fixed cost recovery through the monthly fixed charge, ETPL is proposing to increase the monthly customer charge by $0.77 in the 2008 test year. The net impact of these changes is an increase in the revenue-to-cost ratios for Residential customers (from 91.12% to 101.00%).

The impact on a typical residential customer is an increase of 1.9% on the delivery component of the bill. The overall bill impact on a typical Residential customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

GS<50 kW	Units	2007	2008	% Change
Service Charge	$	$27.6900	$19.1300	-30.91%
Distribution Volumetric Rate	$/kWh	$0.0164	$0.0113	-31.10%
Deferred Revenue Recovery Rate Rider	$/kWh	$0.0140	$0.0140	0.00%
Regulatory Asset Recovery	$/kWh	$0.0030	$0.0005	-83.33%
Retail Transmission Rate – Network Service Rate	$/kWh	$0.0043	$0.0035	-18.60%
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	$0.0046	$0.0044	-4.35%
Wholesale Market Service Rate	$/kWh	$0.0052	$0.0052	0.00%
Rural Rate Protection Charge	$/kWh	$0.0010	$0.0010	0.00%
Regulated Price Plan – Administration Charge	$	$0.2500	$0.2500	0.00%

In order to adjust the fixed cost recovery through the monthly fixed charge, ETPL is proposing to decrease the monthly customer charge by $8.56 in the 2008 test year. The net impact of these changes is a decrease in the revenue-to-cost ratios for Residential customers (from 144.26% to 101.00%).

The impact on a typical GS<50 kW customer is a decrease of 7.0% on the delivery component of the bill. The overall bill impact on a typical GS<50 kW customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

GS>50 to 999 kW	Units	2007	2008	% Change
Service Charge	$	$387.3000	$205.4900	-46.94%
Distribution Volumetric Rate	$/kW	$1.9927	$1.9587	-1.71%
Deferred Revenue Recovery Rate Rider	$/kW	$0.0179	$0.0179	0.00%
Regulatory Asset Recovery	$/kW	$0.3226	$0.2094	-35.09%
Retail Transmission Rate – Network Service Rate	$/kW	$1.9561	$1.5967	-18.37%
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.6359	$1.5513	-5.17%
Wholesale Market Service Rate	$/kWh	$0.0052	$0.0052	0.00%
Rural Rate Protection Charge	$/kWh	$0.0010	$0.0010	0.00%
Regulated Price Plan – Administration Charge	$	$0.2500	$0.2500	0.00%

In order to adjust the fixed cost recovery through the monthly fixed charge, ETPL is proposing to decrease the monthly customer charge by $181.81 in the 2008 test year. The net impact of these changes is a decrease in the revenue-to-cost ratios for GS.50 to 999 kW customers (from 117.00% to 101.00%).

The impact on a typical GS>50 to 999 kW customer is a decrease of 1.0% on the delivery component of the bill. The overall bill impact on a typical GS>50 to 999 kW customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

GS>1000 to 2999 kW	Units	2007	2008	% Change
Service Charge	$	$6,370.0300	$2,376.3300	-62.70%
Distribution Volumetric Rate	$/kW	$2.2348	$3.4455	54.17%
Deferred Revenue Recovery Rate Rider	$/kW	$0.3929	$0.3929	0.00%
Regulatory Asset Recovery	$/kW	$2.0238	$0.2630	-87.00%
Retail Transmission Rate – Network Service Rate	$/kW	$2.1246	$1.7342	-18.38%
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.7592	$1.6682	-5.17%
Wholesale Market Service Rate	$/kWh	$0.0052	$0.0052	0.00%
Rural Rate Protection Charge	$/kWh	$0.0010	$0.0010	0.00%
Regulated Price Plan – Administration Charge	$	$0.2500	$0.2500	0.00%

In order to adjust the fixed cost recovery through the monthly fixed charge, ETPL is proposing to decrease the monthly customer charge by $3,993.70 in the 2008 test year. The net impact of these changes is a decrease in the revenue-to-cost ratios for GS>1000 to 2999 kW customers (from 147.47% to 101.00%).

The impact on a typical GS>1000 to 2999 kW customer is a decrease of 3.0% on the delivery component of the bill. The overall bill impact on a typical GS>1000 to 2999 kW customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

GS>3000 to 4999 kW	Units	2007	2008	% Change
Service Charge	$	$7,138.8200	$2,769.4500	-61.21%
Distribution Volumetric Rate	$/kW	$2.1705	$2.4216	11.57%
Deferred Revenue Recovery Rate Rider	$/kW	$0.1932	$0.1932	0.00%
Regulatory Asset Recovery	$/kW	$0.1437	$0.1906	32.64%
Retail Transmission Rate – Network Service Rate	$/kW	$2.2400	$1.8284	-18.38%
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.8774	$1.7803	-5.17%
Wholesale Market Service Rate	$/kWh	$0.0052	$0.0052	0.00%
Rural Rate Protection Charge	$/kWh	$0.0010	$0.0010	0.00%
Regulated Price Plan – Administration Charge	$	$0.2500	$0.2500	0.00%

In order to adjust the fixed cost recovery through the monthly fixed charge, ETPL is proposing to decrease the monthly customer charge by $4,369.37 in the 2008 test year. The net impact of these changes is a decrease in the revenue-to-cost ratios for GS>3000 to 4999 kW customers (from 190.03% to 101.00%).

The impact on a typical GS>3000 to 4999 kW customer is a decrease of 8.0% on the delivery component of the bill. The overall bill impact on a typical GS<50 kW customer is shown in detail in Exhibit 9, Tab 1, Schedule 9

Large Use	Units	2007	2008	% Change
Service Charge	$	$14,462.5500	$9,704.7600	-32.90%
Distribution Volumetric Rate	$/kW	$1.3281	$2.1118	59.01%
Deferred Revenue Recovery Rate Rider	$/kW	$0.1196	$0.1196	0.00%
Regulatory Asset Recovery	$/kW	-$0.0674	$0.2568	-481.01%
Retail Transmission Rate – Network Service Rate	$/kW	$2.3553	$1.9225	-18.38%
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.9955	$1.8923	-5.17%
Wholesale Market Service Rate	$/kWh	$0.0052	$0.0052	0.00%
Rural Rate Protection Charge	$/kWh	$0.0010	$0.0010	0.00%
Regulated Price Plan – Administration Charge	$	$0.2500	$0.2500	0.00%

Explanation; In order to adjust the fixed cost recovery through the monthly fixed charge, ETPL is proposing to decrease the monthly customer charge by $4,757.79 in the 2008 test year. The net impact of these changes is an increase in the revenue-to-cost ratios for Large Use customers (from 99.29% to 101.00%).

The impact on a typical Large Use customer is an increase of 1.0% on the delivery component of the bill. The overall bill impact on a typical Large Use customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

Street Lighting	**Units**	**2007**	**2008**	**% Change**
Service Charge	$	$0.5200	$3.7000	611.54%
Distribution Volumetric Rate	$/kW	$1.8175	$12.2888	576.14%
Deferred Revenue Recovery Rate Rider	$/kW	$0.1817	$0.1817	0.00%
Regulatory Asset Recovery	$/kW	-$0.1571	$0.1694	-207.83%
Retail Transmission Rate – Network Service Rate	$/kW	$1.5107	$1.2331	-18.38%
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.2633	$1.1980	-5.17%
Wholesale Market Service Rate	$/kWh	$0.0052	$0.0052	0.00%
Rural Rate Protection Charge	$/kWh	$0.0010	$0.0010	0.00%
Regulated Price Plan – Administration Charge	$	$0.2500	$0.2500	0.00%

Explanation; In order to adjust the fixed cost recovery through the monthly fixed charge, ETPL is proposing to increase the monthly customer charge by $3.18 in the 2008 test year. The net impact of these changes is an increase in the revenue-to-cost ratios for Street Lighting connections (from 14.35% to 70.00%).

The impact on a typical Street Lighting connection is an increase of 64.0% on the delivery component of the bill. The overall bill impact on a typical Street Lighting connection is shown in detail in Exhibit 9, Tab 1, Schedule 9.

Sentinel Lighting	**Units**	**2007**	**2008**	**% Change**
Service Charge	$	$2.0800	$5.0800	144.23%
Distribution Volumetric Rate	$/kW	$9.8952	$16.1529	63.24%
Deferred Revenue Recovery Rate Rider	$/kW	$0.8168	$0.8168	0.00%
Regulatory Asset Recovery	$/kW	$4.4848	$0.2022	-95.49%
Retail Transmission Rate – Network Service Rate	$/kW	$1.5107	$1.2331	-18.38%
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.2633	$1.1980	-5.17%
Wholesale Market Service Rate	$/kWh	$0.0052	$0.0052	0.00%
Rural Rate Protection Charge	$/kWh	$0.0010	$0.0010	0.00%
Regulated Price Plan – Administration Charge	$	$0.2500	$0.2500	0.00%

Explanation; In order to adjust the fixed cost recovery through the monthly fixed charge, ETPL is proposing to increase the monthly customer charge by $3.00 in the 2008 test year. The net impact of these changes is a decrease in the revenue-to-cost ratios for Sentinel Lighting customers (from 55.67% to 101.00%).

The impact on a typical Sentinel Lighting customer is an increase of 36.0% on the delivery component of the bill. The overall bill impact on a typical Sentinel Lighting customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

Unmetered Scattered Load	Units	2007	2008	% Change
Service Charge	$	$6.4500	$2.7300	-57.67%
Distribution Volumetric Rate	$/kWh	$0.0372	$0.0141	-62.10%
Deferred Revenue Recovery Rate Rider	$/kWh	$0.0025	$0.0025	0.00%
Regulatory Asset Recovery	$/kWh	$0.0044	$0.0005	-88.64%
Retail Transmission Rate – Network Service Rate	$/kWh	$0.0043	$0.0035	-18.60%
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	$0.0046	$0.0044	-4.35%
Wholesale Market Service Rate	$/kWh	$0.0052	$0.0052	0.00%
Rural Rate Protection Charge	$/kWh	$0.0010	$0.0010	0.00%
Regulated Price Plan – Administration Charge	$	$0.2500	$0.2500	0.00%

Explanation; In order to adjust the fixed cost recovery through the monthly fixed charge, ETPL is proposing to decrease the monthly customer charge by $3.72 in the 2008 test year. The net impact of these changes is a decrease in the revenue-to-cost ratios for Unmetered Scattered Load customers (from 187.92% to 101.00%).

The impact on a typical Unmetered Scattered Load customer is a decrease of 8.0% on the delivery component of the bill. The overall bill impact on a typical Unmetered Scattered Load customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

Embedded Distributor	Units	2007	2008	% Change
Service Charge	$		$2,211.3200	NA
Distribution Volumetric Rate	$/kW		$1.6608	NA
Deferred Revenue Recovery Rate Rider	$/kW		$0.0000	NA
Regulatory Asset Recovery	$/kW		$0.1066	NA
Retail Transmission Rate – Network Service Rate	$/kW		$2.3200	NA
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW		$2.2000	NA
Wholesale Market Service Rate	$/kWh		$0.0052	NA
Rural Rate Protection Charge	$/kWh		$0.0010	NA
Regulated Price Plan – Administration Charge	$		$0.2500	NA

Explanation: This is a new rate class that will allow ETPL to recover its costs to provide electricity to an electricity distributor licensed by the board. This rate class became necessary as Hydro One deregistered wholesale metering points with the IESO.

Specific Service Charges

Erie Thames Powerlines proposes no change to its currently approved Specific Service Charges. The Charges are listed below.

Specific Service Charges		
Customer Administration		
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
Non-Payment of Account		
Late Payment - Per month	%	1.50
Late Payment - Per annum	%	19.56
Collection of account charge-no disconnection	$	30.00
Collection of account charge-no disconnection after regular hours	$	165.00
Disconnect/Reconnect at meter-during regular hours	$	65.00
Disconnect/Reconnect at meter-after regular hours	$	185.00
Disconnect/Reconnect at pole-during regular hours	$	185.00
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
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)

Loss Factors

Loss Factors	2007	2008	% Change
Total Loss Factor - Secondary Metered Customer <5,000 kW	1.0427	1.0436	2.11%
Total Loss Factor - Secondary Metered Customer >5,000 kW	1.0145	1.0145	0.00%
Total Loss Factor - Primary Metered Customer <5,000 kW	1.0322	1.0331	2.80%
Total Loss Factor - Primary Metered Customer >5,000 kW	1.0045	1.0045	0.00%

MAJOR ISSUES

There are a number of issues that, although they may not all be defined as major, are anticipated to be examined in this case. These issues are listed below.

Capital Structure

ETPL is requesting a change in its deemed capital structure. Specifically, ETPL is requesting a decrease in the deemed equity ratio from 50% to 47% consistent with the 3 year phase in of ETPL's capital structure from 50% to 40% equity as outlined in the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation fro Ontario Electricity Distributors dated December 20, 2006.

Return on Equity

In addition, ETPL has assumed a return on equity of 8.68% consistent with the methodology outlined in Appendix B of the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors dated December 20, 2006 ETPL understands the OEB will be finalizing the return on equity for 2008 rates based on January 2008 market interest rate information.

Capital Expenditures

ETPL continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory, and to ensure and enhance its quality of service. This increase in demand comes both from currently un-serviced areas as well as existing areas needing upgrades.

Operating and Maintenance Costs

Operating and maintenance costs have been forecast to reflect the impact of inflation, customer growth, safety, reliability and expected changes in costs.

BUDGET DIRECTIVES

ETPL compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budgets. This budget information is compiled for both the bridge and test years.

Revenue Forecast

The energy sales and revenue forecast model was updated to reflect more recent information. This model was then used to prepare the revenues sales and throughput volume and revenue forecast at existing rates for fiscal 2007 and 2008. The forecast is weather normalized as outlined in Exhibit 3; Tab 2 Schedule 1 and considers such factors as new customer additions and load profiles for all classes of customers.

Operating and Maintenance Expense Forecast

The operating and maintenance expenses for fiscal 2007 bridge year and the 2008 test year have been forecast using a zero based methodology and is strongly influenced by prior year experience. Each item is reviewed account by account for each of the forecast years.

Capital Budget

All capital expenditures are budgeted on a line by line basis based on need and forecasted customer growth. ETPL utilizes an Asset Management tool which weighs the need for new capital projects based on a wide range factors such as reliability, safety, customer growth and economic factors. This tool allows ETPL to weigh all capital projects against these metrics and recommends approval of those projects that best meet the above noted criteria.

CHANGES IN METHODOLOGY

The following is a summary of the changes in methodology requested by ETPL in the current proceeding:

a) Capital Structure
ETPL has applied to change its existing debt equity split to a deemed structure of 53.33% Debt and 46.67% Equity.

b) Return on Equity
ETPL has applied no change to current the methodology in existence for return on equity in this application.

c) Interest Rate Applicable to Deferral/Variance Accounts
ETPL 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
ETPL has applied no change to the current methodology in existence for Cost Allocation & Fully Allocated Costing Study in this application, as per the report of the Board Application of Cost Allocation for Electricity Distributors released November 28th, 2007.

NUMERICAL DETAILS OF CAUSES OF SUFFICIENCY
2008 TEST YEAR

	Per Existing Rates				Application	Revenue
	2006 EDR	IRM Rate Changes	Load Changes	Test Year	Test Year	Sufficiency or Deficiency
Distribution Expenses	5,486,846	49,382	450,492	5,986,720	6,185,182	198,462
Return On Capital	871,254	7,841	71,534	950,629	897,483	-53,146
PILs	701,344	6,312	57,583	765,239	302,852	-462,387
Total Service Revenues	**7,059,444**	**63,535**	**579,609**	**7,702,588**		**-317,071**

CAUSES OF REVENUE SUFFICIENCY

The increase in ETPL's distribution expenses including depreciation expense in the 2008 Test Year of $198,462 relative to estimated amount to be collected in existing rates results are from normal operating expenses plus inflation.

The change in ETPL's return on capital in the 2008 Test Year of ($53,146) relative to estimated amount to be collected in existing rates results from the change in the deemed debt equity split.

The change in ETPL's PILs in the 2008 Test Year of ($462,387) relative to estimated amount to be collected in existing rates reflects the change in the tax rates and the change in deemed taxable revenue.

AUDITED FINANCIAL STATEMENTS AT DECEMBER 31 2006

See Appendix F

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PRO FORMA FINANCIAL STATEMENTS AT DECEMBER 31 2007

See Appendix G

PRO FORMA FINANCIAL STATEMENTS
AT
DECEMBER 31 2008

See Appendix H

RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND FINANCIAL RESULTS FILED

Reconciliation	2006 Board Filed	2006 Actual	Variance form 2006 Board Filed
Operation (Working Capital)			
5005-Operation Supervision and Engineering	8,505	21,164	12,659
5012-Station Buildings and Fixtures Expense	44,353	45,986	1,633
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	3,020	3,364	344
Sub-Total	55,879	70,514	14,635
Maintenance (Working Capital)			
5110-Maintenance of Buildings and Fixtures - Distribution Stations	1,320,693	317,453	-1,003,240
5112-Maintenance of Transformer Station Equipment	0	5,548	5,548
5114-Maintenance of Distribution Station Equipment	4,467		-4,467
5120-Maintenance of Poles, Towers and Fixtures	45,040	104,168	59,128
5125-Maintenance of Overhead Conductors and Devices	0	71,300	71,300
5130-Maintenance of Overhead Services	34,256	186,769	152,513
5135-Overhead Distribution Lines and Feeders - Right of Way	3,391	109,372	105,981
5150-Maintenance of Underground Conductors and Devices	21,557	55,142	33,585
5155-Maintenance of Underground Services	33,158	96,348	63,190
5160-Maintenance of Line Transformers	48,610	92,723	44,113
5175-Maintenance of Meters	86,479	227,602	141,123
Sub-Total	1,597,651	1,266,425	-331,226
Billing and Collections			
5315-Customer Billing	581,697	898,286	316,589
Sub-Total	581,697	898,286	316,589
Administrative and General Expenses			
5610-Management Salaries and Expenses	512,671	515,310	2,639
5615-General Administrative Salaries and Expenses	444,814	442,176	-2,639
Sub-Total	957,485	957,486	0
Amortization Expenses			
5705-Amortization Expense - Property, Plant, and Equipment	823,239	847,309	24,070
5710-Amortization of Limited Term Electric Plant	200,415	176,346	-24,070
Sub-Total	1,023,655	1,023,655	0

Explanation: ETPL filed its 2006 audited trial balance through the RRR process. In order to reconcile the differences ETPL has provided above the variance between 2006 and the 2006 actual utilized in this rate process by general ledger account. As such Operations, Maintenance and Billing and Collections have variances across many GL accounts. The reason for this is as a result of utilizing work order data to allocate affiliate transactions for the 2008 rate setting process. The 2006 year end results are not allocated in this more accurate fashion which has in turn caused the variances. For administrative and general an immaterial amount that offsets each other was allocated between to two accounts. A similar change occurred in the amortization expenses section due to analysis of the amortization schedules.

PROPOSED ACCOUNTING TREATMENT

Erie Thames Powerlines does not have any projects with a life cycle of greater than one year in this application.

INFORMATION ON PARENT AND SUBSIDIARIES

See Appendix I

RATE BASE OVERVIEW

A projection of Erie Thames Powerlines rate base is provided for both the Bridge Year (2007) and the Test Year (2008). Historical data pertaining to rate base is also presented for 2006 Approved through to 2006 Actual.

The Applicant's forecast rate base for the test year is $22,154,852 . The rate base underlying the test year revenue requirement includes a forecast of net fixed assets, plus a working capital allowance. Net fixed assets are gross assets in service minus accumulated depreciation and contributed capital. Details for the utility's working capital allowance are provided at Exhibit 2, Tab 4, Schedule 1.

Continuity schedules for Historical Board Approved, Historical Actual, Bridge and Test years are provided at Exhibit 2, Tab 2, Schedule 1.

Gross Asset – Property, Plant and Equipment and Accumulated Depreciation
The bridge and test year's gross asset balance reflects the capital expenditure programs forecast for both years. These programs are described in detail in the company's written evidence at Exhibit 2, Tab 2, Schedule 1, 2, 3, & 4. The justification for capital projects in excess of 1% of the net fixed assets are filed at Exhibit 2, Tab 2, Schedule 2.

Capital Budget
The Bridge year (2007) and Test year (2008) capital budgets are included in Exhibit 2, Tab, 3 Schedule 1.

Allowance for Working Capital
The allowance for working capital follows the board's current methodology of 15% of predetermined account balances, this calculation is detailed in Exhibit 2, Tab 4, Schedule 1.

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RATE BASE SUMMARY TABLE

RATE BASE SUMMARY	2006 Board Approved	2006 Actual	Variance form 2006 Board Approved	2006 Actual	2007 Bridge	Variance form 2006 Actual	2007 Bridge	2008 Test	Variance form 2007 Bridge
	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)
Gross Asset									
Asset Values at Cost	$17,307,356	$20,412,048	$3,104,692	$20,412,048	$21,362,380	$950,332	$21,362,380	$22,388,786	$1,026,406
Accumulated Depreciation									
Depreciation	-$2,429,563	-$4,008,229	-$1,578,666	-$4,008,229	-$4,897,426	-$889,197	-$4,897,426	-$5,831,190	-$933,764
Net Fixed Asset	$14,877,793	$16,403,819	$1,526,026	$16,403,819	$16,464,954	$61,135	$16,464,954	$16,557,596	$92,642
Allowance for Working Capital									
	$4,670,706	$5,339,877	$669,170	$5,339,877	$5,387,841	$47,964	$5,387,841	$5,597,256	$209,415
Utility Rate Base	$19,548,499	$21,743,696	$2,195,196	$21,743,696	$21,852,795	$109,099	$21,852,795	$22,154,852	$302,057

VARIANCE ANALYSIS ON RATE BASE SUMMARY TABLE

A summary of utility rate base is presented in Exhibit 2, Tab 1, Schedule 2

2008 Test Year

As shown in Exhibit 2, Tab 1, Schedule 2, the total rate base in the 2008 test year is forecast to be $22,154,852. Net fixed assets accounts for $16,557,596 of this total. The allowance for working capital totals $5,597,256.

Comparison to 2007 Bridge Year

The total rate base is expected to increase by $306,326 or 1.4% in the 2008 test year than in the 2007 bridge year. This increase is shown in Exhibit 2, Tab 1, Schedule 2. This increase is the result of a $92,642 increase in net fixed assets due to capital additions and a $213,684 increase in the working capital allowance which is primarily a result of a $198,316 increase in working capital allowance related to the cost of power. This increase in cost of power working capital allowance is a direct result of the weather normalized consumption forecast causing an increase in cost of power.

2007 Bridge Year

Comparison to 2006 Actual

The total rate base is $107,163 or 0.5% higher in the 2007 bridge year than in 2006 actual. This increase is shown in Exhibit 2, Tab 1, Schedule 2. This increase/decrease is the result of a $61,135 increase in net fixed assets due to capital additions and a $46,028 increase in working capital.

2006 Actual

Comparison to 2006 Board Approved

The 2006 total rate base is $2,192,864 or 11% higher in 2006 than the 2006 Board Approved rate base. This increase is shown in Exhibit 2, Tab 1, Schedule 2. This increase is the result of a $1,526,026 increase in net fixed assets due to capital additions for 2005 and 2006, and a $666,838 increase in working capital. Cost of power in the 2006 Board Approved working capital allowance was $26,631,527 for a $3,994,729 allowance while 2006 actual cost of power was $31,378,239 for an allowance of $4,706,736 and a difference in working capital allowance of $712,007, which is more than the total change in working capital allowance.

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CONTINUITY STATEMENTS	2006 Actual Gross Asset Value	Accumulated Depreciation	Net Book Value	2007 Bridge Gross Asset Valu	Accumulated Depreciation	Net Book Value	2008 Test Gross Asset Value	Accumulated Depreciation	Net Book Value
Land and Buildings									
1805-Land -Opening Balance	$120,344	$0	$120,344	$120,344	$0	$120,344	$120,344	$0	$120,344
1805-Land -Additions	$0		$0	$0		$0	$0		$0
1805-Land -Depreciation			$0	$0	$0	$0	$0	$0	$0
1805-Land -Adjustments			$0	$0	$0	$0	$0	$0	$0
1805-Land -Closing Balance	$120,344	$0	$120,344	$120,344	$0	$120,344	$120,344	$0	$120,344
Average	$120,344	$0	$120,344	$120,344	$0	$120,344	$120,344	$0	$120,344
1806-Land Rights -Opening Balance	$26,340	$0	$26,340	$26,340	$0	$26,340	$26,340	$0	$26,340
1806-Land Rights -Additions	$0		$0	$0		$0	$0		$0
1806-Land Rights -Depreciation			$0		$0	$0		$0	$0
1806-Land Rights -Adjustments			$0	$0		$0	$0		$0
1806-Land Rights -Closing Balance	$26,340	$0	$26,340	$26,340	$0	$26,340	$26,340	$0	$26,340
Average	$26,340	$0	$26,340	$26,340	$0	$26,340	$26,340	$0	$26,340
1808-Buildings and Fixtures-Opening Balance	$121,536	-$23,136	$98,400	$122,349	-$27,708	$94,641	$155,349	-$30,485	$124,864
1808-Buildings and Fixtures-Additions	$813	-$4,573	-$3,760	$33,000		$33,000	$0		$0
1808-Buildings and Fixtures-Depreciation			$0		-$2,777	-$2,777		-$3,107	-$3,107
1808-Buildings and Fixtures -Adjustments			$0	$0		$0	$0		$0
1808-Buildings and Fixtures -Closing Balance	$122,349	-$27,708	$94,641	$155,349	-$30,485	$124,864	$155,349	-$33,592	$121,757
Average	$121,942	-$25,422	$96,520	$138,849	-$29,097	$109,753	$155,349	-$32,039	$123,311
Total									
DS									
1820-Distribution Station Equipment Opening Balance	$161,425	-$34,271	$127,154	$203,529	-$41,875	$161,654	$243,529	-$49,319	$194,210
1820-Distribution Station Equipment Additions	$42,104		$42,104	$40,000		$40,000	$40,000		$40,000
1820-Distribution Station Equipment Depreciation		-$7,604	-$7,604		-$7,444	-$7,444		-$8,776	-$8,776
1820-Distribution Station Equipment Adjustments			$0	$0		$0	$0		$0
1820-Distribution Station Equipment Closing Balance	$203,529	-$41,875	$161,654	$243,529	-$49,319	$194,210	$283,529	-$58,095	$225,434
Average	$182,477	-$38,073	$144,404	$223,529	-$45,597	$177,932	$263,529	-$53,707	$209,822
Total									
Poles and Wires									
1830-Poles, Towers and Fixtures-Opening Balance	$1,360,021	-$213,609	$1,146,412	$1,653,773	-$273,946	$1,379,827	$1,927,127	-$345,564	$1,581,563
1830-Poles, Towers and Fixtures-Additions	$293,752		$293,752	$273,354		$273,354	$322,500		$322,500
1830-Poles, Towers and Fixtures-Depreciation		-$60,337	-$60,337		-$71,618	-$71,618		-$83,535	-$83,535
1830-Poles, Towers and Fixtures-Adjustments			$0	$0		$0	$0		$0
1830-Poles, Towers and Fixtures-Closing Balance	$1,653,773	-$273,946	$1,379,827	$1,927,127	-$345,564	$1,581,563	$2,249,627	-$429,099	$1,820,528
Average	$1,506,897	-$243,777	$1,263,119	$1,790,450	-$309,755	$1,480,695	$2,088,377	-$387,332	$1,701,046
1835-Overhead Conductors and Devices-Opening Balance	$6,675,514	-$1,098,949	$5,576,565	$7,267,784	-$1,375,460	$5,892,324	$7,935,000	-$1,679,515	$6,255,485
1835-Overhead Conductors and Devices-Additions	$592,270		$592,270	$667,216		$667,216	$463,500		$463,500
1835-Overhead Conductors and Devices-Depreciation		-$276,511	-$276,511		-$304,056	-$304,056		-$326,670	-$326,670
1835-Overhead Conductors and Devices-Adjustments			$0	$0		$0	$0		$0
1835-Overhead Conductors and Devices-Closing Balance	$7,267,784	-$1,375,460	$5,892,324	$7,935,000	-$1,679,516	$6,255,484	$8,398,500	-$2,006,185	$6,392,315
Average	$6,971,649	-$1,237,205	$5,734,444	$7,601,392	-$1,527,488	$6,073,904	$8,166,750	-$1,842,850	$6,323,900
1840-Underground Conduit-Opening Balance	$781,884	-$112,713	$669,171	$775,029	-$141,073	$633,956	$835,671	-$173,287	$662,384
1840-Underground Conduit-Additions			$0	$60,642		$60,642	$77,000		$77,000
1840-Underground Conduit-Depreciation		-$28,360	-$28,360		-$32,214	-$32,214		-$34,967	-$34,967
1840-Underground Conduit-Adjustments	-$6,855		-$6,855	$0		$0	$0		$0
1840-Underground Conduit-Closing Balance	$775,029	-$141,073	$633,956	$835,671	-$173,287	$662,384	$912,671	-$208,254	$704,417
Average	$778,457	-$126,893	$651,564	$805,350	-$157,180	$648,170	$874,171	-$190,771	$683,401

1845-Underground Conductors and Devices-Opening Balance	$2,852,839	-$507,207	$2,345,632	$3,238,025	-$634,827	$2,603,198	$3,326,383	-$766,116	$2,560,267
1845-Underground Conductors and Devices-Additions	$385,186		$385,186	$88,358		$88,358	$71,000		$71,000
1845-Underground Conductors and Devices-Depreciation		-$127,620	-$127,620		-$131,288	-$131,288		-$134,475	-$134,475
1845-Underground Conductors and Devices-Adjustments			$0	$0		$0	$0		$0
1845-Underground Conductors and Devices-Closing Balance	$3,238,025	-$634,827	$2,603,198	$3,326,383	-$766,115	$2,560,268	$3,397,383	-$900,591	$2,496,792
Average	$3,045,432	-$571,017	$2,474,415	$3,282,204	-$700,471	$2,581,733	$3,361,883	-$833,354	$2,528,530
Total									
Line Transformers									
1850-Line Transformers-Opening Balance	$3,300,582	-$535,385	$2,765,197	$3,566,527	-$670,096	$2,896,431	$3,797,056	-$817,367	$2,979,689
1850-Line Transformers-Additions	$265,945		$265,945	$230,529		$230,529	$462,000		$462,000
1850-Line Transformers-Depreciation		-$134,711	-$134,711		-$147,272	-$147,272		-$161,122	-$161,122
1850-Line Transformers-Adjustments			$0	$0		$0	$0		$0
1850-Line Transformers-Closing Balance	$3,566,527	-$670,096	$2,896,431	$3,797,056	-$817,368	$2,979,688	$4,259,056	-$978,489	$3,280,567
Average	$3,433,554	-$602,741	$2,830,814	$3,681,792	-$743,732	$2,938,060	$4,028,056	-$897,928	$3,130,128
Total									
Services and Meters									
1855-Services-Opening Balance	$1,462,813	-$281,782	$1,181,031	$1,757,899	-$352,682	$1,405,217	$1,913,505	-$426,110	$1,487,395
1855-Services-Additions	$295,086		$295,086	$155,606		$155,606	$157,000		$157,000
1855-Services-Depreciation		-$70,900	-$70,900		-$73,428	-$73,428		-$79,680	-$79,680
1855-Services-Adjustments			$0	$0		$0	$0		$0
1855-Services-Closing Balance	$1,757,899	-$352,682	$1,405,217	$1,913,505	-$426,110	$1,487,395	$2,070,505	-$505,790	$1,564,715
Average	$1,610,356	-$317,232	$1,293,124	$1,835,702	-$389,396	$1,446,306	$1,992,005	-$465,950	$1,526,055
1860-Meters-Opening Balance	$1,670,062	-$281,782	$1,388,280	$1,879,667	-$352,682	$1,526,985	$1,896,295	-$428,201	$1,468,094
1860-Meters-Additions	$209,605		$209,605	$16,627		$16,627	$30,000		$30,000
1860-Meters-Depreciation		-$70,900	-$70,900		-$75,519	-$75,519		-$76,452	-$76,452
1860-Meters-Adjustments			$0	$0		$0	$0		$0
1860-Meters-Closing Balance	$1,879,667	-$352,682	$1,526,985	$1,896,294	-$428,201	$1,468,093	$1,926,295	-$504,653	$1,421,642
Average	$1,774,865	-$317,232	$1,457,633	$1,887,981	-$390,442	$1,497,539	$1,911,295	-$466,427	$1,444,868
Total									
IT Assets									
1920-Computer Equipment - Hardware-Opening Balance	$13,419	-$3,586	$9,833	$13,419	-$5,963	$7,456	$13,419	-$8,646	$4,773
1920-Computer Equipment - Hardware-Additions	$0		$0	$0		$0	$0		$0
1920-Computer Equipment - Hardware-Depreciation		-$2,377	-$2,377		-$2,684	-$2,684		-$2,684	-$2,684
1920-Computer Equipment - Hardware-Adjustments			$0	$0		$0	$0		$0
1920-Computer Equipment - Hardware-Closing Balance	$13,419	-$5,963	$7,456	$13,419	-$8,647	$4,772	$13,419	-$11,330	$2,089
Average	$13,419	-$4,775	$8,644	$13,419	-$7,305	$6,114	$13,419	-$9,988	$3,431
1925-Computer Software-Opening Balance	$271,430	-$86,045	$185,385	$304,107	-$143,103	$161,004	$364,107	-$209,925	$154,182
1925-Computer Software-Additions	$32,677		$32,677	$60,000		$60,000	$0		$0
1925-Computer Software-Depreciation		-$57,058	-$57,058		-$66,821	-$66,821		-$72,821	-$72,821
1925-Computer Software-Adjustments			$0	$0		$0	$0		$0
1925-Computer Software-Closing Balance	$304,107	-$143,103	$161,004	$364,107	-$209,924	$154,183	$364,107	-$282,746	$81,361
Average	$287,768	-$114,574	$173,194	$334,107	-$176,514	$157,594	$364,107	-$246,336	$117,772
Total	$317,526	-$149,066	$168,460	$377,526	-$218,571	$158,955	$377,526	-$294,076	$83,450

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Equipment									
1915-Office Furniture and Equipment-Opening Balance	$14,438	-$3,978	$10,460	$14,438	-$5,422	$9,016	$14,438	-$6,866	$7,572
1915-Office Furniture and Equipment-Additions	$0		$0	$0		$0	$0		$0
1915-Office Furniture and Equipment-Depreciation		-$1,444	-$1,444		-$1,444	-$1,444		-$1,444	-$1,444
1915-Office Furniture and Equipment-Adjustments			$0	$0		$0	$0		$0
1915-Office Furniture and Equipment-Closing Balance	$14,438	-$5,422	$9,016	$14,438	-$6,866	$7,572	$14,438	-$8,310	$6,128
Average	$14,438	-$4,700	$9,738	$14,438	-$6,144	$8,294	$14,438	-$7,588	$6,850
1930-Transportation Equipment-Opening Balance	$14,983	-$9,677	$5,306	$14,983	-$11,550	$3,433	$14,983	-$13,423	$1,561
1930-Transportation Equipment-Additions	$0		$0	$0		$0	$0		$0
1930-Transportation Equipment-Depreciation		-$1,873	-$1,873		-$1,873	-$1,873		-$1,561	-$1,561
1930-Transportation Equipment-Adjustments			$0	$0		$0	$0		$0
1930-Transportation Equipment-Closing Balance	$14,983	-$11,550	$3,433	$14,983	-$13,423	$1,560	$14,983	-$14,984	$0
Average	$14,983	-$10,613	$4,370	$14,983	-$12,487	$2,497	$14,983	-$14,204	$781
1945-Measurement and Testing Equipment-Opening Balance	$0	$0	$0	$11,007	-$83	$10,924	$11,007	-$1,183	$9,824
1945-Measurement and Testing Equipment-Additions	$11,007		$11,007	$0		$0	$0		$0
1945-Measurement and Testing Equipment-Depreciation		-$83	-$83		-$1,101	-$1,101		-$1,101	-$1,101
1945-Measurement and Testing Equipment-Adjustments			$0	$0		$0	$0		$0
1945-Measurement and Testing Equipment-Closing Balance	$11,007	-$83	$10,924	$11,007	-$1,184	$9,823	$11,007	-$2,284	$8,723
Average	$5,503	-$42	$5,462	$11,007	-$634	$10,374	$11,007	-$1,734	$9,274
1950-Power Operated Equipment-Opening Balance	$64,091	$0	$64,091	$64,091	-$468	$63,623	$64,091	-$8,479	$55,611
1950-Power Operated Equipment-Additions	$0		$0	$0		$0	$0		$0
1950-Power Operated Equipment-Depreciation		-$468	-$468		-$8,011	-$8,011		-$8,011	-$8,011
1950-Power Operated Equipment-Adjustments			$0	$0		$0	$0		$0
1950-Power Operated Equipment-Closing Balance	$64,091	-$468	$63,623	$64,091	-$8,479	$55,612	$64,091	-$16,490	$47,600
Average	$64,091	-$234	$63,857	$64,091	-$4,474	$59,618	$64,091	-$12,485	$51,606
1995-Contributions and Grants - Credit-Opening Balance	-$288,263	$7,131	-$281,132	-$621,263	$28,710	-$592,553	-$621,263	$53,560	-$567,702
1995-Contributions and Grants - Credit-Additions	-$333,000		-$333,000	-$675,000		-$675,000	-$500,000		-$500,000
1995-Contributions and Grants - Credit-Depreciation		$21,579	$21,579		$24,851	$24,851		$24,851	$24,851
1995-Contributions and Grants - Credit-Adjustments			$0	$0		$0	$0		$0
1995-Contributions and Grants - Credit-Closing Balance	-$621,263	$28,710	-$592,553	-$1,296,263	$53,561	-$1,242,702	-$1,121,263	$78,411	-$1,042,851
Average	-$454,763	$17,920	-$436,843	-$958,763	$41,135	-$917,628	-$871,263	$65,986	-$805,277
Total									
Total Opening Balance	$18,623,457	-$3,184,989	$15,438,468	$20,412,048	-$4,008,228	$16,403,820	$22,037,381	-$4,910,926	$17,126,456
Total Additions	$1,795,445	-$4,573	$1,790,872	$950,332	$0	$950,332	$1,123,000	$0	$1,123,000
Total Depreciation	$0	-$818,667	-$818,667	$0	-$902,699	-$902,699	$0	-$971,555	-$971,555
Total Adjustments	-$6,855	$0	-$6,855	$0	$0	$0	$0	$0	$0
Total Closing Balance	$20,412,047	-$4,008,229	$16,403,819	$21,362,380	-$4,910,927	$16,451,453	$23,160,381	-$5,882,481	$17,277,901
	$19,517,752	-$3,596,609	$15,921,144	$20,887,214	-$4,459,578	$16,427,636	$22,598,881	-$5,396,704	$17,202,179
Total	$20,412,047	-$4,008,229	$16,403,819	$21,362,380	-$4,910,927	$16,451,453	$23,160,381	-$5,882,481	$17,277,901

GROSS ASSETS TABLE

GROSS ASSET	2006 Board Approved ($'s)	2006 Actual ($'s)	Variance form 2006 Board Approved	2006 Actual ($'s)	2007 Bridge ($'s)	Variance form 2006 Actual	2007 Bridge ($'s)	2008 Test ($'s)	Variance form 2007 Bridge
Land and Buildings									
1805-Land	$120,344	$120,344	$0	$120,344	$120,344	$0	$120,344	$120,344	$0
1806-Land Rights	$25,281	$26,340	-$1,059	$26,340	$26,340	$0	$26,340	$26,340	$0
1808-Buildings and Fixtures	$119,016	$122,349	-$3,333	$122,349	$155,349	-$33,000	$155,349	$155,349	$0
1905-Land			$0	$0		$0	$0		$0
1906-Land Rights			$0	$0		$0	$0		$0
1810-Leasehold Improvements			$0	$0		$0	$0		$0
Sub-Total-Land and Buildings	$264,641	$269,033	-$4,392	$269,033	$302,033	-$33,000	$302,033	$302,033	$0
TS Primary Above 50									
1815-Transformer Station Equipment - Normally Primary above 50 kV				$0			$0		
Sub-Total-TS Primary Above 50	$0	$0	$0	$0	$0	$0	$0	$0	$0
				$0					
DS				$0					
1820-Distribution Station Equipment - Normally Primary below 50 kV	$161,425	$203,529	-$42,104	$203,529	$243,529	-$40,000	$243,529	$283,529	-$40,000
Sub-Total-DS	$161,425	$203,529	-$42,104	$203,529	$243,529	-$40,000	$243,529	$283,529	-$40,000
Poles and Wires									
1830-Poles, Towers and Fixtures	$1,228,716	$1,653,773	-$425,057	$1,653,773	$1,927,127	-$273,354	$1,927,127	$2,249,627	-$322,500
1835-Overhead Conductors and Devices	$6,263,787	$7,267,784	-$1,003,997	$7,267,784	$7,935,000	-$667,216	$7,935,000	$8,398,500	-$463,500
1840-Underground Conduit	$719,078	$775,029	-$55,951	$775,029	$835,671	-$60,642	$835,671	$912,671	-$77,000
1845-Underground Conductors and Devices	$2,740,833	$3,238,025	-$497,192	$3,238,025	$3,326,383	-$88,358	$3,326,383	$3,397,383	-$71,000
Sub-Total-Poles and Wires	$10,952,414	$12,934,611	-$1,982,197	$12,934,611	$14,024,181	-$1,089,570	$14,024,181	$14,958,181	-$934,000
Line Transformers									
1850-Line Transformers	$2,990,261	$3,566,527	-$576,266	$3,566,527	$3,797,056	-$230,529	$3,797,056	$4,259,056	-$462,000
Sub-Total-Line Transformers	$2,990,261	$3,566,527	-$576,266	$3,566,527	$3,797,056	-$230,529	$3,797,056	$4,259,056	-$462,000
Services and Meters									
1855-Services	$1,219,592	$1,757,899	-$538,307	$1,757,899	$1,913,505	-$155,606	$1,913,505	$2,070,505	-$157,000
1860-Meters	$1,609,159	$1,879,667	-$270,508	$1,879,667	$1,896,294	-$16,627	$1,896,294	$1,926,294	-$30,000
Sub-Total-Services and Meters	$2,828,751	$3,637,566	-$808,815	$3,637,566	$3,809,799	-$172,233	$3,809,799	$3,996,799	-$187,000
General Plant									
1908-Buildings and Fixtures									
1910-Leasehold Improvements			$0	$0	$0	$0	$0	$0	$0
Sub-Total-General Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0

IT Assets									
1920-Computer Equipment - Hardware	$10,597	$13,419	-$2,822	$13,419	$13,419	$0	$13,419	$13,419	$0
1925-Computer Software	$195,146	$304,107	-$108,961	$304,107	$364,107	-$60,000	$364,107	$364,107	$0
Sub-Total-IT Assets	$205,743	$317,526	-$111,783	$317,526	$377,526	-$60,000	$377,526	$377,526	$0
Equipment									
1915-Office Furniture and Equipment	$7,975	$14,438	-$6,463	$14,438	$14,438	$0	$14,438	$14,438	$0
1930-Transportation Equipment	$14,983	$14,983	$0	$14,983	$14,983	$0	$14,983	$14,983	$0
1935-Stores Equipment			$0	$0	$0	$0	$0	$0	$0
1940-Tools, Shop and Garage Equipment			$0	$0	$0	$0	$0	$0	$0
1945-Measurement and Testing Equipment	$0	$11,007	-$11,007	$11,007	$11,007	$0	$11,007	$11,007	$0
1950-Power Operated Equipment	$0	$64,091	-$64,091	$64,091	$64,091	$0	$64,091	$64,091	$0
1955-Communication Equipment			$0	$0	$0	$0	$0	$0	$0
1960-Miscellaneous Equipment			$0	$0	$0	$0	$0	$0	$0
Sub-Total-Equipment	$22,958	$104,519	-$81,561	$104,519	$104,519	$0	$104,519	$104,519	$0
Other Distribution Assets									
1825-Storage Battery Equipment			$0	$0	$0	$0	$0	$0	$0
1970-Load Management Controls - Customer Premises			$0	$0	$0	$0	$0	$0	$0
1975-Load Management Controls - Utility Premises			$0	$0	$0	$0	$0	$0	$0
1980-System Supervisory Equipment			$0	$0	$0	$0	$0	$0	$0
1985-Sentinel Lighting Rental Units			$0	$0	$0	$0	$0	$0	$0
1990-Other Tangible Property			$0	$0	$0	$0	$0	$0	$0
1995-Contributions and Grants - Credit	-$118,837	-$621,263	$502,426	-$621,263	-$1,296,263	$675,000	-$1,296,263	-$1,796,263	$500,000
Sub-Total-Other Distribution Assets	-$118,837	-$621,263	$502,426	-$621,263	-$1,296,263	$675,000	-$1,296,263	-$1,796,263	$500,000
GROSS ASSET TOTAL	$17,307,356	$20,412,048	-$3,104,692	$20,412,048	$21,362,380	-$950,332	$21,362,380	$22,485,380	-$1,123,000

MATERIALITY ANALYSIS CALCULATION

The calculation of the Materiality Threshold for Accumulated Depreciation and Gross Assets is shown in the following table:

Materiality Threshold is 1% of net fixed assets.

	2006 Actual	2007 Bridge	2008 Test
Gross cost	$20,412,047	$22,037,380	$23,660,380
Accumulated Amortization	-$4,008,228	-$4,911,980	-$5,884,589
Net Fixed Assets	$16,403,819	$17,125,400	$17,775,791
1% of Net Fixed Assets	$164,038	$171,254	$177,758

Erie Thames Powerlines Corporation has selected the lowest materiality threshold of $164,038 to allow for the most expansive review of Gross Assets and Amortization changes

MATERIALITY ANALYSIS ON GROSS ASSET

For any rate base related variance exceeding the materiality threshold of 1%, a detailed explanation is required.

Asset Account	Bridge Year	Test Year	Variance
1830-Poles Towers and Fixtures	**$1,927,127**	**$2,249,627**	**-$322,500**

Explanation: The majority of system improvement projects will impact this account as invariably poles are replaced either due to deterioration or movement of the poles to ease access. There was also a single project for $100,000 that impacts this account which is ETPL's Pole Replacement program. Only two of the projects that had dollar amounts impact this account were greater than the materiality threshold for 2008 and they will be explained in Exhibit 2, Tab 3, Schedule 2.

Asset Account	Bridge Year	Test Year	Variance
1835-Overhead Conductors and Devices	**$7,935,000**	**$8,398,500**	**-$463,500**

Explanation: Once again the majority of system improvement projects will impact this account as in any enhancement project there will be additions of conductors and devices utilized in the construction project. Only two of the projects that had dollar amounts impact this gl account were greater than the materiality threshold for 2008 and they will be explained in Exhibit 2, Tab 3, Schedule 2.

Asset Account	Bridge Year	Test Year	Variance
1850-Line Transformers	**$3,797,056**	**$4,259,056**	**-$462,000**

Explanation: The majority of system improvement projects will impact this account as in any enhancement project there will be additions of transformers utilized in the construction project. Only two of the projects that had dollar amounts impact this gl account were greater than the materiality threshold for 2008 and they will be explained in Exhibit 2, Tab 3, Schedule 2

ACCUMULATED DEPRECIATION TABLE

ACCUMULATED DEPRECIATION TABLE	2006 Board Approved	2006 Actual	Variance form 2006 Board Approved	2006 Actual	2007 Bridge	Variance form 2006 Actual	2007 Bridge	2008 Test	Variance form 2007 Bridge
	($'s)	($'s)		($'s)	($'s)		($'s)	($'s)	
Land and Buildings									
1805-Land-Depreciation		$0	$0	$0	$0	$0	$0	$0	$0
1806-Land Rights-Depreciation		$0	$0	$0		$0			$0
1808-Buildings and Fixtures-Depreciation	-$18,613	-$27,708	$9,095	-$27,708	-$30,485	$2,777	-$30,485	-$33,592	$3,107
1905-Land-Depreciation			$0			$0			$0
1906-Land Rights-Depreciation			$0			$0			$0
1810-Leasehold Improvements-Depreciation			$0			$0			$0
Sub-Total-Land and Buildings	-$18,613	-$27,708	$9,095	-$27,708	-$30,485	$2,777	-$30,485	-$33,592	$3,107
TS Primary Above 50									
1815-Transformer Station Equipment - Normally Primary above 50 kV-Depreciation			$0			$0			$0
Sub-Total-TS Primary Above 50	$0	$0	$0	$0	$0	$0	$0	$0	$0
DS									
1820-Distribution Station Equipment - Normally Primary below 50 kV-Depreciation	-$27,526	-$41,875	$14,349	-$41,875	-$49,319	$7,444	-$49,319	-$58,094	$8,775
Sub-Total-DS	-$27,526	-$41,875	$14,349	-$41,875	-$49,319	$7,444	-$49,319	-$58,094	$8,775
Poles and Wires									
1830-Poles, Towers and Fixtures-Depreciation	-$161,895	-$273,946	$112,051	-$273,946	-$345,564	$71,618	-$345,564	-$429,099	$83,535
1835-Overhead Conductors and Devices-Depreciation	-$847,342	-$1,375,460	$528,118	-$1,375,460	-$1,679,515	$304,055	-$1,679,515	-$2,006,185	$326,670
1840-Underground Conduit-Depreciation	-$86,907	-$141,073	$54,166	-$141,073	-$173,287	$32,214	-$173,287	-$208,254	$34,967
1845-Underground Conductors and Devices-Depreciation	-$391,081	-$634,827	$243,746	-$634,827	-$766,116	$131,289	-$766,116	-$900,591	$134,475
Sub-Total-Poles and Wires	-$1,487,225	-$2,425,306	$938,081	-$2,425,306	-$2,964,482	$539,176	-$2,964,482	-$3,544,129	$579,647
Line Transformers									
1850-Line Transformers-Depreciation	-$412,808	-$670,096	$257,288	-$670,096	-$817,367	$147,271	-$817,367	-$978,490	$161,123
Sub-Total-Line Transformers	-$412,808	-$670,096	$257,288	-$670,096	-$817,367	$147,271	-$817,367	-$978,490	$161,123
Services and Meters									
1855-Services-Depreciation	-$217,267	-$352,682	$135,415	-$352,682	-$426,110	$73,428	-$426,110	-$505,790	$79,680
1860-Meters-Depreciation	-$217,267	-$352,682	$135,415	-$352,682	-$428,201	$75,519	-$428,201	-$504,643	$76,442
Sub-Total-Services and Meters	-$434,534	-$705,364	$270,830	-$705,364	-$854,311	$148,947	-$854,311	-$1,010,433	$156,122
General Plant									
1908-Buildings and Fixtures-Depreciation			$0			$0			$0
1910-Leasehold Improvements-Depreciation			$0			$0			$0
Sub-Total-General Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0

IT Assets											
1920-Computer Equipment - Hardware-Depreciation	-$1,623	-$5,963	$4,340		-$5,963	-$8,646	$2,683		-$8,646	-$11,330	$2,684
1925-Computer Software-Depreciation	-$38,949	-$143,104	$104,155		-$143,104	-$209,925	$66,821		-$209,925	-$282,746	$72,821
Sub-Total-IT Assets	-$40,572	-$149,067	$108,495		-$149,067	-$218,571	$69,504		-$218,571	-$294,076	$75,505
Equipment											
1915-Office Furniture and Equipment-Depreciation	-$2,858	-$5,422	$2,564		-$5,422	-$6,866	$1,444		-$6,866	-$8,310	$1,444
1930-Transportation Equipment-Depreciation	-$7,804	-$11,550	$3,746		-$11,550	-$13,423	$1,873		-$13,423	-$14,203	$780
1935-Stores Equipment-Depreciation			$0				$0				$0
1940-Tools, Shop and Garage Equipment-Depreciation			$0				$0				$0
1945-Measurement and Testing Equipment-	$0	-$83	$83		-$83	-$1,183	$1,100		-$1,183	-$2,284	$1,101
1945-Measurement and Testing Equipment-Depreciation			$0				$0				$0
1950-Power Operated Equipment-Depreciation	$0	-$468	$468		-$468	-$8,479	$8,011		-$8,479	-$16,490	$8,011
1955-Communication Equipment-Depreciation			$0				$0				$0
1960-Miscellaneous Equipment-Depreciation			$0				$0				$0
Sub-Total-Equipment	-$10,662	-$17,523	$6,861		-$17,523	-$29,951	$12,428		-$29,951	-$41,287	$11,336
Other Distribution Assets											
1825-Storage Battery Equipment-Depreciation			$0				$0				$0
1970-Load Management Controls - Customer Premises-Depreciation			$0				$0				$0
1975-Load Management Controls - Utility Premises-Depreciation			$0				$0				$0
1980-System Supervisory Equipment-Depreciation			$0				$0				$0
1985-Sentinel Lighting Rental Units-Depreciation			$0				$0				$0
1990-Other Tangible Property-Depreciation			$0				$0				$0
1995-Contributions and Grants - Credit-Depreciation	$2,377	$28,710	-$26,333		$28,710	$67,060	-$38,350		$67,060	$128,911	-$61,851
Sub-Total-Other Distribution Assets	$2,377	$28,710	-$26,333		$28,710	$67,060	-$38,350		$67,060	$128,911	-$61,851
ACCUMULATED DEPRICIATION TOTAL	-$2,429,563	-$4,008,229	$1,578,666		-$4,008,229	-$4,897,426	$889,197		-$4,897,426	-$5,831,190	$933,764

MATERIALITY ANALYSIS ON ACCUMULATED DEPRICIATION

For any rate base related variance exceeding the materiality threshold of 1%, a detailed explanation is required.

Asset Account	Bridge Year	Test Year	Variance
1835-Overhead Conductors and Devices - Depreciation	**$1,679,515**	**$2,006,185**	**$326,670**

Explanation: The accumulated depreciation increased by more than materiality for Overhead Conductors and Devices due to the fact that the associated asset account represents a large portion of the Distribution Assets in service for ETPL. The associated asset account is $8,398,500 of ETPL's total gross asset base and consequently will generate a large amount of amortization as a result. It is important to note that amortization rates have not changed on this account throughout the whole timeframe of the application.

ERIE THAMES POWERLINES
CORPORATION

CAPITAL BUDGET BY PROJECT				
Project Description	**USoA Account**	**Expansion or Enhancement**	**Amount**	**Spend Year**
1004 Increase Capacity/Improvements	1835	Enhancement	$28,654	Bridge
1010 Increase Capacity/Improvements	1835	Enhancement	$22,679	Bridge
1040 Station Upgrade	1808	Enhancement	$33,000	Bridge
1048 Increase Capacity/Improvements	1830,1835,1850,1850	Enhancement	$292,000	Bridge
1043 Increase Capacity/Improvements	1830,1835,1850,1850	Enhancement	$274,000	Bridge
1029 Increase Capacity/Improvements	1830,1835,1850,1850	Enhancement	$136,000	Bridge
5355 Line Extension Serve New C&I	1830,1835,1850,1850	Expansion	$155,000	Bridge
1044 Line Extension Serve New C&I	1830,1835,1850,1850	Expansion	$83,000	Bridge
1056 Transformer Station Upgrade	1820	Enhancement	$40,000	Bridge
1050 Broken Pole Primary Removal	1830	Enhancement	$20,000	Bridge
1046 Servicing Relocation	1850,1855,1860	Enhancement	$48,000	Bridge
1064 Burial of OH lines	1845	Enhancement	$40,000	Bridge
1058 Serve New Residential	1850,1855,1860	Enhancement	$70,000	Bridge
1059 Serve New C&I	1830,1835,1850,1855,1860	Enhancement	$80,000	Bridge
1049 Feeder Line Upgrade	1835	Enhancement	$68,000	Bridge
1036 Line Conversion	1840,1845	Enhancement	$55,000	Bridge
1003 Poles Relocation	1830,1835	Enhancement	$32,000	Bridge
1033 Increase Capacity/Improvements	1840	Enhancement	$16,155	Bridge
1003 Increase Capacity/Improvements	1845	Enhancement	$37,845	Bridge
1037 Line Enhancement/Pole Replacement	1835	Enhancement	$34,000	Bridge
1000 GIS Mapping System	1925	Enhancement	$60,000	Bridge
Project Description	**USoA Account**	**Expansion or Enhancement**	**Amount**	**Spend Year**
1113 C&I Meter Changes	1860	Enhancement	$30,000	Test
1011 Increase Capacity/Improvements	1830,1835,1840,1845,1850	Enhancement	$130,000	Test
1035 Increase Capacity/Improvements	1830,1835,1850	Enhancement	$46,000	Test
1052 Pole Replacement Program	1830,1835,1850	Enhancement	$100,000	Test
1058 Serve New Residential	1850,1855	Enhancement	$110,000	Test
1059 Serve New C&I	1830,1835,1845,1850,	Enhancement	$90,000	Test
1094 Serve New C&I	1830,1835,1850	Enhancement	$40,000	Test
1095 Increase Capacity/Improvements	1835	Expansion	$40,000	Test
1096 Increase Capacity/Improvements	1850	Enhancement	$35,000	Test
1097 Serve New Residential	1830,1835	Expansion	$60,000	Test
1098 Increase Capacity/Improvements	1840,1845,1850	Enhancement	$80,000	Test
1100 Serve New Residential	1830,1835,1850	Expansion	$17,000	Test
1101 Increase Capacity/Improvements	1830,1835,1840,1845,1850	Enhancement	$180,000	Test
1103 Increase Capacity/Improvements	1835	Enhancement	$30,000	Test
1104 Increase Capacity/Improvements	1850	Enhancement	$25,000	Test
1105 Serve New Residential	1830,1835,1850	Expansion	$75,000	Test
1107 Increase Capacity/Improvements	1830,1835,1840,1845,1850,1855	Enhancement	$175,000	Test
1108 Increase Capacity/Improvements	1830,1835,1850,1855	Enhancement	$95,000	Test
1109 Increase Capacity/Improvements	1830,1835,1850,1855	Enhancement	$100,000	Test
1110 Increase Capacity/Improvements	1835	Enhancement	$45,000	Test
1099 Increase Capacity/Improvements	1820	Enhancement	$40,000	Test
1013 Increase Capacity/Improvements	1830,1835,1850,1855	Enhancement	$80,000	Test

MATERIALITY ANALYSIS ON CAPITAL BUDGETS

For each projects over the materiality threshold of 1% of the total net fixed assets should include the following information

Project Description: 1048 Warren & Colbourn Port Stanley

Need: Feeder at end of usefull life, Safety and Reliabilty issues.

Scope: Replacement of the main feeder line for the town of Port Stanley, the existing line is over 60 years old. Project took a new route to the existing 4kV MS with new poles and hardware being installed which will allow for future load growth and voltage conversion which will reduce future line losses.

Capital Costs $292,000

Start Dates February 2007

In-Service Date April 2007

Project Description: 1043 John St. South Aylmer

Need: Asset replacement and Offloading a 4kV MS

Scope: This is a 27 kV voltage conversion project that will replace assets that are in excess of 50 years old. This project will alleviated two health and safety concerns for ETPL. Firstly to off load on or our existing municipal 4 kV stations which has been showing elevations in its gas levels within the oil samples taken from the transformer yearly. The project also replaced assets that are 50 to 60 years old and provides necessary conductor upgrades.

Capital Costs $274,000

Start Dates November 2007

In-Service Date December 2007

MATERIALITY ANALYSIS ON CAPITAL BUDGETS

For each projects over the materiality threshold of 1% of the total net fixed assets should include the following information

Project Description: 1101 Caverly Rd PH1 Aylmer

Need: Adequate Reliable Supply to the town of Aylmer

Scope: This project will enhance the distribution system for the town of Aylmer The project will create a 27 kV tie between two existing feeders supplied by two different transmission stations. This project will help to optimize the potential of the distribution system located in the area and put off costly expansion requirements for the Aylmer Transmission Station. The project also will reduce losses and off load the existing 4kV MS as well as upgrades to assets that are over 50 years old.

Capital Costs $180,000

Start Dates February 2008

In-Service Date April 2008

Project Description: 1107 Treelawn Aylmer

Need: Municipal Road Reconstruction

Scope: The existing 60 year old rear yard infrastructure is access restricted and has multiple tree issues and public/employee safety and reliability concerns. These concerns are corrected due to Municipal Road Reconstruction plans allowing the relocation of the assets with reduced expense to ETPL and its customers.

Capital Costs $175,000

Start Dates May 2008

In-Service Date July 2008

SYSTEM EXPANSIONS

2008 Test Year

1094 Serve New C&I: Expansion of the distribution system to eliminate Long Term Load Transfers off of Hydro One's Distribution System. Capital Contribution calculation is not required.

1097 Serve New Residential: Expansion of the distribution system to eliminate Long Term Load Transfers off of Hydro One's Distribution System. Capital Contribution calculation is not required.

1100 Serve New Residential: Expansion of the distribution system to eliminate Long Term Load Transfers off of Hydro One's Distribution System. Capital Contribution calculation is not required.

1105 Serve New Residential: Expansion of the distribution system to eliminate Long Term Load Transfers off of Hydro One's Distribution System. Capital Contribution calculation is not required.

2007 Bridge Year

5355 Line Extension Serve New C&I: Expansion of Distribution system to connect Otterville Golf Course which is a new customer within Erie Thames Powerlines distribution territory. Calculation of capital contribution is consistent with Appendix B of the Distribution System Code.

1044 Line Extension Serve New C&I: Expansion of the distribution system to connect the new Aylmer Ethanol Plant and provide alternate supply configurations for the town of Aylmer. Calculation of capital contribution is consistent with Appendix B of the Distribution System Code.

ERIE THAMES POWERLINES CORPORATION

CAPITALIZATION POLICY

POLICIES, PROCEDURES & DIRECTIVES

APPROVAL DATE: October 28, 2004

DATE PREPARED: October 28, 2004

POLICY: Fixed Asset and Acquisition Policy

1. PURPOSE

The purpose of this policy is to lay out the authorization levels required for the purchase of fixed assets and to detail the costs that shall be capitalized as acquisition value. It also provides guidance on the accounting treatment of lease-to-purchase assets.

2. SCOPE

This policy applies to all employees engaged in the purchase of fixed assets.

3. POLICY

3.01 Only fixed assets with a cost exceeding $500 shall be capitalized.
3.02 Fixed asset purchases not included in the capital budget may be authorized by the President.
3.03 Fixed asset purchases greater than $50,000 shall always require a business case to be presented before the purchase will be authorized.
3.04 Fixed asset purchases shall follow all purchasing policies except where superseded by this policy.

4 RESPONSIBILITY
4.01 The initiating department is responsible for preparing and presenting a business case for any purchase valued at $50,000.00 or more. Finance and purchasing will assist as required.
4.02 The Finance Department is responsible for maintaining fixed asset records.

5. PROCEDURES
5.01 Only fixed assets with a cost exceeding $500.00 shall be capitalized. In the case of the purchase of a set or group of items, this limit applies to the entire set or group.

5.02 Fixed asset purchases greater than $50,000.00 whether or not included in the capital budget, shall require a business case that explains why the purchase is required and demonstrates the financial justification. Where applicable it should also review alternative solutions, and whether the asset should be purchased or leased. Financial justification is not required for purchases required for health and safety reasons.

5.03 Fixed asset purchase not included in the capital budget must be authorized by the President.

5.04 The acquisition value of a fixed asset purchased outright shall incorporate:
i. Purchase price
ii. Taxes, excluding GST
iii. Shipping and handling costs
iv. Installation, retrofit or fit-up costs
v. Cost of major additions or improvements to the asset
vi.

5.05 Leased to purchase assets require additional approval of the CFO or designate who will review the effect of the transaction on the company's balance sheet and bank agreements.

5.06 The acquisition value of leased to purchase assets shall incorporate:
i. The present value of the lease costs
ii. The present value of the future purchase price specified in the contract
iii. Taxes, excluding GST/HST
iv. Shipping and handling costs
v. Installation, retrofit or fit-up costs
vi. Cost of major leasehold improvements

5.07 In determining whether a specific expenditure is in fact a fixed asset, reference should be made to Section 3061 of the CICA Handbook.

5.08 Fixed assets shall be assigned to one of the following categories:
Land, building, transportation equipment, communications, office furniture, computer equipment and software, leasehold improvements, poles, OH&UG, conductors and devices.

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WORKING CAPITAL ALLOWANCE CALCULATION BY ACCOUNT	2006 Actual	15%	Allowance for Working Capital	2007 Bridge	15%	Allowance for Working Capital	2008 Test	15%	Allowance for Working Capital
Operation (Working Capital)									
5005-Operation Supervision and Engineering	$21,164.00	15%	$3,174.60	$22,981.00	15%	$3,447.15	$20,259.00	15%	$3,038.85
5010-Load Dispatching		15%	$0.00		15%	$0.00		15%	$0.00
5012-Station Buildings and Fixtures Expense	$45,986.00	15%	$6,897.90	$16,746.00	15%	$2,511.90	$12,949.00	15%	$1,942.35
5014-Transformer Station Equipment - Operation Labour		15%	$0.00		15%	$0.00		15%	$0.00
5015-Transformer Station Equipment - Operation Supplies and Expenses		15%	$0.00		15%	$0.00		15%	$0.00
5016-Distribution Station Equipment - Operation Labour		15%	$0.00		15%	$0.00		15%	$0.00
5017-Distribution Station Equipment - Operation Supplies and Expenses		15%	$0.00		15%	$0.00		15%	$0.00
5020-Overhead Distribution Lines and Feeders - Operation Labour		15%	$0.00		15%	$0.00		15%	$0.00
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$3,364.00	15%	$504.60	$329.00	15%	$49.35	$329.00	15%	$49.35
5030-Overhead Sub transmission Feeders - Operation		15%	$0.00		15%	$0.00		15%	$0.00
5035-Overhead Distribution Transformers- Operation		15%	$0.00		15%	$0.00		15%	$0.00
5040-Underground Distribution Lines and Feeders - Operation Labour		15%	$0.00		15%	$0.00		15%	$0.00
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses		15%	$0.00		15%	$0.00		15%	$0.00
5050-Underground Sub transmission Feeders - Operation		15%	$0.00		15%	$0.00		15%	$0.00
5055-Underground Distribution Transformers - Operation		15%	$0.00		15%	$0.00		15%	$0.00
5060-Street Lighting and Signal System Expense		15%	$0.00		15%	$0.00		15%	$0.00
5065-Meter Expense		15%	$0.00	$0.00	15%	$0.00		15%	$0.00
5070-Customer Premises - Operation Labour		15%	$0.00		15%	$0.00		15%	$0.00
5075-Customer Premises - Materials and Expenses		15%	$0.00		15%	$0.00		15%	$0.00
5085-Miscellaneous Distribution Expense		15%	$0.00		15%	$0.00		15%	$0.00
5090-Underground Distribution Lines and Feeders - Rental Paid		15%	$0.00		15%	$0.00		15%	$0.00
5095-Overhead Distribution Lines and Feeders - Rental Paid		15%	$0.00		15%	$0.00		15%	$0.00
5096-Other Rent	$1,219.00	15%	$182.85	$1,626.00	15%	$243.90	$1,219.00	15%	$182.85
Sub-Total	$71,733.00		$10,759.95	$41,682.00		$6,252.30	$34,756.00		$5,213.40
Maintenance (Working Capital)									
5105-Maintenance Supervision and Engineering		15%	$0.00		15%	$0.00		15%	$0.00
5110-Maintenance of Buildings and Fixtures - Distribution Stations	$317,453.00	15%	$47,617.95	$386,318.00	15%	$57,947.70	$390,088.00	15%	$58,513.20
5112-Maintenance of Transformer Station Equipment	$5,548.00	15%	$832.20	$51,645.00	15%	$7,746.75	$51,667.00	15%	$7,750.05
5114-Maintenance of Distribution Station Equipment		15%	$0.00		15%	$0.00		15%	$0.00
5120-Maintenance of Poles, Towers and Fixtures	$104,168.00	15%	$15,625.20	$198,336.00	15%	$29,750.40	$199,567.00	15%	$29,935.05
5125-Maintenance of Overhead Conductors and Devices	$71,300.00	15%	$10,695.00	$68,117.00	15%	$10,217.55	$69,602.00	15%	$10,440.30
5130-Maintenance of Overhead Services	$186,769.00	15%	$28,015.35	$177,498.00	15%	$26,624.70	$180,674.00	15%	$27,101.10
5135-Overhead Distribution Lines and Feeders - Right of Way	$109,372.00	15%	$16,405.80	$116,085.00	15%	$17,412.75	$118,292.00	15%	$17,743.80
5145-Maintenance of Underground Conduit		15%	$0.00		15%	$0.00		15%	$0.00
5150-Maintenance of Underground Conductors and Devices	$55,142.00	15%	$8,271.30	$76,980.00	15%	$11,547.00	$77,680.00	15%	$11,652.00
5155-Maintenance of Underground Services	$96,348.00	15%	$14,452.20	$72,859.00	15%	$10,928.85	$74,175.00	15%	$11,126.25
5160-Maintenance of Line Transformers	$92,723.00	15%	$13,908.45	$121,418.00	15%	$18,212.70	$122,337.00	15%	$18,350.55
5165-Maintenance of Street Lighting and Signal Systems		15%	$0.00		15%	$0.00		15%	$0.00
5170-Sentinel Lights - Labour		15%	$0.00		15%	$0.00		15%	$0.00
5172-Sentinel Lights - Materials and Expenses		15%	$0.00		15%	$0.00		15%	$0.00
5175-Maintenance of Meters	$227,602.00	15%	$34,140.30	$174,876.00	15%	$26,231.40	$177,815.00	15%	$26,672.25
5178-Customer Installations Expenses- Leased Property		15%	$0.00		15%	$0.00		15%	$0.00
5185-Water Heater Rentals - Labour		15%	$0.00		15%	$0.00		15%	$0.00
5186-Water Heater Rentals - Materials and Expenses		15%	$0.00		15%	$0.00		15%	$0.00
5190-Water Heater Controls - Labour		15%	$0.00		15%	$0.00		15%	$0.00
5192-Water Heater Controls - Materials and Expenses		15%	$0.00		15%	$0.00		15%	$0.00
5195-Maintenance of Other Installations on Customer Premises		15%	$0.00		15%	$0.00		15%	$0.00
Sub-Total	$1,266,425.00		$189,963.75	$1,444,132.00		$216,619.80	$1,461,897.00		$219,284.55
Billing and Collections									
5305-Supervision		15%	$0.00		15%	$0.00		15%	$0.00
5310-Meter Reading Expense		15%	$0.00		15%	$0.00		15%	$0.00
5315-Customer Billing	$898,286.00	15%	$134,742.90	$925,235.00	15%	$138,785.25	$943,739.00	15%	$141,560.85
5320-Collecting		15%	$0.00		15%	$0.00		15%	$0.00
5325-Collecting- Cash Over and Short		15%	$0.00		15%	$0.00		15%	$0.00
5330-Collection Charges	$3,215.00	15%	$482.25	$10,669.00	15%	$1,600.35	$10,669.00	15%	$1,600.35
5335-Bad Debt Expense	$61,727.00	15%	$9,259.05	$119,078.00	15%	$17,861.70	$119,078.00	15%	$17,861.70
5340-Miscellaneous Customer Accounts Expenses		15%	$0.00		15%	$0.00		15%	$0.00

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Billing and Collections									
5305-Supervision		15%	$0.00		15%	$0.00		15%	$0.00
5310-Meter Reading Expense		15%	$0.00		15%	$0.00		15%	$0.00
5315-Customer Billing	$898,286.00	15%	$134,742.90	$925,235.00	15%	$138,785.25	$943,739.00	15%	$141,560.85
5320-Collecting		15%	$0.00		15%	$0.00		15%	$0.00
5325-Collecting- Cash Over and Short		15%	$0.00		15%	$0.00		15%	$0.00
5330-Collection Charges	$3,215.00	15%	$482.25	$10,669.00	15%	$1,600.35	$10,669.00	15%	$1,600.35
5335-Bad Debt Expense	$61,727.00	15%	$9,259.05	$119,078.00	15%	$17,861.70	$119,078.00	15%	$17,861.70
5340-Miscellaneous Customer Accounts Expenses		15%	$0.00		15%	$0.00		15%	$0.00
Sub-Total	$963,228.00		$144,484.20	$1,054,982.00		$158,247.30	$1,073,486.00		$161,022.90
Community Relations									
5405-Supervision	$33,282.00	15%	$4,992.30	$27,879.00	15%	$4,181.85	$27,879.00	15%	$4,181.85
5410-Community Relations - Sundry		15%	$0.00		15%	$0.00		15%	$0.00
5415-Energy Conservation		15%	$0.00		15%	$0.00		15%	$0.00
5420-Community Safety Program		15%	$0.00		15%	$0.00		15%	$0.00
5425-Miscellaneous Customer Service and Informational Expenses		15%	$0.00		15%	$0.00		15%	$0.00
5505-Supervision		15%	$0.00		15%	$0.00		15%	$0.00
5510-Demonstrating and Selling Expense		15%	$0.00		15%	$0.00		15%	$0.00
5515-Advertising Expense	$3,427.00	15%	$514.05	$1,000.00	15%	$150.00	$1,000.00	15%	$150.00
5520-Miscellaneous Sales Expense		15%	$0.00		15%	$0.00		15%	$0.00
Sub-Total	$36,709.00		$5,506.35	$28,879.00		$4,331.85	$28,879.00		$4,331.85
Administrative and General Expenses									
5605-Executive Salaries and Expenses	$125,123.00	15%	$18,768.45	$119,348.00	15%	$17,902.20	$119,348.00	15%	$17,902.20
5610-Management Salaries and Expenses	$515,310.00	15%	$77,296.50	$518,045.00	15%	$77,706.75	$691,640.00	15%	$103,746.00
5615-General Administrative Salaries and Expenses	$442,176.00	15%	$66,326.40	$455,441.00	15%	$68,316.15	$464,550.00	15%	$69,682.50
5620-Office Supplies and Expenses	$133,264.00	15%	$19,989.60	$109,949.00	15%	$16,492.35	$110,848.00	15%	$16,627.20
5625-Administrative Expense Transferred Credit		15%	$0.00		15%	$0.00		15%	$0.00
5630-Outside Services Employed	$247,341.00	15%	$37,101.15	$280,000.00	15%	$42,000.00	$178,000.00	15%	$26,700.00
5635-Property Insurance	$51,204.00	15%	$7,680.60	$52,740.00	15%	$7,911.00	$51,685.00	15%	$7,752.75
5640-Injuries and Damages		15%	$0.00		15%	$0.00		15%	$0.00
5645-Employee Pensions and Benefits	-$313.00	15%	-$46.95	-$208.00	15%	-$31.20	-$208.00	15%	-$31.20
5650-Franchise Requirements		15%	$0.00		15%	$0.00		15%	$0.00
5655-Regulatory Expenses	$132,940.00	15%	$19,941.00	$40,000.00	15%	$6,000.00	$40,000.00	15%	$6,000.00
5660-General Advertising Expenses		15%	$0.00		15%	$0.00		15%	$0.00
5665-Miscellaneous General Expenses	$89,993.00	15%	$13,498.95	$65,687.00	15%	$9,853.05	$65,687.00	15%	$9,853.05
5670-Rent	$130,258.00	15%	$19,538.70	$144,089.00	15%	$21,613.35	$108,190.00	15%	$16,228.50
5675-Maintenance of General Plant		15%	$0.00		15%	$0.00		15%	$0.00
5680-Electrical Safety Authority Fees		15%	$0.00		15%	$0.00		15%	$0.00
5685-Independent Market Operator Fees and Penalties		15%	$0.00		15%	$0.00		15%	$0.00
Sub-Total	$1,867,296.00		$280,094.40	$1,785,091.00		$267,763.65	$1,829,740.00		$274,461.00

Amortization Expenses									
5705-Amortization Expense - Property, Plant, and Equipment	$847,309.00	0%	$0.00	$890,252.00	0%	$0.00	$935,609.00	0%	$0.00
5710-Amortization of Limited Term Electric Plant	$176,346.00	0%	$0.00	$0.00	0%	$0.00		0%	$0.00
5715-Amortization of Intangibles and Other Electric Plant		0%	$0.00		0%	$0.00		0%	$0.00
5720-Amortization of Electric Plant Acquisition Adjustments		0%	$0.00		0%	$0.00		0%	$0.00
5725-Miscellaneous Amortization		0%	$0.00		0%	$0.00		0%	$0.00
5730-Amortization of Unrecovered Plant and Regulatory Study Costs		0%	$0.00		0%	$0.00		0%	$0.00
5735-Amortization of Deferred Development Costs		0%	$0.00		0%	$0.00		0%	$0.00
5740-Amortization of Deferred Charges		0%	$0.00		0%	$0.00		0%	$0.00
Sub-Total	$1,023,655.00		$0.00	$890,252.00		$0.00	$935,609.00		$0.00
6105-Taxes other than Income Taxes	$15,548.00	15%	$2,332.20	$28,457.00	15%	$4,268.55	$28,458.00	15%	$4,268.70
Cost of Power									
4705-Power Purchased	$24,121,034.00	15%	$3,618,155.10	$25,162,639.56	15%	$3,774,395.93	$25,455,869.03	15%	$3,818,380.36
4708-Charges-WMS	$2,797,033.00	15%	$419,554.95	$2,735,069.52	15%	$410,260.43	$2,766,942.29	15%	$415,041.34
4710-Cost of Power Adjustments		15%	$0.00		15%	$0.00		15%	$0.00
4712-Charges-One-Time	$31.00	15%	$4.65	$0.00	15%	$0.00		15%	$0.00
4714-Charges-NW	$2,343,440.00	15%	$351,516.00	$1,892,051.17	15%	$283,807.68	$2,429,770.00	15%	$364,465.50
4716-Charges-CN	$2,116,701.00	15%	$317,505.15	$1,745,956.32	15%	$261,893.45	$2,205,242.00	15%	$330,786.30
4730-Rural Rate Assistance Expense		15%	$0.00		15%	$0.00		15%	$0.00
5685-Independent Market Operator Fees and Penalties		15%	$0.00		15%	$0.00		15%	$0.00
Sub-Total	$31,378,239.00		$4,706,735.85	$31,535,716.57		$4,730,357.48	$32,857,823.32		$4,928,673.50
WORKING CAPITAL ALLOWANCE TOTAL			**$5,339,876.70**			**$5,387,840.93**			**$5,597,255.90**

Ex.	Tab	Schedule	Contents of Schedule
3 - Operating Revenue			
	1	1	Overview of Operation Revenue
		2	Summary of Operating Revenue Table
		3	Variance Analysis on Operating Revenue
	2		**Throughput Revenue**
		1	Weather Normalized Forecasting Methodology
		2	Normalized Volume Forecast Table
		3	Variance Analysis on Normalized Volume Forecast
		4	Customer Count Forecast Table
		5	Variance Analysis on Customer Count Forecast
	3		**Other Revenue**
		1	Other Distribution Revenue
		2	Materiality Analysis on Other Distribution Revenue
		3	Rate of Return on Other Distribution Revenue
		4	Distribution Revenue Data
	4		**Revenue Sharing**
		1	Description of Revenue Sharing

OVERVIEW OF OPERATING REVENUE

(The following are examples which need to be reviewed and revised by the Applicant)

This exhibit provides the details on Erie Thames Powerlines operating revenue for Historical, 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 RP-2005-0020 Rate Order, EB-2005-0361, EB-2006-0197, EB-2007-0524, EB-2007-0016, dated July, 12, 2007. Distribution revenue does not include Regulatory Asset Recovery and Deferred Revenue Recovery Rate Rider revenues. Distribution revenues do, however, include PILS Revenue Recovery amounts and Low Voltage Wheeling revenues. A summary of normalized operating revenues is presented in Exhibit 3, Tab 3, and Schedule 4.

Throughput Revenue

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.

Other Revenue

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.

Revenue Sharing

Erie Thames Powerlines and its employees do not participate in revenue sharing.

SUMMARY OF OPERATING REVENUE TABLE

SUMMARY OF OPERATING REVENUE TABLE	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2006 Actual	2007 Bridge	Variance from 2006 Actual	2007 Bridge	2008 Test	Variance from 2007 Actual
	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)
Distribution Revenues									
Residential	$3,414,217	$3,109,505	-$304,711	$3,109,505	$3,674,484	$564,979	$3,674,484	$4,051,170	$376,686
GS<50	$1,076,188	$851,697	-$224,491	$851,697	$1,056,289	$204,592	$1,056,289	$775,919	-$280,369
GS>50 to 999	$993,110	$797,156	-$195,954	$797,156	$1,342,809	$545,653	$1,342,809	$1,052,150	-$290,659
GS>1000 to 2999	$829,973	$666,208	-$163,765	$666,208	$918,349	$252,141	$918,349	$621,507	-$296,842
GS>3000 to 4999	$157,792	$107,961	-$49,831	$107,961	$163,124	$55,163	$163,124	$119,653	-$43,471
Large Use	$279,379	$170,605	-$108,775	$170,605	$390,870	$220,265	$390,870	$466,190	$75,321
Street Lighting	$30,900	$34,148	$3,248	$34,148	$33,314	-$834	$33,314	$283,600	$250,286
Sentinel Lighting	$15,519	$5,249	-$10,270	$5,249	$12,432	$7,183	$12,432	$30,646	$18,214
Unmetered Scattered Load	$20,495	$22,609	$2,114	$22,609	$26,109	$3,500	$26,109	$11,661	-$14,448
Embedded Distributor	$0	$0	$0	$0	$0	$0	$0	$218,771	$218,771
	$6,817,572	**$5,765,138**	**-$1,052,434**	**$5,765,138**	**$7,617,781**	**$1,852,643**	**$7,617,781**	**$7,631,268**	**$13,488**
Other Distribution Revenue									
Late Payment Charges	$43,528	$84,570	$41,042	$84,570	$92,667	$8,098	$92,667	$95,447	$2,780
Specific Service Charges	$321,804	$153,160	-$168,644	$153,160	$243,027	$89,867	$243,027	$253,659	$10,632
Other Distribution Revenue	$132,521	$157,259	$24,738	$157,259	$177,277	$20,018	$177,277	$182,596	$5,318
	$497,852.55	**$394,988.94**	**-$102,863.61**	**$394,988.94**	**$512,971.49**	**$117,982.55**	**$512,971.49**	**$531,701.80**	**$18,730.31**
Total Operating revenue	$7,315,425	$6,160,127	-$1,155,298	$6,160,127	$8,130,752	$1,970,625	$8,130,752	$8,162,970	$32,218

VARIANCE ANALYSIS ON OPERATING REVENUE

Erie Thames Powerlines distribution revenue has been calculated using the most recently approved rates. In particular, delivery rates are based on the RP-2005-0020, EB-2005-0361, EB-2006-0197, EB-2007-0524, and EB-2007-0016 Rate Order, dated July 12, 2007. Distribution revenue does not include commodity related revenue.

A summary of normalized operating revenues is presented in Exhibit, Tab, Schedule, which is a summary of the information provided in Tab 4, Schedule 3 of Exhibit 3.

2008 Test Year

Erie Thames Powerlines operating revenue is forecast to be $8,160,190in Fiscal 2008, as shown in Exhibit 3, Tab 1, and Schedule 2. Distribution revenue totals $7,631,268 or 93% of total revenues. Other operating revenue (net) accounts for the remaining revenue of $531,702.

Comparison to 2007 Bridge Year

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue is expected to be $32,218 above the bridge year level in fiscal 2007. This increase is the result of the change in debt equity split for deemed revenue requirement, a reduction in operating expenses, the change in PILS revenue and Hydro One Low Voltage revenue embedded in distribution rates.

2007 Bridge Year

Comparison to Fiscal 2006 Actual

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue is expected to be $1,970,625 above the 2006 Actual level in fiscal 2006. This increase is the result of the 2006 EDR rates being approved January 1st, 2007 as opposed to May 1st 2006, coupled with the use of normalized consumption levels for 2007 distribution revenue.

2006 Actual

Comparison to 2006 Board Approved

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue was $1,155,298 below the Board Approved level for 2006 rates. This decrease is the result of the 2006 EDR rates being approved January 1st, 2007 as opposed to May 1st 2006.

WEATHER NORMALIZED FORECASTING METHODOLOGY

This exhibit discusses the methodology used to determine Erie Thames Powerlines customer and load forecast. A projection for the number of customers in each customer class is provided for both the Bridge Year (2007) and the Test Year (2008). As a result of the limited amount of data available, time series techniques that are often used to help estimate forecast values cannot be used. Rather, the Applicant has used a simple trend growth in customer connections, by class, to forecast Bridge and Test Year customer numbers. Given the consistent trend in customer numbers in ETPL's service territory over the past five years, the resulting customer forecast is likely not materially different than what would result from using more sophisticated time series techniques. In recent history, there has been very little year-to-year variation in customer growth by class. Historical and forecast customer numbers, by class, are displayed in the next section.

As required by the OEB Filing Requirements for Transmission and Distribution Applications, we are providing normalized historical and forecast (Bridge Year and Test Year) throughput data. Weather normalization (where required) is based on normalized average use per customer ("NAC") calculated from the weather-normalized throughput of the utility from 2004. This weather-normalized throughput was generated by Hydro One using their weather normalization model for the Cost Allocation process previously undertaken by the Board. The process to obtain these weather normal data was an intensive effort for all parties involved, and we are leveraging the value of this work by using it for this process.

Customer Forecast

Table 1 below presents historical and forecast customer numbers, by class, for Erie Thames Powerlines.

CUSTOMER COUNT FORECAST TABLE	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2006 Actual	2007 Actual	Variance from 2006 Actual	2007 Bridge	2008 Test	Variance from 2007 Actual
Residential	12,075	12,206	1.08%	12,206	12328	1.00%	12328	12451	1.00%
GS<50	1,352	1,375	1.67%	1,375	1375	0.00%	1375	1388	1.00%
GS>50 to 999 kW	113	135	19.47%	135	138	2.22%	138	141	2.17%
GS>1000 to 2999 kW	8	8	0.00%	8	8	0.00%	8	8	0.00%
GS>3000 kW to 4999 kW	1	1	0.00%	1	1	0.00%	1	1	0.00%
Large Use	1	1	0.00%	1	1	0.00%	1	1	0.00%
Unmetered Scattered Load	60	95	58.33%	95	95	0.00%	95	95	0.00%
Sentinel Lighting	235	256	8.94%	256	256	0.00%	256	256	0.00%
Street Lighting	2,870	2,870	0.00%	2,870	2870	0.00%	2870	2956	3.00%
Embedded Distributor	0	0	0.00%	-	2	100.00%	2	2	0.00%
	16,715	16,947		16,947	17074		17,074	17,300	

Annual percentage change is presented for Residential, GS<50, and GS>50-999 classes. For Residential and GS<50 customer classes, the percentage change for 2007 represents the annual average geometric mean growth rate for 2002 to 2006. The annual trend growth rate is used to project customer growth into 2007 and 2008. For the GS>50 to 5000 customer classes, an annual growth rate of 0% was assumed for 2007 and 2008.

The large use and GS>3000 kW to 4999 kW classes contains only one customer each. The 2007 customer number is the current actual number of customers in this class. The Applicant does not expect the number of customers in this class to change within the next year to 18 months, and has used this for the number of customers expected at Bridge Year end and Test Year.

Customer numbers for Sentinel Lighting, Street Lighting, and USL classes in 2007 also represent current number of connections in each of these classes. The Applicant does not expect the number of customers in the Sentinel and USL classes to change within the next year and the 2007 current figures are used for 2008. Customer growth for the Street Lighting Class is calculated based on the actual addition of street lights in 2007 and 2008.

<u>Load Forecast</u>

Weather sensitive load (Residential, GS<50, and GS>50 classes) is calculated by using a retail normalized average use per customer ("retail NAC"). This is calculated by dividing the class weather normal retail kWh for 2004 by the number of customers in class in 2004. Class weather normal retail kWh for 2004 is determined by dividing the class weather normal wholesale kWh for 2004 reported in the Hydro One weather normalization analysis by the class loss factor. The class loss factor is calculated for 2004 by dividing the class weather actual wholesale consumption for 2004 (Hydro One file) by the class weather actual retail consumption (utility data). Weather sensitive class weather actual wholesale and retail kWh and associated loss factors are reported in the following table below.

2004 Weather Actual kWh and Loss Factors for Weather Sensitive Load The Applicant Utilities			
Class	Weather Actual Wholesale kWh	Weather Actual Retail kWh	Loss Factor
Residential	121,978,814	116,983,614	4.27%
GS < 50	40,428,875	38,773,257	4.27%
GS >50 to 999	71,033,813	68,124,881	4.27%

Weather sensitive class wholesale weather normal kWh, number of customers, and retail NAC for 2004 is reported in the table below.

Class	Weather Normal Wholesale kWh (2004)	Customer Connections (2004)	Retail NAC
Residential	119,453,498	12,075	9,893
GS < 50	39,401,386	1,352	29,143
GS >50 to 999	69,144,592	113	611,899

Annual class kWh for weather sensitive load (Residential, GS<50, GS>50) for Bridge Year and Test Year are calculated by multiplying retail NAC by forecast number of customers in class. Class kWh for the Large User (“LU”) class, Unmetered Scattered Load (“USL”), and Sentinel Lighting is not weather sensitive and is not expected to differ in 2008 from current 2007 levels. Utility budgeted throughput for these classes based on year-to-date consumption is used to estimate Bridge Year and Test Year values for these classes. Consumption for Street Lighting is not weather sensitive and has been projected based on historical consumption patterns for the street light class.

Several classes are billed based on demand charges (GS>50 to 999, GS>1000 to 2999, GS>3000 to 4999, Large Use, Sentinel, and Street Lighting) and require an estimate of billed kW. Billed kW is estimated based on a load factor calculated using a ratio of historical billed kW to historical retail kWh, by class. The following table summarizes the results of The Applicant’s customer and load forecast.

Erie Thames Powerlines		Historical Actual	Board Approved	Historical Normalized	Bridge Year Estimate	Bridge Year Normalized	Test Year Normalized
Year		2006	2004	2006	2007	2007	2008
Customer Class							
Residential	#	12,206	12,075	12,206	12,328	12,328	12,451
	kWh	116,128,274	117,010,418	120,749,432	116,386,436	121,956,927	123,176,496
GS<50 kW	#	1,375	1,352	1,375	1,375	1,375	1,388
	kWh	36,565,918	42,147,488	39,663,673	36,556,903	40,060,310	40,460,913
GS>50 to 999 kW	#	135	113	135	138	138	141
	kWh	75,156,430	102,344,447	82,606,371	114,845,468	84,442,069	86,277,766
	kW	206,825	298,327	206,825	212,983	352,005	359,657
GS>1000 to 2999	#	8	8	8	8	8	8
	kWh	65,158,720	53,797,056	69,529,869	65,097,696	69,529,869	69,529,869
	kW	135,587	113,648	135,587	137,295	135,587	135,587
GS>3000 to 4999	#	1	1	1	1	1	1
	kWh	16,315,706	17,703,447	17,528,668	17,629,292	17,528,668	17,528,668
	kW	35,687	43,930	35,687	40,302	35,687	35,687
Large Use >5000 kW	#	1	1	1	1	1	1
	kWh	91,950,056	69,925,689	84,605,665	86,761,150	84,605,665	84,605,665
	kW	165,609	132,542	165,609	163,632	165,609	165,609
Unmetered Scattered Load	#	95	60	95	95	95	95
	kWh	602,137	448,854	606,271	504,181	606,271	606,271
Sentinel Lighting	#	256	235	256	256	256	256
	kWh	212,859	181,782	238,372	238,372	238,372	238,372
	kW	535	1,018	605	611	931	931
Street Lighting	#	2,870	2,870	2,870	2,870	2,870	2,956
	kWh	3,164,059	3,077,398	3,024,750	3,120,960	3,024,750	3,115,492
	kW	8,538	8,843	9,157	8,476	9,157	9,432
Embedded Distributor	#	2	0	2	2	2	2
	kWh	20,741,502	0	20,948,917	16,585,721	20,741,502	20,741,502
	kW	99,771	0	99,771	85,007	99,771	99,771

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NORMALIZED VOLUME FORECAST TABLE

NORMALIZED VOLUME FORECAST	2006 Board Approved	2006 Board Approved	2006 Actual	2006 Actual	Variance from 2006 Board Approved	2006 Actual	2006 Actual	2007 Actual	2007 Actual	Variance from 2006 Actual	2007 Bridge	2007 Bridge	2008 Test	2008 Test	Variance from 2007 Actual
	(kWh)	(kW)	(kWh)	(kW)		(kWh)	(kW)	(kWh)	(kW)		(kWh)	(kW)	(kWh)	(kW)	
(Volumetric + Monthly Service Charge)															
Rate Classes															
Residential	117,010,418		116,128,274		882,144	116,128,274	0	121,956,927		-5,828,653	121,956,927		123,176,496		-1,219,569
GS<50	42,147,488		36,565,918		5,581,570	36,565,918	0	40,060,310		-3,494,392	40,060,310		40,460,913		-400,603
GS>50 to 999	102,344,447	298,327	75,156,430	206,825	91,502	75,156,430	206,825	84,442,069	352,005	-145,180	84,442,069	352,005	86,277,766	359,657	-7,652
GS>1000 to 2999	53,797,056	113,648	65,158,720	135,587	-21,939	65,158,720	135,587	69,529,869	135,587	0	69,529,869	135,587	69,529,869	135,587	0
GS>3000 to 4999	17,703,447	43,930	16,315,706	35,687	8,243	16,315,706	35,687	17,528,668	35,687	0	17,528,668	35,687	17,528,668	35,687	0
Large Use	69,925,689	132,542	91,950,056	165,609	-33,067	91,950,056	165,609	84,605,665	165,609	0	84,605,665	165,609	84,605,665	165,609	0
Street Lighting	3,077,398	8,843	3,164,059	8,538	305	3,164,059	8,538	3,024,750	9,157	-619	3,024,750	9,157	3,115,492	9,432	-275
Sentinel Lighting	181,782	1,018	212,859	535	483	212,859	535	238,372	931	-396	238,372	931	238,372	931	0
Unmetered Scattered Load	448,854		602,137		-153,283	602,137		606,271		-4,134	606,271	0	606,271		0
Embedded Distributor								20,741,502	99,771	-99,771	20,741,502	99,771	20,741,502	99,771	0

VARIANCE ANALYSIS ON NORMALIZED VOLUME FORECAST

(The following are examples which need to reviewed and revised by the Applicant)

The purpose of the evidence contained in Schedules 1, 2 and 4, Tab 2, of Exhibit 3, is to provide the Board with a review of Erie Thames Powerlines actual and forecasted customers, consumption and revenues for the historical, bridge and test years. Test year revenues have been calculated using the approved RP-2005-0020 Rate Order, EB-2005-0361, EB-2006-0197, EB-2007-0524, EB-2007-0016, dated July, 12, 2007.

Exhibit 3, Tab 2, Schedule 3, provides a summary of the normalized throughput numbers from the schedules noted above.

Fiscal 2008 Test Year

Comparison to Fiscal 2007 Bridge Year

Due the use of 2004 weather normalized consumptions per customer the variance in consumption for 2007 Bridge Year to 2008 Test Year is attributable to the forecast change in customer growth.

2007 Bridge Year

Comparison to Fiscal 2006 Actual

Due the use of 2004 weather normalized consumptions per customer the variance in consumption for 2006 Actual to 2008 Bridge Year is attributable to the forecast change in customer growth.

CUSTOMER COUNT FORECAST TABLE

CUSTOMER COUNT FORECAST TABLE	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2006 Actual	2007 Actual	Variance from 2006 Actual	2007 Bridge	2008 Test	Variance from 2007 Actual
Residential	12,075	12,206	131	12,206	12328	122	12328	12451	123
GS<50	1,352	1,375	23	1,375	1375	0	1375	1388	14
GS>50 to 999 kW	113	135	22	135	138	3	138	141	3
GS>1000 to 2999 kW	8	8	0	8	8	0	8	8	0
GS>3000 kW to 4999 kW	1	1	0	1	1	0	1	1	0
Large Use	1	1	0	1	1	0	1	1	0
Unmetered Scattered Load	60	95	35	95	95	0	95	95	0
Sentinel Lighting	235	256	21	256	256	0	256	256	0
Street Lighting	2,870	2,870	0	2,870	2870	0	2870	2956	86
Embedded Distributor	0	0	0	-	2	2	2	2	0
	16,715	16,947	232	16,947	17074	127	17,074	17,300	226

VARIANCE ANALYSIS ON CUSTOMER COUNT FORECAST

The purpose of the evidence contained in Schedules 1, 2 and 4, Tab 2, of Exhibit 3, is to provide the Board with a review of Erie Thames Powerlines actual and forecasted customers, consumption and revenues for the historical, bridge and test years. Test year revenues have been calculated using the approved RP-2005-0020 Rate Order, EB-2005-0361, EB-2006-0197, EB-2007-0524, EB-2007-0016, dated July, 12, 2007.

Exhibit 3, Tab 2, Schedule 4, provides a summary of the normalized customer numbers from the schedules noted above.

Fiscal 2008 Test Year

Comparison to Fiscal 2007 Bridge Year

2008 increases are based on the forecasted number of connections based on our capital projects and historical customer growth for residential and GS<50 kW classes. For GS>50 to 999 kW we utilized our historical customer growth for that class of approximately 2%. We have projected no change for 2008 in the GS>1000 to 2999 kW, GS> 3000 to 4999 kW, Large Use, Unmetered Scattered Load, Sentinel Lighting and Embedded Distributor classes. For Street Lighting we have used a growth factor of 3% to mirror the residential growth of 1% in each of the past 3 years.

2007 Bridge Year

Comparison to Fiscal 2006 Actual

For all rate classes we have updated our customer numbers as of the end of June YTD and applied the resulting growth factor for the remainder of the year. No change was experienced or forecast for the GS>1000 to 2999 kW, GS> 3000 to 4999 kW, Large Use, Unmetered Scattered Load, Sentinel Lighting, Street Lighting and Embedded Distributor classes.

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OTHER DISTRIBUTION REVENUE

OTHER DISTRIBUTION REVENUE	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2006 Actual	2007 Actual	Variance from 2006 Actual	2007 Bridge	2008 Test	Variance from 2007 Actual
	($'s)	($'s)	($'s)	($'s)	($'s)				
Other Distribution Revenue									
Retail Services Revenues	$9,782	$13,712	$3,930	$13,712	$18,510	$4,798	$18,510	$19,065	$555
Service Transaction Requests (STR) Revenues	$5,119	$8,586	$3,467	$8,586	$10,599	$2,014	$10,599	$10,917	$318
Electric Services Incidental to Energy Sales			$0	$0		$0	$0		$0
Transmission Charges Revenue									
Transmission Services Revenue									
Interdepartmental Rents			$0	$0		$0	$0		$0
Rent from Electric Property	$72,471	$85,826	$13,355	$85,826	$85,826	$0	$85,826	$88,401	$2,575
Other Utility Operating Income	$45,149	$49,136	$3,987	$49,136	$62,342	$13,206	$62,342	$64,213	$1,870
Other Electric Revenues	$122,200	$90,250	-$31,950	$90,250	$89,393	-$857	$89,393	$92,075	$2,682
Late Payment Charges	$43,528	$84,570	$41,042	$84,570	$92,667	$8,098	$92,667	$95,447	$2,780
Sales of Water and Water Power			$0	$0		$0	$0		$0
Miscellaneous Service Revenues	$199,604	$62,910	-$136,694	$62,910	$153,634	$90,724	$153,634	$161,584	$7,950
Provision for Rate Refunds									
TOTAL	$497,853	$394,989	-$102,864	$394,989	$512,971	$117,983	$512,971	$531,702	$18,730

MATERIALITY ANALYSIS ON OTHER DISTRIBUTION REVENUE

For any rate base related variance exceeding the materiality threshold of 1%, a detailed explanation is required. Materiality of 1% of 2006 board approved distribution expenses of $5,486,846 is $54,868.

Variance Explanations

Revenue Account	2006 Actual	2007 Test	Variance
Miscellaneous Service Revenues	$62,910	$153,634	$90,724

Explanation: The change in specific service charges for 2006 EDR was approved in 2007 Resulting in higher revenue in 2007 than 2006 at old rates.

Variance Explanations

Revenue Account	2006 Approved	2006 Actual	Variance
Miscellaneous Service Revenues	$199,604	$62,910	-$136,694

Explanation: The change in specific service charges for 2006 EDR was approved in 2007 Resulting in higher revenue in 2007 than 2006 at old rates.

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RATE OF RETURN ON OTHER DISTRIBUTION ACTIVITIES

In this application Erie Thames Powerlines has applied for the same Specific Service Charges schedule previously approved in the 2007 Tariffs of Rates and Charges from RP-2005-0020, EB-2005-0361, EB-2006-0197, EB-2007-0524, and EB-2007-0016 Rate Order, dated July 12, 2007.

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DISTRIBUTION REVENUE DATA

2006 Board Approved

	Customers (Year-End)	Consumption (kWh / KW)	Distribution Revenues ($)	Unit Revenues $/kWh
Residential	12,075	117,010,418	$3,414,217	$0.0292
GS<50	1,352	42,147,488	$1,076,188	$0.0255
GS>50 to 999 kW	113	298,327	$993,110	$3.3289
GS>1000 to 2999 kW	8	113,648	$829,973	$7.3030
GS>3000 kW to 4999 kW	1	43,930	$157,792	$3.5919
Large Use	1	132,542	$279,379	$2.1079
Unmetered Scattered Load	60	448,854	$30,900	$0.0688
Sentinel Lighting	235	1,018	$15,519	$15.2505
Street Lighting	2,870	8,843	$20,495	$2.3175
Embedded Distributor	0	0	0	
TOTAL	16,715		$6,817,572	

2006 Actual

	Customers (Year-End)	Consumption (kWh / KW)	Distribution Revenues ($)	Unit Revenues $/kWh
Residential	12,206	116,128,274	$3,109,505.41	$0.0268
GS<50	1,375	36,565,918	$851,696.80	$0.0233
GS>50 to 999 kW	135	206,825	$797,155.84	$3.8543
GS>1000 to 2999 kW	8	135,587	$666,208.45	$4.9135
GS>3000 kW to 4999 kW	1	35,687	$107,961.17	$3.0252
Large Use	1	165,609	$170,604.81	$1.0302
Unmetered Scattered Load	95	602,137	$34,147.80	$0.0567
Sentinel Lighting	256	535	$5,248.76	$9.8108
Street Lighting	2,870	8,538	$22,608.69	$2.6480
Embedded Distributor	0	0	$0.00	
TOTAL	16,947		$5,765,137.73	

2006 Actual - Normalized

	Customers (Year-End)	Consumption (kWh / KW)	Distribution Revenues ($)	Normalized Consumption (kWh / KW)	Normalized Distribution Revenues ($)	Unit Revenues $/kWh
Residential	12,206	116,128,274	$3,109,505.41	120,749,432	$3,658,505.98	$0.0303
GS<50	1,375	36,565,918	$851,696.80	39,663,673	$1,089,902.32	$0.0275
GS>50 to 999 kW	135	206,825	$797,155.84	206,825	$797,155.84	$3.8543
GS>1000 to 2999 kW	8	135,587	$666,208.45	135,587	$666,208.45	$4.9135
GS>3000 kW to 4999 kW	1	35,687	$107,961.17	35,687	$107,961.17	$3.0252
Large Use	1	165,609	$170,604.81	165,609	$170,604.81	$1.0302
Unmetered Scattered Load	95	602,137	$34,147.80	606,271	$34,147.80	$0.0563
Sentinel Lighting	256	535	$5,248.76	605	$12,175.61	$20.1384
Street Lighting	2,870	2,870	$22,608.69	9,157	$34,131.07	$3.7273
Embedded Distributor	0	0	$0.00	0		
TOTAL	16,947		$5,765,137.73		$6,570,793.05	

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	2007 Bridge - Normalized					
	Customers	Consumption	Distribution Revenues	Normalized Consumption	Normalized Distribution Revenues	
	(Year-End)	(kWh / KW)	($)	(kWh / KW)	($)	
Residential	12,328	121,956,927	$3,674,484.46	121,956,927	$3,750,800.18	$0.0308
GS<50	1,375	40,060,310	$1,056,288.62	40,060,310	$1,113,744.49	$0.0278
GS>50 to 999 kW	138	352,005	$1,342,809.22	352,005	$1,358,057.92	$3.8581
GS>1000 to 2999 kW	8	135,587	$918,349.28	135,587	$914,533.22	$6.7450
GS>3000 kW to 4999 kW	1	35,687	$163,124.47	35,687	$173,142.09	$4.8517
Large Use	1	165,609	$390,869.61	165,609	$393,495.91	$2.3761
Unmetered Scattered Load	95	606,271	$26,108.53	606,271	$29,906.28	$0.0493
Sentinel Lighting	256	931	$12,432.18	931	$15,603.57	$16.7600
Street Lighting	2,870	9,157	$33,314.22	9,157	$34,551.65	$3.7732
Embedded Distributor			$0.00		$0.00	
TOTAL	17,072		$7,617,780.59		$7,783,835.32	

	2008 Test - Normalized			
	Customers	Consumption	Distribution Revenues	Unit Revenues
	(Year-End)	(kWh / KW)	($)	$/kWh
Residential	12,451	123,176,496	$4,051,170.36	$0.032889
GS<50	1,388	40,460,913	$775,919.34	$0.019152
GS>50 to 999 kW	141	359,657	$1,052,149.85	$2.925426
GS>1000 to 2999 kW	8	135,587	$621,506.91	$4.583824
GS>3000 kW to 4999 kW	1	35,687	$119,653.04	$3.352847
Large Use	1	165,609	$466,190.21	$2.815005
Unmetered Scattered Load	95	606,271	$11,660.62	$0.019233
Sentinel Lighting	256	931	$30,646.37	$32.917685
Street Lighting	2,956	9,432	$283,600.31	$30.067887
Embedded Distributor	2	99,771	$218,771.36	$2.192735
TOTAL	17,300		$7,631,268.37	

DESCRIPTION OF REVENUE SHARING

Erie Thames Powerlines does not participate in revenue sharing.

4 - Operating Costs

OVERVIEW OF OPERATING COSTS

Operating Costs

The operating costs presented in this exhibit represent the annual expenditures required to sustain Distribution Operations. The information presented in this exhibit is grouped into two different categories: Operation & Maintenance and Other Costs which include items such as Administration & General, Sales Promotion & Customer Accounting, Depreciation, Amortization and Depletion, Shared Services 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.

The proposed OM&A cost expenditures for the 2008 test year result from a rigorous business planning and work prioritization process that reflects risk-based decision making to ensure that the most appropriate, cost effective solutions are put in place.

OM&A expenditures totaled $32,267,172 for 2006 Board Approved, $36,696,822 for 2006 Actual results and are forecast to be $37,236,016 in 2007 and $38,254,648 in 2008.

Income Tax, Large Corporation Tax and Ontario Capital Taxes

This information consists of detailed calculations of income taxes, and indemnity payments to the Province. Details of the expenditures are filed at Exhibit 4, Tab 3 Schedule 1.

The Income Taxes, Large Corporation Taxes and Ontario Capital Taxes expenditures totaled $452,787 in 2006 Board Approved, $122,234 in 2006 Actual and are forecast to be $781,100 in 2007 and $302,852 in 2008.

SUMMARY OF OPERATING COSTS TABLE

SUMMARY OF OPERATING COSTS		2006 Board Approved	2006 Actual	2007 Bridge	2008 Test
OM&A expenses					
Operation (Working Capital)		$13,887.00	$71,733.00	$52,845.00	$53,150.00
Maintenance (Working Capital)		$1,093,343.00	$1,266,426.00	$1,095,636.00	$1,113,402.00
Billing and Collections		$867,185.00	$963,228.00	$1,054,982.00	$1,073,487.00
Community Relations		$33,218.00	$36,709.00	$28,879.00	$28,879.00
Administrative and General Expenses		$2,097,378.00	$1,867,295.00	$1,747,954.00	$1,792,285.00
Amortization Expenses		$970,610.00	$1,023,655.00	$890,252.00	$935,609.00
Cost of Power		$26,490,207.00	$31,378,239.00	$31,535,716.57	$32,919,565.66
Other Operating Costs		$0.00	$0.00	$0.00	$0.00
LCT,OCT and Income Taxes		$701,344.00	$89,537.00	$829,751.59	$338,270.08
Total Operating Costs		**$32,267,172.00**	**$36,696,822.00**	**$37,236,016.15**	**$38,254,647.74**

OM&A COSTS TABLE

OM&A COSTS	2006 Board Approved	2006 Actual	Variance form 2006 Board Approved		2006 Actual	2007 Bridge	Variance form 2006 Actual		2007 Bridge	2008 Test	Variance form 2007 Bridge
Operation (Working Capital)											
5005-Operation Supervision and Engineering	$18,334.00	$21,164.00	$2,830.00		$21,164.00	$22,981.00	$1,817.00		$22,981.00	$20,259.00	-$2,722.00
5010-Load Dispatching			$0.00		$0.00		$0.00		$0.00		$0.00
5012-Station Buildings and Fixtures Expense	$8,963.00	$45,986.00	$37,023.00		$45,986.00	$16,746.00	-$29,240.00		$16,746.00	$12,949.00	-$3,797.00
5014-Transformer Station Equipment - Operation Labour			$0.00		$0.00		$0.00		$0.00		$0.00
5015-Transformer Station Equipment - Operation Supplies and Expenses			$0.00		$0.00		$0.00		$0.00		$0.00
5016-Distribution Station Equipment - Operation Labour			$0.00		$0.00		$0.00		$0.00		$0.00
5017-Distribution Station Equipment - Operation Supplies and Expenses			$0.00		$0.00		$0.00		$0.00		$0.00
5020-Overhead Distribution Lines and Feeders - Operation Labour			$0.00		$0.00		$0.00		$0.00		$0.00
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$998.00	$3,364.00	$2,366.00		$3,364.00	$329.00	-$3,035.00		$329.00	$329.00	$0.00
5030-Overhead Subtransmission Feeders - Operation			$0.00		$0.00		$0.00		$0.00		$0.00
5035-Overhead Distribution Transformers- Operation			$0.00		$0.00		$0.00		$0.00		$0.00
5040-Underground Distribution Lines and Feeders - Operation Labour			$0.00		$0.00		$0.00		$0.00		$0.00
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses			$0.00		$0.00		$0.00		$0.00		$0.00
5050-Underground Subtransmission Feeders - Operation			$0.00		$0.00		$0.00		$0.00		$0.00
5055-Underground Distribution Transformers - Operation			$0.00		$0.00		$0.00		$0.00		$0.00
5060-Street Lighting and Signal System Expense			$0.00		$0.00		$0.00		$0.00		$0.00
5065-Meter Expense	-$14,942.00		$14,942.00		$0.00	$0.00	$0.00		$0.00		$0.00
5070-Customer Premises - Operation Labour			$0.00		$0.00		$0.00		$0.00		$0.00
5075-Customer Premises - Materials and Expenses			$0.00		$0.00		$0.00		$0.00		$0.00
5085-Miscellaneous Distribution Expense			$0.00		$0.00		$0.00		$0.00		$0.00
5090-Underground Distribution Lines and Feeders - Rental Paid			$0.00		$0.00		$0.00		$0.00		$0.00
5095-Overhead Distribution Lines and Feeders - Rental Paid			$0.00		$0.00		$0.00		$0.00		$0.00
5096-Other Rent	$534.00	$1,219.00	$685.00		$1,219.00	$1,626.00	$407.00		$1,626.00	$1,219.00	-$407.00
Sub-Total	$13,887.00	$71,733.00	$57,846.00		$71,733.00	$41,682.00	-$30,051.00		$41,682.00	$34,756.00	-$6,926.00

ERIE THAMES POWERLINES CORPORATION

Maintenance (Working Capital)												
5105-Maintenance Supervision and Engineering			$0.00		$0.00		$0.00		$0.00		$0.00
5110-Maintenance of Buildings and Fixtures - Distribution Stations	$241,231.00	$317,453.00	$76,222.00		$317,453.00	$386,318.00	$68,865.00		$386,318.00	$390,088.00	$3,770.00
5112-Maintenance of Transformer Station Equipment	$15,530.00	$5,548.00	-$9,982.00		$5,548.00	$51,645.00	$46,097.00		$51,645.00	$51,667.00	$22.00
5114-Maintenance of Distribution Station Equipment			$0.00		$0.00		$0.00		$0.00		$0.00
5120-Maintenance of Poles, Towers and Fixtures	$89,705.00	$104,168.00	$14,463.00		$104,168.00	$198,336.00	$94,168.00		$198,336.00	$199,567.00	$1,231.00
5125-Maintenance of Overhead Conductors and Devices	$82,514.00	$71,300.00	-$11,214.00		$71,300.00	$68,117.00	-$3,183.00		$68,117.00	$69,602.00	$1,485.00
5130-Maintenance of Overhead Services	$172,071.00	$186,769.00	$14,698.00		$186,769.00	$177,498.00	-$9,271.00		$177,498.00	$180,674.00	$3,176.00
5135-Overhead Distribution Lines and Feeders - Right of Way	$115,748.00	$109,372.00	-$6,376.00		$109,372.00	$116,085.00	$6,713.00		$116,085.00	$118,292.00	$2,207.00
5145-Maintenance of Underground Conduit			$0.00		$0.00		$0.00		$0.00		$0.00
5150-Maintenance of Underground Conductors and Devices	$37,709.00	$55,142.00	$17,433.00		$55,142.00	$76,980.00	$21,838.00		$76,980.00	$77,680.00	$700.00
5155-Maintenance of Underground Services	$70,804.00	$96,348.00	$25,544.00		$96,348.00	$72,859.00	-$23,489.00		$72,859.00	$74,175.00	$1,316.00
5160-Maintenance of Line Transformers	$77,210.00	$92,723.00	$15,513.00		$92,723.00	$121,418.00	$28,695.00		$121,418.00	$122,337.00	$919.00
5165-Maintenance of Street Lighting and Signal Systems			$0.00		$0.00		$0.00		$0.00		$0.00
5170-Sentinel Lights - Labour			$0.00		$0.00		$0.00		$0.00		$0.00
5172-Sentinel Lights - Materials and Expenses			$0.00		$0.00		$0.00		$0.00		$0.00
5175-Maintenance of Meters	$190,821.00	$227,602.00	$36,781.00		$227,602.00	$174,876.00	-$52,726.00		$174,876.00	$177,815.00	$2,939.00
5178-Customer Installations Expenses- Leased Property			$0.00		$0.00		$0.00		$0.00		$0.00
5185-Water Heater Rentals - Labour			$0.00		$0.00		$0.00		$0.00		$0.00
5186-Water Heater Rentals - Materials and Expenses			$0.00		$0.00		$0.00		$0.00		$0.00
5190-Water Heater Controls - Labour			$0.00		$0.00		$0.00		$0.00		$0.00
5192-Water Heater Controls - Materials and Expenses			$0.00		$0.00		$0.00		$0.00		$0.00
5195-Maintenance of Other Installations on Customer Premises			$0.00		$0.00		$0.00		$0.00		$0.00
Sub-Total	$1,093,343.00	$1,266,425.00	$173,082.00		$1,266,425.00	$1,444,132.00	$177,707.00		$1,444,132.00	$1,461,897.00	$17,765.00

ERIE THAMES POWERLINES
CORPORATION

Billing and Collections											
5305-Supervision			$0.00		$0.00		$0.00		$0.00		$0.00
5310-Meter Reading Expense			$0.00		$0.00		$0.00		$0.00		$0.00
5315-Customer Billing	$871,337.00	$898,286.00	$26,949.00		$898,286.00	$925,235.00	$26,949.00		$925,235.00	$943,739.00	$18,504.00
5320-Collecting			$0.00		$0.00		$0.00		$0.00		$0.00
5325-Collecting- Cash Over and Short	-$8,530.00		$8,530.00		$0.00		$0.00		$0.00		$0.00
5330-Collection Charges	$4,378.00	$3,215.00	-$1,163.00		$3,215.00	$10,669.00	$7,454.00		$10,669.00	$10,669.00	$0.00
5335-Bad Debt Expense		$61,727.00	$61,727.00		$61,727.00	$119,078.00	$57,351.00		$119,078.00	$119,078.00	$0.00
5340-Miscellaneous Customer Accounts Expenses			$0.00		$0.00		$0.00		$0.00		$0.00
Sub-Total	$867,185.00	$963,228.00	$96,043.00		$963,228.00	$1,054,982.00	$91,754.00		$1,054,982.00	$1,073,486.00	$18,504.00
Community Relations											
5405-Supervision	$30,162.00	$33,282.00	$3,120.00		$33,282.00	$27,879.00	-$5,403.00		$27,879.00	$27,879.00	$0.00
5410-Community Relations - Sundry			$0.00		$0.00		$0.00		$0.00		$0.00
5415-Energy Conservation			$0.00		$0.00		$0.00		$0.00		$0.00
5420-Community Safety Program			$0.00		$0.00		$0.00		$0.00		$0.00
5425-Miscellaneous Customer Service and Informational Expenses			$0.00		$0.00		$0.00		$0.00		$0.00
5505-Supervision			$0.00		$0.00		$0.00		$0.00		$0.00
5510-Demonstrating and Selling Expense			$0.00		$0.00		$0.00		$0.00		$0.00
5515-Advertising Expense	$3,056.00	$3,427.00	$371.00		$3,427.00	$1,000.00	-$2,427.00		$1,000.00	$1,000.00	$0.00
5520-Miscellaneous Sales Expense			$0.00		$0.00		$0.00		$0.00		$0.00
Sub-Total	$33,218.00	$36,709.00	$3,491.00		$36,709.00	$28,879.00	-$7,830.00		$28,879.00	$28,879.00	$0.00

Administrative and General Expenses											
5605-Executive Salaries and Expenses	$553,796.00	$125,123.00	-$428,673.00		$125,123.00	$119,348.00	-$5,775.00		$119,348.00	$119,348.00	$0.00
5610-Management Salaries and Expenses	$398,996.00	$515,310.00	$116,314.00		$515,310.00	$518,045.00	$2,735.00		$518,045.00	$691,640.00	$173,595.00
5615-General Administrative Salaries and Expenses	$500,193.00	$442,176.00	-$58,017.00		$442,176.00	$455,441.00	$13,265.00		$455,441.00	$464,550.00	$9,109.00
5620-Office Supplies and Expenses	$57,604.00	$133,264.00	$75,660.00		$133,264.00	$109,949.00	-$23,315.00		$109,949.00	$110,848.00	$899.00
5625-Administrative Expense Transferred Credit			$0.00		$0.00		$0.00		$0.00		$0.00
5630-Outside Services Employed	$173,753.00	$247,341.00	$73,588.00		$247,341.00	$280,000.00	$32,659.00		$280,000.00	$178,000.00	-$102,000.00
5635-Property Insurance	$10,132.00	$51,204.00	$41,072.00		$51,204.00	$52,740.00	$1,536.00		$52,740.00	$51,685.00	-$1,055.00
5640-Injuries and Damages			$0.00		$0.00		$0.00		$0.00		$0.00
5645-Employee Pensions and Benefits	-$41.00	-$313.00	-$272.00		-$313.00	-$208.00	$105.00		-$208.00	-$208.00	$0.00
5650-Franchise Requirements			$0.00		$0.00		$0.00		$0.00		$0.00
5655-Regulatory Expenses	$105,793.00	$132,940.00	$27,147.00		$132,940.00	$40,000.00	-$92,940.00		$40,000.00	$40,000.00	$0.00
5660-General Advertising Expenses			$0.00		$0.00		$0.00		$0.00		$0.00
5665-Miscellaneous General Expenses	$49,718.00	$89,993.00	$40,275.00		$89,993.00	$65,687.00	-$24,306.00		$65,687.00	$65,687.00	$0.00
5670-Rent	$247,433.00	$130,258.00	-$117,175.00		$130,258.00	$144,089.00	$13,831.00		$144,089.00	$108,190.00	-$35,899.00
5675-Maintenance of General Plant			$0.00		$0.00		$0.00		$0.00		$0.00
5680-Electrical Safety Authority Fees			$0.00		$0.00		$0.00		$0.00		$0.00
5685-Independent Market Operator Fees and Penalties			$0.00		$0.00		$0.00		$0.00		$0.00
Sub-Total	$2,097,377.00	$1,867,296.00	-$230,081.00		$1,867,296.00	$1,785,091.00	-$82,205.00		$1,785,091.00	$1,829,740.00	$44,649.00

ERIE THAMES POWERLINES
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Amortization Expenses											
5705-Amortization Expense - Property, Plant, and Equipment	$684,788.00	$847,309.00	$162,521.00		$847,309.00	$890,252.00	$42,943.00		$890,252.00	$935,609.00	$45,357.00
5710-Amortization of Limited Term Electric Plant	$285,822.00	$176,346.00	-$109,476.00		$176,346.00	$0.00	-$176,346.00		$0.00		$0.00
5715-Amortization of Intangibles and Other Electric Plant			$0.00		$0.00		$0.00		$0.00		$0.00
5720-Amortization of Electric Plant Acquisition Adjustments			$0.00		$0.00		$0.00		$0.00		$0.00
5725-Miscellaneous Amortization			$0.00		$0.00		$0.00		$0.00		$0.00
5730-Amortization of Unrecovered Plant and Regulatory Study Costs			$0.00		$0.00		$0.00		$0.00		$0.00
5735-Amortization of Deferred Development Costs			$0.00		$0.00		$0.00		$0.00		$0.00
5740-Amortization of Deferred Charges			$0.00		$0.00		$0.00		$0.00		$0.00
Sub-Total	$970,610.00	$1,023,655.00	$53,045.00		$1,023,655.00	$890,252.00	-$133,403.00		$890,252.00	$935,609.00	$45,357.00
Cost of Power											
4705-Power Purchased	$19,673,754.00	$24,121,034.00	$4,447,280.00		$24,121,034.00	$25,162,639.56	$1,041,605.56		$25,162,639.56	$25,455,869.03	$293,229.48
4708-Charges-WMS	$2,679,726.00	$2,797,033.00	$117,307.00		$2,797,033.00	$2,735,069.52	-$61,963.48		$2,735,069.52	$2,766,942.29	$31,872.77
4710-Cost of Power Adjustments			$0.00		$0.00		$0.00		$0.00		$0.00
4712-Charges-One-Time	$9,598.00	$31.00	-$9,567.00		$31.00	$0.00	-$31.00		$0.00		$0.00
4714-Charges-NW	$2,169,467.00	$2,343,440.00	$173,973.00		$2,343,440.00	$1,892,051.17	-$451,388.83		$1,892,051.17	$2,463,321.37	$571,270.20
4716-Charges-CN	$1,957,662.00	$2,116,701.00	$159,039.00		$2,116,701.00	$1,745,956.32	-$370,744.68		$1,745,956.32	$2,233,432.97	$487,476.65
4730-Rural Rate Assistance Expense			$0.00		$0.00		$0.00		$0.00		$0.00
5685-Independent Market Operator Fees and Penalties			$0.00		$0.00		$0.00		$0.00		$0.00
Sub-Total	$26,490,207.00	$31,378,239.00	$4,888,032.00		$31,378,239.00	$31,535,716.57	$157,477.57		$31,535,716.57	$32,919,565.66	$1,383,849.09

VARIANCE ANALYSIS ON OM&A COSTS

A summary of operating and maintenance costs is presented in Exhibit 4, Tab 1, Schedule 2.

2008 Test year

The 2008 test year Operating & Maintenance forecast is shown in Exhibit 4, Tab 2, Schedule 1. The total net cost is expected to be $38,283,933. Administration and General costs represent 4.78% of the total cost. Billing and Collection costs accounts for 2.80% of the total Operating Costs. Finally Cost of Power accounts for 85.99% of the total Operating Costs

Comparison to Fiscal 2007 Bridge Year

Exhibit 4, Tab 2, Schedule 1, provides a comparison of the 2008 test year forecast of Operation & Maintenance expenses to that forecast for the 2007 bridge year. Total net Operation & Maintenance costs are forecast to increase $73,992 or 1.69%. The resulting cost per customer increases $0.94 or 0.37%.

2007 Bridge Year

The 2008 test year Operating & Maintenance forecast is shown in Exhibit 4, Tab 2, Schedule 1. The total net cost is expected to be $37,363,028. Administration and General costs represent 4.78% of the total cost. Billing and Collection costs accounts for 2.82% of the total Operating Costs. Finally Cost of Power accounts for 85.96% of the total Operating Costs

Comparison to Fiscal 2006 Actual

Exhibit 4, Tab 2, Schedule 1, provides a comparison of the 2008 test year forecast of Operation & Maintenance expenses to that forecast for the 2007 bridge year. Total net Operation & Maintenance costs are forecast to increase $149,375 or 3.55%. The resulting cost per customer increases $6.90 or 2.78%.

2006 Actual

The 2008 test year Operating & Maintenance forecast is shown in Exhibit 4, Tab 2, Schedule 1. The total net cost is expected to be $36,607,285. Administration and General costs represent 5.10% of the total cost. Billing and Collection costs accounts for 2.63% of the total Operating Costs. Finally Cost of Power accounts for 85.72% of the total Operating Costs

Comparison to Fiscal 2006 Approved

Exhibit 4, Tab 2, Schedule 1, provides a comparison of the 2008 test year forecast of Operation & Maintenance expenses to that forecast for the 2007 bridge year. Total net Operation & Maintenance costs are forecast to increase $100,381 or 2.45%. The resulting cost per customer increases $2.57 or 1.05%.

MATERIALITY ANALYSIS ON OM&A COSTS

For any variance exceeding the materiality threshold of 1%, a detailed explanation is required. Materiality of 1% of 2006 board approved distribution expenses of $5,486,846 is $54,868.

2006 Board Approved to 2006 Actual

Asset Account	Year 1	Year 2	Variance
5110-Maintenance of Buildings and Fixtures Distribution Stations	$241,231	$317,453	$76,222

Explanation: Allocation of expenditures is being completed by work order results from 2006 on.

Asset Account	Year 1	Year 2	Variance
5340-Miscellaneous Customer Accounts Expenses	$0	$61,727	$61,727

Explanation: New account not utilized in 2004 financial results.

Asset Account	Year 1	Year 2	Variance
5610 Management Salaries and Expenses	$398,996	$515,310	$116,314

Explanation: Corporate overhead charges were reallocated between 5610 and 5605
Account 5605 shows an offsetting reduction in costs.

Asset Account	Year 1	Year 2	Variance
5620-Office Supplies and Expenses	$57,604	$113,264	$55,660

Explanation: Increase is related to several projects in 2006 and more accurate posting of invoices.

Asset Account	Year 1	Year 2	Variance
5705-Amortization Expense-Property Plant and Equipment	$684,788	$847,309	$162,521

Explanation: this change represents two years worth of amortization costs
2006 Approved is based on 2004 actual.

Asset Account	Year 1	Year 2	Variance
4705-Power Purchased	$19,673,754	$24,121,034	$4,447,280

Explanation: 2006 was a higher consumption year than 2004 and is beyond ETPL's control.

Asset Account	Year 1	Year 2	Variance
4708-Charges WMS	$2,679,726	$2,797,033	$117,307

Explanation: 2006 was a higher consumption year than 2004 and is beyond ETPL's control.

Asset Account	Year 1	Year 2	Variance
4714-Charges NW	$2,169,467	$2,343,440	$173,973

Explanation: 2006 was a higher consumption year than 2004 and is beyond ETPL's control.

Asset Account	Year 1	Year 2	Variance
4716-Charges CN	$1,957,662	$2,116,701	$159,039

Explanation: 2006 was a higher consumption year than 2004 and is beyond ETPL's control.

2006 Actual to 2007 Bridge

Asset Account	Year 1	Year 2	Variance
5110-Maintenance of Buildings and Fixtures Distribution Stations	$317,453	$386,318	$68,865

Explanation: Allocation of expenditures is being completed by work order results from 2006 on.

Asset Account	Year 1	Year 2	Variance
5120-Maintenance of Poles towers and Fixtures	$104,168	$198,336	$94,168

Explanation: Allocation of expenditures is being completed by work order results from 2006 on.

Asset Account	Year 1	Year 2	Variance
4705-Power Purchased	$24,121,034	$25,253,570	$1,132,536

Explanation: 2007 Bridge year amount calculated using normalized consumption which are higher than 2006

2007 Bridge to 2008 Test

Asset Account	Year 1	Year 2	Variance
5610-Management Salaries and Expenses	$518,045	$691,640	$173,595

Explanation: Addition of Corporate Lawyer and Finance Personel, outside services are reduced to offset.

Asset Account	Year 1	Year 2	Variance
4705-Power Purchased	$25,253,570	$25,455,869	$202,299

Explanation: 2008 Test year amount calculated using normalized consumption which are higher than 2007

Asset Account	Year 1	Year 2	Variance
4714-Charges NW	$2,149,959	$2,463,321	$313,362

Explanation: 2008 Test year amount calculated using normalized consumption which are higher than 2007

Asset Account	Year 1	Year 2	Variance
4716-Charges CN	$1,969,527	$2,233,433	$263,906

Explanation: 2008 Test year amount calculated using normalized consumption which are higher than 2007

SHARED SERVICES

A summary of shared services for actual fiscal 2006, along with the projections for the 2007 bridge year and 2008 test year are shown in the following table.

Erie Thames Services Corporation

	2006 Actual	2007 Bridge	2008 Test
Captial Expenditures			
Cost allocator	Quoted & estimated projects	Quoted & estimated projects	Quoted & estimated projects
Explanation	ETPL identifies and costs each project and then determines service provider		
Total Annual Expense	$1,856,500	$1,625,333	$1,623,000
OM&A			
Cost Allocator	Fixed Price per Customer	Fixed Price per Customer	Fixed Price per Customer
Explanation	As per ETPL's MSA OM&A expenditures are charged on a fixed price for identified services based on number of customers. Any other services outside these services are billed on a time and materials basis as per the Master Services Agreement. These costs remain relatively unchanged and represent a 2% reduction in per customer costs.		
Total Annual Expense	$2,979,797	$3,030,390	$2,974,753

Erie Thames Power Corporation

	2006 Actual	2007 Bridge	2008 Test
Executive Services			
Cost allocator	Actual Costs/Revenue/Assets	Actual Costs/Revenue/Assets	Actual Costs/Revenue/Assets
Explanation	ETPL is billed for use of its parent company's executive team based on their utilization For expenses not tracked by time, costs are allocated by revenue and assets.		
Total Annual Expense	$503,629	$703,914	$878,453
Building Rent			
Cost Allocator	Market Based Pricing	Market Based Pricing	Market Based Pricing
Explanation	ETPL pays a market based price for each square foot of space it uses. For 2006 some executive services were allocated to rent in error and in 2008 more office space is being utilized by other affiliates thereby decreasing the costs to ETPL.		
Total Annual Expense	$219,536	$144,089	$108,190

RDI Consulting Inc.

	2006 Actual	2007 Bridge	2008 Test
Consulting Services			
Cost allocator	Market Based Pricing	Market Based Pricing	Market Based Pricing
Explanation	Erie Thames Power Corp. aquired RDI in July of 2006. RDI continues to bill ETPL for services rendered as it would any other client and as it had prior to acquisition.		
Total Annual Expense	$35,406	$70,812	$72,228

Utilismart Corporation

	2006 Actual	2007 Bridge	2008 Test
Settlement Services			
Cost allocator	Market Based Pricing	Market Based Pricing	Market Based Pricing
Explanation	Erie Thames Power Corp. aquired 2/3rds of Utilismart in July of 2006. ETPL had an agreement in place with Utilismart for its settlement services that continues on into 2009. This agreement is was in place prior to negotiations of the purchase and is based on pricing similar to Utilismart's other LDC customers.		
Total Annual Expense	$57,600	$115,200	$117,504

CORPORATE COST ALLOCATION

The Shared Services and other Administrative costs includes the provision of Common Corporate Functions and Services and Asset Management programs to support the Distribution business, such as Executive oversight and Director remuneration as well as infrastructure costs including, facilities. These costs are allocated as per Erie Thames Power Corporation in Exhibit 4, Tab 2, Schedule 4 above.

PURCHASE OF SERVICES

Erie Thames Powerlines Purchase of Services			
Affiliate Transactions from Erie Thames Services 2006 to 2008			
	2006	2007	2008
Capital Expenditures	$1,856,500	$1,625,333	$1,623,000
OM&A	$2,979,797	$3,030,390	$2,974,753
	$4,836,297	*$4,655,723*	*$4,597,753*
Affiliate Transactions from Erie Thames Power 2006 to 2008			
	2006	2007	2008
Executive Services	$503,629	$703,914	$878,453
Building Rent	$219,536	$144,089	$108,190
	$723,165	*$848,003*	*$986,643*
Affiliate Transactions from RDI Consulting 2006 to 2008			
	2006	2007	2008
Consulting Services	$35,406	$70,812	$72,228
	$35,406	*$70,812*	*$72,228*
Affiliate Transactions from Utilismart Corporation 2006 to 2008			
	2006	2007	2008
Settlement	$57,600	$115,200	$117,504
	$57,600	*$115,200*	*$117,504*
Total Affiliate Expenses	$5,652,468	$5,689,738	$5,774,128

EMPLOYEE DESCRIPTION

Number of employees (Full-time equivalents (FTE's):

	2006 Board Approved	2006 Actual	2007 Bridge	2008 Test
Executive	1	1	1	1
Management				
Non-Unionized	1	1	1	1
Unionized				

ERIE THAMES POWERLINES
CORPORATION

DEPRECIATION, AMORTIZATION AND DEPLETION

DEPRECIATION, AMORTIZATION AND DEPLETION	2006 Board Approved ($'s)	Depreciation Rate	Depreciation	2006 Actual ($'s)	Rate %	Depreciation ($'s)	2007 Bridge ($'s)	Rate %	Depreciation ($'s)	2008 Test ($'s)	Rate %	Depreciation ($'s)
Land and Buildings	$264,641.00	2.00%	-$18,613.00	$269,033.00	2.00%	-$27,708.00	$302,033.00	2.00%	-$30,485.00	$302,033.00	2.00%	-$33,592.00
TS Primary Above 50	$0.00		$0.00	$0.00			$0.00			$0.00		
DS	$161,425.00	3.30%	-$27,526.00	$203,529.00	3.30%	-$41,875.00	$243,529.00	3.30%	-$49,319.00	$283,529.00	3.30%	-$58,094.00
Poles and Wires	$10,952,414.00	4.00%	-$1,487,225.00	$12,934,611.00	4.00%	-$2,425,306.00	$14,024,181.00	4.00%	-$2,964,482.00	$14,958,181.00	4.00%	-$3,544,129.00
Line Transformers	$2,990,261.00	4.00%	-$412,808.00	$3,566,527.00	4.00%	-$670,096.00	$3,797,056.00	4.00%	-$817,367.00	$4,259,056.00	4.00%	-$978,490.00
Services and Meters	$2,828,751.00	4.00%	-$434,534.00	$3,637,566.00	4.00%	-$705,364.00	$3,809,799.00	4.00%	-$854,311.00	$3,996,799.00	4.00%	-$1,010,433.00
General Plant	$0.00	4.00%	$0.00	$0.00	4.00%	$0.00	$0.00	4.00%	$0.00	$0.00	4.00%	$0.00
IT Assets	$205,743.00	20.00%	-$40,572.00	$317,526.00	20.00%	-$149,067.00	$377,526.00	20.00%	-$218,571.00	$377,526.00	20.00%	-$294,076.00
Equipment	$22,958.00	10.00%	-$10,662.00	$104,519.00	10.00%	-$17,523.00	$104,519.00	10.00%	-$29,951.00	$104,519.00	10.00%	-$41,287.00
Other Distribution Assets	-$118,837.00	4.00%	$2,377.00	-$621,263.00	4.00%	$28,710.00	-$1,296,263.00	4.00%	$67,060.00	-$1,796,263.00	4.00%	$128,911.00
GROSS ASSET TOTAL	**$17,307,356.00**		**-$2,429,563.00**	**$20,412,048.00**		**-$4,008,229.00**	**$21,362,380.00**		**-$4,897,426.00**	**$22,485,380.00**		**-$5,831,190.00**

LOSS ADJUSTMENT FACTOR CALCULATION

	LOSS ADJUSTMENT FACTOR CALCULATION						
		2002	**2003**	**2004**	**2005**	**2006**	**Total**
A	"Wholesale" kWh (IESO)	372,508,926	390,082,254	414,178,296	449,150,417	450,865,003	**2,076,784,896**
B	Wholesale kWh for Large Use customer(s) (IESO)	-	-	-	-	-	-
C	Net "Wholesale" kWh (A)-(B)	372,508,926	390,082,254	414,178,296	449,150,417	450,865,003	**2,076,784,896**
D	Retail kWh (Distributor)	359,173,975	375,518,978	393,683,695	435,533,295	426,203,076	**1,990,113,019**
E	Retail kWh for Large Use Customer(s) (1% loss)	-					-
F	Net "Retail" kWh (D)-(E)	359,173,975	375,518,978	393,683,695	435,533,295	426,203,076	**1,990,113,019**
G	Loss Factor [(C)/(F)]	1.037126718	1.038781731	1.052058547	1.031265398	1.057864264	**1.043551234**
H	Distribution Loss Adjustment Factor						
	Total Utility Loss Adjustment Factor	**LAF**					
	Supply Facility Loss Factor	1.0045					
	Distribution Loss Factors						
	Secondary Metered Customer						
	Total Loss Factor - Secondary Metered Customer < 5,000kW	1.0389					
	Total Loss Factor - Secondary Metered Customer > 5,000kW	1.0100					
	Primary Metered Customer						
	Total Loss Factor - Primary Metered Customer < 5,000kW	1.0285					
	Total Loss Factor - Primary Metered Customer > 5,000kW	1.0000					
	Total Loss Factor						
	Secondary Metered Customer						
	Total Loss Factor - Secondary Metered Customer < 5,000kW	1.0436					
	Total Loss Factor - Secondary Metered Customer > 5,000kW	1.0145					
	Primary Metered Customer						
	Total Loss Factor - Primary Metered Customer < 5,000kW	1.0331					
	Total Loss Factor - Primary Metered Customer > 5,000kW	1.0045					

MATERIALITY ANALYSIS ON DISTRIBUTION LOSSES

The resulting Loss Factor adjustment is less than 5%.

ERIE THAMES POWERLINES
CORPORATION

Exhibit: 4
Tab: 3
Schedule: 1
Page: 1

TAX CALCULATIONS

Summary of Income Tax Calculation

	2006 Board Approved	2006 Actual	2007 Bridge	2008 Test
Determination of Taxable Income				
Regulatory Net Income (before tax)	$870,241	$17,588	$2,033,460	$897,742
Book to Tax Adjustments				
Additions to Accounting Income:				
Depreciation and amortization	$975,330	$1,023,654	$890,252	$935,609
Meals & entertainment / Mileage		$1,354		
Other Additions		-$16,029	$792,352	$792,352
Total Additions	$975,330	$1,008,979	$1,682,604	$1,727,961
Deductions from Accounting Income:				
Capital Cost Allowance	$654,758	$709,668	$790,597	$826,372
Cumulative eligible capital deductions		$30,743	$28,591	$26,590
Gain on Disposal			$58,199	$58,199
Other Deductions		$14,501	$732,617	$732,617
Total Deductions	$654,758	$754,912	$1,610,004	$1,643,778
Regulatory Taxable Income	$1,190,813	$271,655	$2,106,060	$981,925
Corporate Income Tax Rate	36.12%	38.00%	36.12%	28.77%
Subtotal				
Less: R&D ITC (0.3)				
Regulatory Income Tax	$430,122	$103,229	$760,709	$282,461
Calculation of Utility Income Taxes				
Income Taxes (Line 23)	$430,122	$103,229	$760,709	$282,461
Ontario Capital Tax	$22,665	$19,005	$20,391	$20,391
Large Corporation Tax (Line 14, page 2)			$0	$0
Total Taxes	$452,787	$122,234	$781,100	$302,852

INTEREST EXPENSE

Interest Expense				
	2006 Board Approved	2006 Actual	2007 Bridge	2008 Test
Actual Interest Expense	$598,303.00	$598,303.00	$598,303.00	$598,303.00
Capitalized Interest	$0.00	$0.00	$0.00	$0.00
Actual Interest	$598,303.00	$598,303.00	$598,303.00	$598,303.00
Interest forecast Adjustments	$0.00	$0.00	$0.00	$0.00
Total Interest	$598,303.00	$598,303.00	$598,303.00	$598,303.00
Deemed Interest	$598,303.00	$598,303.00	$791,136.00	$792,683.00
Excess Interest	$0.00	$0.00	-$192,833.00	-$194,380.00

ERIE THAMES POWERLINES CORPORATION

CAPITAL COST ALLOWANCE

2006 Board Approved										
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	$14,682,301	$243,000		$14,925,301	$121,500	$14,803,801	4%	$592,152	$14,333,149
2	Distribution System - pre 1988	$0			$0		$0	6%	$0	$0
8	General Office/Stores Equip	$3,531			$3,531		$3,531	20%	$706	$2,825
10	Computer Hardware/ Vehicles	$8,012			$8,012		$8,012	30%	$2,404	$5,608
10.1	Certain Automobiles				$0		$0	30%	$0	$0
12	Computer Software	$59,496			$59,496		$59,496	100%	$59,496	$0
13 1	Lease # 1				$0		$0			$0
13 2	Lease #2				$0		$0			$0
13 3	Lease # 3				$0		$0			$0
13 4	Lease # 4				$0		$0			$0
14	Franchise				$0		$0			$0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				$0		$0			$0
43.1	Certain Energy-Efficient Electrical Generating Equipment				$0		$0			$0
45	Computers & Systems Software acq'd post Mar 22/04				$0		$0			$0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				$0		$0			$0
47	Distribution System - post 22-Feb-2005				$0		$0			$0
98	No CCA				$0		$0			$0
	TOTAL	$14,753,340	$243,000	$0	$14,996,340	$121,500	$14,874,840		$654,758	$14,341,582

2006 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	$15,310,017	$1,860,475		$17,170,492	$930,238	$16,240,255	4%	$649,610	$16,520,882
2	Distribution System - pre 1988				$0	$0	$0	6%	$0	$0
8	General Office/Stores Equip	$8,642	$11,820		$20,462	$5,910	$14,552	20%	$2,910	$17,551
10	Computer Hardware/ Vehicles	$5,608	$0		$5,608	$0	$5,608	30%	$1,682	$3,926
10.1	Certain Automobiles				$0	$0	$0	30%	$0	$0
12	Computer Software	$38,143	$32,677		$70,820	$16,339	$54,482	100%	$54,482	$16,339
13 1	Lease # 1				$0	$0	$0		$0	$0
13 2	Lease #2				$0	$0	$0		$0	$0
13 3	Lease # 3				$0	$0	$0		$0	$0
13 4	Lease # 4				$0	$0	$0		$0	$0
14	Franchise				$0	$0	$0		$0	$0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				$0	$0	$0		$0	$0
43.1	Certain Energy-Efficient Electrical Generating Equipment				$0	$0	$0		$0	$0
45	Computers & Systems Software acq'd post Mar 22/04	$2,187			$2,187	$0	$2,187	45%	$984	$1,203
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				$0	$0	$0		$0	$0
47	Distribution System - post 22-Feb-2005				$0	$0	$0		$0	$0
98	No CCA				$0	$0	$0		$0	$0
	TOTAL	$15,364,597	$1,904,972	$0	$17,269,569	$952,486	$16,317,083		$709,669	$16,559,899

2007 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	$16,520,882	$33,000		$16,553,882	$16,500	$16,537,382	4%	$661,495	$15,892,387
2	Distribution System - pre 1988	$0			$0	$0	$0	6%	$0	$0
8	General Office/Stores Equip	$17,551			$17,551	$0	$17,551	20%	$3,510	$14,041
10	Computer Hardware/ Vehicles	$3,926			$3,926	$0	$3,926	30%	$1,178	$2,748
10.1	Certain Automobiles				$0	$0	$0	30%	$0	$0
12	Computer Software	$16,339	$60,000		$76,339	$30,000	$46,339	100%	$46,339	$30,000
13 1	Lease # 1				$0	$0	$0		$0	$0
13 2	Lease #2				$0	$0	$0		$0	$0
13 3	Lease # 3				$0	$0	$0		$0	$0
13 4	Lease # 4				$0	$0	$0		$0	$0
14	Franchise				$0	$0	$0		$0	$0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				$0	$0	$0		$0	$0
43.1	Certain Energy-Efficient Electrical Generating Equipment				$0	$0	$0		$0	$0
45	Computers & Systems Software acq'd post Mar 22/04	$1,203			$1,203	$0	$1,203	45%	$541	$662
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				$0	$0	$0		$0	$0
47	Distribution System - post 22-Feb-2005	$0	$857,333		$857,333	$428,666	$428,666	8%	$34,293	$823,039
98	No CCA				$0	$0	$0			
	TOTAL	$16,559,901	$950,333	$0	$17,510,234	$475,166	$17,035,067		$747,357	$16,762,876

2008 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	$15,892,387			$15,892,387	$0	$15,892,387	4%	$635,695	$15,256,692
2	Distribution System - pre 1988	$0			$0	$0	$0	6%	$0	$0
8	General Office/Stores Equip	$14,041			$14,041	$0	$14,041	20%	$2,808	$11,233
10	Computer Hardware/ Vehicles	$2,748			$2,748	$0	$2,748	30%	$824	$1,924
10.1	Certain Automobiles				$0	$0	$0	30%	$0	$0
12	Computer Software	$30,000			$30,000	$0	$30,000	100%	$30,000	$0
13 1	Lease # 1				$0	$0	$0		$0	$0
13 2	Lease #2				$0	$0	$0		$0	$0
13 3	Lease # 3				$0	$0	$0		$0	$0
13 4	Lease # 4				$0	$0	$0		$0	$0
14	Franchise				$0	$0	$0		$0	$0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				$0	$0	$0		$0	$0
43.1	Certain Energy-Efficient Electrical Generating Equipment				$0	$0	$0		$0	$0
45	Computers & Systems Software acq'd post Mar 22/04	$662			$662	$0	$662	45%	$298	$364
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				$0	$0	$0		$0	$0
47	Distribution System - post 22-Feb-2005	$823,039	$1,123,000		$1,946,039	$561,499	$1,384,538	8%	$110,763	$1,835,275
98	No CCA				$0	$0	$0			
	TOTAL	$16,762,877	$1,123,000	$0	$17,885,877	$561,499	$17,324,376		$780,389	$17,105,487

5 – Deferral and Variance Accounts

DESCRIPTION OF DEFERRAL AND VARIANCE ACCOUNTS

COMMODITY ACCOUNTS ARE CLASSIFIED AS FOLLOWS:

1588 Retail Settlement Variance Account – Power

1588 RSVA Power, Sub-account Global Adjustments

NON-COMMODITY ACCOUNTS ARE CLASSIFIED IN TWO CATEGORIES AS FOLLOWS:

Wholesale and Retail Market Variance Accounts

1518 Retail Cost Variance Account – Retail

1548 Retail Cost Variance Account – STR

1580 Retail Settlement Variance Account - Wholesale Market Service Charges

1582 Retail Settlement Variance Account - One-time Wholesale Market Service

1584 Retail Settlement Variance Account - Retail Transmission Network Charges

1586 Retail Settlement Variance Account - Retail Transmission Connection Charges

1588 Retail Settlement Variance Account - Power

1588 Retail Settlement Variance Account - Power Sub-Account Global

Utility Deferral Accounts

1508 Other Regulatory Assets

1508 Other Regulatory Assets - Sub-account OEB Cost Assessments

1508 Other Regulatory Assets - Sub-account Pension Contributions

1525 Miscellaneous Deferred Debits

1555 Smart Meter Capital and Recovery Offset Variance

1565 Smart Meter OM&A Variance

1562 Deferred Payments in Lieu of Taxes

1563 PILs contra account

1565 Conservation and Demand Management Expenditures and Recoveries

1566 CDM Contra

1572 Extraordinary Event Losses

1574 Deferred Rate Impact Amounts

1592 PLS & Tax Variance

2425 Other Deferred Credits

Closed Accounts not classified are as follows:

1570 Qualifying Transition Costs (closed December 31, 2002)

1571 Pre-Market Opening Energy Variances (closed April 30, 2002)

Note 1:
The RSVA power account 1588 is designed to capture variances due to billing timing differences (i.e. electricity charged by IESO to LDCs vs. electricity billed by LDCs to their customers), price and quantity differences (i.e. arising from final vs. preliminary IESO settlement invoices), and line loss differences (i.e. actual vs. estimated line loss factors).

This account is not designed to capture any price differences between the regulated price plan (RPP) and spot prices applicable to RPP customers. This is the function of the Ontario Power Authority (OPA) RPP variance account which is trued-up in accordance with the terms established by the Board for the RPP.

Accordingly, since the RSVA power account is generic to all customers of an LDC, disposition of the account balance in rates is attributable to all its customers.

The 1588 RSVA power - Sub-account Global Adjustments is designed for the global adjustments applicable to non-RPP customers. Hence, the disposition of the account balance should be attributable to non-RPP customers.

CALCULATION OF BALANCES BY ACCOUNT

Deferred Charge Accounts

Account Description	Account Number	Dec 31/06 Balance Principal Portion	Accum. Interest	Total	Apply for Disposal?
LV Variance Account	1550	342,769	5,918	348,687	YES
RSVA - Wholesale Market Service Charge	1580	(163,545)	41,090	(122,454)	YES
RSVA - One-time Wholesale Market Service	1582	49,454	2,894	52,348	YES
RSVA - Retail Transmission Network Charge	1584	(91,476)	9	(91,467)	YES
RSVA - Retail Transmission Connection Charge	1586	(186,585)	(43,629)	(230,213)	YES
RSVA - Power	1588	374,717	105,132	479,849	YES
Sub-totals		**325,334**	**111,414**	**436,748**	

Deferred Charge Accounts

Account Description	Account Number	Jan1/07 to Apr30/07 Interest	Other	Balance
LV Variance Account	1550	5,244		353,931
RSVA - Wholesale Market Service Charge	1580	(2,502)		(124,957)
RSVA - One-time Wholesale Market Service	1582	757		53,104
RSVA - Retail Transmission Network Charge	1584	(1,400)		(92,867)
RSVA - Retail Transmission Connection Charge	1586	(2,855)		(233,068)
RSVA - Power	1588	5,733		485,582
Sub-totals		**4,978**	**-**	**441,726**

Deferred Charge Accounts

Account Description	Account Number	May1/07 to Dec31/07 Interest	Other	Balance
LV Variance Account	1550	10,960		364,891
RSVA - Wholesale Market Service Charge	1580	(5,229)		(130,186)
RSVA - One-time Wholesale Market Service	1582	1,581		54,686
RSVA - Retail Transmission Network Charge	1584	(2,925)		(95,792)
RSVA - Retail Transmission Connection Charge	1586	(5,966)		(239,034)
RSVA - Power	1588	11,982		497,564
Sub-totals		**10,403**	**-**	**452,128**

Deferred Charge Accounts

Account Description	Account Number	Jan1 to Apr30/08 Interest	Other	Balance
LV Variance Account	1550	5,873		370,764
RSVA - Wholesale Market Service Charge	1580	(2,802)		(132,988)
RSVA - One-time Wholesale Market Service	1582	847		55,533
RSVA - Retail Transmission Network Charge	1584	(1,567)		(97,359)
RSVA - Retail Transmission Connection Charge	1586	(3,197)		(242,231)
RSVA - Power	1588	6,420		503,984
Sub-totals		**5,574**	**-**	**457,702**

Annual Interest Rate:	4.59%	Q1 to Q3 2007 inclusive
	5.14%	Q4 2007 to April 30, 2008

METHOD OF RECOVERY

Approach to Inclusion in 2008 Rates

Erie Thames Powerlines Limited (ETPL) is submitting its application for regulatory asset recovery utilizing a parallel methodology to the 2006 EDR recovery process.

Audited December 31, 2006 balances have been split between principal and interest components. The principal component has been improved with interest for the period from January 1, 2007 to April 30, 2008 using Board prescribed interest improvement rates. Individual USOA account amounts are allocated to customer classes using the same allocators as used in the 2006 EDR rate setting process.

The new LV Variance Account (USOA 1550) which came into effect in 2006 is essentially the same as a RSVA account so it has been allocated to customers on the same energy sales basis.

Essentially the balances to be dispositioned represent the balances accumulated over the period from January 1, 2005 to December 31, 2006 (balances as of December 31, 2004 that were approved as part of the 2006 rate approval have been reversed out of the individual USOA accounts per accounting instructions from the Board).

ETPL is applying for a recovery over 2 years, the same as the period for accumulating the balances.

ETPL's 2006 rate application approval was delayed from May 1, 2006 to January 1, 2007. As a result ETPL continued to charge its customers the 2005 approved rate riders for the recovery of regulatory assets for this 8 month period. The annual amount of regulatory asset recovery included in the rates is:

- 2005 rates - $1,010,830
- January 1, 2007 rates - $947,986

The slightly higher amount included in 2005 rates results in an increased recovery of $41,896 for this 8 month period ($1,010,830 - $947,986 X 8/12). Given this immaterial difference and the fact that a future true-up is anticipated ETPL has not made any adjustments to its application.

ETPL intends that the current approved regulatory asset rate rider will end as of April 30, 2008 and be replaced with the new rate rider included in this application.

The true-up related to the current approved regulatory asset recoveries (through 2006 EDR process) and revenues actually obtained through the existing approved regulatory asset rate riders (over the 2006 and 2007 rate years – May 1, 2006 to April 30, 2007) is assumed to be part of a future process.

<u>Adjustments to December 31, 2006 year-end audited trial balance</u>

ETPL has made adjustments for rate setting purposes to the December 31, 2006 trial balance amounts filed with the Board. The majority of the dollar adjustments resulted in reallocations within the regulatory asset accounts to reflect proper regulatory accounting direction from the Board.

Adjustments were made due to the following primary factors:

- ETPL's 2006 rate application was not approved until 2007. As a result the reversing entry reflecting the Board approved value for recovery of regulatory assets was not reflected in the year-end trial balance

- Amounts were written off to reflect the non recovery of a portion of the 1571 Pre-Market Opening COP balance and the write-off related to Transition costs due to the selection of the minimum filing option

- Costs related to the issuing of the $75 rebate cheques originally expensed and associated interest improvement were set up as a regulatory asset

- Costs related to the remaining balances payable (portion from January 1, 2007 on) on the 2 tranches of Hydro One regulatory asset recoveries over the 3 year and 4 year period were not originally accrued in the regulatory asset accounts at year-end

- Regulatory asset recoveries originally credited against the 1570 Transition cost account were moved to the proper 1590 regulatory asset recovery account

The following reconciliation shows the original Trial Balance values and the adjusted values used for rate setting purposes.

Erie Thames Powerlines
Reconciliation of Regulatory Asset Account Balances as of December 31, 2006

	Balance per DQF Filing	Adjusted Balances
Commodity accounts are classified as follows:		
1520 Power Purchase Variance Account	2	
1588 Retail Settlement Variance Account - Power	1,328,845	479,849
1588 RSVA Power - Sub-account Global Adjustments		
Non-commodity accounts are classified in two categories as follows:		
Wholesale and Retail Market Variance Accounts		
1518 Retail Cost Variance Account - Retail		
1548 Retail Cost Variance Account - STR		
1550 LV Variance Account	348,687	348,687
1580 Retail Settlement Variance Account - Wholesale Market Service Charges	611,095	(122,454)
1582 Retail Settlement Variance Account - One-time Wholesale Market Service	80,355	52,348
1584 Retail Settlement Variance Account - Retail Transmission Network Charges	(87,751)	(91,467)
1586 Retail Settlement Variance Account - Retail Transmission Connection Charges	(371,103)	(230,213)
Utility Deferral Accounts		
1508 Other Regulatory Assets		
1508 Other Regulatory Assets - Sub-account OEB Cost Assessments		
1508 Other Regulatory Assets - Sub-account Pension Contributions		
1525 Miscellaneous Deferred Debits		
1555 Smart Meter Capital and Recovery Offset Variance	(22,693)	(22,693)
1556 Smart Meter OM&A Variance		
1562 Deferred Payments in Lieu of Taxes	83,915	83,915
1563 PILs contra account		
1565 Conservation and Demand Management Expenditures and Recoveries	184,732	184,732
1566 Conservation and Demand Management Contra Account		
1572 Extraordinary Event Losses		
1574 Deferred Rate Impact Amounts		
2425 Other Deferred Credits		
Closed Accounts not classified are as follows:		
1570 Qualifying Transition Costs (closed December 31, 2002)	126,731	0
1571 Pre-Market Opening Energy Variances (closed April 30, 2002)	1,225,987	0
1590 Regulatory Asset Recoveries	(2,051,155)	1,290,385
NEW Account - 2405 (record balance of H1 regulatory asset payments)		(563,322)
Total	**1,457,645**	**1,409,765**
	per audited Financial Statements	**47,880** ***Difference***

Reconciliation of Difference	
Write-off of Transition costs - 1570	48,919
Write-of of non approved Pre Market Opening COP costs	20,556
Setup of $75 cheque rebate costs + interest originally expensed	(21,595)
	47,880

Regulatory Asset Accounts Excluded from the Application

The following regulatory asset accounts that have balances as of December 31, 2006 have been excluded from the regulatory assets rate setting process:

- 1555 – Smart Meter Capital and Recovery Offset Variance (ongoing account to be dealt with upon completion of smart metering implementation)
- 1562 Deferred PILS – to be dealt with on a generic basis by the Board
- 1565 CDM Expenditures and Recoveries – tracking account not to be dispositioned
- 1590 Regulatory Asset Recoveries – subject to future true-up process
- 2405 Accrual Account for balance of Hydro One regulatory asset payments (will decline to zero as monthly payments are made)

The only accounts ETPL is applying to disposition are the 5 RSVA accounts (1580 to 1588) and the LV Variance Account (1550)

<u>Determination of New Rate Riders</u>

The December 31, 2006 adjusted principal value and interest improvement together with interest improvement from January 1, 2007 to April 31, 2008 on the 6 accounts to be dispositioned have been allocated to customer classes on the basis of relative energies.

The energy allocation base is based on the 2008 forward test year forecast.

The following tables show:

- The determination of the amounts to be dispositioned
- The relative energies based on the forward test year forecast to be used to allocate the amounts
- The determination of the customer class specific rate riders

Account Description	Account Number	Dec31/06 Balance	Apr 30/08 Balance	Allocation Basis
Unrecovered Plant and Regulatory Study Costs	1505	-	-	
Other Regulatory Assets	1508	-	-	
Preliminary Survey and Investigation Charges	1510	-	-	
Emission Allowance Inventory	1515	-	-	
Emission Allowances Withheld	1516	-	-	
Retail Cost Variance Account - Retail	1518	-	-	
Power Purchase Variance Account	1520	-	-	
Misc. Deferred Debits - incl. Rebate Cheques	1525	-	-	
Deferred Losses from Disposition of Utility Plant	1530	-	-	
Unamortized Loss on Reacquired Debt	1540	-	-	
Development Charge Deposits/ Receivables	1545	-	-	
Retail Cost Variance Account - STR	1548	-	-	
LV Variance Account	1550	348,687	370,764	KWh
Smart Meter Capital Variance Account	1555	-	-	
Smart Meters OM&A Variance Account	1556	-	-	
Deferred Development Costs	1560	-	-	
Deferred Payments in Lieu of Taxes	1562	-	-	
PILS Contra Account	1563	-	-	
CDM Expenditures and Recoveries	1565	-	-	
CDM Contra Account	1566	-	-	
Qualifying Transition Costs	1570	-	-	
Pre-Market Opening Energy Variances Total	1571	-	-	
Extra-Ordinary Event Losses	1572	-	-	
Deferred Rate Impact Amounts	1574	-	-	
RSVA - Wholesale Market Service Charge	1580	(122,454)	(132,988)	KWh
RSVA - One-time Wholesale Market Service	1582	52,348	55,533	KWh
RSVA - Retail Transmission Network Charge	1584	(91,467)	(97,359)	KWh
RSVA - Retail Transmission Connection Charge	1586	(230,213)	(242,231)	KWh
RSVA - Power	1588	479,849	503,984	KWh
Deferred PILs Account	1592	-	-	
Other Deferred Credits	2425	-	-	
Sub-total to Dispose at May1/08 or Dec31/06?	Apr30/08	**436,748**	**457,702**	
Clear residual 1590 balance as of April 30/08?	NO			
Total to Dispose at May1/08				
Disposal period?	2 YEARS			

Projected 2008 Rate Riders

Rate Determinant

Account Description	Account Number		Residential	GS < 50 KW	GS > 50 to 999 kW
Unrecovered Plant and Regulatory Study Costs	1505				
Other Regulatory Assets	1508				
Preliminary Survey and Investigation Charges	1510				
Emission Allowance Inventory	1515				
Emission Allowances Withheld	1516				
Retail Cost Variance Account - Retail	1518				
Power Purchase Variance Account	1520				
Misc. Deferred Debits - incl. Rebate Cheques	1525				
Deferred Losses from Disposition of Utility Plant	1530				
Unamortized Loss on Reacquired Debt	1540				
Development Charge Deposits/ Receivables	1545				
Retail Cost Variance Account - STR	1548				
LV Variance Account	1550		102,333	33,614	71,678
Smart Meter Capital Variance Account	1555				
Smart Meters OM&A Variance Account	1556				
Deferred Development Costs	1560				
Deferred Payments in Lieu of Taxes	1562				
PILS Contra Account	1563				
CDM Expenditures and Recoveries	1565				
CDM Contra Account	1566				
Qualifying Transition Costs	1570				
Pre-Market Opening Energy Variances Total	1571				
Extra-Ordinary Event Losses	1572				
Deferred Rate Impact Amounts	1574				
RSVA - Wholesale Market Service Charge	1580		(36,706)	(12,057)	(25,710)
RSVA - One-time Wholesale Market Service	1582		15,327	5,035	10,736
RSVA - Retail Transmission Network Charge	1584		(26,872)	(8,827)	(18,822)
RSVA - Retail Transmission Connection Charge	1586		(66,857)	(21,961)	(46,830)
RSVA - Power	1588		139,103	45,692	97,433
Deferred PILs Account	1592				
Other Deferred Credits	2425				
Sub-total to Dispose at May1/08 or Dec31/06?	Apr30/08		**126,329**	**41,496**	**88,486**
Clear residual 1590 balance as of April 30/08?	NO		-	-	-
Total to Dispose at May1/08			**126,329**	**41,496**	**88,486**
Disposal period?	2 YEARS		63,164	20,748	44,243
Projected 2008 Rate Riders			**0.0005**	**0.0005**	**0.2094**
Rate Determinant			kWh	kWh	kW

ERIE THAMES POWERLINES CORPORATION

Exhibit: 5
Tab: 1
Schedule: 3

Account Description	Account Number	GS > 1000 to 2999 kW	GS > 3000 to 4999 kW	Large Users
Unrecovered Plant and Regulatory Study Costs	1505			
Other Regulatory Assets	1508			
Preliminary Survey and Investigation Charges	1510			
Emission Allowance Inventory	1515			
Emission Allowances Withheld	1516			
Retail Cost Variance Account - Retail	1518			
Power Purchase Variance Account	1520			
Misc. Deferred Debits - incl. Rebate Cheques	1525			
Deferred Losses from Disposition of Utility Plant	1530			
Unamortized Loss on Reacquired Debt	1540			
Development Charge Deposits/ Receivables	1545			
Retail Cost Variance Account - STR	1548			
LV Variance Account	1550	57,764	14,563	70,289
Smart Meter Capital Variance Account	1555			
Smart Meters OM&A Variance Account	1556			
Deferred Development Costs	1560			
Deferred Payments in Lieu of Taxes	1562			
PILS Contra Account	1563			
CDM Expenditures and Recoveries	1565			
CDM Contra Account	1566			
Qualifying Transition Costs	1570			
Pre-Market Opening Energy Variances Total	1571			
Extra-Ordinary Event Losses	1572			
Deferred Rate Impact Amounts	1574			
RSVA - Wholesale Market Service Charge	1580	(20,719)	(5,223)	(25,212)
RSVA - One-time Wholesale Market Service	1582	8,652	2,181	10,528
RSVA - Retail Transmission Network Charge	1584	(15,168)	(3,824)	(18,457)
RSVA - Retail Transmission Connection Charge	1586	(37,739)	(9,514)	(45,922)
RSVA - Power	1588	78,520	19,795	95,545
Deferred PILs Account	1592			
Other Deferred Credits	2425			
Sub-total to Dispose at May1/08 or Dec31/06?	Apr30/08	**71,309**	**17,977**	**86,771**
Clear residual 1590 balance as of April 30/08?	NO	-	-	-
Total to Dispose at May1/08		**71,309**	**17,977**	**86,771**
Disposal period?	2 YEARS	35,655	8,989	43,385
Projected 2008 Rate Riders		**0.2630**	**0.1906**	**0.2568**
Rate Determinant		kW	kW	kW

Account Description	Account Number	Small Scattered Load	Embedded Distributor
Unrecovered Plant and Regulatory Study Costs	1505		
Other Regulatory Assets	1508		
Preliminary Survey and Investigation Charges	1510		
Emission Allowance Inventory	1515		
Emission Allowances Withheld	1516		
Retail Cost Variance Account - Retail	1518		
Power Purchase Variance Account	1520		
Misc. Deferred Debits - incl. Rebate Cheques	1525		
Deferred Losses from Disposition of Utility Plant	1530		
Unamortized Loss on Reacquired Debt	1540		
Development Charge Deposits/ Receivables	1545		
Retail Cost Variance Account - STR	1548		
LV Variance Account	1550	504	17,232
Smart Meter Capital Variance Account	1555		
Smart Meters OM&A Variance Account	1556		
Deferred Development Costs	1560		
Deferred Payments in Lieu of Taxes	1562		
PILS Contra Account	1563		
CDM Expenditures and Recoveries	1565		
CDM Contra Account	1566		
Qualifying Transition Costs	1570		
Pre-Market Opening Energy Variances Total	1571		
Extra-Ordinary Event Losses	1572		
Deferred Rate Impact Amounts	1574		
RSVA - Wholesale Market Service Charge	1580	(181)	(6,181)
RSVA - One-time Wholesale Market Service	1582	75	2,581
RSVA - Retail Transmission Network Charge	1584	(132)	(4,525)
RSVA - Retail Transmission Connection Charge	1586	(329)	(11,258)
RSVA - Power	1588	685	23,423
Deferred PILs Account	1592		
Other Deferred Credits	2425		
Sub-total to Dispose at May1/08 or Dec31/06?	Apr30/08	**622**	**21,272**
Clear residual 1590 balance as of April 30/08?	NO	-	-
Total to Dispose at May1/08		**622**	**21,272**
Disposal period?	2 YEARS	311	10,636
Projected 2008 Rate Riders		**0.0005**	**0.1066**
Rate Determinant		kWh	kW

ERIE THAMES POWERLINES CORPORATION

Exhibit: 5
Tab: 1
Schedule: 3

Account Description	Account Number	Sentinel Lighting	Street Lighting	Totals
Unrecovered Plant and Regulatory Study Costs	1505			-
Other Regulatory Assets	1508			-
Preliminary Survey and Investigation Charges	1510			-
Emission Allowance Inventory	1515			-
Emission Allowances Withheld	1516			-
Retail Cost Variance Account - Retail	1518			-
Power Purchase Variance Account	1520			-
Misc. Deferred Debits - incl. Rebate Cheques	1525			-
Deferred Losses from Disposition of Utility Plant	1530			-
Unamortized Loss on Reacquired Debt	1540			-
Development Charge Deposits/ Receivables	1545			-
Retail Cost Variance Account - STR	1548			-
LV Variance Account	1550	198	2,588	370,764
Smart Meter Capital Variance Account	1555			-
Smart Meters OM&A Variance Account	1556			-
Deferred Development Costs	1560			-
Deferred Payments in Lieu of Taxes	1562			-
PILS Contra Account	1563			-
CDM Expenditures and Recoveries	1565			-
CDM Contra Account	1566			-
Qualifying Transition Costs	1570			-
Pre-Market Opening Energy Variances Total	1571			-
Extra-Ordinary Event Losses	1572			-
Deferred Rate Impact Amounts	1574			-
RSVA - Wholesale Market Service Charge	1580	(71)	(928)	(132,988)
RSVA - One-time Wholesale Market Service	1582	30	388	55,533
RSVA - Retail Transmission Network Charge	1584	(52)	(680)	(97,359)
RSVA - Retail Transmission Connection Charge	1586	(129)	(1,691)	(242,231)
RSVA - Power	1588	269	3,518	503,984
Deferred PILs Account	1592			-
Other Deferred Credits	2425			-
Sub-total to Dispose at May1/08 or Dec31/06?	Apr30/08	**244**	**3,195**	**457,702**
Clear residual 1590 balance as of April 30/08?	NO	-	-	**-**
Total to Dispose at May1/08		**244**	**3,195**	**457,702**
Disposal period?	2 YEARS	122	1,598	**228,851**
Projected 2008 Rate Riders		**0.2022**	**0.1694**	
Rate Determinant		kW	kW	

Ex.	Tab	Schedule	Contents of Schedule

6 – Cost of Capital and Rate of Return

ERIE THAMES POWERLINES CORPORATION

OVERVIEW

The purpose of this evidence is to summarize the method and cost of financing the Applicant's capital requirements for the 2008 test years.

Capital Structure

Erie Thames Powerlines has a deemed current capital structure of 50% debt, 50% equity, as approved by the Ontario Energy Board in RP-2005-0020, and a return on equity of 9.00%, consistent with the return specified in the Board's Decision in EB-2005-0361, and EB-2006-0197 dated January 2, 2007. Erie Thames Powerlines is requesting Board approval of a deemed capital structure of 53.33% debt, 46.67% equity including an equity return of 8.68%.

This change in deemed capital structure complies with Ontario Energy Board's report on cost of Capital and 2nd Generation IRM for Ontario's Electricity Distributors dated December 20th, 2006. The OEB report indicates that Distributors will be required to phase in a 60/40 Debt to Equity capital structure that must be completed by 2010.

Return on Equity

Erie Thames Powerlines is requesting an equity return of 8.68% for its 2008 Rates.

Cost of Debt

Exhibit 6, Tab 1, Schedule 3 provides the detailed calculation of Erie Thames Powerlines forecast long-term debt cost of 7.25% for 2007 and 7.25% for 2008.

CAPITAL STRUCTURE

2006 Board Approved

Elements	$ Million	Ratio (%)	Cost Rate (%)	Return (%)
Long-term debt	$8,038,524.00	45.49%	7.25%	7.25%
Unfunded short-term debt	$841,294.00	4.76%		
Preference shares	$8,038,524.00	45.49%		9.00%
Common equity	$753,462.00	4.26%		9.00%
Total	$17,671,804.00			

2007 Bridge

Elements	$ Million	Ratio (%)	Cost Rate (%)	Return (%)
Long-term debt	$8,038,524.00	45.49%	7.25%	7.25%
Unfunded short-term debt	$786,509.00	4.45%		
Preference shares	$8,038,524.00	45.49%		9.00%
Common equity	$753,462.00	4.26%		9.00%
Total	$17,617,019.00			

2008 Test

Elements	$ Million	Ratio (%)	Cost Rate (%)	Return (%)
Long-term debt	$8,038,524.00	45.76%	7.25%	7.25%
Unfunded short-term debt	$735,291.59	4.19%	4.77%	
Preference shares	$8,038,524.00	45.76%		8.68%
Common equity	$753,462.00	4.29%		8.68%
Total	$17,565,801.59			

Erie Thames Powerlines Corporation's Debt Equity split shown here for 2008 does not match its deemed amounts for the rate making process. ETPL plans to adjust its actual debt equity split to match the deemed proportion in early 2008 prior to the implementation of its new rates. ETPL is in the process of investigating options for adjusting its Debt Equity split.

ERIE THAMES POWERLINES CORPORATION

COST OF DEBT

	2006 Board Approved			2006 Actual			2007 Bridge			2008 Test		
	Principle	Carrying Costs	Calculated Cost Rate	Principle	Carrying Costs	Calculated Cost Rate	Principle	Carrying Costs	Calculated Cost Rate	Principle	Carrying Costs	Calculated Cost Rate
Long-Term Debt												
Town of Aylmer	$1,694,863	$122,878	7.25%	$1,694,863	$122,878	7.25%	$1,694,863	$122,878	7.25%	$1,694,863	$122,878	7.25%
Township of Central Elgin	$806,436	$58,467	7.25%	$806,436	$58,467	7.25%	$806,436	$58,467	7.25%	$806,436	$58,467	7.25%
Township of East Zorra Tavistock	$569,073	$41,258	7.25%	$569,073	$41,258	7.25%	$569,073	$41,258	7.25%	$569,073	$41,258	7.25%
Town of Ingersoll	$3,402,080	$246,651	7.25%	$3,402,080	$246,651	7.25%	$3,402,080	$246,651	7.25%	$3,402,080	$246,651	7.25%
Town of Norwich	$763,755	$55,372	7.25%	$763,755	$55,372	7.25%	$763,755	$55,372	7.25%	$763,755	$55,372	7.25%
Township of South West Oxford	$192,062	$13,924	7.25%	$192,062	$13,924	7.25%	$192,062	$13,924	7.25%	$192,062	$13,924	7.25%
Township of Zorra	$610,255	$44,243	7.25%	$610,255	$44,243	7.25%	$610,255	$44,243	7.25%	$610,255	$44,243	7.25%
Total	$8,038,524	$582,793	7.25%	$8,038,524	$582,793	7.25%	$8,038,524	$582,793	7.25%	$8,038,524	$582,793	7.25%

RETURN ON EQUITY

The calculations used to determine the return on equity and the debt are taken from the "Report to the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors" issued December 20, 2006.

Excerpt from the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors Appendix A and Appendix B

Method to Update the Deemed Long-term Debt Rate

The Board will use the Long Canada Bond Forecast plus an average spread with "A/BBB" rated corporate bond yields to determine the updated deemed debt rate.

The following approach is consistent with the ROE method. As per the approach adopted in the 2006 EDRH, the ROE and the long-term debt rates are based on the same risk-free rate forecast. Therefore, they differ only through the risk premiums that reflect their distinct natures and for which lenders/investors seek commensurate returns. This approach simplifies the calculations and aims to make it easier to understand the numbers. Specifically, the Long Canada Bond Forecast (*LCBFt*) used will be the same as that used for updating the ROE. The average spread between "A/BBB" rated corporate bond yields and 30-year (long) Government of Canada Bond yields will be calculated as the average spread over the weeks of the month corresponding to the Consensus Forecasts.

The deemed Long-Term Debt Rate (*LTDRt*) will be calculated as follows:

$$LTDR_t = LCBF_t + \frac{\sum_w (CorpBonds_{w,t} - {}_{30}CB_{w,t})}{n}$$

Where:

- ***CorpBonds*** $_{w,t}$ is the average long-term corporate bond yield from Scotia Capital Inc. for week *w* of period *t* [Series V121761];

- $_{30}CB_{w,t}$ is the 30-year (long) Government of Canada bond yield for week *w* of period *t* [Series V121791]; and

- ***n*** is the number of weeks in the month for which data are reported.

Method to Update ROE - ROE Update for any Period

Using March 1999 as the starting calculation and substituting for the initial ROE and Long Canada Bond Forecast approved by the Board in the Decision RP-1998-0001 the following is the adjustment formula for calculating the ROE at time *t*:

$$ROE_t = 9.35\% \ + 0.75 \times (LCBF_t - 5.50\%)$$

The ROE must be set in advance of the approved rates. The final ROE will be factored into rates using the Long Canada Bond Forecast based on *Consensus Forecasts* (as detailed below) and Bank of Canada data three months in advance of the effective date for the rate change. Therefore, for May 1 rate changes, the ROE will be based on January data – effectively *Consensus Forecasts* published during that month and Bank of Canada data for all business days during the month of January. The necessary data is available within the first or second business days after the end of the month and thus poses no delay for determining rates.

Long Canada Bond Forecast for any Period

For any period *t* the Long Canada Bond Forecast *LCBFt* can be expressed as:

$$LCBF_t = \left[\frac{{}_{10}CBF_{3,t} + {}_{10}CBF_{12,t}}{2} \right] + \frac{\sum_i ({}_{30}CB_{i,t} - {}_{10}CB_{i,t})}{I_t}$$

Where:

$_{10}CB_{3,T}$ is the 3-month forecast of the 10-year Government of Canada bond yield as published in *Consensus Forecasts* at time *t*;

$_{10}CB_{12,t}$ is the 12-month forecast of the 10-year Government of Canada bond yield as published in *Consensus Forecasts* at time *t*;

$_{30}CB_{i,t}$ is the actual rate for the 30-year Government of Canada bond yield at the close of day *i* (as published by the Bank of Canada) [Series V39056] during the month (this is the previous month data, the same as used for updating the ROE for natural gas distribution) corresponding to time *t*;

$_{10}CB_{i,t}$ is the actual rate for the 10-year Government of Canada bond yield at the close of day *i* (as published by the Bank of Canada) [Series V39055] during the month corresponding to time *t*; and

It is the number of business days for which published 10- and 30- Government of Canada bond yields are published during the month corresponding to time *t*.

Return on Equity Calculation

Government of Canada Bond Yields	Rate
3-month forecast of the 10 year bond yield	4.60%
12-month forecast of the 10-year bond yield	4.80%
Average actual prior month 30-year bond yield	4.03%
Average actual prior month 10-year bond yield	4.12%
Long Term Canada Bond Forcast	4.61%
Return on Equity	**8.68%**

Weighted Average Cost of Capital

	Deemed Portion	Effective Rate	Average Cost of Capital
Cost of Debt	53.33%	7.06%	3.77%
Return on Equity	46.67%	8.68%	4.05%
Weighted Average Cost of Capital			**7.82%**

Ex.	Tab	Schedule	Contents of Schedule
7 - Calculation of Revenue Deficiency or Surplus			
	1	1	Determination of Net Utility Income and Calculation of Revenue Deficiency or Surplus

OVERVIEW OF CALCULATION OF REVENUE DEFICIENCY OR SURPLUS

The information in this Exhibit supports Erie Thames Powerlines Corporation's request in this Application for a decrease in its 2008 Revenue Requirement. ETPL requires a distribution revenue requirement of $6,918,858 to continue to provide its customers safe reliable supply of electricity, service its debt and pay its deemed PILS.

Erie Thames Powerlines Target return on Rate Base is calculated using 46.67% of Rate Base with a target return on Rate base of $897,483. Utilizing current rates and 2008 forecasted customer data ETPL would expect $7,402,936 in distribution revenue which creates a revenue sufficiency of $317,071, which grossed up for tax purposes is $484,078.

This revenue sufficiency is in large part attributable to the change in PILS recovery from the 2006 EDR process of $701,344, to a 2008 Test Year amount of $416,908. Consequently the portion of the revenue sufficiency which is not related to the impact of PILS is $32,635.

ETPL's 2008 revenue sufficiency is outlined in detail below in the Determination of Net Utility Income Table.

DETERMINATION OF NET UTILITY INCOME

Determination of Net Utility Income	2008 Test Existing Rates	2008 Test Proposed Rates
Revenue		
Revenue Sufficiency (Grossed Up)		-$484,078
Distribution Revenue	$7,402,936	$7,402,936
Other Operating Revenue (Net)	$477,013	$477,013
Total Revenue	**$7,879,949**	**$7,395,871**
Costs and Expenses		
Distribution Costs	$2,932,106	$2,932,106
Operation & Maintenance	$1,496,655	$1,496,655
Depreciation & Amortization	$935,609	$935,609
Property & Capital Taxes	$28,458	$28,458
Interest	$792,354	$792,354
Total Costs and Expenses	**$6,185,182**	**$6,185,182**
Utility Income Before Income Taxes	$1,694,767	$1,210,689
Net Adjustments per 2008 Pils	-$302,847	-$302,847
Utility Income before Taxes	$1,391,920	$907,842
Income Taxes	$480,212	$313,205
Utility Income	**$1,214,555**	**$897,483**
Rate Base	$22,154,852	$22,154,852
Equity Portion	46.67%	46.67%
Equity Component of Rate Base	$10,339,669	$10,339,669
Target Return on Equity	8.68%	8.68%
Return on Rate Base	$897,483	$897,483
Revenue Sufficiency	**$317,071**	$0.00

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8 – Cost Allocation

COST ALLOCATION OVERVIEW

Introduction:

In a staff discussion paper released on June 28, 2007, Board Staff provided some guidelines on both the allocation of costs and on general fixed-variable rate design. The starting point for the 2008 allocated costs is the 2006 Cost Allocation Information Filings filed in late 2006 to early 2007.

Board staff suggested the following generic guidelines on page 25 of the June 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 80% and 120%
- 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%
- Large Use customers (above 5,000 kW)
  - Revenue to cost ratios between 80% and 180%
- Sentinel Light
  - Revenue to cost ratios between 70% to 120%
- Street Light
  - Revenue to cost ratios between 70% to 120%

Background:

The Erie Thames 2006 Cost Allocation Information Filing produced the following results:

- Residential Class = 91.12%
- General Service < 50 kW = 144.26%
- General Service 50 to 999 kW = 117.00%
- General Service 1,000 to 2,999 kW = 147.47%
- General Service 3,000 to 4,999 kW = 190.03%
- Large Use > 5,000 kW = 99.29%
- Street Light = 14.35%
- Sentinel Light = 55.67%
- Unmetered Scattered Load = 187.92%
- Embedded Distributor (new class) = 5.00%

The cost allocation portion of this 2008 rebasing application was handled using a three step approach.

SUMMARY OF RESULTS AND PROPOSED CHANGES

Step 1

The first step was to determine the minimum required changes in revenue to cost ratios, by customer class, between the 2006 CA informational filing values compared to the June 28 Board Staff guidelines.

Customer Class	2006 CA RC Ratio	Board Staff RC Target	Minimum Recommended Movement
Residential	91.12%	80% - 120%	0.00%
GS < 50 kW	144.26%	80% - 120%	- 24.26%
GS 50 to 999 kW	117.00%	80% - 180%	0.00%
GS 1,000 to 2,999	147.47%	80% - 180%	0.00%
GS 3,000 to 4,999 kW	190.03%	80% - 180%	- 10.03%
Large Use (above 5,000 kW)	99.29%	80% - 180%	0.00%
Street Light	14.35%	70% - 120%	55.65%
Sentinel Light	55.67%	70% - 120%	14.23%
Unmetered Load	187.92%	80% - 120%	-67.92%
Embedded Distributor	5.00%	80% - 180%	75.00%

Note: Erie Thames has used the same recommended RC band as with the large use class as demand levels are similar

The process utilized for adjusting revenue to cost ratios was as follows:

1. Adjust the 2006 cost allocation total revenue requirement (distribution revenue plus miscellaneous service charge revenue) calculated by customer class to incorporate the minimum recommended movement as outlined above (e.g. GS < 50 kW class total revenue divided by 144.26 multiplied by 120 = 120% RC%)
2. Calculate class specific adjusted 2006 total revenue requirement and adjust to ensure revenue neutrality (minimum movement's results in a $133,189 over recovery of distribution revenue which needs to be spread over a selected group of customer classes to ensure revenue neutrality).
3. Upon generating revenue neutral adjusted class specific total revenue requirement, calculate 2006 adjusted % share to LDC 2006 total revenue requirement (see chart below) and use values to allocate 2008 total revenue requirement.
4. Isolate 2008 distribution revenue requirement by class (total revenue requirement less class allocation of miscellaneous revenue) to be used in rate design process.

After implementation, of the above minimum adjustments, the 2006 total revenue requirement was $133,189 over the 2006 cost allocation distribution revenue requirement. This $133,189 is due to the fact that the minimum adjustments are not equal and offsetting. Erie Thames spread the $133,189 over recovery to provide partial relief to the remaining customer classes that were over contributing on revenue to cost ratios (GS < 50 kW, GS 50 to 999 kW, GS 1,000 to 2,999 kW, GS 3,000 to 4,999 kW and unmetered customer classes) using distribution revenue as an allocation base. After the minimum recommended adjustments and the $133,189 over recovery adjustment, the specific customer class revenue to cost ratios are as follows:

Customer Class	2006 Adjusted Cost Allocation RC %	2006 Total Revenue Allocation	2008 Total Revenue Requirement
Residential	91.12%	50.27%	$ 3,921,806
GS < 50 kW	114.81%	12.26%	$ 939,275
GS 50 to 999 kW	111.94%	13.83%	$ 1,018,541
GS 1,000 to 2,999	141.09%	11.54%	$ 827,831
GS 3,000 to 4,999 kW	172.22%	2.07%	$ 147,505
Large Use (above 5,000 kW)	99.29%	4.07%	$ 296,120
Street Light	70.00%	3.54%	$ 265,430
Sentinel Light	70.00%	0.29%	$ 22,227
Unmetered Load	114.81%	0.18%	$ 13,089
Embedded Distributor	80.00%	1.93%	$ 141,163
Total		100.00%	$ 7,592,989

The resulting bill impacts from the above revenue to cost ratios did not produce customer impacts outside of the standard 10% threshold that has been previously used by the OEB for evaluating appropriate rate design changes, with the exception of the Street Light and Sentinel Light classes. As these classes were expected to create such a problem due to significant underpayment related to cost causality, no immediate mitigation techniques were utilized.

Step 2

As the minimum adjustments (Board Staff guidelines) did not create any "unacceptable" customer impacts, a second approach to cost allocation was utilized, namely moving everyone to a 100% revenue to cost ratio.

A similar approach was utilized to move all classes to 100% revenue to cost ratios as described in Step 1 above. On a class by class basis, the 2006 cost allocation total revenue value was forced to ensure all classes had a 100% revenue to cost ratio. This determined the % of total revenue requirement that each class should pay for as seen on the following chart. As this process is revenue neutral there was no need for a secondary adjustment as was utilized in step 1 above. A class specific allocation of 2006 total revenue was calculated and utilized to distribute 2008 total revenue requirement.

Customer Class	2006 Adjusted Cost Allocation RC %	2006 Total Revenue Allocation	2008 Total Revenue Requirement
Residential	100%	56.62%	$ 4,299,222
GS < 50 kW	100%	10.76%	$ 817,197
GS 50 to 999 kW	100%	11.97%	$ 908,886
GS 1,000 to 2,999	100%	7.72%	$ 586,083
GS 3,000 to 4,999 kW	100%	1.13%	$ 85,556
Large Use (above 5,000 kW)	100%	3.92%	$ 297,902
Street Light	100%	4.99%	$ 378,774
Sentinel Light	100%	0.42%	$ 31,719
Unmetered Load	100%	0.15%	$ 11,388
Embedded Distributor	100%	2.32%	$ 176,262
Total		100.00%	$ 7,592,987

Step 3

The third phase of cost allocation and the option being applied for by Erie Thames is a hybrid of the two methodologies above. Erie Thames is applying for all classes to move to the 100% revenue to cost ratios (as no adverse revenue impacts were discovered) with the exception of the Street Light classification. Street Lights have been left at the Board Staff recommended minimum of 70% revenue to cost ratio while all other classes are contributing 101% revenue to cost. This marginal difference between a 100% revenue to cost ratio is comprised of cross subsidization to the Street Light class of $113,716. The $113,716 has been split evenly over the remaining customer classes based on distribution revenue. Please refer to summary table below.

Customer Class	**Board Staff RC Targets**	**Erie Thames Applied for RC%**	**Subsidization Value**	**2006 Total Revenue Allocation**	**2008 Total Revenue Requirement**
Residential	80% - 120%	101%	$ 67,768	56.72%	$ 4,366,939
GS < 50 kW	80% - 120%	101%	$ 12,881	10.68%	$ 830,069
GS 50 to 999 kW	80% - 180%	101%	$ 14,327	12.45%	$ 923,202
GS 1,000 to 2,999	80% - 180%	101%	$ 9,238	8.17%	$ 595,314
GS 3,000 to 4,999 kW	80% - 180%	101%	$ 1,349	1.19%	$ 86,904
Large Use (above 5,000 kW)	80% - 180%	101%	$ 4,696	4.17%	$ 302,594
Street Light	70% - 120%	70%	($ 113,716)	3.54%	$ 265,142
Sentinel Light	70% - 120%	101%	$ 500	0.44%	$ 32,219
Unmetered Load	80% - 120%	101%	$ 180	0.16%	$ 11,568
Embedded Distributor	80% - 180%	101%	$ 2,778	2.48%	$ 179,038
Total			$ 1	100%	$ 7,592,989

Erie Thames proposes moving the Street Light class to parity (revenue to cost ratio of 100%), with the other classes, upon the next rebasing window using the appropriate cost allocation guidelines in place at that time.

The 70% revenue to cost ratios utilized by Erie Thames results in a monthly total bill impact to the Street Light customers of 66%, while using a 100% revenue to cost ratio would raise this monthly impact to 68%. Putting the $113,716 street light subsidization into perspective, an individual residential customer's monthly bill increase in 2008 is calculated at $0.45 ($67,768 / 12 months / 12,451 {2008 projected residential customer count}).

Erie Thames is including a sample of customer impacts for reference, full impact analysis can be found on pages 4 to 6 of section 2.

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Residential
100 kWh Consumption

	Metric	2007 BILL Volume	2007 BILL Rate $	2007 BILL Charge $	2008 BILL Volume	2008 BILL Rate $	2008 BILL Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				14.06			14.83	0.77	5.5%	3.1%
Distribution	kWh	100	0.01370	1.37	100	0.01490	1.49	0.12	8.8%	0.5%
Sub-Total				**15.43**			**16.32**	**0.89**	**5.8%**	**3.6%**
Regulatory Asset Recovery	kWh	100	0.00470	0.47	100	0.00050	0.05	-0.42	-89.4%	-1.7%
Retail Transmission - Network	kWh	104	0.00470	0.49	104	0.00470	0.49	0.00	0.1%	0.0%
Retail Transmission - Line and Transformation Connection	kWh	104	0.00500	0.52	104	0.00500	0.52	0.00	0.1%	0.0%
Wholesale Market Service	kWh	104	0.00520	0.54	104	0.00520	0.54	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	104	0.00100	0.10	104	0.00100	0.10	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	100	0.00700	0.70	100	0.00700	0.70	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	104	0.05704	5.95	104	0.05704	5.95	0.00	0.1%	0.0%
Total Bill				**24.21**			**24.68**	**0.48**	**2.0%**	**1.9%**

Residential
250 kWh Consumption

	Metric	2007 BILL Volume	2007 BILL Rate $	2007 BILL Charge $	2008 BILL Volume	2008 BILL Rate $	2008 BILL Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				14.06			14.83	0.77	5.5%	2.0%
Distribution	kWh	250	0.01370	3.43	250	0.01490	3.73	0.30	8.8%	0.8%
Sub-Total				**17.49**			**18.56**	**1.07**	**6.1%**	**2.7%**
Regulatory Asset Recovery	kWh	250	0.00470	1.18	250	0.00050	0.13	-1.05	-89.4%	-2.7%
Retail Transmission - Network	kWh	261	0.00470	1.23	261	0.00470	1.23	0.00	0.1%	0.0%
Retail Transmission - Line and Transformation Connection	kWh	261	0.00500	1.30	261	0.00500	1.30	0.00	0.1%	0.0%
Wholesale Market Service	kWh	261	0.00520	1.36	261	0.00520	1.36	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	261	0.00100	0.26	261	0.00100	0.26	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	250	0.00700	1.75	250	0.00700	1.75	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	261	0.05704	14.87	261	0.05704	14.88	0.01	0.1%	0.0%
Total Bill				**39.42**			**39.46**	**0.04**	**0.1%**	**0.1%**

Residential
500 kWh Consumption

	Metric	2007 BILL Volume	2007 BILL Rate $	2007 BILL Charge $	2008 BILL Volume	2008 BILL Rate $	2008 BILL Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				14.06			14.83	0.77	5.5%	1.2%
Distribution	kWh	500	0.01370	6.85	500	0.01490	7.45	0.60	8.8%	0.9%
Sub-Total				**20.91**			**22.28**	**1.37**	**6.6%**	**2.1%**
Regulatory Asset Recovery	kWh	500	0.00470	2.35	500	0.00050	0.25	-2.10	-89.4%	-3.3%
Retail Transmission - Network	kWh	521	0.00470	2.45	522	0.00470	2.45	0.00	0.1%	0.0%
Retail Transmission - Line and Transformation Connection	kWh	521	0.00500	2.61	522	0.00500	2.61	0.00	0.1%	0.0%
Wholesale Market Service	kWh	521	0.00520	2.71	522	0.00520	2.71	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	521	0.00100	0.52	522	0.00100	0.52	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	500	0.00700	3.50	500	0.00700	3.50	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	521	0.05704	29.74	522	0.05704	29.76	0.02	0.1%	0.0%
Total Bill				**64.79**			**64.09**	**-0.70**	**-1.1%**	**-1.1%**

Residential
750 kWh Consumption

	Metric	2007 BILL Volume	2007 BILL Rate $	2007 BILL Charge $	2008 BILL Volume	2008 BILL Rate $	2008 BILL Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				14.06			14.83	0.77	5.5%	0.9%
Distribution	kWh	750	0.01370	10.28	750	0.01490	11.18	0.90	8.8%	1.0%
Sub-Total				**24.34**			**26.01**	**1.67**	**6.9%**	**1.9%**
Regulatory Asset Recovery	kWh	750	0.00470	3.53	750	0.00050	0.38	-3.15	-89.4%	-3.6%
Retail Transmission - Network	kWh	782	0.00470	3.68	783	0.00470	3.68	0.00	0.1%	0.0%
Retail Transmission - Line and Transformation Connection	kWh	782	0.00500	3.91	783	0.00500	3.91	0.00	0.1%	0.0%
Wholesale Market Service	kWh	782	0.00520	4.07	783	0.00520	4.07	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	782	0.00100	0.78	783	0.00100	0.78	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	750	0.00700	5.25	750	0.00700	5.25	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	782	0.05704	44.61	783	0.05704	44.64	0.04	0.1%	0.0%
Total Bill				**90.15**			**88.72**	**-1.43**	**-1.6%**	**-1.6%**

Residential
1,000 kWh Consumption

	Metric	2007 BILL Volume	2007 BILL Rate $	2007 BILL Charge $	2008 BILL Volume	2008 BILL Rate $	2008 BILL Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				14.06			14.83	0.77	5.5%	0.7%
Distribution	kWh	1,000	0.01370	13.70	1,000	0.01490	14.90	1.20	8.8%	1.1%
Sub-Total				**27.76**			**29.73**	**1.97**	**7.1%**	**1.7%**
Regulatory Asset Recovery	kWh	1,000	0.00470	4.70	1,000	0.00050	0.50	-4.20	-89.4%	-3.7%
Retail Transmission - Network	kWh	1,043	0.00470	4.90	1,044	0.00470	4.90	0.00	0.1%	0.0%
Retail Transmission - Line and Transformation Connection	kWh	1,043	0.00500	5.21	1,044	0.00500	5.22	0.00	0.1%	0.0%
Wholesale Market Service	kWh	1,043	0.00520	5.42	1,044	0.00520	5.43	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	1,043	0.00100	1.04	1,044	0.00100	1.04	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	1,000	0.00700	7.00	1,000	0.00700	7.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,043	0.05704	59.48	1,044	0.05704	59.52	0.05	0.1%	0.0%
Total Bill				**115.51**			**113.35**	**-2.17**	**-1.9%**	**-1.9%**

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GS <50
1,000 kWh Consumption

		2007 BILL			2008 BILL			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				27.69			19.13	-8.56	-30.9%	-7.6%
Distribution	kWh	1,000	0.01640	16.40	1,000	0.01130	11.30	-5.10	-31.1%	-4.5%
Sub-Total				**44.09**			**30.43**	**-13.66**	**-31.0%**	**-12.1%**
Regulatory Asset Recovery	kWh	1,000	0.00300	3.00	1,000	0.00050	0.50	-2.50	-83.3%	-2.2%
Retail Transmission - Network	kWh	1,043	0.00430	4.48	1,044	0.00430	4.49	0.00	0.1%	0.0%
Retail Transmission - Line and Transformation Connection	kWh	1,043	0.00460	4.80	1,044	0.00460	4.80	0.00	0.1%	0.0%
Wholesale Market Service	kWh	1,043	0.00520	5.42	1,044	0.00520	5.43	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	1,043	0.00100	1.04	1,044	0.00100	1.04	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	1,000	0.00700	7.00	1,000	0.00700	7.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,043	0.05704	59.48	1,044	0.05704	59.52	0.05	0.1%	0.0%
Total Bill				**129.31**			**113.21**	**-16.10**	**-12.4%**	**-14.2%**

GS <50
2,000 kWh Consumption

		2007 BILL			2008 BILL			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				27.69			19.13	-8.56	-30.9%	-4.1%
Distribution	kWh	2,000	0.01640	32.80	2,000	0.01130	22.60	-10.20	-31.1%	-4.9%
Sub-Total				**60.49**			**41.73**	**-18.76**	**-31.0%**	**-9.0%**
Regulatory Asset Recovery	kWh	2,000	0.00300	6.00	2,000	0.00050	1.00	-5.00	-83.3%	-2.4%
Retail Transmission - Network	kWh	2,085	0.00430	8.97	2,087	0.00430	8.97	0.01	0.1%	0.0%
Retail Transmission - Line and Transformation Connection	kWh	2,085	0.00460	9.59	2,087	0.00460	9.60	0.01	0.1%	0.0%
Wholesale Market Service	kWh	2,085	0.00520	10.84	2,087	0.00520	10.85	0.01	0.1%	0.0%
Rural Rate Protection Charge	kWh	2,085	0.00100	2.09	2,087	0.00100	2.09	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	2,000	0.00700	14.00	2,000	0.00700	14.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	2,085	0.05704	118.95	2,087	0.05704	119.05	0.10	0.1%	0.0%
Total Bill				**230.93**			**207.29**	**-23.64**	**-10.2%**	**-11.4%**

GS <50
5,000 kWh Consumption

		2007 BILL			2008 BILL			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				27.69			19.13	-8.56	-30.9%	-1.7%
Distribution	kWh	5,000	0.01640	82.00	5,000	0.01130	56.50	-25.50	-31.1%	-5.2%
Sub-Total				**109.69**			**75.63**	**-34.06**	**-31.1%**	**-7.0%**
Regulatory Asset Recovery	kWh	5,000	0.00300	15.00	5,000	0.00050	2.50	-12.50	-83.3%	-2.6%
Retail Transmission - Network	kWh	5,214	0.00430	22.42	5,218	0.00430	22.44	0.02	0.1%	0.0%
Retail Transmission - Line and Transformation Connection	kWh	5,214	0.00460	23.98	5,218	0.00460	24.00	0.02	0.1%	0.0%
Wholesale Market Service	kWh	5,214	0.00520	27.11	5,218	0.00520	27.13	0.02	0.1%	0.0%
Rural Rate Protection Charge	kWh	5,214	0.00100	5.21	5,218	0.00100	5.22	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	5,000	0.00700	35.00	5,000	0.00700	35.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	5,214	0.05704	297.38	5,218	0.05704	297.62	0.24	0.1%	0.0%
Total Bill				**535.79**			**489.54**	**-46.25**	**-8.6%**	**-9.4%**

GS <50
10,000 kWh Consumption

		2007 BILL			2008 BILL			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				27.69			19.13	-8.56	-30.9%	-0.9%
Distribution	kWh	10,000	0.01640	164.00	10,000	0.01130	113.00	-51.00	-31.1%	-5.3%
Sub-Total				**191.69**			**132.13**	**-59.56**	**-31.1%**	**-6.2%**
Regulatory Asset Recovery	kWh	10,000	0.00300	30.00	10,000	0.00050	5.00	-25.00	-83.3%	-2.6%
Retail Transmission - Network	kWh	10,427	0.00430	44.84	10,436	0.00430	44.87	0.04	0.1%	0.0%
Retail Transmission - Line and Transformation Connection	kWh	10,427	0.00460	47.96	10,436	0.00460	48.00	0.04	0.1%	0.0%
Wholesale Market Service	kWh	10,427	0.00520	54.22	10,436	0.00520	54.26	0.04	0.1%	0.0%
Rural Rate Protection Charge	kWh	10,427	0.00100	10.43	10,436	0.00100	10.44	0.01	0.1%	0.0%
Debt Retirement Charge	kWh	10,000	0.00700	70.00	10,000	0.00700	70.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	10,427	0.05704	594.76	10,436	0.05704	595.24	0.49	0.1%	0.1%
Total Bill				**1,043.89**			**959.95**	**-83.94**	**-8.0%**	**-8.7%**

GS>50 to 999 kW
60 kW Consumption
15,000 kWh Consumption

	Metric	2007 BILL Volume	Rate $	Charge $	2008 BILL Volume	Rate $	Charge $	IMPACT Change $	Change %	% of Total Bill
Monthly Service Charge				387.30			205.49	-181.81	-46.9%	-11.0%
Distribution	kW	60	1.99270	119.56	60	1.95870	117.52	-2.04	-1.7%	-0.1%
Sub-Total				**506.86**			**323.01**	**-183.85**	**-36.3%**	**-11.1%**
Regulatory Asset Recovery	kW	60	0.32260	19.36	60	0.20940	12.56	-6.79	-35.1%	-0.4%
Retail Transmission - Network	kW	63	1.95610	122.38	63	1.95610	122.48	0.10	0.1%	0.0%
Retail Transmission - Line and Transformation Connection	kW	63	1.63590	102.35	63	1.63590	102.43	0.08	0.1%	0.0%
Wholesale Market Service	kWh	15,641	0.00520	81.33	15,653	0.00520	81.40	0.07	0.1%	0.0%
Rural Rate Protection Charge	kWh	15,641	0.00100	15.64	15,653	0.00100	15.65	0.01	0.1%	0.0%
Debt Retirement Charge	kWh	15,000	0.00700	105.00	15,000	0.00700	105.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	15,641	0.05704	892.13	15,653	0.05704	892.87	0.73	0.1%	0.0%
Total Bill				**1,845.05**			**1,655.40**	**-189.65**	**-10.3%**	**-11.5%**

GS>50 to 999 kW
100 kW Consumption
40,000 kWh Consumption

	Metric	2007 BILL Volume	Rate $	Charge $	2008 BILL Volume	Rate $	Charge $	IMPACT Change $	Change %	% of Total Bill
Monthly Service Charge				387.30			205.49	-181.81	-46.9%	-4.9%
Distribution	kW	100	1.99270	199.27	100	1.95870	195.87	-3.40	-1.7%	-0.1%
Sub-Total				**586.57**			**401.36**	**-185.21**	**-31.6%**	**-5.0%**
Regulatory Asset Recovery	kW	100	0.32260	32.26	100	0.20940	20.94	-11.32	-35.1%	-0.3%
Retail Transmission - Network	kW	104	1.95610	203.96	104	1.95610	204.13	0.17	0.1%	0.0%
Retail Transmission - Line and Transformation Connection	kW	104	1.63590	170.58	104	1.63590	170.72	0.14	0.1%	0.0%
Wholesale Market Service	kWh	41,708	0.00520	216.88	41,742	0.00520	217.06	0.18	0.1%	0.0%
Rural Rate Protection Charge	kWh	41,708	0.00100	41.71	41,742	0.00100	41.74	0.03	0.1%	0.0%
Debt Retirement Charge	kWh	40,000	0.00700	280.00	40,000	0.00700	280.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	41,708	0.05704	2,379.02	41,742	0.05704	2,380.97	1.95	0.1%	0.1%
Total Bill				**3,910.98**			**3,716.92**	**-194.06**	**-5.0%**	**-5.2%**

GS>50 to 999 kW
500 kW Consumption
100,000 kWh Consumption

	Metric	2007 BILL Volume	Rate $	Charge $	2008 BILL Volume	Rate $	Charge $	IMPACT Change $	Change %	% of Total Bill
Monthly Service Charge				387.30			205.49	-181.81	-46.9%	-1.7%
Distribution	kW	500	1.99270	996.35	500	1.95870	979.35	-17.00	-1.7%	-0.2%
Sub-Total				**1,383.65**			**1,184.84**	**-198.81**	**-14.4%**	**-1.9%**
Regulatory Asset Recovery	kW	500	0.32260	161.30	500	0.20940	104.70	-56.60	-35.1%	-0.5%
Retail Transmission - Network	kW	521	1.95610	1,019.81	522	1.95610	1,020.65	0.84	0.1%	0.0%
Retail Transmission - Line and Transformation Connection	kW	521	1.63590	852.88	522	1.63590	853.58	0.70	0.1%	0.0%
Wholesale Market Service	kWh	104,270	0.00520	542.20	104,355	0.00520	542.65	0.44	0.1%	0.0%
Rural Rate Protection Charge	kWh	104,270	0.00100	104.27	104,355	0.00100	104.36	0.09	0.1%	0.0%
Debt Retirement Charge	kWh	100,000	0.00700	700.00	100,000	0.00700	700.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	104,270	0.05704	5,947.56	104,355	0.05704	5,952.44	4.88	0.1%	0.0%
Total Bill				**10,711.67**			**10,463.21**	**-248.47**	**-2.3%**	**-2.4%**

GS>50 to 999 kW
1,000 kW Consumption
400,000 kWh Consumption

	Metric	2007 BILL Volume	Rate $	Charge $	2008 BILL Volume	Rate $	Charge $	IMPACT Change $	Change %	% of Total Bill
Monthly Service Charge				387.30			205.49	-181.81	-46.9%	-0.5%
Distribution	kW	1,000	1.99270	1,992.70	1,000	1.95870	1,958.70	-34.00	-1.7%	-0.1%
Sub-Total				**2,380.00**			**2,164.19**	**-215.81**	**-9.1%**	**-0.6%**
Regulatory Asset Recovery	kW	1,000	0.32260	322.60	1,000	0.20940	209.40	-113.20	-35.1%	-0.3%
Retail Transmission - Network	kW	1,043	1.95610	2,039.63	1,044	1.95610	2,041.30	1.67	0.1%	0.0%
Retail Transmission - Line and Transformation Connection	kW	1,043	1.63590	1,705.75	1,044	1.63590	1,707.15	1.40	0.1%	0.0%
Wholesale Market Service	kWh	417,080	0.00520	2,168.82	417,422	0.00520	2,170.59	1.78	0.1%	0.0%
Rural Rate Protection Charge	kWh	417,080	0.00100	417.08	417,422	0.00100	417.42	0.34	0.1%	0.0%
Debt Retirement Charge	kWh	400,000	0.00700	2,800.00	400,000	0.00700	2,800.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	417,080	0.05704	23,790.24	417,422	0.05704	23,809.75	19.51	0.1%	0.1%
Total Bill				**35,624.12**			**35,319.81**	**-304.31**	**-0.9%**	**-0.9%**

ERIE THAMES POWERLINES
CORPORATION

9 - Rate Design

RATE DESIGN OVERVIEW - 2008 Rebasing Application

In the June 28, 2007 Staff discussion paper section 4.4 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 floor, ceiling and applied for values contained in the Erie Thames application.

Customer Class	Floor Value	Ceiling Value	120% Ceiling Value	Applied for Value
Residential	$ 7.69	$ 17.22	$ 20.66	$ 14.83
GS < 50 kW	$ 13.89	$ 24.91	$ 29.89	$ 19.13
GS 50 to 999 kW	$ 130.72	$ 171.24	$ 205.49	$ 205.49
GS 1,000 to 2,999 kW	$ 159.77	$ 216.16	$ 259.39	$ 2,376.33
GS 3,000 to 4,999 kW	$ 132.80	$ 181.31	$ 217.57	$ 2,769.45
Large Use	$ 161.15	$ 245.16	$ 294.19	$ 9,704.76
Street Light	$ 0.07	$ 10.67	$ 12.80	$ 3.70
Sentinel Light	$ 0.23	$ 10.82	$ 12.98	$ 5.08
Unmetered Load	$ 0.73	$ 9.49	$ 11.39	$ 2.73
Embedded Distributor	$ 1,833.18	$ 2,211.32	$ 2,653.58	$ 2,211.32

In general, Erie Thames has followed the guidelines outlined by Board Staff in the June 28 communication. The exceptions to these guidelines are the larger use general service customer classes, namely GS 1,000 to 2,999 kW, GS 3,000 to 4,999 kW and Large Use customer classes.

Historically the issue of fixed / variable rates has been widely debated since the commencement of the Ontario Government White Paper with arguments made for entirely fixed distribution rates to the fixed / variable structure currently employed and in the near future with a further reduction to values between the floor / ceiling as guided by Board Staff.

Currently Erie Thames collects the following fixed charge from the identified customer classes:

- General Service 50 to 999 kW = $381.03 representing 113 customers
- General Service 1,000 to 2,999 kW = $6,266.70 representing 8 customers
- General Service 3,000 to 4,999 kW = $7,023.01 representing 1 customers
- Large Use = $14,227.93 representing 1 customers

In an effort to stabilize revenues, Erie Thames has elected to move the General Service 50 to 999 kW class Regular fixed charge to 120% of the ceiling value. The General Service 50 to 999 kW fixed/variable split (39.55%/60.45%) has then been utilized for the GS 1,000 to 2,999 kW, GS 3,000 to 4,999 kW and Large Use classes.

It is Erie Thames opinion that moving the Large Use fixed charge from $14,227.30 to $294.19 does not meet the revenue stability objectives from the utility perspective or rate stability from the customer perspective. The applied for value of $12,530.23 is a compromise between the competing objectives and promotes consistency between the General Service classes with respect to fixed / variable splits. The same rationale applies to the TOU and Intermediate use classes.

EXISTING RATE CLASSES

RESIDENTIAL

Regular

This classification refers to the supply of electrical energy to customers residing in residential dwelling units.
Further servicing details are available in the distributor's Conditions of Service

GENERAL SERVICE

Less than 50 kW

This classification applies to a non residential account whose average monthly maximum demand is less than or is forecast to be less than, 50 kW, and town houses and condominiums that require centralized bulk metering.
Further servicing details are available in the distributor's Conditions of Service

Greater than 50 kW (to 999 kW)

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 1000 kW.
Note that for the application of Retail Transmission Rate-Network Service Rate and the Retail Transmission Rate- Line and Transformation Connection Service Rae the following sub-classifications apply.

General Service 50 to 1,000 kW non-interval metered
General Service 50 to 1,000 kW interval metered

Further servicing details are available in the distributor's Conditions of Service

Other > 50 kW (1000 kW to 2999 kW) .

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, 1,000 kW but less than 3,000 kW.
Note that for the application of Retail Transmission Rate-Network Service Rate and the Retail Transmission Rate- Line and Transformation Connection Service Rae the following sub-classifications apply.

General Service 1,000 to 3,000 kW non-interval metered
General Service 1,000 to 3,000 kW interval metered

Further servicing details are available in the distributor's Conditions of Service

Intermediate Use (3000 kW to 4999 kW)

This classification applies to an 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, 3,000 kW but less than 5,000 kW.
Further servicing details are available in the distributor's Conditions of Service

Large Use (> 5000 kW)
This classification applies to an 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, 5,000 kW.
Further servicing details are available in the distributor's Conditions of Service

Unmetered Scattered Load
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, decorative street lighting, billboards, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information and documentation with regard to electrical consumption of the unmetered load or periodic monitoring of the actual consumption.
Further servicing details are available in the distributor's Conditions of Service

Sentinel Lighting
This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light.

Street Lighting
This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and privat 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. Street Lighting plant, facilities or equipment owned by the customer are subject to the ESA requirements.

EXISTING RATE SCHEDULE

Residential	UOM	Rate
Service Charge	$	$14.0600
Distribution Volumetric Rate	$/kWh	$0.0137
Deferred Revenue Recovery Rate Rider	$/kWh	$0.0016
Regulatory Asset Recovery	$/kWh	$0.0047
Retail Transmission Rate – Network Service Rate	$/kWh	$0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	$0.0050
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0010
Regulated Price Plan – Administration Charge	$	$0.2500

GS<50 kW		
Service Charge	$	$27.6900
Distribution Volumetric Rate	$/kWh	$0.0164
Deferred Revenue Recovery Rate Rider	$/kWh	$0.0140
Regulatory Asset Recovery	$/kWh	$0.0030
Retail Transmission Rate – Network Service Rate	$/kWh	$0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	$0.0046
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0010
Regulated Price Plan – Administration Charge	$	$0.2500

GS>50 to 999 kW		
Service Charge	$	$387.3000
Distribution Volumetric Rate	$/kW	$1.9927
Deferred Revenue Recovery Rate Rider	$/kW	$0.0179
Regulatory Asset Recovery	$/kW	$0.3226
Retail Transmission Rate – Network Service Rate	$/kW	$1.9561
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.6359
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0010
Regulated Price Plan – Administration Charge	$	$0.2500

GS>1000 to 2999 kW		
Service Charge	$	$6,370.0300
Distribution Volumetric Rate	$/kW	$2.2348
Deferred Revenue Recovery Rate Rider	$/kW	$0.3929
Regulatory Asset Recovery	$/kW	$2.0238
Retail Transmission Rate – Network Service Rate	$/kW	$2.1246
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.7592
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0010
Regulated Price Plan – Administration Charge	$	$0.2500

GS>3000 to 4999 kW		
Service Charge	$	$7,138.8200
Distribution Volumetric Rate	$/kW	$2.1705
Deferred Revenue Recovery Rate Rider	$/kW	$0.1932
Regulatory Asset Recovery	$/kW	$0.1437
Retail Transmission Rate – Network Service Rate	$/kW	$2.2400
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.8774
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0010
Regulated Price Plan – Administration Charge	$	$0.2500
Large Use		
Service Charge	$	$14,462.5500
Distribution Volumetric Rate	$/kW	$1.3281
Deferred Revenue Recovery Rate Rider	$/kW	$0.1196
Regulatory Asset Recovery	$/kW	-$0.0674
Retail Transmission Rate – Network Service Rate	$/kW	$2.3553
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.9955
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0010
Regulated Price Plan – Administration Charge	$	$0.2500
Street Lighting		
Service Charge	$	$0.5200
Distribution Volumetric Rate	$/kW	$1.8175
Deferred Revenue Recovery Rate Rider	$/kW	$0.1817
Regulatory Asset Recovery	$/kW	-$0.1571
Retail Transmission Rate – Network Service Rate	$/kW	$1.5107
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.2633
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0010
Regulated Price Plan – Administration Charge	$	$0.2500
Sentinel Lighting		
Service Charge	$	$2.0800
Distribution Volumetric Rate	$/kW	$9.8952
Deferred Revenue Recovery Rate Rider	$/kW	$0.8168
Regulatory Asset Recovery	$/kW	$4.4848
Retail Transmission Rate – Network Service Rate	$/kW	$1.5107
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.2633
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0010
Regulated Price Plan – Administration Charge	$	$0.2500

Unmetered Scattered Load	$	$6.4500
Distribution Volumetric Rate	$/kWh	$0.0372
Deferred Revenue Recovery Rate Rider	$/kWh	$0.0025
Regulatory Asset Recovery	$/kWh	$0.0044
Retail Transmission Rate – Network Service Rate	$/kWh	$0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	$0.0046
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0010
Regulated Price Plan – Administration Charge	$	$0.2500

PROPOSED RATE CLASSES IF DIFFERENT THAN EXISTING

Erie Thames Powerlines proposes only one change to its existing rate classes. The Embedded Distributor class (as follows) is being requested to give ETPL a rate class to charge Hydro One for electricity provided by its distribution system as a result of Hydro One's decision to deregister its wholesale meter points the serve ETPL's distribution territory.

Embedded Distributor

This classification applies to an electricity distributor licensed by the Board, that is provided electricity by means of this distributor's facilities.

PROPOSED RATE SCHEDULE

Residential	UOM	Rate
Service Charge	$	$14.8300
Distribution Volumetric Rate	$/kWh	$0.0149
Deferred Revenue Recovery Rate Rider	$/kWh	$0.0016
Regulatory Asset Recovery	$/kWh	$0.0005
Retail Transmission Rate – Network Service Rate	$/kWh	$0.0038
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	$0.0047
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0010
Regulated Price Plan – Administration Charge	$	$0.2500
GS<50 kW		
Service Charge	$	$19.1300
Distribution Volumetric Rate	$/kWh	$0.0113
Deferred Revenue Recovery Rate Rider	$/kWh	$0.0140
Regulatory Asset Recovery	$/kWh	$0.0005
Retail Transmission Rate – Network Service Rate	$/kWh	$0.0035
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	$0.0044
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0010
Regulated Price Plan – Administration Charge	$	$0.2500
GS>50 to 999 kW		
Service Charge	$	$205.4900
Distribution Volumetric Rate	$/kW	$1.9587
Deferred Revenue Recovery Rate Rider	$/kW	$0.0179
Regulatory Asset Recovery	$/kW	$0.2094
Retail Transmission Rate – Network Service Rate	$/kW	$1.5967
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.5513
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0010
Regulated Price Plan – Administration Charge	$	$0.2500

GS>1000 to 2999 kW		
Service Charge	$	$2,376.3300
Distribution Volumetric Rate	$/kW	$3.4455
Deferred Revenue Recovery Rate Rider	$/kW	$0.3929
Regulatory Asset Recovery	$/kW	$0.2630
Retail Transmission Rate – Network Service Rate	$/kW	$1.7342
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.6682
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0010
Regulated Price Plan – Administration Charge	$	$0.2500

GS>3000 to 4999 kW		
Service Charge	$	$2,769.4500
Distribution Volumetric Rate	$/kW	$2.4216
Deferred Revenue Recovery Rate Rider	$/kW	$0.1932
Regulatory Asset Recovery	$/kW	$0.1906
Retail Transmission Rate – Network Service Rate	$/kW	$1.8284
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.7803
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0010
Regulated Price Plan – Administration Charge	$	$0.2500

Large Use		
Service Charge	$	$9,704.7600
Distribution Volumetric Rate	$/kW	$2.1118
Deferred Revenue Recovery Rate Rider	$/kW	$0.1196
Regulatory Asset Recovery	$/kW	$0.2568
Retail Transmission Rate – Network Service Rate	$/kW	$1.9225
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.8923
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0010
Regulated Price Plan – Administration Charge	$	$0.2500

Street Lighting		
Service Charge	$	$3.7000
Distribution Volumetric Rate	$/kW	$12.2888
Deferred Revenue Recovery Rate Rider	$/kW	$0.1817
Regulatory Asset Recovery	$/kW	$0.1694
Retail Transmission Rate – Network Service Rate	$/kW	$1.2331
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.1980
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0010
Regulated Price Plan – Administration Charge	$	$0.2500
Sentinel Lighting		
Service Charge	$	$5.0800
Distribution Volumetric Rate	$/kW	$16.1529
Deferred Revenue Recovery Rate Rider	$/kW	$0.8168
Regulatory Asset Recovery	$/kW	$0.2022
Retail Transmission Rate – Network Service Rate	$/kW	$1.2331
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$1.1980
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0010
Regulated Price Plan – Administration Charge	$	$0.2500
Unmetered Scattered Load	$	$2.7300
Distribution Volumetric Rate	$/kWh	$0.0141
Deferred Revenue Recovery Rate Rider	$/kWh	$0.0025
Regulatory Asset Recovery	$/kWh	$0.0005
Retail Transmission Rate – Network Service Rate	$/kWh	$0.0035
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	$0.0044
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0010
Regulated Price Plan – Administration Charge	$	$0.2500

Embedded Distributor

Service Charge	$	$2,211.3200
Distribution Volumetric Rate	$/kW	$1.6608
Deferred Revenue Recovery Rate Rider	$/kW	$0.0000
Regulatory Asset Recovery	$/kW	$0.1066
Retail Transmission Rate – Network Service Rate	$/kW	$2.3200
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	$2.2000
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0010
Regulated Price Plan – Administration Charge	$	$0.2500

SUMMARY OF PROPOSED RATE SCHEDULE

The following is a summary of the proposed changes to Erie Thames Powerlines rates for the 2008 test year. The Applicant is forecasting a distribution related delivery sufficiency for the 2008 test year of $317,071.

The impact on each rate class is described below.

Residential:
The proposed changes to Residential are summarized below.

	2006 Board Approved	2008 Proposed	% change
Service Charge	$14.06	$14.83	5.48%
Distribution Volumetric Rate	$0.0137	$0.0149	8.76%

In order to adjust the fixed cost recovery through the monthly fixed charge, ETPL is proposing to increase the monthly customer charge by $0.77 in the 2008 test year. The net impact of these changes is an increase in the revenue-to-cost ratios for Residential customers (from 91.12% to 101.00%).

The impact on a typical residential customer is an increase of 1.9% on the delivery component of the bill. The overall bill impact on a typical Residential customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

GS<50 kW:
The proposed changes to GS<50 kW are summarized below.

	2006 Board Approved	2008 Proposed	% change
Service Charge	$27.69	$19.13	-30.91%
Distribution Volumetric Rate	$0.0164	$0.0113	-31.10%

In order to adjust the fixed cost recovery through the monthly fixed charge, ETPL is proposing to decrease the monthly customer charge by $8.56 in the 2008 test year. The net impact of these changes is a decrease in the revenue-to-cost ratios for Residential customers (from 144.26% to 101.00%).

The impact on a typical GS<50 kW customer is a decrease of 7.0% on the delivery component of the bill. The overall bill impact on a typical GS<50 kW customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

GS>50 to 999 kW:
The proposed changes to GS>50 to 999 kW are summarized below.

	2006 Board Approved	2008 Proposed	% change
Service Charge	$387.30	$205.49	-46.94%
Distribution Volumetric Rate	$1.9927	$1.9587	-1.71%

In order to adjust the fixed cost recovery through the monthly fixed charge, ETPL is proposing to decrease the monthly customer charge by $181.81 in the 2008 test year. The net impact of these changes is a decrease in the revenue-to-cost ratios for GS.50 to 999 kW customers (from 117.00% to 101.00%).

The impact on a typical GS>50 to 999 kW customer is a decrease of 1.0% on the delivery component of the bill. The overall bill impact on a typical GS>50 to 999 kW customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

GS>1000 to 2999 kW:
The proposed changes to GS>1000 to 2999 kW are summarized below.

	2006 Board Approved	2008 Proposed	% change
Service Charge	$6,370.03	$2,376.33	-62.70%
Distribution Volumetric Rate	$2.2348	$3.4455	54.17%

In order to adjust the fixed cost recovery through the monthly fixed charge, ETPL is proposing to decrease the monthly customer charge by $3,993.70 in the 2008 test year. The net impact of these changes is a decrease in the revenue-to-cost ratios for GS>1000 to 2999 kW customers (from 147.47% to 101.00%).

The impact on a typical GS>1000 to 2999 kW customer is a decrease of 3.0% on the delivery component of the bill. The overall bill impact on a typical GS>1000 to 2999 kW customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

GS>3000 to 4999 kW:
The proposed changes to GS>3000 to 4999 kW are summarized below.

	2006 Board Approved	2008 Proposed	% change
Service Charge	$7,138.82	$2,769.45	-61.21%
Distribution Volumetric Rate	$2.1705	$2.4216	11.57%

In order to adjust the fixed cost recovery through the monthly fixed charge, ETPL is proposing to decrease the monthly customer charge by $4,369.37 in the 2008 test year. The net impact of these changes is a decrease in the revenue-to-cost ratios for GS>3000 to 4999 kW customers (from 190.03% to 101.00%).

The impact on a typical GS>3000 to 4999 kW customer is a decrease of 8.0% on the delivery component of the bill. The overall bill impact on a typical GS<50 kW customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

Large Use:
The proposed changes to Large Use are summarized below.

	2006 Board Approved	2008 Proposed	% change
Service Charge	$14,462.55	$9,704.76	-32.90%
Distribution Volumetric Rate	$1.3281	$2.1118	59.01%

Explanation; In order to adjust the fixed cost recovery through the monthly fixed charge, ETPL is proposing to decrease the monthly customer charge by $4,757.79 in the 2008 test year. The net impact of these changes is an increase in the revenue-to-cost ratios for Large Use customers (from 99.29% to 101.00%).

The impact on a typical Large Use customer is an increase of 1.0% on the delivery component of the bill. The overall bill impact on a typical Large Use customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

Street Lighting:
The proposed changes to Street Lighting are summarized below.

	2006 Board Approved	2008 Proposed	% change
Service Charge	$0.52	$3.70	611.54%
Distribution Volumetric Rate	$1.8175	$12.2888	576.14%

Explanation; In order to adjust the fixed cost recovery through the monthly fixed charge, ETPL is proposing to increase the monthly customer charge by $3.18 in the 2008 test year. The net impact of these changes is an increase in the revenue-to-cost ratios for Street Lighting connections (from 14.35% to 70.00%).

The impact on a typical Street Lighting connection is an increase of 64.0% on the delivery component of the bill. The overall bill impact on a typical Street Lighting connection is shown in detail in Exhibit 9, Tab 1, Schedule 9.

Sentinel Lighting:
The proposed changes to Sentinel Lighting are summarized below.

	2006 Board Approved	2008 Proposed	% change
Service Charge	$2.08	$5.08	144.23%
Distribution Volumetric Rate	$9.8952	$16.1529	63.24%

Explanation; In order to adjust the fixed cost recovery through the monthly fixed charge, ETPL is proposing to increase the monthly customer charge by $3.00 in the 2008 test year. The net impact of these changes is a decrease in the revenue-to-cost ratios for Sentinel Lighting customers (from 55.67% to 101.00%).

The impact on a typical Sentinel Lighting customer is an increase of 36.0% on the delivery component of the bill. The overall bill impact on a typical Sentinel Lighting customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

Unmetered Scattered Load:
The proposed changes to Unmetered Scattered Load are summarized below.

	2006 Board Approved	2008 Proposed	% change
Service Charge	$6.45	$2.73	-57.67%
Distribution Volumetric Rate	$.0372	$0.0141	-62.10%

Explanation; In order to adjust the fixed cost recovery through the monthly fixed charge, ETPL is proposing to decrease the monthly customer charge by $3.72 in the 2008 test year. The net impact of these changes is a decrease in the revenue-to-cost ratios for Unmetered Scattered Load customers (from 187.92% to 101.00%).

The impact on a typical Unmetered Scattered Load customer is a decrease of 8.0% on the delivery component of the bill. The overall bill impact on a typical Unmetered Scattered Load customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

RECONCILIATION OF RATE CLASS REVENUE TO TOTAL REVENUE REQUIREMENT

	Customers (Year-End)	Consumption (kWh / KW)	Proposed Fixed Charge	Proposed Variable Charge	Distribution Revenues($)
Residential	12,451	123,176,496	$14.8300	$0.0149	$4,051,170.36
GS<50	1,388	40,460,913	$19.1300	$0.0113	$775,919.34
GS>50 to 999 kW	141	359,657	$205.4900	$1.9587	$1,052,149.85
GS>1000 to 2999 kW	8	135,587	$2,376.3300	$3.4455	$621,506.91
GS>3000 kW to 4999 kW	1	35,687	$2,769.4500	$2.4216	$119,653.04
Large Use	1	165,609	$9,704.7600	$2.1118	$466,190.21
Unmetered Scattered Load	95	606,271	$2.7300	$0.0141	$11,660.62
Sentinel Lighting	256	931	$5.0800	$16.1529	$30,646.37
Street Lighting	2,956	9,432	$3.7000	$12.2888	$283,600.31
Embedded Distributor	2	99,771	$2,211.3200	$1.6608	$218,771.36
TOTAL	17,300				$7,631,268.37

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 May 1, 2006 rates and the proposed 2008 distribution rates, (including Rate Rider for the recovery of Regulatory Asset Variance Accounts) and adjusting the 2006 Retail Transmission Service Rates to the proposed 2008 levels.

The total bill impacts are calculated for the average customer per residential rate class and for General Service Classes at certain levels of consumption. The rates are assessed on the basis of moving to the proposed distribution rates derived in Exhibit 9, Tab 1, Schedule 5, including the Rate Rider for the recovery of regulatory asset variance accounts derived in Exhibit 5, Tab 1, Schedule 3. The total bill impacts are premised on the distribution rates arising from the new revenue requirements

RATE IMPACTS

Residential
100 kWh Consumption

		2007 BILL			2008 BILL			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				14.06			14.83	0.77	5.5%	3.1%
Distribution	kWh	100	0.01370	1.37	100	0.01490	1.49	0.12	8.8%	0.5%
Sub-Total				**15.43**			**16.32**	**0.89**	**5.8%**	**3.6%**
Regulatory Asset Recovery	kWh	100	0.00470	0.47	100	0.00050	0.05	-0.42	-89.4%	-1.7%
Retail Transmission - Network	kWh	104	0.00470	0.49	104	0.00380	0.40	-0.09	-19.1%	-0.4%
Retail Transmission - Line and Transformation	kWh	104	0.00500	0.52	104	0.00470	0.49	-0.03	-5.9%	-0.1%
Wholesale Market Service	kWh	104	0.00520	0.54	104	0.00520	0.54	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	104	0.00100	0.10	104	0.00100	0.10	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	100	0.00700	0.70	100	0.00700	0.70	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	104	0.05704	5.95	104	0.05704	5.95	0.00	0.1%	0.0%
Total Bill				**24.21**			**24.56**	**0.35**	**1.5%**	**1.4%**

Residential
250 kWh Consumption

		2007 BILL			2008 BILL			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				14.06			14.83	0.77	5.5%	2.0%
Distribution	kWh	250	0.01370	3.43	250	0.01490	3.73	0.30	8.8%	0.8%
Sub-Total				**17.49**			**18.56**	**1.07**	**6.1%**	**2.7%**
Regulatory Asset Recovery	kWh	250	0.00470	1.18	250	0.00050	0.13	-1.05	-89.4%	-2.7%
Retail Transmission - Network	kWh	261	0.00470	1.23	261	0.00380	0.99	-0.23	-19.1%	-0.6%
Retail Transmission - Line and Transformation	kWh	261	0.00500	1.30	261	0.00470	1.23	-0.08	-5.9%	-0.2%
Wholesale Market Service	kWh	261	0.00520	1.36	261	0.00520	1.36	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	261	0.00100	0.26	261	0.00100	0.26	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	250	0.00700	1.75	250	0.00700	1.75	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	261	0.05704	14.87	261	0.05704	14.88	0.01	0.1%	0.0%
Total Bill				**39.42**			**39.15**	**-0.28**	**-0.7%**	**-0.7%**

Residential
500 kWh Consumption

		2007 BILL			2008 BILL			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				14.06			14.83	0.77	5.5%	1.2%
Distribution	kWh	500	0.01370	6.85	500	0.01490	7.45	0.60	8.8%	0.9%
Sub-Total				**20.91**			**22.28**	**1.37**	**6.6%**	**2.2%**
Regulatory Asset Recovery	kWh	500	0.00470	2.35	500	0.00050	0.25	-2.10	-89.4%	-3.3%
Retail Transmission - Network	kWh	521	0.00470	2.45	522	0.00380	1.98	-0.47	-19.1%	-0.7%
Retail Transmission - Line and Transformation	kWh	521	0.00500	2.61	522	0.00470	2.45	-0.15	-5.9%	-0.2%
Wholesale Market Service	kWh	521	0.00520	2.71	522	0.00520	2.71	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	521	0.00100	0.52	522	0.00100	0.52	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	500	0.00700	3.50	500	0.00700	3.50	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	521	0.05704	29.74	522	0.05704	29.76	0.02	0.1%	0.0%
Total Bill				**64.79**			**63.46**	**-1.32**	**-2.0%**	**-2.1%**

Residential
750 kWh Consumption

	Metric	2007 BILL Volume	2007 BILL Rate $	2007 BILL Charge $	2008 BILL Volume	2008 BILL Rate $	2008 BILL Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				14.06			14.83	0.77	5.5%	0.9%
Distribution	kWh	750	0.01370	10.28	750	0.01490	11.18	0.90	8.8%	1.0%
Sub-Total				**24.34**			**26.01**	**1.67**	**6.9%**	**1.9%**
Regulatory Asset Recovery	kWh	750	0.00470	3.53	750	0.00050	0.38	-3.15	-89.4%	-3.6%
Retail Transmission - Network	kWh	782	0.00470	3.68	783	0.00380	2.97	-0.70	-19.1%	-0.8%
Retail Transmission - Line and Transformation	kWh	782	0.00500	3.91	783	0.00470	3.68	-0.23	-5.9%	-0.3%
Wholesale Market Service	kWh	782	0.00520	4.07	783	0.00520	4.07	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	782	0.00100	0.78	783	0.00100	0.78	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	750	0.00700	5.25	750	0.00700	5.25	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	782	0.05704	44.61	783	0.05704	44.64	0.04	0.1%	0.0%
Total Bill				**90.15**			**87.78**	**-2.37**	**-2.6%**	**-2.7%**

Residential
1,000 kWh Consumption

	Metric	2007 BILL Volume	2007 BILL Rate $	2007 BILL Charge $	2008 BILL Volume	2008 BILL Rate $	2008 BILL Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				14.06			14.83	0.77	5.5%	0.7%
Distribution	kWh	1,000	0.01370	13.70	1,000	0.01490	14.90	1.20	8.8%	1.1%
Sub-Total				**27.76**			**29.73**	**1.97**	**7.1%**	**1.8%**
Regulatory Asset Recovery	kWh	1,000	0.00470	4.70	1,000	0.00050	0.50	-4.20	-89.4%	-3.7%
Retail Transmission - Network	kWh	1,043	0.00470	4.90	1,044	0.00380	3.97	-0.94	-19.1%	-0.8%
Retail Transmission - Line and Transformation	kWh	1,043	0.00500	5.21	1,044	0.00470	4.90	-0.31	-5.9%	-0.3%
Wholesale Market Service	kWh	1,043	0.00520	5.42	1,044	0.00520	5.43	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	1,043	0.00100	1.04	1,044	0.00100	1.04	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	1,000	0.00700	7.00	1,000	0.00700	7.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,043	0.05704	59.48	1,044	0.05704	59.52	0.05	0.1%	0.0%
Total Bill				**115.51**			**112.09**	**-3.42**	**-3.0%**	**-3.1%**

Residential
1,500 kWh Consumption

	Metric	2007 BILL Volume	2007 BILL Rate $	2007 BILL Charge $	2008 BILL Volume	2008 BILL Rate $	2008 BILL Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				14.06			14.83	0.77	5.5%	0.5%
Distribution	kWh	1,500	0.01370	20.55	1,500	0.01490	22.35	1.80	8.8%	1.1%
Sub-Total				**34.61**			**37.18**	**2.57**	**7.4%**	**1.6%**
Regulatory Asset Recovery	kWh	1,500	0.00470	7.05	1,500	0.00050	0.75	-6.30	-89.4%	-3.9%
Retail Transmission - Network	kWh	1,564	0.00470	7.35	1,565	0.00380	5.95	-1.40	-19.1%	-0.9%
Retail Transmission - Line and Transformation	kWh	1,564	0.00500	7.82	1,565	0.00470	7.36	-0.46	-5.9%	-0.3%
Wholesale Market Service	kWh	1,564	0.00520	8.13	1,565	0.00520	8.14	0.01	0.1%	0.0%
Rural Rate Protection Charge	kWh	1,564	0.00100	1.56	1,565	0.00100	1.57	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	1,500	0.00700	10.50	1,500	0.00700	10.50	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,564	0.05704	89.21	1,565	0.05704	89.29	0.07	0.1%	0.0%
Total Bill				**166.24**			**160.73**	**-5.51**	**-3.3%**	**-3.4%**

Residential
2,000 kWh Consumption

	Metric	2007 BILL Volume	2007 BILL Rate $	2007 BILL Charge $	2008 BILL Volume	2008 BILL Rate $	2008 BILL Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				14.06			14.83	0.77	5.5%	0.4%
Distribution	kWh	2,000	0.01370	27.40	2,000	0.01490	29.80	2.40	8.8%	1.1%
Sub-Total				**41.46**			**44.63**	**3.17**	**7.6%**	**1.5%**
Regulatory Asset Recovery	kWh	2,000	0.00470	9.40	2,000	0.00050	1.00	-8.40	-89.4%	-4.0%
Retail Transmission - Network	kWh	2,085	0.00470	9.80	2,087	0.00380	7.93	-1.87	-19.1%	-0.9%
Retail Transmission - Line and Transformation	kWh	2,085	0.00500	10.43	2,087	0.00470	9.81	-0.62	-5.9%	-0.3%
Wholesale Market Service	kWh	2,085	0.00520	10.84	2,087	0.00520	10.85	0.01	0.1%	0.0%
Rural Rate Protection Charge	kWh	2,085	0.00100	2.09	2,087	0.00100	2.09	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	2,000	0.00700	14.00	2,000	0.00700	14.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	2,085	0.05704	118.95	2,087	0.05704	119.05	0.10	0.1%	0.0%
Total Bill				**216.97**			**209.36**	**-7.61**	**-3.5%**	**-3.6%**

GS <50
1,000 kWh Consumption

	Metric	2007 BILL Volume	2007 BILL Rate $	2007 BILL Charge $	2008 BILL Volume	2008 BILL Rate $	2008 BILL Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				27.69			19.13	-8.56	-30.9%	-7.6%
Distribution	kWh	1,000	0.01640	16.40	1,000	0.01130	11.30	-5.10	-31.1%	-4.5%
Sub-Total				**44.09**			**30.43**	**-13.66**	**-31.0%**	**-12.2%**
Regulatory Asset Recovery	kWh	1,000	0.00300	3.00	1,000	0.00050	0.50	-2.50	-83.3%	-2.2%
Retail Transmission - Network	kWh	1,043	0.00430	4.48	1,044	0.00350	3.65	-0.83	-18.5%	-0.7%
Retail Transmission - Line and Transformation	kWh	1,043	0.00460	4.80	1,044	0.00440	4.59	-0.20	-4.3%	-0.2%
Wholesale Market Service	kWh	1,043	0.00520	5.42	1,044	0.00520	5.43	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	1,043	0.00100	1.04	1,044	0.00100	1.04	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	1,000	0.00700	7.00	1,000	0.00700	7.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,043	0.05704	59.48	1,044	0.05704	59.52	0.05	0.1%	0.0%
Total Bill				**129.31**			**112.17**	**-17.14**	**-13.3%**	**-15.3%**

GS <50
2,000 kWh Consumption

	Metric	2007 BILL Volume	2007 BILL Rate $	2007 BILL Charge $	2008 BILL Volume	2008 BILL Rate $	2008 BILL Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				27.69			19.13	-8.56	-30.9%	-4.2%
Distribution	kWh	2,000	0.01640	32.80	2,000	0.01130	22.60	-10.20	-31.1%	-5.0%
Sub-Total				**60.49**			**41.73**	**-18.76**	**-31.0%**	**-9.1%**
Regulatory Asset Recovery	kWh	2,000	0.00300	6.00	2,000	0.00050	1.00	-5.00	-83.3%	-2.4%
Retail Transmission - Network	kWh	2,085	0.00430	8.97	2,087	0.00350	7.30	-1.66	-18.5%	-0.8%
Retail Transmission - Line and Transformation	kWh	2,085	0.00460	9.59	2,087	0.00440	9.18	-0.41	-4.3%	-0.2%
Wholesale Market Service	kWh	2,085	0.00520	10.84	2,087	0.00520	10.85	0.01	0.1%	0.0%
Rural Rate Protection Charge	kWh	2,085	0.00100	2.09	2,087	0.00100	2.09	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	2,000	0.00700	14.00	2,000	0.00700	14.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	2,085	0.05704	118.95	2,087	0.05704	119.05	0.10	0.1%	0.0%
Total Bill				**230.93**			**205.21**	**-25.72**	**-11.1%**	**-12.5%**

GS <50
5,000 kWh Consumption

	Metric	2007 BILL Volume	Rate $	Charge $	2008 BILL Volume	Rate $	Charge $	IMPACT Change $	Change %	% of Total Bill
Monthly Service Charge				27.69			19.13	-8.56	-30.9%	-1.8%
Distribution	kWh	5,000	0.01640	82.00	5,000	0.01130	56.50	-25.50	-31.1%	-5.3%
Sub-Total				**109.69**			**75.63**	**-34.06**	**-31.1%**	**-7.0%**
Regulatory Asset Recovery	kWh	5,000	0.00300	15.00	5,000	0.00050	2.50	-12.50	-83.3%	-2.6%
Retail Transmission - Network	kWh	5,214	0.00430	22.42	5,218	0.00350	18.26	-4.16	-18.5%	-0.9%
Retail Transmission - Line and Transformation	kWh	5,214	0.00460	23.98	5,218	0.00440	22.96	-1.02	-4.3%	-0.2%
Wholesale Market Service	kWh	5,214	0.00520	27.11	5,218	0.00520	27.13	0.02	0.1%	0.0%
Rural Rate Protection Charge	kWh	5,214	0.00100	5.21	5,218	0.00100	5.22	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	5,000	0.00700	35.00	5,000	0.00700	35.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	5,214	0.05704	297.38	5,218	0.05704	297.62	0.24	0.1%	0.1%
Total Bill				**535.79**			**484.32**	**-51.47**	**-9.6%**	**-10.6%**

GS <50
10,000 kWh Consumption

	Metric	2007 BILL Volume	Rate $	Charge $	2008 BILL Volume	Rate $	Charge $	IMPACT Change $	Change %	% of Total Bill
Monthly Service Charge				27.69			19.13	-8.56	-30.9%	-0.9%
Distribution	kWh	10,000	0.01640	164.00	10,000	0.01130	113.00	-51.00	-31.1%	-5.4%
Sub-Total				**191.69**			**132.13**	**-59.56**	**-31.1%**	**-6.3%**
Regulatory Asset Recovery	kWh	10,000	0.00300	30.00	10,000	0.00050	5.00	-25.00	-83.3%	-2.6%
Retail Transmission - Network	kWh	10,427	0.00430	44.84	10,436	0.00350	36.52	-8.31	-18.5%	-0.9%
Retail Transmission - Line and Transformation	kWh	10,427	0.00460	47.96	10,436	0.00440	45.92	-2.05	-4.3%	-0.2%
Wholesale Market Service	kWh	10,427	0.00520	54.22	10,436	0.00520	54.26	0.04	0.1%	0.0%
Rural Rate Protection Charge	kWh	10,427	0.00100	10.43	10,436	0.00100	10.44	0.01	0.1%	0.0%
Debt Retirement Charge	kWh	10,000	0.00700	70.00	10,000	0.00700	70.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	10,427	0.05704	594.76	10,436	0.05704	595.24	0.49	0.1%	0.1%
Total Bill				**1,043.89**			**949.51**	**-94.38**	**-9.0%**	**-9.9%**

GS <50
15,000 kWh Consumption

	Metric	2007 BILL Volume	Rate $	Charge $	2008 BILL Volume	Rate $	Charge $	IMPACT Change $	Change %	% of Total Bill
Monthly Service Charge				27.69			19.13	-8.56	-30.9%	-0.6%
Distribution	kWh	15,000	0.01640	246.00	15,000	0.01130	169.50	-76.50	-31.1%	-5.4%
Sub-Total				**273.69**			**188.63**	**-85.06**	**-31.1%**	**-6.0%**
Regulatory Asset Recovery	kWh	15,000	0.00300	45.00	15,000	0.00050	7.50	-37.50	-83.3%	-2.7%
Retail Transmission - Network	kWh	15,641	0.00430	67.25	15,653	0.00350	54.79	-12.47	-18.5%	-0.9%
Retail Transmission - Line and Transformation	kWh	15,641	0.00460	71.95	15,653	0.00440	68.87	-3.07	-4.3%	-0.2%
Wholesale Market Service	kWh	15,641	0.00520	81.33	15,653	0.00520	81.40	0.07	0.1%	0.0%
Rural Rate Protection Charge	kWh	15,641	0.00100	15.64	15,653	0.00100	15.65	0.01	0.1%	0.0%
Debt Retirement Charge	kWh	15,000	0.00700	105.00	15,000	0.00700	105.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	15,641	0.05704	892.13	15,653	0.05704	892.87	0.73	0.1%	0.1%
Total Bill				**1,552.00**			**1,414.71**	**-137.29**	**-8.8%**	**-9.7%**

GS>50 to 999 kW

60 kW Consumption
15,000 kWh Consumption

	Metric	2007 BILL Volume	2007 BILL Rate $	2007 BILL Charge $	2008 BILL Volume	2008 BILL Rate $	2008 BILL Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				387.30			205.49	-181.81	-46.9%	-11.2%
Distribution	kW	60	1.99270	119.56	60	1.95870	117.52	-2.04	-1.7%	-0.1%
Sub-Total				**506.86**			**323.01**	**-183.85**	**-36.3%**	**-11.3%**
Regulatory Asset Recovery	kW	60	0.32260	19.36	60	0.20940	12.56	-6.79	-35.1%	-0.4%
Retail Transmission - Network	kW	63	1.95610	122.38	63	1.59670	99.97	-22.40	-18.3%	-1.4%
Retail Transmission - Line and Transformation	kW	63	1.63590	102.35	63	1.55130	97.13	-5.21	-5.1%	-0.3%
Wholesale Market Service	kWh	15,641	0.00520	81.33	15,653	0.00520	81.40	0.07	0.1%	0.0%
Rural Rate Protection Charge	kWh	15,641	0.00100	15.64	15,653	0.00100	15.65	0.01	0.1%	0.0%
Debt Retirement Charge	kWh	15,000	0.00700	105.00	15,000	0.00700	105.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	15,641	0.05704	892.13	15,653	0.05704	892.87	0.73	0.1%	0.0%
Total Bill				**1,845.05**			**1,627.60**	**-217.45**	**-11.8%**	**-13.4%**

GS>50 to 999 kW

100 kW Consumption
40,000 kWh Consumption

	Metric	2007 BILL Volume	2007 BILL Rate $	2007 BILL Charge $	2008 BILL Volume	2008 BILL Rate $	2008 BILL Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				387.30			205.49	-181.81	-46.9%	-5.0%
Distribution	kW	100	1.99270	199.27	100	1.95870	195.87	-3.40	-1.7%	-0.1%
Sub-Total				**586.57**			**401.36**	**-185.21**	**-31.6%**	**-5.0%**
Regulatory Asset Recovery	kW	100	0.32260	32.26	100	0.20940	20.94	-11.32	-35.1%	-0.3%
Retail Transmission - Network	kW	104	1.95610	203.96	104	1.59670	166.62	-37.34	-18.3%	-1.0%
Retail Transmission - Line and Transformation	kW	104	1.63590	170.58	104	1.55130	161.89	-8.69	-5.1%	-0.2%
Wholesale Market Service	kWh	41,708	0.00520	216.88	41,742	0.00520	217.06	0.18	0.1%	0.0%
Rural Rate Protection Charge	kWh	41,708	0.00100	41.71	41,742	0.00100	41.74	0.03	0.1%	0.0%
Debt Retirement Charge	kWh	40,000	0.00700	280.00	40,000	0.00700	280.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	41,708	0.05704	2,379.02	41,742	0.05704	2,380.97	1.95	0.1%	0.1%
Total Bill				**3,910.98**			**3,670.59**	**-240.39**	**-6.1%**	**-6.5%**

GS>50 to 999 kW

500 kW Consumption
100,000 kWh Consumption

	Metric	2007 BILL Volume	2007 BILL Rate $	2007 BILL Charge $	2008 BILL Volume	2008 BILL Rate $	2008 BILL Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				387.30			205.49	-181.81	-46.9%	-1.8%
Distribution	kW	500	1.99270	996.35	500	1.95870	979.35	-17.00	-1.7%	-0.2%
Sub-Total				**1,383.65**			**1,184.84**	**-198.81**	**-14.4%**	**-1.9%**
Regulatory Asset Recovery	kW	500	0.32260	161.30	500	0.20940	104.70	-56.60	-35.1%	-0.6%
Retail Transmission - Network	kW	521	1.95610	1,019.81	522	1.59670	833.12	-186.69	-18.3%	-1.8%
Retail Transmission - Line and Transformation	kW	521	1.63590	852.88	522	1.55130	809.43	-43.44	-5.1%	-0.4%
Wholesale Market Service	kWh	104,270	0.00520	542.20	104,355	0.00520	542.65	0.44	0.1%	0.0%
Rural Rate Protection Charge	kWh	104,270	0.00100	104.27	104,355	0.00100	104.36	0.09	0.1%	0.0%
Debt Retirement Charge	kWh	100,000	0.00700	700.00	100,000	0.00700	700.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	104,270	0.05704	5,947.56	104,355	0.05704	5,952.44	4.88	0.1%	0.0%
Total Bill				**10,711.67**			**10,231.54**	**-480.14**	**-4.5%**	**-4.7%**

ERIE THAMES POWERLINES
CORPORATION

GS>50 to 999 kW

1,000 kW Consumption
400,000 kWh Consumption

	Metric	2007 BILL Volume	Rate $	Charge $	2008 BILL Volume	Rate $	Charge $	IMPACT Change $	Change %	% of Total Bill
Monthly Service Charge				387.30			205.49	-181.81	-46.9%	-0.5%
Distribution	kW	1,000	1.99270	1,992.70	1,000	1.95870	1,958.70	-34.00	-1.7%	-0.1%
Sub-Total				**2,380.00**			**2,164.19**	**-215.81**	**-9.1%**	**-0.6%**
Regulatory Asset Recovery	kW	1,000	0.32260	322.60	1,000	0.20940	209.40	-113.20	-35.1%	-0.3%
Retail Transmission - Network	kW	1,043	1.95610	2,039.63	1,044	1.59670	1,666.24	-373.38	-18.3%	-1.1%
Retail Transmission - Line and Transformation Connection	kW	1,043	1.63590	1,705.75	1,044	1.55130	1,618.87	-86.89	-5.1%	-0.2%
Wholesale Market Service	kWh	417,080	0.00520	2,168.82	417,422	0.00520	2,170.59	1.78	0.1%	0.0%
Rural Rate Protection Charge	kWh	417,080	0.00100	417.08	417,422	0.00100	417.42	0.34	0.1%	0.0%
Debt Retirement Charge	kWh	400,000	0.00700	2,800.00	400,000	0.00700	2,800.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	417,080	0.05704	23,790.24	417,422	0.05704	23,809.75	19.51	0.1%	0.1%
Total Bill				**35,624.12**			**34,856.47**	**-767.65**	**-2.2%**	**-2.2%**

GS>50 to 999 kW

3,000 kW Consumption
1,000,000 kWh Consumption

	Metric	2007 BILL Volume	Rate $	Charge $	2008 BILL Volume	Rate $	Charge $	IMPACT Change $	Change %	% of Total Bill
Monthly Service Charge				387.30			205.49	-181.81	-46.9%	-0.2%
Distribution	kW	3,000	1.99270	5,978.10	3,000	1.95870	5,876.10	-102.00	-1.7%	-0.1%
Sub-Total				**6,365.40**			**6,081.59**	**-283.81**	**-4.5%**	**-0.3%**
Regulatory Asset Recovery	kW	3,000	0.32260	967.80	3,000	0.20940	628.20	-339.60	-35.1%	-0.4%
Retail Transmission - Network	kW	3,128	1.95610	6,118.88	3,131	1.59670	4,998.73	-1,120.14	-18.3%	-1.3%
Retail Transmission - Line and Transformation Connection	kW	3,128	1.63590	5,117.26	3,131	1.55130	4,856.60	-260.66	-5.1%	-0.3%
Wholesale Market Service	kWh	1,042,700	0.00520	5,422.04	1,043,555	0.00520	5,426.49	4.45	0.1%	0.0%
Rural Rate Protection Charge	kWh	1,042,700	0.00100	1,042.70	1,043,555	0.00100	1,043.55	0.85	0.1%	0.0%
Debt Retirement Charge	kWh	1,000,000	0.00700	7,000.00	1,000,000	0.00700	7,000.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,042,700	0.05704	59,475.61	1,043,555	0.05704	59,524.37	48.77	0.1%	0.1%
Total Bill				**91,509.68**			**89,559.54**	**-1,950.14**	**-2.1%**	**-2.2%**

Large Use

6,000 kW Consumption
2,800,000 kWh Consumption

	Metric	2007 BILL Volume	Rate $	Charge $	2008 BILL Volume	Rate $	Charge $	IMPACT Change $	Change %	% of Total Bill
Monthly Service Charge				14,462.55			9,704.76	-4,757.79	-32.9%	-2.0%
Distribution	kW	6,000	1.32810	7,968.60	6,000	2.11180	12,670.80	4,702.20	59.0%	1.9%
Sub-Total				**22,431.15**			**22,375.56**	**-55.59**	**-0.2%**	**0.0%**
Regulatory Asset Recovery	kW	6,000	-0.06740	-404.40	6,000	0.25680	1,540.80	1,945.20	-481.0%	0.8%
Retail Transmission - Network	kW	6,000	2.35530	14,131.80	6,000	1.92250	11,535.00	-2,596.80	-18.4%	-1.1%
Retail Transmission - Line and Transformation Connection	kW	6,000	1.99550	11,973.00	6,000	1.89230	11,353.80	-619.20	-5.2%	-0.3%
Wholesale Market Service	kWh	2,800,000	0.00520	14,560.00	2,800,000	0.00520	14,560.00	0.00	0.0%	0.0%
Rural Rate Protection Charge	kWh	2,800,000	0.00100	2,800.00	2,800,000	0.00100	2,800.00	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	2,800,000	0.00700	19,600.00	2,800,000	0.00700	19,600.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	2,800,000	0.05704	159,712.00	2,800,000	0.05704	159,712.00	0.00	0.0%	0.0%
Total Bill				**244,803.55**			**243,477.16**	**-1,326.39**	**-0.5%**	**-0.5%**

Large Use

15,000 kW Consumption
7,000,000 kWh Consumption

		2007 BILL			2008 BILL			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				14,462.55			9,704.76	-4,757.79	-32.9%	-0.8%
Distribution	kW	15,000	1.32810	19,921.50	15,000	2.11180	31,677.00	11,755.50	59.0%	2.0%
Sub-Total				**34,384.05**			**41,381.76**	**6,997.71**	**20.4%**	**1.2%**
Regulatory Asset Recovery	kW	15,000	-0.06740	-1,011.00	15,000	0.25680	3,852.00	4,863.00	-481.0%	0.8%
Retail Transmission - Network	kW	15,000	2.35530	35,329.50	15,000	1.92250	28,837.50	-6,492.00	-18.4%	-1.1%
Retail Transmission - Line and Transformation Connection	kW	15,000	1.99550	29,932.50	15,000	1.89230	28,384.50	-1,548.00	-5.2%	-0.3%
Wholesale Market Service	kWh	7,000,000	0.00520	36,400.00	7,000,000	0.00520	36,400.00	0.00	0.0%	0.0%
Rural Rate Protection Charge	kWh	7,000,000	0.00100	7,000.00	7,000,000	0.00100	7,000.00	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	7,000,000	0.00700	49,000.00	7,000,000	0.00700	49,000.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	7,000,000	0.05704	399,280.00	7,000,000	0.05704	399,280.00	0.00	0.0%	0.0%
Total Bill				**590,315.05**			**594,135.76**	**3,820.71**	**0.6%**	**0.6%**

Large Use

30,000 kW Consumption
20,000,000 kWh Consumption

		2007 BILL			2008 BILL			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				14,462.55			9,704.76	-4,757.79	-32.9%	-0.3%
Distribution	kW	30,000	1.32810	39,843.00	30,000	2.11180	63,354.00	23,511.00	59.0%	1.5%
Sub-Total				**54,305.55**			**73,058.76**	**18,753.21**	**34.5%**	**1.2%**
Regulatory Asset Recovery	kW	30,000	-0.06740	-2,022.00	30,000	0.25680	7,704.00	9,726.00	-481.0%	0.6%
Retail Transmission - Network	kW	30,000	2.35530	70,659.00	30,000	1.92250	57,675.00	-12,984.00	-18.4%	-0.8%
Retail Transmission - Line and Transformation Connection	kW	30,000	1.99550	59,865.00	30,000	1.89230	56,769.00	-3,096.00	-5.2%	-0.2%
Wholesale Market Service	kWh	20,000,000	0.00520	104,000.00	20,000,000	0.00520	104,000.00	0.00	0.0%	0.0%
Rural Rate Protection Charge	kWh	20,000,000	0.00100	20,000.00	20,000,000	0.00100	20,000.00	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	20,000,000	0.00700	140,000.00	20,000,000	0.00700	140,000.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	20,000,000	0.05704	1,140,800.00	20,000,000	0.05704	1,140,800.00	0.00	0.0%	0.0%
Total Bill				**1,587,607.55**			**1,600,006.76**	**12,399.21**	**0.8%**	**0.8%**

Large Use

100,000 kW Consumption
53,000,000 kWh Consumption

		2007 BILL			2008 BILL			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				14,462.55			9,704.76	-4,757.79	-32.9%	-0.1%
Distribution	kW	100,000	1.32810	132,810.00	100,000	2.11180	211,180.00	78,370.00	59.0%	1.8%
Sub-Total				**147,272.55**			**220,884.76**	**73,612.21**	**50.0%**	**1.7%**
Regulatory Asset Recovery	kW	100,000	-0.06740	-6,740.00	100,000	0.25680	25,680.00	32,420.00	-481.0%	0.7%
Retail Transmission - Network	kW	100,000	2.35530	235,530.00	100,000	1.92250	192,250.00	-43,280.00	-18.4%	-1.0%
Retail Transmission - Line and Transformation Connection	kW	100,000	1.99550	199,550.00	100,000	1.89230	189,230.00	-10,320.00	-5.2%	-0.2%
Wholesale Market Service	kWh	53,000,000	0.00520	275,600.00	53,000,000	0.00520	275,600.00	0.00	0.0%	0.0%
Rural Rate Protection Charge	kWh	53,000,000	0.00100	53,000.00	53,000,000	0.00100	53,000.00	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	53,000,000	0.00700	371,000.00	53,000,000	0.00700	371,000.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	53,000,000	0.05704	3,023,120.00	53,000,000	0.05704	3,023,120.00	0.00	0.0%	0.0%
Total Bill				**4,298,332.55**			**4,350,764.76**	**52,432.21**	**1.2%**	**1.2%**

Street Light

1 kW Consumption
25 kWh Consumption

	Metric	2007 BILL Volume	Rate $	Charge $	2008 BILL Volume	Rate $	Charge $	IMPACT Change $	Change %	% of Total Bill
Monthly Service Charge				0.52			3.70	3.18	611.5%	19.0%
Distribution	kW	1	1.81750	1.36	1	12.28880	9.22	7.85	576.1%	46.9%
Sub-Total				**1.88**			**12.92**	**11.03**	**585.9%**	**65.9%**
Regulatory Asset Recovery	kW	1	-0.15710	-0.12	1	0.16940	0.13	0.24	-207.8%	1.5%
Retail Transmission - Network	kW	1	1.51070	1.17	1	1.23310	0.96	-0.21	-18.3%	-1.3%
Retail Transmission - Line and Transformation Connection	kW	1	1.26330	0.98	1	1.19800	0.93	-0.05	-5.1%	-0.3%
Wholesale Market Service	kWh	26	0.00520	0.13	26	0.00520	0.13	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	26	0.00100	0.03	26	0.00100	0.03	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	25	0.00700	0.18	25	0.00700	0.18	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	26	0.05704	1.47	26	0.05704	1.47	0.00	0.1%	0.0%
Total Bill				**5.72**			**16.74**	**11.02**	**192.6%**	**65.8%**

Sentinel

0.75 kW Consumption
25 kWh Consumption

	Metric	2007 BILL Volume	Rate $	Charge $	2008 BILL Volume	Rate $	Charge $	IMPACT Change $	Change %	% of Total Bill
Monthly Service Charge				2.08			5.08	3.00	144.2%	14.2%
Distribution	kW	1	9.73620	7.30	1	16.15290	12.11	4.81	65.9%	22.8%
Sub-Total				**9.38**			**17.19**	**7.81**	**83.3%**	**37.1%**
Regulatory Asset Recovery	kW	1	4.48480	3.36	1	0.20220	0.15	-3.21	-95.5%	-15.2%
Retail Transmission - Network	kW	1	1.51070	1.18	1	1.23310	0.97	-0.22	-18.3%	-1.0%
Retail Transmission - Line and Transformation Connection	kW	1	1.26330	0.99	1	1.19800	0.94	-0.05	-5.1%	-0.2%
Wholesale Market Service	kWh	26	0.00520	0.14	26	0.00520	0.14	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	26	0.00100	0.03	26	0.00100	0.03	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	25	0.00700	0.18	25	0.00700	0.18	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	26	0.05704	1.49	26	0.05704	1.49	0.00	0.1%	0.0%
Total Bill				**16.74**			**21.07**	**4.34**	**25.9%**	**20.6%**

Sentinel

0.75 kW Consumption
50 kWh Consumption

	Metric	2007 BILL Volume	Rate $	Charge $	2008 BILL Volume	Rate $	Charge $	IMPACT Change $	Change %	% of Total Bill
Monthly Service Charge				2.08			5.08	3.00	144.2%	13.1%
Distribution	kW	1	9.73620	7.30	1	16.15290	12.11	4.81	65.9%	21.0%
Sub-Total				**9.38**			**17.19**	**7.81**	**83.3%**	**34.1%**
Regulatory Asset Recovery	kW	1	4.48480	3.36	1	0.20220	0.15	-3.21	-95.5%	-14.0%
Retail Transmission - Network	kW	1	1.51070	1.18	1	1.23310	0.97	-0.22	-18.3%	-0.9%
Retail Transmission - Line and Transformation Connection	kW	1	1.26330	0.99	1	1.19800	0.94	-0.05	-5.1%	-0.2%
Wholesale Market Service	kWh	52	0.00520	0.27	52	0.00520	0.27	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	52	0.00100	0.05	52	0.00100	0.05	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	50	0.00700	0.35	50	0.00700	0.35	0.00	0.0%	0.0%
Cost of Power Commodity				2.97	52	0.05704	2.98	0.00	0.1%	0.0%
Total Bill				**18.56**			**22.90**	**4.34**	**23.4%**	**18.9%**

Consumption levels for unmetered
scattered load and Back/Stand-by

Unmetered Scattered Load

1	kW Consumption
600	kWh Consumption

		2007 BILL			2008 BILL			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				6.45			2.73	-3.72	-57.7%	-8.0%
Distribution	kW	1	0.03720	0.04	1	0.01410	0.01	-0.02	-62.1%	0.0%
Sub-Total				**6.49**			**2.74**	**-3.74**	**-57.7%**	**-8.0%**
Regulatory Asset Recovery	kW	1	0.00440	0.00	1	0.00050	0.00	-0.00	-88.6%	0.0%
Retail Transmission - Network	kW	1	0.00430	0.00	1	0.00350	0.00	-0.00	-18.5%	0.0%
Retail Transmission - Line and Transformation Connection	kW	1	0.00460	0.00	1	0.00440	0.00	-0.00	-4.3%	0.0%
Wholesale Market Service	kWh	626	0.00520	3.25	626	0.00520	3.26	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	626	0.00100	0.63	626	0.00100	0.63	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	600	0.00700	4.20	600	0.00700	4.20	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	626	0.05704	35.69	626	0.05704	35.71	0.03	0.1%	0.1%
Total Bill				**50.27**			**46.55**	**-3.72**	**-7.4%**	**-8.0%**

GS>1000 to 2999 kW

1700	kW Consumption
700000	kWh Consumption

		2007 BILL			2008 BILL			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				6,370.03			2,376.33	-3,993.70	-62.7%	-6.3%
Distribution	kW	1,700	2.23480	3,799.16	1,700	3.44550	5,857.35	2,058.19	54.2%	3.2%
Sub-Total				**10,169.19**			**8,233.68**	**-1,935.51**	**-19.0%**	**-3.0%**
Regulatory Asset Recovery	kW	1,700	2.02380	3,440.46	1,700	0.19060	324.02	-3,116.44	-90.6%	-4.9%
Retail Transmission - Network	kW	1,700	2.12460	3,611.82	1,700	1.73420	2,948.14	-663.68	-18.4%	-1.0%
Retail Transmission - Line and Transformation Connection	kW	1,700	1.75920	2,990.64	1,700	1.66820	2,835.94	-154.70	-5.2%	-0.2%
Wholesale Market Service	kWh	700,000	0.00520	3,640.00	700,000	0.00520	3,640.00	0.00	0.0%	0.0%
Rural Rate Protection Charge	kWh	700,000	0.00100	700.00	700,000	0.00100	700.00	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	700,000	0.00700	4,900.00	700,000	0.00700	4,900.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	700,000	0.05704	39,928.00	700,000	0.05704	39,928.00	0.00	0.0%	0.0%
Total Bill				**69,380.11**			**63,509.78**	**-5,870.33**	**-8.5%**	**-9.2%**

GS>1000 to 2999 kW

1500	kW Consumption
750000	kWh Consumption

		2007 BILL			2008 BILL			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				6,370.03			2,376.33	-3,993.70	-62.7%	-6.3%
Distribution	kW	1,500	2.23480	3,352.20	1,500	3.44550	5,168.25	1,816.05	54.2%	2.9%
Sub-Total				**9,722.23**			**7,544.58**	**-2,177.65**	**-22.4%**	**-3.4%**
Regulatory Asset Recovery	kW	1,500	2.02380	3,035.70	1,500	0.19060	285.90	-2,749.80	-90.6%	-4.3%
Retail Transmission - Network	kW	1,500	2.12460	3,186.90	1,500	1.73420	2,601.30	-585.60	-18.4%	-0.9%
Retail Transmission - Line and Transformation Connection	kW	1,500	1.75920	2,638.80	1,500	1.66820	2,502.30	-136.50	-5.2%	-0.2%
Wholesale Market Service	kWh	750,000	0.00520	3,900.00	750,000	0.00520	3,900.00	0.00	0.0%	0.0%
Rural Rate Protection Charge	kWh	750,000	0.00100	750.00	750,000	0.00100	750.00	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	750,000	0.00700	5,250.00	750,000	0.00700	5,250.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	750,000	0.05704	42,780.00	750,000	0.05704	42,780.00	0.00	0.0%	0.0%
Total Bill				**71,263.63**			**65,614.08**	**-5,649.55**	**-7.9%**	**-8.9%**

GS>1000 to 2999 kW

1000	kW Consumption
450000	kWh Consumption

		2007 BILL			2008 BILL			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				6,370.03			2,376.33	-3,993.70	-62.7%	-6.3%
Distribution	kW	1,000	2.23480	2,234.80	1,000	3.44550	3,445.50	1,210.70	54.2%	1.9%
Sub-Total				**8,604.83**			**5,821.83**	**-2,783.00**	**-32.3%**	**-4.4%**
Regulatory Asset Recovery	kW	1,000	2.02380	2,023.80	1,000	0.19060	190.60	-1,833.20	-90.6%	-2.9%
Retail Transmission - Network	kW	1,000	2.12460	2,124.60	1,000	1.73420	1,734.20	-390.40	-18.4%	-0.6%
Retail Transmission - Line and Transformation Connection	kW	1,000	1.75920	1,759.20	1,000	1.66820	1,668.20	-91.00	-5.2%	-0.1%
Wholesale Market Service	kWh	450,000	0.00520	2,340.00	450,000	0.00520	2,340.00	0.00	0.0%	0.0%
Rural Rate Protection Charge	kWh	450,000	0.00100	450.00	450,000	0.00100	450.00	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	450,000	0.00700	3,150.00	450,000	0.00700	3,150.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	450,000	0.05704	25,668.00	450,000	0.05704	25,668.00	0.00	0.0%	0.0%
Total Bill				**46,120.43**			**41,022.83**	**-5,097.60**	**-11.1%**	**-8.0%**

GS>1000 to 2999 kW

1800	kW Consumption
1000000	kWh Consumption

		2007 BILL			2008 BILL			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				6,370.03			2,376.33	-3,993.70	-62.7%	-6.3%
Distribution	kW	1,800	2.23480	4,022.64	1,800	3.44550	6,201.90	2,179.26	54.2%	3.4%
Sub-Total				**10,392.67**			**8,578.23**	**-1,814.44**	**-17.5%**	**-2.9%**
Regulatory Asset Recovery	kW	1,800	2.02380	3,642.84	1,800	0.19060	343.08	-3,299.76	-90.6%	-5.2%
Retail Transmission - Network	kW	1,800	2.12460	3,824.28	1,800	1.73420	3,121.56	-702.72	-18.4%	-1.1%
Retail Transmission - Line and Transformation Connection	kW	1,800	1.75920	3,166.56	1,800	1.66820	3,002.76	-163.80	-5.2%	-0.3%
Wholesale Market Service	kWh	1,000,000	0.00520	5,200.00	1,000,000	0.00520	5,200.00	0.00	0.0%	0.0%
Rural Rate Protection Charge	kWh	1,000,000	0.00100	1,000.00	1,000,000	0.00100	1,000.00	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	1,000,000	0.00700	7,000.00	1,000,000	0.00700	7,000.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,000,000	0.05704	57,040.00	1,000,000	0.05704	57,040.00	0.00	0.0%	0.0%
Total Bill				**91,266.35**			**85,285.63**	**-5,980.72**	**-6.6%**	**-9.4%**

GS>1000 to 2999 kW

2000	kW Consumption
800000	kWh Consumption

		2007 BILL			2008 BILL			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				6,370.03			2,376.33	-3,993.70	-62.7%	-6.3%
Distribution	kW	2,000	2.23480	4,469.60	2,000	3.44550	6,891.00	2,421.40	54.2%	3.8%
Sub-Total				**10,839.63**			**9,267.33**	**-1,572.30**	**-14.5%**	**-2.5%**
Regulatory Asset Recovery	kW	2,000	2.02380	4,047.60	2,000	0.19060	381.20	-3,666.40	-90.6%	-5.8%
Retail Transmission - Network	kW	2,000	2.12460	4,249.20	2,000	1.73420	3,468.40	-780.80	-18.4%	-1.2%
Retail Transmission - Line and Transformation Connection	kW	2,000	1.75920	3,518.40	2,000	1.66820	3,336.40	-182.00	-5.2%	-0.3%
Wholesale Market Service	kWh	800,000	0.00520	4,160.00	800,000	0.00520	4,160.00	0.00	0.0%	0.0%
Rural Rate Protection Charge	kWh	800,000	0.00100	800.00	800,000	0.00100	800.00	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	800,000	0.00700	5,600.00	800,000	0.00700	5,600.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	800,000	0.05704	45,632.00	800,000	0.05704	45,632.00	0.00	0.0%	0.0%
Total Bill				**78,846.83**			**72,645.33**	**-6,201.50**	**-7.9%**	**-9.8%**

GS > 3000 to 4999 kW

3,000	kW Consumption
800,000	kWh Consumption

		2007 BILL			2008 BILL			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				7,138.82			2.769.45			
Distribution	kW	3,000	2.17050	6,511.50	3,000	2.42160	7,264.80	753.30	11.6%	1.0%
Sub-Total				**13,650.32**			**7,264.80**	**-6,385.52**	**-46.8%**	**-8.2%**
Regulatory Asset Recovery	kW	3,000	0.14370	431.10	3,000	0.26300	789.00	357.90	83.0%	0.5%
Retail Transmission - Network	kW	3,128	2.24000	7,006.94	3,131	1.82840	5,724.11	-1,282.84	-18.3%	-1.7%
Retail Transmission - Line and Transformation Connection	kW	3,128	1.87740	5,872.69	3,131	1.78030	5,573.52	-299.17	-5.1%	-0.4%
Wholesale Market Service	kWh	834,160	0.00520	4,337.63	834,844	0.00520	4,341.19	3.56	0.1%	0.0%
Rural Rate Protection Charge	kWh	834,160	0.00100	834.16	834,844	0.00100	834.84	0.68	0.1%	0.0%
Debt Retirement Charge	kWh	800,000	0.00700	5,600.00	800,000	0.00700	5,600.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	834,160	0.05704	47,580.49	834,844	0.05704	47,619.50	39.01	0.1%	0.1%
Total Bill				**85,313.34**			**77,746.96**	**-7,566.37**	**-8.9%**	**-9.7%**

GS > 3000 to 4999 kW

3,000	kW Consumption
1,000,000	kWh Consumption

		2007 BILL			2008 BILL			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				7,138.82			2.769.45			
Distribution	kW	3,000	2.17050	6,511.50	3,000	2.42160	7,264.80	753.30	11.6%	1.0%
Sub-Total				**13,650.32**			**7,264.80**	**-6,385.52**	**-46.8%**	**-8.2%**
Regulatory Asset Recovery	kW	3,000	0.14370	431.10	3,000	0.26300	789.00	357.90	83.0%	0.5%
Retail Transmission - Network	kW	3,128	2.24000	7,006.94	3,131	1.82840	5,724.11	-1,282.84	-18.3%	-1.7%
Retail Transmission - Line and Transformation Connection	kW	3,128	1.87740	5,872.69	3,131	1.78030	5,573.52	-299.17	-5.1%	-0.4%
Wholesale Market Service	kWh	1,042,700	0.00520	5,422.04	1,043,555	0.00520	5,426.49	4.45	0.1%	0.0%
Rural Rate Protection Charge	kWh	1,042,700	0.00100	1,042.70	1,043,555	0.00100	1,043.55	0.85	0.1%	0.0%
Debt Retirement Charge	kWh	1,000,000	0.00700	7,000.00	1,000,000	0.00700	7,000.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,042,700	0.05704	59,475.61	1,043,555	0.05704	59,524.37	48.77	0.1%	0.1%
Total Bill				**99,901.41**			**92,345.85**	**-7,555.56**	**-7.6%**	**-9.7%**

GS > 3000 to 4999 kW

4,000	kW Consumption
1,200,000	kWh Consumption

		2007 BILL			2008 BILL			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				7,138.82			2.769.45			
Distribution	kW	4,000	2.17050	8,682.00	4,000	2.42160	9,686.40	1,004.40	11.6%	1.3%
Sub-Total				**15,820.82**			**9,686.40**	**-6,134.42**	**-38.8%**	**-7.9%**
Regulatory Asset Recovery	kW	4,000	0.14370	574.80	4,000	0.26300	1,052.00	477.20	83.0%	0.6%
Retail Transmission - Network	kW	4,171	2.24000	9,342.59	4,174	1.82840	7,632.14	-1,710.45	-18.3%	-2.2%
Retail Transmission - Line and Transformation Connection	kW	4,171	1.87740	7,830.26	4,174	1.78030	7,431.36	-398.90	-5.1%	-0.5%
Wholesale Market Service	kWh	1,251,240	0.00520	6,506.45	1,252,266	0.00520	6,511.78	5.33	0.1%	0.0%
Rural Rate Protection Charge	kWh	1,251,240	0.00100	1,251.24	1,252,266	0.00100	1,252.27	1.03	0.1%	0.0%
Debt Retirement Charge	kWh	1,200,000	0.00700	8,400.00	1,200,000	0.00700	8,400.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,251,240	0.05704	71,370.73	1,252,266	0.05704	71,429.25	58.52	0.1%	0.1%
Total Bill				**121,096.89**			**113,395.21**	**-7,701.68**	**-6.4%**	**-9.9%**

GS > 3000 to 4999 kW

4,000	kW Consumption
1,800,000	kWh Consumption

	Metric	2007 BILL Volume	2007 BILL Rate $	2007 BILL Charge $	2008 BILL Volume	2008 BILL Rate $	2008 BILL Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				7,138.82			2.769.45			
Distribution	kW	4,000	2.17050	8,682.00	4,000	2.42160	9,686.40	1,004.40	11.6%	1.3%
Sub-Total				**15,820.82**			**9,686.40**	**-6,134.42**	**-38.8%**	**-7.9%**
Regulatory Asset Recovery	kW	4,000	0.14370	574.80	4,000	0.26300	1,052.00	477.20	83.0%	0.6%
Retail Transmission - Network	kW	4,171	2.24000	9,342.59	4,174	1.82840	7,632.14	-1,710.45	-18.3%	-2.2%
Retail Transmission - Line and Transformation Connection	kW	4,171	1.87740	7,830.26	4,174	1.78030	7,431.36	-398.90	-5.1%	-0.5%
Wholesale Market Service	kWh	1,876,860	0.00520	9,759.67	1,878,399	0.00520	9,767.67	8.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	1,876,860	0.00100	1,876.86	1,878,399	0.00100	1,878.40	1.54	0.1%	0.0%
Debt Retirement Charge	kWh	1,800,000	0.00700	12,600.00	1,800,000	0.00700	12,600.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,876,860	0.05704	107,056.09	1,878,399	0.05704	107,143.87	87.78	0.1%	0.1%
Total Bill				**164,861.10**			**157,191.86**	**-7,669.24**	**-4.7%**	**-9.9%**

GS > 3000 to 4999 kW

3,000	kW Consumption
1,000,000	kWh Consumption

	Metric	2007 BILL Volume	2007 BILL Rate $	2007 BILL Charge $	2008 BILL Volume	2008 BILL Rate $	2008 BILL Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge				7,138.82			2.769.45			
Distribution	kW	3,000	2.17050	6,511.50	3,000	2.42160	7,264.80	753.30	11.6%	1.0%
Sub-Total				**13,650.32**			**7,264.80**	**-6,385.52**	**-46.8%**	**-8.2%**
Regulatory Asset Recovery	kW	3,000	0.14370	431.10	3,000	0.26300	789.00	357.90	83.0%	0.5%
Retail Transmission - Network	kW	3,128	2.24000	7,006.94	3,131	1.82840	5,724.11	-1,282.84	-18.3%	-1.7%
Retail Transmission - Line and Transformation Connection	kW	3,128	1.87740	5,872.69	3,131	1.78030	5,573.52	-299.17	-5.1%	-0.4%
Wholesale Market Service	kWh	1,042,700	0.00520	5,422.04	1,043,555	0.00520	5,426.49	4.45	0.1%	0.0%
Rural Rate Protection Charge	kWh	1,042,700	0.00100	1,042.70	1,043,555	0.00100	1,043.55	0.85	0.1%	0.0%
Debt Retirement Charge	kWh	1,000,000	0.00700	7,000.00	1,000,000	0.00700	7,000.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,042,700	0.05704	59,475.61	1,043,555	0.05704	59,524.37	48.77	0.1%	0.1%
Total Bill				**99,901.41**			**92,345.85**	**-7,555.56**	**-7.6%**	**-9.7%**

PROPOSED CHANGES TO TERMS AND CONDITIONS OF SERVICES

Please refer back to Exhibit 1, Tab 1, Schedule 17 for proposed changes to terms and conditions of service

Ontario

Electricity Distribution Licence

ED-2002-00516

Erie Thames Powerlines Corporation

Valid Until
December 17, 2023

M.C. Garner

Mark C. Garner
Managing Director, Market Operations
Ontario Energy Board
Date of Issuance: December 18, 2003
Date of Amendment: July 9, 2004

Ontario Energy Board	Commission de l'Énergie de l'Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
26th. Floor	26e étage
Toronto, ON M4P 1E4	Toronto ON M4P 1E4

1 Definitions 1

In this Licence: 2

"**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; 3

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B; 4

"**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; 5

"**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; 6

"**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; 7

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

"**Licensee**" means: Erie Thames Powerlines Corporation; 9

"**Market Rules**" means the rules made under section 32 of the Electricity Act; 10

"**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; 11

"**Rate Order**" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge; 12

"**regulation**" means a regulation made under the Act or the Electricity Act; 13

"**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; 14

"**service area**" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity; 15

"**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; 16

"**wholesaler**" means a person that purchases electricity or ancillary services in the IMO-administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IMO-administered markets or directly to another person other than a consumer. 17

2 Interpretation 18

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 and where the time for doing an act expires on a holiday, the act may be done on the next day. 19

3 Authorization 20

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence: 21

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence; 22

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 23

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. 24

4 Obligation to Comply with Legislation, Regulations and Market Rules 25

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. 26

4.2 The Licensee shall comply with all applicable Market Rules. 27

5 Obligation to Comply with Codes 28

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: 29

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters; 30

b) the Distribution System Code; 31

c) the Retail Settlement Code; and 32

d) the Standard Supply Service Code. 33

5.2 The Licensee shall: 34

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 35

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. 36

6 Obligation to Provide Non-discriminatory Access 37

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. 38

7 Obligation to Connect 39

7.1 The Licensee shall connect a building to its distribution system if: 40

a) the building lies along any of the lines of the distributor's distribution system; and 41

b) the owner, occupant or other person in charge of the building requests the connection in writing. 42

7.2 The Licensee shall make an offer to connect a building to its distribution system if: 43

a) the building is within the Licensee's service area as described in Schedule 1; and 44

b) the owner, occupant or other person in charge of the building requests the connection in writing. 45

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. 46

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. 47

8 Obligation to Sell Electricity 48

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. 49

9 Obligation to Maintain System Integrity 50

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. 51

10 Market Power Mitigation Rebates 52

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence. 53

11 Distribution Rates 54

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. 55

12 Separation of Business Activities 56

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. 57

13 Expansion of Distribution System 58

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. 59

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. 60

14 Provision of Information to the Board 61

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. 62

14.2 Without limiting the generality of condition 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. 63

14.3 The licensee shall inform the Board as soon as possible of any material changes to the service agreement with Erie Thames Services Corporation (the "Service Agreement"). 64

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: 65

a) Immediately notify the Board in writing of the notice; and 66

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. 67

14.5 In the event of termination of the Service Agreement for any reason, the Licensee shall: 68

a) ensure there is no interruption of distribution services to the consumers as a result of the termination, 69

b) notify the Board of the name of the new company that will provide the distribution services, and 70

c) file with the Board the distribution services agreement with the new company. 71

15 Restrictions on Provision of Information 72

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. 73

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: 74

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence; 75

b) for billing, settlement or market operations purposes; 76

c) for law enforcement purposes; or 77

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator. 78

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. 79

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. 80

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. 81

16 Customer Complaint and Dispute Resolution 82

16.1 The Licensee shall: 83

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner; 84

b) publish information which will make its customers aware of and help them to use its dispute resolution process; 85

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; 86

d) give or send free of charge a copy of the process to any person who reasonably requests it; and 87

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. 88

17 Term of Licence 89

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. 90

18 Fees and Assessments 91

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board. 92

19 Communication 93

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. 94

19.2 All official communication relating to this Licence shall be in writing. 95

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee: 96

a) when delivered in person to the addressee by hand, by registered mail or by courier; 97

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and 98

c) when received by facsimile transmission by the addressee, according to the sender's transmission report. 99

20 Copies of the Licence 100

20.1 The Licensee shall: 101

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 102

b) provide a copy of the Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies. 103

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA 104

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence. 105

1. The former Villages of Belmont and Port Stanley as of December 31, 1997, now in the Municipality of Central Elgin. 106

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. 107

3. The Town of Ingersoll as of December 31, 2000. 108

4. The former Village of Beachville as of December 31, 1974, now in the Township of South-West Oxford. 109

5. The former Town of Tavistock as of December 31, 1974, now in the Township of East Zorra-Tavistock. 110

6. The former Villages of Norwich, Otterville & Burgessville as of December 31,1974, now in the Township of Norwich. 111

7. The Villages of Embro & Thamesford as of December 31, 1974, now in the Township of Zorra . 112

8. Block 1 Plan 11M-123, Municipality of Central Elgin, County of Elgin. 113

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE 114

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the 115
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 116
in accordance with condition 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 117

This Schedule specifies any specific Code requirements from which the Licensee has been exempted. 118

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. 119

APPENDIX A MARKET POWER MITIGATION REBATES 120

1 Definitions and Interpretation 121

In this Licence, 122

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity; 123

"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; 124

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant. 125

In this Licence, a reference to the payment of a rebate amount by the IMO includes interim payments made by the IMO. 126

2 Information Given to IMO 127

a Prior to the payment of a rebate amount by the IMO to a distributor, the distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with information in respect of the volumes of electricity withdrawn by the distributor from the IMO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to: 128

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 129

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998.* 130

b Prior to the payment of a rebate amount by the IMO 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 IMO 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: 131

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 132

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998.* 133

c Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with the information provided to the host distributor by the embedded distributor in accordance with section 2. 134

The IMO may issue instructions or directions providing for any information to be given under this section. The IMO 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. 135

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 IMO-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 IMO-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. 136

3 Pass Through of Rebate 137

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 IMO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to: 138

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; 139

b consumers who are not receiving the fixed price under sections 79.4 and 79.5 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 140

c embedded distributors to whom the distributor distributes electricity. 141

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. 142

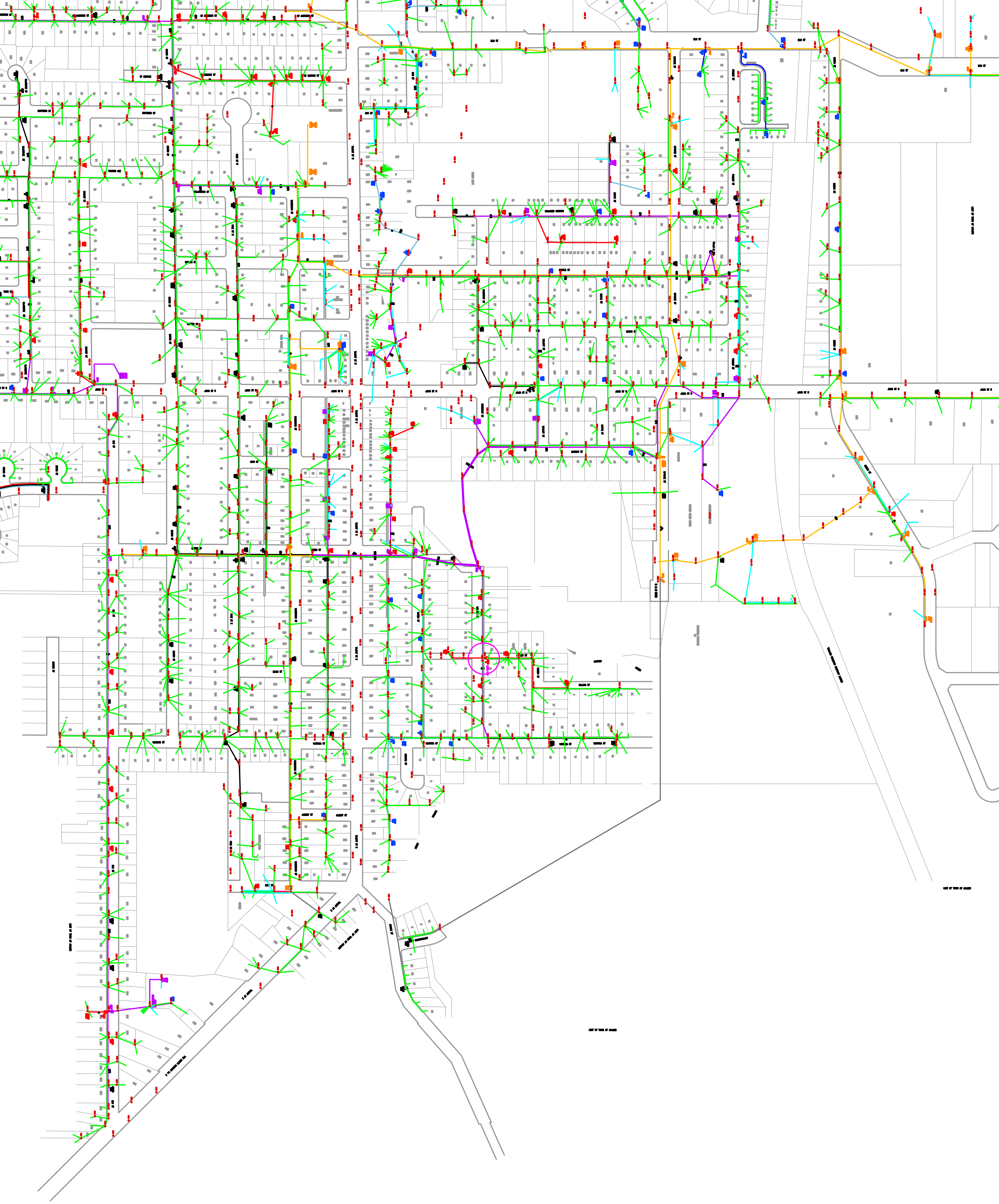
If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement: 143

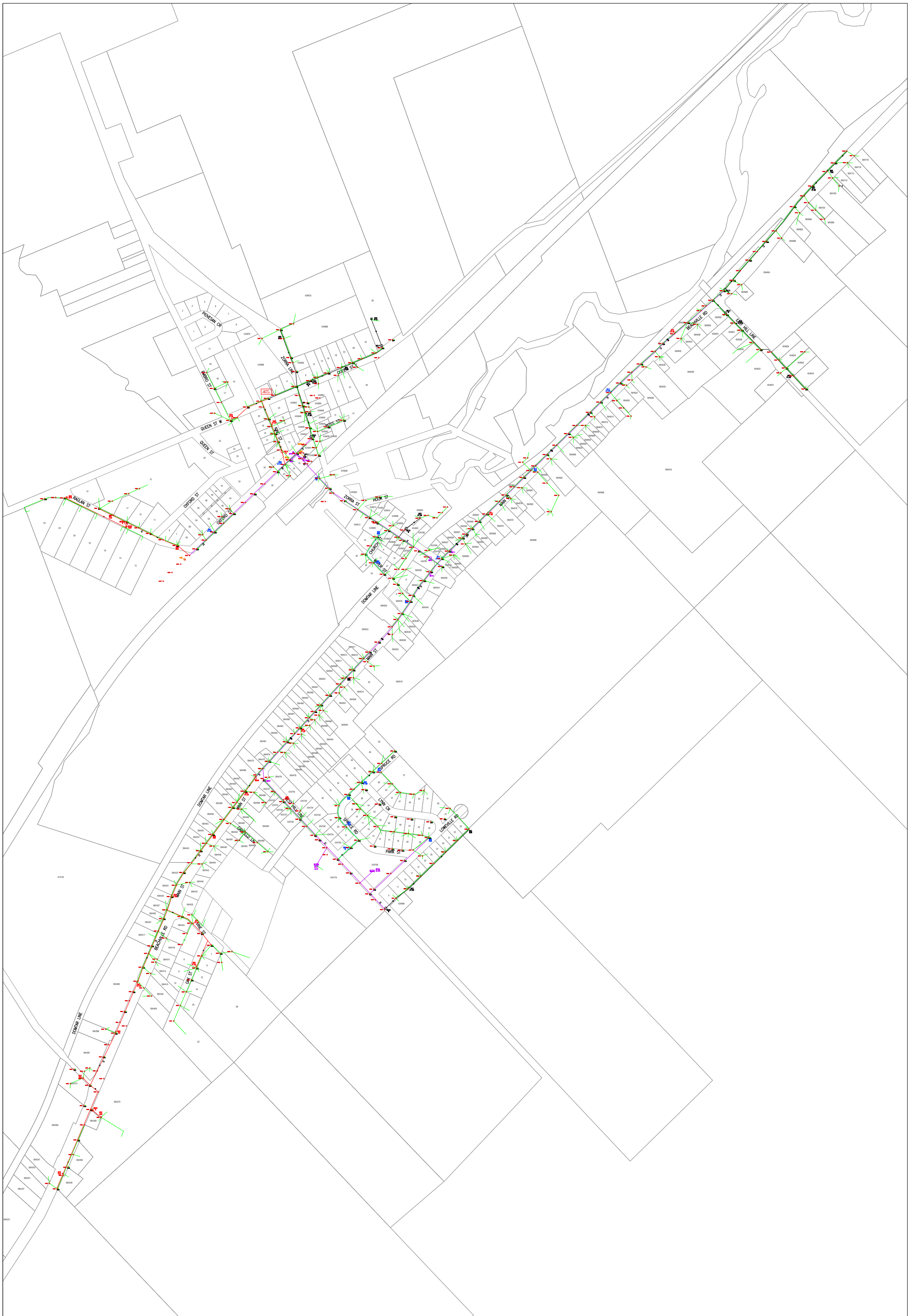
"ONTARIO POWER GENERATION INC. rebate" 144

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 IMO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt. 145

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party. 146

Pending pass-through or return to the IMO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account. 147





Operating Map Legend

3ø 4 kV OVERHEAD	SWITCH
3ø 8 kV OVERHEAD	CAPACITOR
3ø CAMI FEEDER	STEP DOWN TRANSFORMER
3ø 27 kV OVERHEAD	RECLOSER
Bø OVERHEAD	P.M.E.
Rø OVERHEAD	M.S.O.
Wø OVERHEAD	OPEN POINT
Bø UNDERGROUND	STATION
Rø UNDERGROUND	SWITCHING CUBICLE
Wø UNDERGROUND	FAULT INDICATOR
HYDRO ONE LINES	
1ø OVERHEAD SERVICE	
3ø OVERHEAD SERVICE	
1ø UNDERGROUND SERVICE	
3ø UNDERGROUND SERVICE	

TRANSFORMERS

1ø OVERHEAD	1ø PADMOUNT
3ø OVERHEAD	3ø PADMOUNT

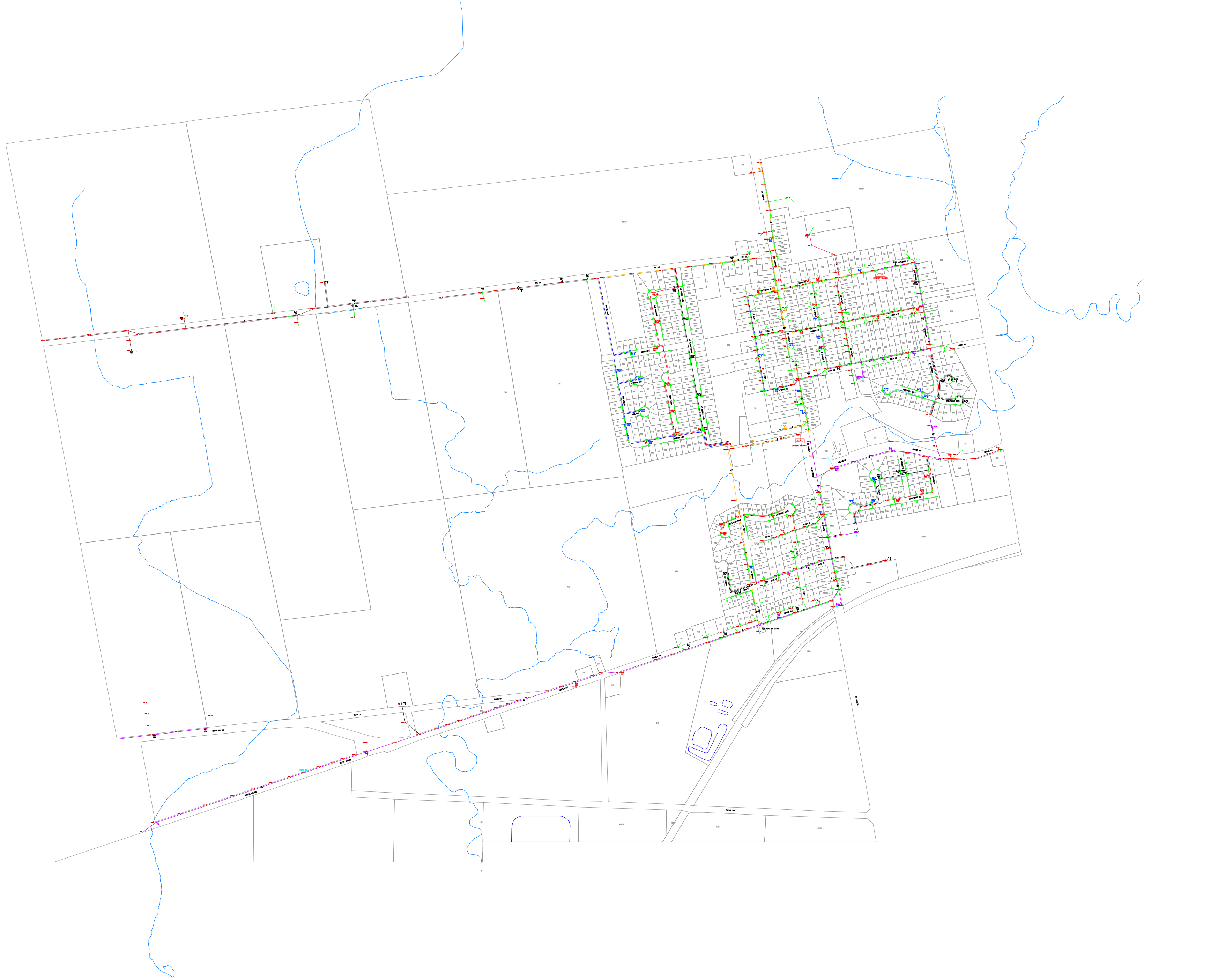
ETS ERIE THAMES SERVICES

143 BELL ST, INGERSOLL
ONTARIO, N5C 3K5
Ph: (519) 485-6038
Fx: (519) 485-5838

280 ELM ST, AYLMER
ONTARIO, N5H 3G3

CITY: BEACHVILLE		
DESCRIPTION: DISTRIBUTION MAP		
DRAWING NO.: ETP-MAP-BEACHVILLE.DWG		
DATE: JUNE 23/07	DRAWN BY: MG	CHECKED BY:
SCALE: NTS	PAGE: PAGE 1 OF 1	
REVISION: 00	REV DESCRIPTION	

REV 6



LEGEND

RECONSTRUCTION

- STREET LIGHT WIRE
- SECONDARY 1Ø
- SECONDARY 3Ø
- RWB 3ø 1/0 — 4KV PRIMARY
- RWB 3ø 1/0 — 27KV PRIMARY
- U/G DUCT - CABLE/TV
- WIRE - OVERHEAD
- WIRE - UNDERGROUND
- SWITCHING CUBICLE
- 75R — 1Ø PADMOUNT TRANSFORMER (SIZE,PHASE)
- 75KVA — 3Ø PADMOUNT TRANSFORMER (SIZE)
- 75R — 1Ø OH TRANSFORMER (SIZE,PHASE)
- 75KVA — 3Ø OH TRANSFORMER (SIZE)
- FAULT INDICATOR
- FIRE HYDRANT
- 100W — STREET LIGHT (WATTS)
- STRET LIGHT DISCONNECT
- CONDUIT — ROAD CROSSING
- CABLE TV PEDESTAL
- TELEPHONE PEDESTAL
- GROUND
- OPEN POINT
- DEMARCATION POINT
- EXISTING HYDRO POLE
- NEW HYDRO POLE
- EXISTING ANCHOR
- NEW ANCHOR
- REMOVE OBJECT
- TRANSFER OBJECT
- LINE CONNECTION
- 40A — SWITCH (FUSED)
- LB — SWITCH (LOAD BREAK)

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Fx: (519) 485-5838

280 ELM ST, AYLMER
ONTARIO, N5H 3G3

CITY: BELMONT		
DESCRIPTION: DISTRIBUTION		
DRAWING NO.: ETP-MAP-BELMONT.DWG		
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REV. 4

Operating Map Legend

- 3ø 4 kV OVERHEAD
- 3ø 8 kV OVERHEAD
- 3ø CAMI FEEDER
- 3ø 27 kV OVERHEAD
- Bø OVERHEAD
- Rø OVERHEAD
- Wø OVERHEAD
- Bø UNDERGROUND
- Rø UNDERGROUND
- Wø UNDERGROUND
- HYDRO ONE LINES
- 1ø OVERHEAD SERVICE
- 3ø OVERHEAD SERVICE
- 1ø UNDERGROUND SERVICE
- 3ø UNDERGROUND SERVICE

- SWITCH
- CAPACITOR
- STEP DOWN TRANSFORMER
- RECLOSER
- P.M.E.
- M.S.O.
- OPEN POINT
- STATION
- SWITCHING CUBICLE
- FAULT INDICATOR

TRANSFORMERS

- 1ø OVERHEAD
- 1ø PADMOUNT
- 3ø OVERHEAD
- 3ø PADMOUNT

ERIE THAMES SERVICES

143 BELL ST, INGERSOLL
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CITY	BURGESSVILLE
DESCRIPTION	DISTRIBUTION MAP
DRAWING NO.	ETP-MAP-BURGESSVILLE.DWG

DATE	DRAWN BY	CHECKED BY
JUNE 23/07	MG	

SCALE	PAGE
NTS	PAGE 1 OF 1

REVISION	REV DESCRIPTION
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REV 6

Operating Map Legend

- 3ø 4 kV OVERHEAD
- 3ø 8 kV OVERHEAD
- 3ø CAMI FEEDER
- 3ø 27 kV OVERHEAD
- Bø OVERHEAD
- Rø OVERHEAD
- Wø OVERHEAD
- Bø UNDERGROUND
- Rø UNDERGROUND
- Wø UNDERGROUND
- HYDRO ONE LINES
- 1ø OVERHEAD SERVICE
- 3ø OVERHEAD SERVICE
- 1ø UNDERGROUND SERVICE
- 3ø UNDERGROUND SERVICE

- SWITCH
- CAPACITOR
- STEP DOWN TRANSFORMER
- RECLOSER
- P.M.E.
- M.S.O.
- OPEN POINT
- STATION
- SWITCHING CUBICLE
- FAULT INDICATOR

TRANSFORMERS

- 1ø OVERHEAD
- 1ø PADMOUNT
- 3ø OVERHEAD
- 3ø PADMOUNT

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Fx: (519) 485-5838

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CITY		
EMBRO		
DESCRIPTION: DISTRIBUTION MAP		
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DATE: JUNE 23/07	DRAWN BY: MG	CHECKED BY:
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REV 6

Operating Map Legend

	3ø 4 kV OVERHEAD
	3ø 8 kV OVERHEAD
	3ø CAMI FEEDER
	3ø 27 kV OVERHEAD
B	Bø OVERHEAD
R	Rø OVERHEAD
W	Wø OVERHEAD
B	Bø UNDERGROUND
R	Rø UNDERGROUND
W	Wø UNDERGROUND
	HYDRO ONE LINES
	1ø OVERHEAD SERVICE
	3ø OVERHEAD SERVICE
	1ø UNDERGROUND SERVICE
	3ø UNDERGROUND SERVICE
S	SWITCH
	CAPACITOR
	STEP DOWN TRANSFORMER
	RECLOSER
	P.M.E.
	M.S.O.
	OPEN POINT
	STATION
SC	SWITCHING CUBICLE
	FAULT INDICATOR

TRANSFORMERS

1ø OVERHEAD — 1ø PADMOUNT

3ø OVERHEAD — 3ø PADMOUNT

ETS
ERIE THAMES SERVICES

143 BELL ST, INGERSOLL
ONTARIO, N5C 3K5
Ph: (519) 485-6038
Fx: (519) 485-5838

280 ELM ST, AYLMER
ONTARIO, N5H 3G3

CITY: INGERSOLL		
DESCRIPTION: DISTRIBUTION MAP		
DRAWING NO.: ETP-MAP-INGERSOLL.DWG		
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REVISION: 00	REV DESCRIPTION:	

REV 6

Operating Map Legend

- 3ø 4 kV OVERHEAD
- 3ø 8 kV OVERHEAD
- 3ø CAMI FEEDER
- 3ø 27 kV OVERHEAD
- Bø OVERHEAD
- Rø OVERHEAD
- Wø OVERHEAD
- Bø UNDERGROUND
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- HYDRO ONE LINES
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- SWITCH
- CAPACITOR
- STEP DOWN TRANSFORMER
- RECLOSER
- P.M.E.
- M.S.O.
- OPEN POINT
- STATION
- SWITCHING CUBICLE
- FAULT INDICATOR

TRANSFORMERS

- 1ø OVERHEAD
- 1ø PADMOUNT
- 3ø OVERHEAD
- 3ø PADMOUNT

ETS
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Ph: (519) 485-6038
Fx: (519) 485-5838

280 ELM ST, AYLMER
ONTARIO, N5H 3G3

CITY: NORWICH		
DESCRIPTION: DISTRIBUTION MAP		
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SCALE: NTS	PAGE: PAGE 1 OF 1	
REVISION: 00	REV DESCRIPTION:	

REV 6

Operating Map Legend

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- 3Ø 8 kV OVERHEAD
- 3Ø CAMI FEEDER
- 3Ø 27 kV OVERHEAD
- BØ OVERHEAD
- RØ OVERHEAD
- WØ OVERHEAD
- BØ UNDERGROUND
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- WØ UNDERGROUND
- HYDRO ONE LINES
- 1Ø OVERHEAD SERVICE
- 3Ø OVERHEAD SERVICE
- 1Ø UNDERGROUND SERVICE
- 3Ø UNDERGROUND SERVICE
- SWITCH
- CAPACITOR
- STEP DOWN TRANSFORMER
- RECLOSER
- P.M.E.
- M.S.O.
- OPEN POINT
- STATION
- SWITCHING CUBICLE
- FAULT INDICATOR

TRANSFORMERS

- 1Ø OVERHEAD
- 1Ø PADMOUNT
- 3Ø OVERHEAD
- 3Ø PADMOUNT

ETS ERIE THAMES SERVICES

143 BELL ST, INGERSOLL
ONTARIO, N5C 3K5
Ph: (519) 485-6038
Fx: (519) 485-5838

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ONTARIO, N5H 3G3

CITY	OTTERVILLE
DESCRIPTION	DISTRIBUTION MAP
DRAWING NO.	ETP-MAP-OTTERVILLE.DWG

DATE	DRAWN BY	CHECKED BY
JUNE 23/07	MG	

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REVISION	REV DESCRIPTION
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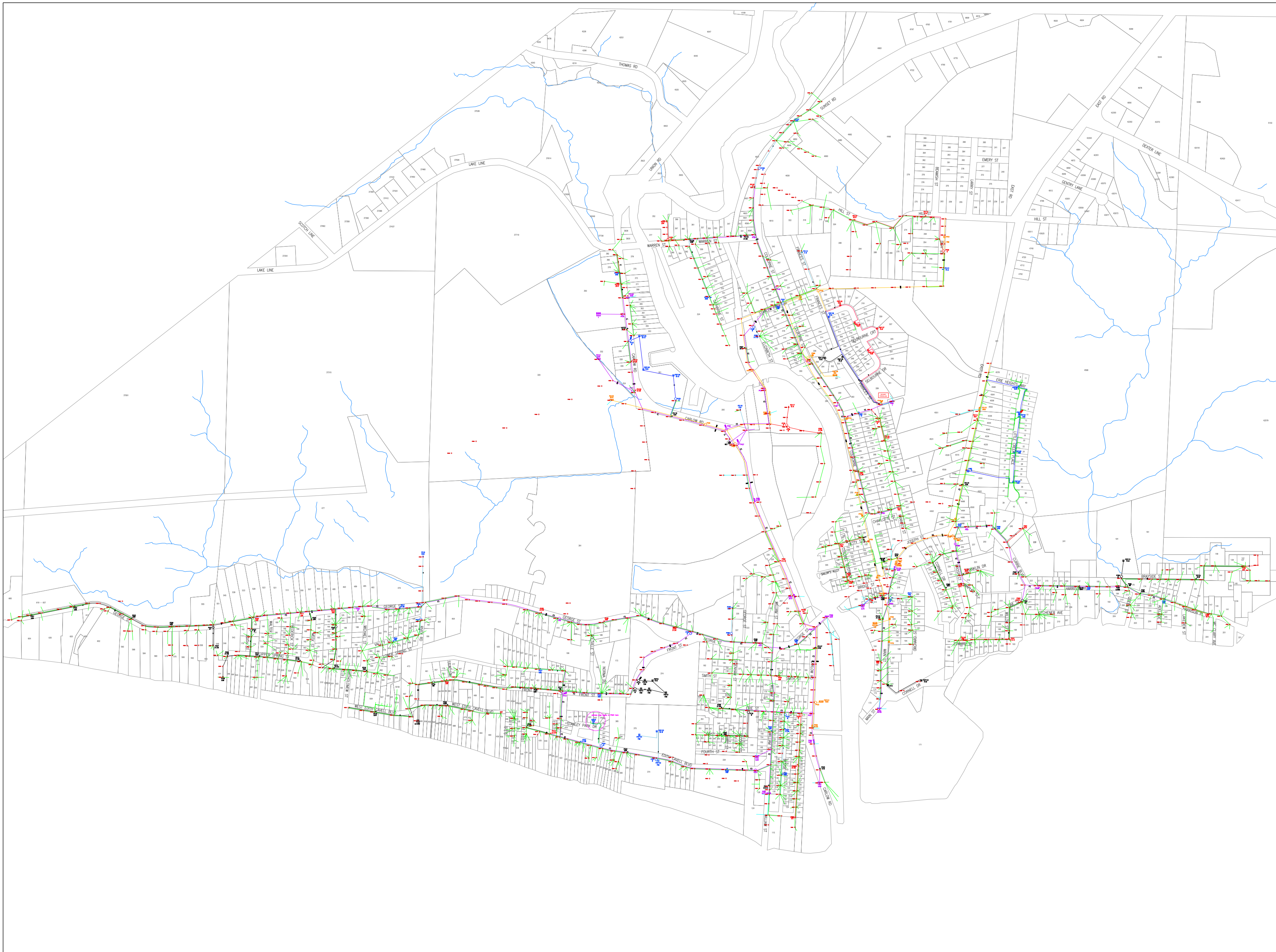
REV. 6



Operating Map Legend

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- 3ø 8 kV OVERHEAD
- 3ø CAMI FEEDER
- 3ø 27 kV OVERHEAD
- B — Bø OVERHEAD
- R — Rø OVERHEAD
- W — Wø OVERHEAD
- B — Bø UNDERGROUND
- R — Rø UNDERGROUND
- W — Wø UNDERGROUND
- HYDRO ONE LINES
- 1ø OVERHEAD SERVICE
- 3ø OVERHEAD SERVICE
- 1ø UNDERGROUND SERVICE
- 3ø UNDERGROUND SERVICE
- S — SWITCH
- CAPACITOR
- STEP DOWN TRANSFORMER
- RECLOSER
- P.M.E.
- M.S.O.
- OPEN POINT
- STATION
- SC — SWITCHING CUBICLE
- FAULT INDICATOR

TRANSFORMERS

- 1ø OVERHEAD
- 1ø PADMOUNT
- 3ø OVERHEAD
- 3ø PADMOUNT

ERIE THAMES SERVICES

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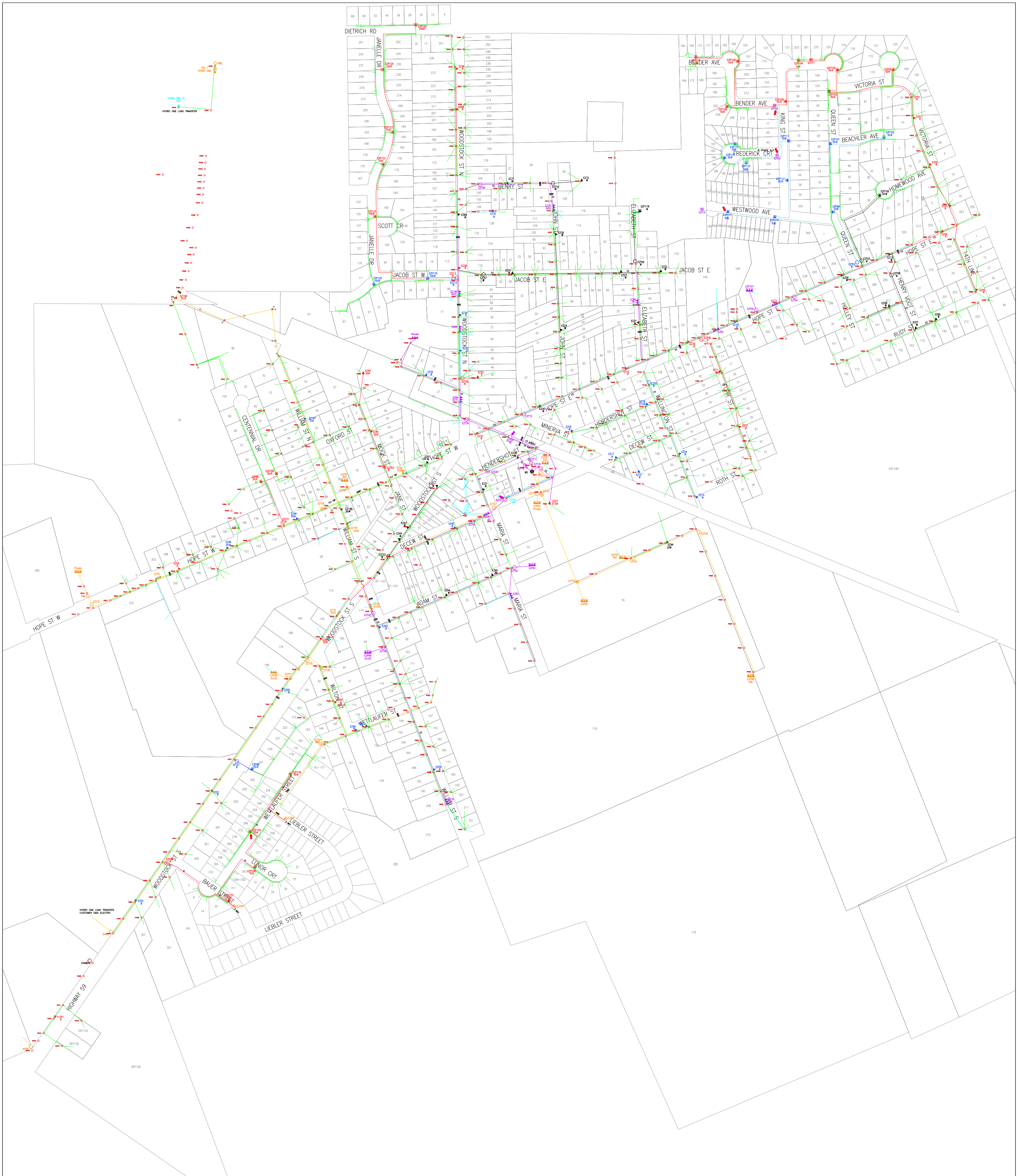
Ph: (519) 485-6038
Fx: (519) 485-5838

280 ELM ST, AYLMER
ONTARIO, N5H 3G3

CITY: PT STANLEY	
DESCRIPTION: DISTRIBUTION MAP	
DRAWING NO.: ETP-MAP-PT STANLEY.DWG	
DATE: JUNE 23/07	DRAWN BY: MG / CHECKED BY:
SCALE: NTS	PAGE: PAGE 1 OF 1
REVISION: 00	REV DESCRIPTION:

REV 6



Operating Map Legend

- 3ø 4 kV OVERHEAD
- 3ø 8 kV OVERHEAD
- 3ø CAMI FEEDER
- 3ø 27 kV OVERHEAD
- Bø OVERHEAD
- Rø OVERHEAD
- Wø OVERHEAD
- Bø UNDERGROUND
- Rø UNDERGROUND
- Wø UNDERGROUND
- HYDRO ONE LINES
- 1ø OVERHEAD SERVICE
- 3ø OVERHEAD SERVICE
- 1ø UNDERGROUND SERVICE
- 3ø UNDERGROUND SERVICE

- SWITCH
- CAPACITOR
- STEP DOWN TRANSFORMER
- RECLOSER
- P.M.E.
- M.S.O.
- OPEN POINT
- STATION
- SWITCHING CUBICLE
- FAULT INDICATOR

TRANSFORMERS

- 1ø OVERHEAD
- 1ø PADMOUNT
- 3ø OVERHEAD
- 3ø PADMOUNT

ETS ERIE THAMES SERVICES

143 BELL ST, INGERSOLL
ONTARIO, N5C 3K5
Ph: (519) 485-6038
Fx: (519) 485-5838

280 ELM ST, AYLMER
ONTARIO, N5H 3G3

CITY		
TAVISTOCK		
DESCRIPTION: DISTRIBUTION MAP		
DRAWING NO.: ETP-MAP-TAVISTOCK.DWG		
DATE: JUNE 23/07	DRAWN BY: MG	CHECKED BY
SCALE: NTS	PAGE: PAGE 1 OF 1	
REVISION: 00	REV DESCRIPTION	

REV 6

Operating Map Legend

- 3ø 4 kV OVERHEAD
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- 3ø CAMI FEEDER
- 3ø 27 kV OVERHEAD
- Bø OVERHEAD
- Rø OVERHEAD
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TRANSFORMERS

- 1ø OVERHEAD
- 1ø PADMOUNT
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CITY	THAMESFORD
DESCRIPTION	DISTRIBUTION MAP
DRAWING NO.	ETP-MAP-THAMESFORD.DWG

DATE	DRAWN BY	CHECKED BY
JUNE 23/07	MG	

SCALE	PAGE
NTS	PAGE 1 OF 1

REVISION	REV DESCRIPTION
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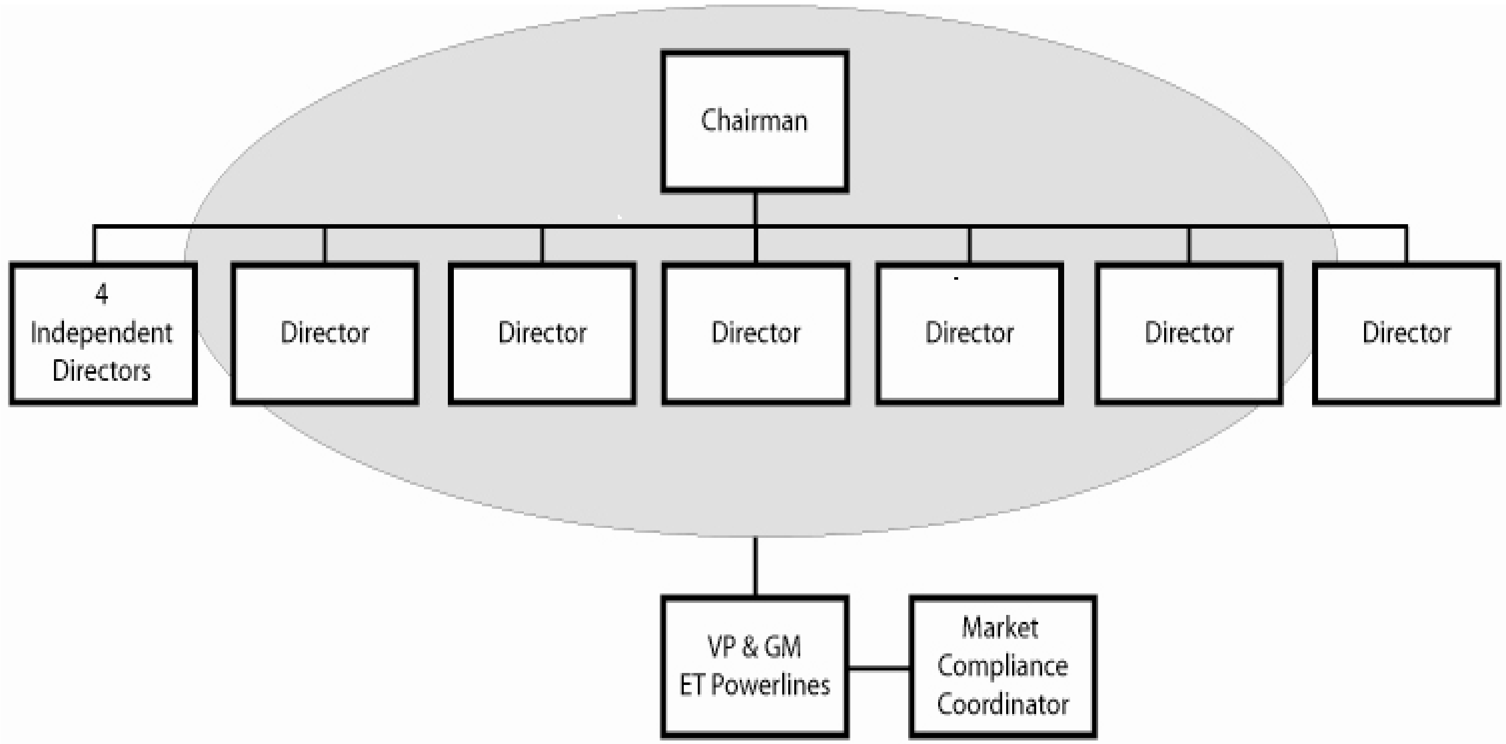
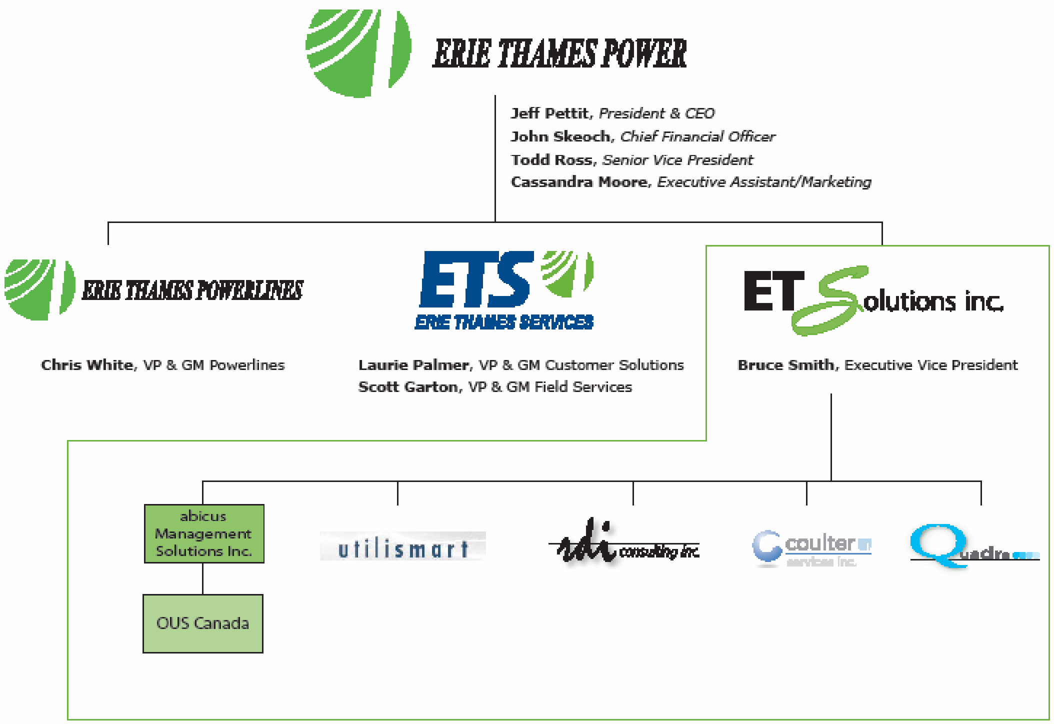
ERIE THAMES POWERLINES
CORPORATION




ERIE THAMES POWER
Jeff Pettit, President & CEO
John Skeoch, Chief Financial Officer
Todd Ross, Senior Vice President
Cassandra Moore, Executive Assistant/Marketing
ERIE THAMES POWERLINES
Chris White, VP & GM Powerlines
ETS
ERIE THAMES SERVICES
Laurie Palmer, VP & GM Customer Solutions
Scott Garton, VP & GM Field Services
ET Solutions inc.
Bruce Smith, Executive Vice President
abicus Management Solutions Inc.
OUS Canada
utilismart
consulting inc
coulter
Quadra

ERIE THAMES POWERLINES
CORPORATION

CONDITIONS OF SERVICE

Revised June 2007
(Replacing version 5.3 – 2004)

ERIE THAMES POWERLINES
CORPORATION

CONDITIONS OF SERVICE

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3.3 General Service (Above 50 kW)

3.3.1 General
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SECTION 1 INTRODUCTION

1.1 Identification of Distributor and Territory

The Distributor is a corporation, incorporated under the laws of the Province of Ontario to distribute electricity.

The Distributor is licensed by the Ontario Energy Board "OEB" to supply electricity to Customers as described in the Transitional Distribution License and thereafter by the Distribution License issued to the Distributor by the OEB. Additionally there are requirements imposed on the Distributor by the various codes referred to in the License and by the Electricity Act and the Ontario Energy Board Act.

The Distributor is limited to operate distribution facilities within their Licensed Territory as defined in the Distribution License.

1.1.1 General

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

The Distributor 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 the Distributor 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. The Distributor will confirm, in writing, the Characteristics of Electric Supply available at a specific site.

The customer is required to provide the Distributor 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 the Distributors' equipment that has been damaged through the customers' action or neglect.

The supply of electricity is conditional upon the Distributor being permitted and able to provide such a supply, obtaining the necessary apparatus and material, and constructing works to provide the service. Should the Distributor 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 the Distributor, interfere with the proper and safe operation of the Distributor's facilities or adversely affect compliance with any applicable legislation in the sole opinion of the Distributor.

Prior to commencing any service work, the customer must consult with the Distributor 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

The Distributor is limited in its scope of operation by the:

1. *Electricity Act, 1998*
   http://www.eriethamespower.com/Electricity Act, 1998, S_O_ 1998, c_ 15, Sched_ A.htm
2. *Ontario Energy Board Act, 1998*
   http://www.eriethamespower.com/Ontario Energy Board Act, 1998, S_O_ 1998, c_ 15, Sched_ B.htm
3. *Distribution Licence*
   ED-2002-0526
4. *Affiliate Relationships Code*
   http://www.eriethamespower.com/Affiliate Relationships Code.pdf
5. *Distribution System Code*
   http://www.eriethamespower.com/Distribution System Code.pdf

6. *Retail Settlements Code*
   http://www.eriethamespower.com/Retail Settlement Code.pdf
7. *Standard Service Supply Code*
   http://www.eriethamespower.com/Standard Service Supply Code.pdf
8. *Transmission System Code*
   http://www.eriethamespower.com/Transmission System Code.pdf

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 the Distributor 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 either a notice in the local newspaper, customer bill note, or a notice on the Distributors' Website.

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

1.5 Contact Information

The Distributor and its agents can be contacted during normal working hours (Monday to Friday between 8:30 and 4:30) at 519 485-1820 or toll free 1-877-850-3128. In an event of an emergency, outside of normal working hours, the contact phone numbers remain the same, the answering service will forward the information. The mailing address is 280 Elm Street, Aylmer Ontario N5H 3G3.

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 the distributor.

A customer, who believes that he has suffered damages to his property or equipment as a result of negligence on the part of the Distributor, may submit a written claim for damages to the Distributor. The Distributor 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 the Distributors' system, the Distributor shall have the right to require the Contractor to submit proof of previous experience and satisfactory performance, and, the Distributor 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.

The Distributor 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 the Distributor, a resolution cannot be reached, the dispute may be submitted to a dispute resolution process.

Any dispute which shall arise between the Distributor and a customer(s) and other market participants subject to the terms of these Conditions of Service concerning the rights, duties or obligations of the Distributor 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 the distributor. 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 the Distributor 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 the distributor's distribution system, and meets the conditions listed in the Conditions of Service of the distributor 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. The Distributor may refuse to connect a customer for the reason described in subsection 2.1.3 of the Distributors' Conditions of Service. The Offer to connect must be fair and reasonable and be based on the distributors' design standard. The Offer to Connect must also be made within a reasonable time from the request for connection.

The Distributor 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 the distributor'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 the Distributor money for distribution services, or for non-payment of a security deposit. The Distributor 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

The Distributor 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.

The Distributor 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.

The Distributor 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 the Distributor prior to connection.

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

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

The Distributor reserves the right to inspect any underground trenches prior to backfilling.

The Distributor 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 the Distributor. The installation of submarine cable must meet the requirements of all governing legislation.

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

In accordance with the Distribution System Code, if the Distributor refuses to connect a building in its service territory that lies along one of its distribution lines, the distributor shall inform the person requesting the connection of the reasons for not connecting, and where the distributor is able to provide a remedy, make an offer to connect. If the Distributor 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

The Distributor 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, the Distributor has the right to have supply facilities on private property registered against title to the property. Easements are required whenever the Distributors' 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 the distributors name, at no cost to the Distributor, where required, an easement to permit installation and maintenance of service. The width and extent of this easement shall be determined by the Distributor. The easement shall be granted prior to connection of the service.

The Owner shall furnish to the Distributor, 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 the Distributors' solicitor prior to its registration and register the easement plan. Details will be provided upon application for service.

Where surface restoration by the Distributor is required following any repairs or maintenance to a service, the Distributor 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 the distributor, and receipt of approval by the Electrical Safety Authority.

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 the Distributor 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 the Distributor by any Person or Persons constitutes the acceptance of the terms and conditions of all regulations, conditions and rates as established by the Distributor. Such acceptance and use of energy shall be deemed to be the acceptance of a binding contract with the Distributor 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*

2.2 Disconnection

The Distributor has the right and/or obligation to disconnect the supply of electrical energy to a Customer 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 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 the distributor money for distribution services, or for a security deposit. The distributor shall give the customer a reasonable opportunity to provide the security deposit consistent with Section 2.2.20 of the Distribution System Code.

2.3 Conveyance of Electricity

2.3.1 Guaranty of Supply

The Distributor 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 the Distributor. The Distributor will respond to and take reasonable steps to restore power. The Distributor reserves the right to recover costs from the customer for making false claims of interruptions.

Although it is the Distributors' policy to minimize inconvenience to Customers, it is necessary to occasionally interrupt a Customers' supply to maintain or improve the Distributors' system, or to provide new or upgraded services to other Customers. Whenever practical and cost effective, as determined by the Distributor, arrangements suitable to the Customer and the Distributor may be made to minimize any inconvenience. The Distributor 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.

The Distributor 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 the

Distributor or the public, service may be discontinued without notice.

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

2.3.2 Power Quality

The distributor 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 the Distributor.

If the source of a power quality problem is caused by the consumer making the complaint, the distributor 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, the Distributor may direct the consumer to take corrective action. If the Consumer does not take such action within a reasonable time, the Distributor 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 the Distributor 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 the Distributor.
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 the Distributor.

The Distributor 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 the Distributors' 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 the distributor.

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 the Distributor.

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 the Distributor:

- *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 the distributor.

2.3.5 Voltage Guidelines

The Distributor 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: http://www.csa-intl.org/onlinestore/GetCatalogDrillDown.asp?Parent=542,

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 http://www.esainspection.net/code.html and in particular, shall ensure that customer emergency generation does not back-feed on the Distributors' system.

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

The distributor 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 the Distributor shall be subject to immediate disconnection.

2.3.7 Metering

2.3.7.1 General

2.3.7.1.1 Access

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

All metering installations shall be accessible from a public area.

2.3.7.1.2 Costs

All the Distributor 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 the Distributor and maintenance of this equipment shall be the Distributors' responsibility.

2.3.7.1.3 Voltage

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

Customer-owned substations may require primary metering. The provisions required for these installations shall be specified and approved by the Distributor 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, the Distributor 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. The Distributor 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 the Distributor 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) the Distributor 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 the Distributor 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 the Distributor, under no circumstances shall anyone remove the lock and energize it without first receiving approval from the Distributor.

At the discretion of the Distributor, a dual locking arrangement, a Distributor 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 the Distributor, 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 the Distributor 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 the Distributor.

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 the Distributor to meter Customers of specific load levels with pulse-recording meters, or interval meters, which are interrogated remotely. The Distributor, 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 the distributors' requirements.

Where such metering exists the Distributor 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, the Distributor 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 the Distributor.

2.3.7.3.1 Interval Metering Communications

- Solid-state recorders and/or Electronic Interval Meters installed by the Distributor have provision for remote interrogation over a telephone line. To accommodate this feature the Owner will provide shared access to a telephone line for the Distributors' metering purposes.
- At its' sole discretion, for metering installations where loss of metering data would cause a substantial impact on the Distributors Settlement System, the Distributor 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.

2.3.7.4 Meter Reading

The Distributor 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 the Distributor sufficient notice of the date so that a final meter reading can be obtained. The Customer shall provide access to the Distributor 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. The Distributors' 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, the Distributor 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 the Distributor, 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. The Distributor 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

The Distributor will attempt to resolve billing enquiries. However, to give Customers confidence in the accuracy of electricity meters, the Distributor 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 the Distributor may request Measurement Canada to test the meter.
http://www.eriethamespower.com/measurement erros.pdf

If the test indicates that the meter is not accurate, the Customer's historic billing will be adjusted, and the Distributor 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 the Distributor. If a meter is recessed or enclosed after installation, without the prior approval of the Distributor, 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 the Distributor. 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 the Distributor, as follows:

- *An electrical room reserved solely for metering equipment or*
- *Metal enclosed switchgear approved by the Distributor 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 the Distributor 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 the Distributor 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 the Distributor. Meter sockets will be directly accessible to the Distributors' staff.

A listing of approved revenue metering sockets is available from the Distributor.

2.3.7.12 Cabinets

Where required by these Conditions of Service the Owner shall supply and install a meter cabinet to The Distributors' requirements.

Meter cabinets shall be installed indoors, except where special permission is granted by the Distributor 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.

The Distributor will provide the following revenue metering equipment as required:

- Colour coded secondary wiring
- Revenue meters

The Owner shall:

- Consult with The Distributor 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 the Distributor 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 The Distributors' metering equipment.

Meters shall be installed by the Distributor in a customer-owned metal cabinet of a size and type pre-approved by the Distributor, 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 the Distributor 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 the Distributor.

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 the distributor'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. http://www.theIESO.com/

2.4 Tariffs and Charges

2.4.1 Service Connection

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

2.4.2 Energy Supply

The Distributor 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 the Distributor.

Customers will be switched to their Retailer of choice only if the retailer has a Service Agreement with the Distributor. 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.

The Distributor 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 the Distributor for Distribution Services and or Standard Supply Service.

2.4.2.1 Wheeling of Power

Customers considering delivery of electricity through the Distributors' Distribution System shall contact the Distributor for technical requirements and current applicable Rates.

2.4.3 Supply Deposits & Agreements

Whenever required by the Distributor, the Customer shall provide and maintain security in an amount that the Distributor has been mandated to collect, or deems necessary and reasonable. The Distributor shall require security amounts based on the existing security and deposit policies. The current deposit policy is included as an Appendix of the Distributors Conditions of Service.

Where a customer proposes the development of premises that requires the Distributor 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 the Distributor.

2.4.4 Billing

The Distributor 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 the Distributor.

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:

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, the Distributor 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.

The Distributor 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

The Distributor shall use its discretion in taking action to mitigate unauthorized energy use. Upon identification of possible unauthorized energy use, the Distributor 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.

The Distributor may recover from the parties responsible for the unauthorized energy use all costs incurred by the Distributor 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 the Distributor.

Prior to reconnection, the Distributor shall require proper authorization from applicable authorities.

2.5 Customer Information

The Distributor 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, the Distributor 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 the Distributors' distribution system:

- The Distributors' account number for the customer,
- The Distributors' 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. The Distributor 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.

The Distributor 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 the Distributor 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.
HOTLINK http://www.eriethamespower.com/privacy act.doc

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 the Distributors' technical specification document.

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

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

3.1.2 Early Consultation

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

The Customer must obtain a Demarcation Point Location from the Distributor 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 the Distributor 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 the Distributor.

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 the Distributor'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:

- *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 the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.1.7 Access:

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

The Customer will provide unimpeded and safe access to the Distributor 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 the Distributor. Meter sockets will be directly accessible to the Local Distribution Company 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 the Distributor 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 the Distributors' 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 the Distributor'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 the Distributor, 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 the Distributor 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.
- The Distributor 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 the Distributor.
- 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 the Distributor.

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

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

- 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 the Distributor 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 the Distributor, governing the terms and conditions under which the electrical distribution system services will be provided.

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

3.1.12.2 Access:

- **Night crossings**

  The Distributors' 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 the Distributor whether they will board customer owned transportation equipment in these circumstances.

- **Ice conditions**

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

- **Severe weather conditions**

  Recognizing that severe weather conditions may pose undue safety hazards, the Distributor 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 the Distributor prior to connection.

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

(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 the Distributor in the early planning stages to ascertain the Distributors' requirements.

The Owner shall supply a completed Electrical Service Connection Form to the Distributor well in advance of installation commencement to allow the Distributor 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. The distributor 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 the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor 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 the Distributor 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 the Distributor.

The Distributor shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by the Distributor 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 the distributor, 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, the Distributor 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 the Distributor'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 the Distributor. The Owner shall obtain prior approval

from the Distributor for the use of any specific voltage at any specific location.

3.2.7 Access:

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

The Customer will provide unimpeded and safe access to the Distributor 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 the Distributor. Meter sockets will be directly accessible to the Distributor 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 the Distributor 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, the Distributor 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 the Distributor.

3.2.11 Supply of Equipment:

The Distributor 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 the Distributor prior to connection.

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

(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 the Distributor in the early planning stages to ascertain the Distributors' requirements.

The Owner shall supply a completed Electrical Service Connection Form to the Distributor well in advance of installation commencement to allow the Distributor 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. The distributor 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 the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor 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 the Distributor 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 the Distributor.

The Distributor shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by the Distributor 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 the distributor, 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, the Distributor 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 the Distributor. 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 the Distributor'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 the Distributor 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 the Distributors' 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 the Distributor:

- *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 the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.3.7 Access:

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

The Customer will provide unimpeded and safe access to the Distributor 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 the Distributor. The owner will consult with the Distributor well in advance of installation commencement to allow the Distributor 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, the Distributor 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 the Distributor.

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

3.3.12 Supply of Equipment:

The Distributor 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 the Distributor prior to connection.

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

(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 the Distributor in the early planning stages to ascertain the Distributors' requirements.

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

The Distributor 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 the Distributor, 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. The distributor 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 the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor 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 the Distributor 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 the Distributor.

The Distributor shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by the Distributor 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

The Distributor 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 the distributor. This delivery point might be located on an adjacent property from which the Distributor has an authorized easement. In all cases the final Demarcation Point will be the decision of the Distributor.

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

The Distributor 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 the Distributor and shall be within 30 metres of the Distributors' 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 the Distributor. The customer owned termination pole must comply with items as prescribed by the Distributor.

At the Distributors' discretion, the customers' underground service may be connected to a termination pole owned by the distributor. In such cases, the Distributor 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 the Distributors' 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 the Distributor:

- *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 the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.4.7 Access:

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

The Customer will provide unimpeded and safe access to the Distributor 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 the Distributor.

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.

The Distributor 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 the Distributor.

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 the Distributor lines shall be complete with suitable hardware for attaching the suspension insulators that will be supplied and installed by the Distributor.

- Fencing arrangement.

- Grounding details. (In the case of indoor metal enclosed switchgear, when the Distributor has operating control of any interrupter switches, the assembly shall further incorporate ground rod parking stands and stirrups per the Distributors 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 the Distributors' cables terminate in the switchgear, the customer shall provide suitable terminators for the size and type of cable as specified by the Distributor.

- When the customer's switchgear is used for loop feeding the Distributors' 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 the distributor, the customer shall make provisions for a future system neutral connection to the customer's dead-ending pole or structures installed by the Distributor. Where the Distributors' 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 the Distributor.

3.4.12 Pre-Service Inspection

The customer shall present to the Distributor 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 the Distributor 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 the Distributor prior to connection.

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

(Refer to section 2.1.4 for further inspection details)

3.5 Embedded Generation

3.5.1 General

An Embedded Generator shall provide the Distributor with proof of compliance of IESO or OEB registration Requirements, and appropriate Licences.
http://www.eriethamespower.com/Generator Application.pdf

The Distributor 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 the distributors' distribution system shall enter into a Connection Agreement with the Distributor.

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

The Embedded Generator is responsible for providing suitable embedded generator equipment to protect his plant and equipment for any conditions on the distributor 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 the distributor 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 the distributor contact as identified by the distributor.

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 the distributor.

The purpose of the distributor review is to establish that the embedded generator electrical interface design meets the distributor 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 the distributor or transmission authority system.

The embedded generator may be required to submit a Ground Potential Rise study for review by the distributor, 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 the Distributor 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 the Distributor 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 the Distributor 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 the Distributor and the Generator) and financial and material requirements. The Distributor shall be notified of any deficiencies involving critical protective equipment.
- The Distributor shall be provided with copies of all relevant inspection and repair reports that may affect the protection and performance of the Distributors' systems. The Distributor has the right to witness any relevant test being performed by the generator.

3.6 Embedded Market Participant

An Embedded Market Participant shall provide the Distributor 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 the Distributors' distribution facilities.

3.7 Embedded Distributor

An Embedded Distributor shall provide the Distributor 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 the Distributors' 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 the Distributor, 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 the Distributors' plant, and will be established for each application through consultation with the Distributor.

Where specified by the Distributor during the Early Consultation process, the Customer will provide underground ducts to the Distributor's specifications.

The Owner shall be responsible for all costs associated with the supply and installation of service conductors

The Distributor at the Owners' expense will install required transformation.

Where at the discretion of the Distributor, 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 the Distributor 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 the Distributor well in advance of installation commencement to allow the Distributor 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 the Distributor shall be fully funded by the Municipality to ensure adherence to the Affiliate Relationship Code and the Distributors' 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 the distributor in accordance with subsection 2.3 of the Distribution System Code, that describes the operating practices and connection rules for the distributor;

"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 the Distributor 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 the distributor 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 the distributor distribution system without an expansion or enhancement, and meets the conditions listed in the Conditions of Service of the distributor 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 Ac*t;

"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 the distributor 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 the distributor 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;

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SECTION 5 APPENDICIES

Appendix 1 - Electrical Service Connection Form

Appendix 2 - Electric Service Meter Base/ Service Verification Form

Appendix 3 - Deposit Policy

Appendix 4 - Collection Policy

Appendix 5 - Disconnection Policy

Appendix 1

ERIE THAMES POWER

143 Bell Street, Box 157 Ingersoll ON N5C 3K5 (519)485-1820 Toll free 1866-878-0037 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#

0

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 >3000KW	
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: ______________________ 58-03

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Appendix 2

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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)
	5)
	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

Policy 6.0 **Security Deposits**	**Version 3.0** *Created: June, 2002* *Latest Revision: June 21, 2004*

6.0.1 PURPOSE:

This policy describes the terms and conditions distributors will use for collection, maintaining and returning customer security deposits while complying with the applicable legislation and codes.

In accordance with the Distribution System Code and Retail Settlement Code it must 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 customer 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:

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

A distributor will comply with the deposit requirements as defined in the Distribution System and Retail Settlement Codes but may waive these requirements in favour of a customer or potential customer.

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 to the distributor.

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.

The distributor may also accept other forms of security.

The distributor shall permit customer to pay security deposit in 4 equal monthly instalments, the first instalment being due on the implementation of an implied contract or the signing of service agreement. The customer may pay the security deposit over a shorter period of time.

The reasons for requiring the security deposit must be disclosed to the customer.

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 is calculated using:

- the billing cycle factor times the estimated bill based on the customer's average monthly load with the distributor in the most recent 12 consecutive months within the last 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 the distributor.

Where a customer has a payment history which discloses more than one disconnection notice in a relevant 12 month period, the distributor 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 distributors.

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 the distributor 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:

The distributor 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.

When the distributor determines in conducting a review that the maximum amount of the security deposit is to be adjusted upward, the distributor may require the customer to pay this additional amount at the same time the customer's next regular bill comes due.

A customer may demand in writing, no earlier than 12 months after payment of a security deposit or the making of a prior demand for a review, that the distributor undertake a review to determine whether the 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. If some or all of the security deposit is to be returned to the customer, the distributor shall promptly return this amount.

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 the distributor. 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:

The distributor 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 ay 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 distributor, or
- more than one cheque given to the distributor by the customer has been returned for insufficient funds, or
- more than one pre-authorized payment to the distributor has been returned for insufficient funds, or
- a disconnection/collection trip has occurred.

The distributor 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,
- 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 the distributor 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%

However, when the distributor determines in conducting a review that the maximum amount of the security deposit is to be adjusted upward, the distributor may require the customer to pay this additional amount at the same time the customer's next regular bill comes due.

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 the distributor, the distributor is only required to return 50% of 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 the distributor's 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 distributor 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

Electricity Distribution Rates Handbook – The Ontario Energy Board

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Appendix 4

Policy 7.0	**Version 3.0**
COLLECTION OVERVIEW	*Created: September, 2002* *Latest Revision: June 21, 2004*

7.0.1 PURPOSE:

The purpose of this policy is to establish a process to ensure money owed to the LDC by consumers is collected.

7.0.2 POLICY STATEMENT:

The LDC shall follow the regulation and direction set out in the Distribution Rate Handbook Chapter 9 when implementing the collection process.

The LDC will collect all outstanding money owed from Customers and Retailers served by the LDC's distribution system in accordance with the principles defined in the *Electricity Act (1998), the Electricity Distribution Rate Handbook* and the *Retail Settlement Code*. The policies in this set are intended to provide guidance to the LDC's 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

The LDC will collect all outstanding money owed from Customers and Retailers served by the LDC's distribution system in accordance with the principles defined in the *Electricity Act*

7.0.3 DEFINITIONS:

Licensed Competitive Retailer is a company that has a valid electricity retailer's license from the Ontario Energy Board.

Standard Service Supply Customer is a company or person who purchases electricity at spot market price or statutory pricing from a LDC's distribution system as a direct pass through from the IESO.

Customer and Consumer will be understood herein as one and the same.

Non-Competitive Charges is made up of the Wholesale Market Service charge, the Debt Retirement charge, Transmission Connection charge, Transmission Network charge and Distribution charges.

Distributor-Consolidated Billing is when a retailer marketer who has signed contracts in the LDC service area and has opted for the distributor to do the billing and collection of the electricity commodity and all related non-competitive charges.

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 the LDC 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.

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.

Errors and Omissions Excepted the LDC shall reserve the right to make adjustments to any bill issued in error either in whole or in part.

Non-Payment Risk Mitigation the LDC may use any risk mitigation options available to manage consumer non-payment risk.

7.0.4 COLLECTION PAYMENT METHODS:

The LDC may accept one or more of the following methods of payment but are 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
Interac
Preauthorized Chequing

7.0.5 RESPONSIBILTIES:

The Board of Directors are responsible for the approval of the policies contained in this manual.

7.0.6 REFERENCES:

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

Electricity Distribution Rate Handbook – The Ontario Energy Board

Retail Settlement – The Ontario Energy Board

Distribution System Code – The Ontario Energy Board

Electricity Gas and Inspection Act – Government of Canada

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Policy 7.1	Version 3.0
CUSTOMER COLLECTIONS	*Created: September, 2002* *Latest Revision: June 21, 2004*

7.1.1 PURPOSE:

This policy confirms that the LDC 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 the LDC's management and staff, to help them make operational decisions to ensure that monies owed to the LDC by the consumer or retailer are collected in a timely manner.

7.1.2 POLICY STATEMENT:

The LDC will take steps to collect the total amount for the customer's bill, if not paid within the time specified, which shall be a minimum of sixteen calendar days from the date of mailing or hand delivery of the bill. A collection of account charge may be made if a representative of the utility is dispatched to collect the account.

The customer shall be subject either to a collection of account charge or a reconnection charge in the event service has been interrupted in order to collect outstanding amounts owed in any billing period, unless partial payment of the account has been accepted by the LDC.

The LDC may apply more than one collection of account charge or reconnection charge in one billing period if a partial payment has been accepted through a collection trip.

The LDC shall begin the collection process immediately following the application of late payment charge.

The LDC shall treat all customers in the same rate class in a non-discriminatory fashion when collecting unpaid accounts.

The LDC shall have the right to limit or disconnect service for non-payment, theft of power and/or failing to keep payment arrangements.

The LDC shall reserve the right to make adjustments to any bill issued in error either in whole or in part.

7.1.3 RESPONSIBILITIES:

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

7.1.4 REFERENCES:

The Electricity Act, 1998 – Province of Ontario, Ministry of Energy, Science and Technology
Retail Settlement Code – The Ontario Energy Board
Electricity Distribution Rates Handbook – The Ontario Energy Board
Distribution System Code – The Ontario Energy Board
Electricity Gas and Inspection Act – Government of Canada

Policy 7.2	**Version 3.0**
RETAILER COLLECTIONS	*Created: September, 2002* *Latest Revision: June 21, 2004*

7.2.0 PURPOSE:

This policy describes the processes to collect outstanding balances from retailers who have signed sales agreements with consumers served by the LDC's 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:

The LDC requires Retailers to pay invoices on the due date as specified in the code.

The LDC reserves the right to refuse service transaction requests, requests for information, invoices or other transactions from retailers with whom the LDC does not have an up-to-date service agreement and/or financial security arrangements.

The LDC shall review the required level of deposit from a Retailer for customers served through Distributor Consolidated Billing on a quarterly basis as a minimum.

The LDC 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.

The LDC shall not access the funds available through the relevant security arrangement until five business days have elapsed.

The LDC 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 – Province of Ontario, Ministry of Energy, Science and Technology

Market Rules – The Independent Electricity Market Operator

Retail Settlement Code – The Ontario Energy Board

Electricity Distribution Rates Handbook – The Ontario Energy Board

Electricity Gas and Inspection Act – Government of Canada

Appendix 5

Policy 8.0 **DISCONNECTION/RECONNECTION OVERVIEW**	**Version 3.0** *Created: September, 2002* *Latest Revision: June 21, 2004*

8.0.1 PURPOSE:

The detailed policies in this set are intended to establish and document a process that will provide guidance to the LDC's management and staff to help them make operational decisions when disconnecting and/or reconnecting the electrical service of a consumer.

8.0.2 POLICY STATEMENT:

The LDC will ensure that it has developed a physical and business process for disconnection ensuring safety and reliability as a primary requirement. The LDC will not be held liable for any damages or loss as the result of disconnection or limiting of service.

The LDC shall follow the regulation and direction set out in the Distribution Rate Handbook Chapter 9 when implementing the disconnection and/or reconnection process.

- A disconnection notice will be issued in writing not less than seven days after the date specified on the bill as the due date. Notice must be given by hand delivery or by registered mail. Both the customer and tenants of the customer will receive seven days' notice before cut-off.
- Prior to the disconnection of the electricity service, a representative of the utility will make reasonable efforts to establish direct contact with the customer. The utility should also where possible, notify the occupants of each separately occupied unit in the premises. The electricity service will not be disconnected by reason of the non-payment of bills until seven days after a disconnection notice has been given to the customer and as set out in Chapter 9 of the Distribution Rate Handbook.
- Where the electricity service has been disconnected on order to collect the account and then reconnected, a reconnection of service charge may be applied to the customers account.

The LDC reserves the right to physically disconnect or limit the amount of electricity that a customer can consume.

(i) Disconnection/Reconnection

(ii) Disconnection/Reconnection by Request

(iii) Safety and Reliability

(iv) Unauthorized use of Electricity

8.0.3 DEFINITIONS:

Current Limiting Device is a device that will limit the electrical current available to the customer.

Customer and Consumer will be understood herein as one and the same.

Disconnection is when the LDC discontinues the delivery of electricity to a property and/or premise.

Reconnection is when a property or premise has electrical service energized or re-established by the LDC.

Security Deposit is an amount collected by the LDC 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 – Province of Ontario, Ministry of Energy, Science and Technology

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

Condition of Service – The Distributor

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CORPORATION

Policy 8.1 **DISCONNECTION/RECONNECTION**	**Version 3.0** *Created: September, 2002* *Latest Revision: June 21, 2004*

8.1.1 PURPOSE:

This policy confirms that the LDC has established a process for the disconnection and/or reconnection of a property and/or premise, and the specific timing and means of notification consistent with the Electricity Act, 1998.

The detailed policies in this set are intended to establish and document a process that will provide guidance to the LDC's management and staff that will help them make operational decisions to disconnect and/or reconnect the electrical service of a consumer.

8.1.2. POLICY STATEMENT:

The LDC shall follow the regulation and direction set out in the Distribution Rate Handbook Chapter 9 when implementing disconnect or reconnection process.

- A disconnection notice will be issued in writing not less than seven days after the date specified on the bill as the due date. Notice must be given by hand delivery or by registered mail. Both the customer and tenants of the customer will receive seven days' notice before disconnection.
- Prior to the disconnection of the electricity service, a representative of the utility will make reasonable efforts to establish direct contact with the customer. The utility should also where possible, notify the occupants of each separately occupied unit in the premises. The electricity service will not be disconnected by reason of the non-payment of bills until seven days after a disconnection notice has been given to the customer and as set out in Chapter 9 of the Distribution Rate Handbook.
- Where the electricity service has been disconnected on order to collect the account and then reconnected, a reconnection of service charge may be applied to the customers account.

The LDC will ensure that it has developed a physical and business process for disconnection and/or reconnection ensuring safety and reliability as a primary requirement.

The LDC shall treat all customers in a non-discriminatory fashion when disconnecting and/or reconnecting an electrical service.

The LDC shall have the right to limit or discontinue service <u>without further notification</u> to the customer for payment default, including default of payment arrangements, bankruptcy, receivership, or property foreclosure.

The LDC shall have the right to limit or discontinue service for non-payment of a security deposit from customers that have defaulted on payment arrangements.

The LDC shall have the right to refuse the reconnection if there are any outstanding amounts owed by the consumer or if the service is found to have an adverse effect on the safety and/or reliability of the system.

The LDC shall have the right to discontinue electrical service of a consumer if the service causes safety or reliability risk to the distributor's system.

The LDC 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. Not withstanding the LDC reserves the right to require, an Electrical Safety Authority inspection certificate at any time prior to reconnection at the expense of the customer.

The LDC 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.

8.1.4 REFERENCES:

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

Retail Settlement Code – The Ontario Energy Board

Electricity Distribution Rates Handbook – The Ontario Energy Board

Distribution System Code – The Ontario Energy Board

Electricity Gas and Inspection Act – Government of Canada

Condition of Service – The Distributor

Policy 8.3 **DISCONNECTION/RECONNECTION BY REQUEST**	**Version 3.0** *Created: September, 2002* *Latest Revision: June 21, 2004*

8.3.1 PURPOSE:

This policy confirms that the LDC has established a process for the disconnection and/or reconnection of an electrical service and may require a written request from the consumer.

8.3.2 POLICY STATEMENT:

The LDC shall respond to a customer's request for a disconnection and reconnection of an electrical service in a prompt and efficient manner.

The LDC shall have the right to refuse the reconnection of and electrical service if there is an outstanding amount of money owed by the consumer or if the connection is found to have an adverse effect on the safety and/or reliability of the distribution system.

The LDC 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. Not withstanding the LDC reserves the right to require an Electrical Safety Authority certificate at any time prior to reconnection at the customer expense.

The LDC 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 corporation is protected from undue risk of bad debt.

8.3.4 REFERENCES:

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

Retail Settlement Code – The Ontario Energy Board

Electricity Distribution Rates Handbook – The Ontario Energy Board

Distribution System Code – The Ontario Energy Board

Electricity Gas and Inspection Act – Government of Canada

Condition of Service – The Distributor

Policy 8.4.0	Version 3.0
SAFETY AND RELIABILITY	*Created: September, 2002* *Latest Revision: June 21, 2004*

8.4.1 PURPOSE:

This policy confirms that the LDC has established a process for ensuring the safety and reliability of the distribution system.

8.4.2 POLICY STATEMENT:

The LDC 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.

The LDC 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 the LDC's distribution system.

The LDC may require that any consumer conditions that adversely affect the distribution system be corrected immediately by the consumer and at the consumer's expense.

The LDC 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. Not withstanding the LDC reserves the right to require an Electrical Safety Authority certificate at any time prior to reconnection at the customer expense.

The LDC 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.

The LDC shall have the right to disconnect the electrical service of a consumer if the service causes safety or reliability risk to the distributor's system.

The LDC shall insist that a responsible representative of the property be present when electrical service is energized or reconnected.

8.4.3 RESPONSIBILITIES:

The management of the company is responsible for ensuring that the service quality of the distribution system is safe and reliable.

8.4.4 REFERENCES:

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

Retail Settlement Code – The Ontario Energy Board

Electricity Distribution Rates Handbook – The Ontario Energy Board

Distribution System Code – The Ontario Energy Board

Electricity Gas and Inspection Act – Government of Canada

Condition of Service – The Distributor

Policy 8.5.0	Version 3.0
UNAUTHORIZED USE OF ELECTRICITY	*Created: September, 2002* *Latest Revision: June 21, 2004*

8.5.1 PURPOSE:

This policy confirms that the LDC has established a process that management and staff can follow if it is discovered that there is unauthorized use of electricity.

8.5.2 POLICY STATEMENT:

The LDC shall use its discretion in taking action to mitigate unauthorized energy use.

The LDC shall use its discretion in taking action to mitigate unauthorized energy use. Upon identification of possible unauthorized energy use, the LDC shall notify, if appropriate, Measurement Canada, the Electrical Safety Authority, police officials, retailers that service the customers affected by the unauthorized energy use, or other entities.

The LDC shall monitor losses and unaccounted for energy use on an annual basis to detect any upward trends.

The LDC may recover from the parties responsible for the unauthorized energy use all energy and other applicable charges incurred by the distributor arising from the unauthorized energy use, including inspection, administration fees and repair costs.

8.5.3 RESPONSIBILITIES:

The management of the company is responsible for monitoring losses and unaccounted for energy.

8.5.4 REFERENCES:

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

Retail Settlement Code – The Ontario Energy Board

Electricity Distribution Rates Handbook – The Ontario Energy Board

Distribution System Code – The Ontario Energy Board

Electricity Gas and Inspection Act – Government of Canada

Conditions of Service – The Distributor

ERIE THAMES POWERLINES CORPORATION

FINANCIAL STATEMENTS

DECEMBER 31, 2006

ERIE THAMES POWERLINES CORPORATION

INDEX TO AUDITED FINANCIAL STATEMENTS

DECEMBER 31, 2006

Davis Martindale LLP
CHARTERED ACCOUNTANTS

Bruce Barran CA CFP
Mike Evans CA CFP
Michael Koenig CGA CFP*
L Ron Martindale CA
Ron L Martindale Jr CA CBV
Ian McIntosh FCA
Paul Panabaker CA CFP RFP
William Simpson CA CBV*
Brenda Walton CMA*
Michael Watson CA
*Principal

AUDITORS' REPORT

To the Shareholder of:
Erie Thames Powerlines Corporation

We have audited the balance sheet of Erie Thames Powerlines Corporation as at December 31, 2006 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, 2006 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
Chartered Accountants
Licensed Public Accountants

London, Ontario
March 30, 2007

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ERIE THAMES POWERLINES CORPORATION

BALANCE SHEET

AS AT DECEMBER 31, 2006

ASSETS

	2006	2005
Current Assets		
Bank	$ 361,200	$ 457,704
Accounts receivable (note 3)	7,077,857	6,249,082
Prepaid expenses	80,873	78,254
Current portion of note receivable (note 4)	29,304	29,304
Payment in lieu of income taxes recoverable	-	5,966
	7,549,234	6,820,310
Note Receivable (note 4)	29,304	58,608
Property, Plant and Equipment (note 6)	16,403,820	15,438,469
Future Payment in Lieu of Income Tax Asset	190,500	93,896
Regulatory Assets (note 5)	1,457,643	2,482,517
Intangible Asset (note 8)	76,667	76,667
Deferred Charges (note 7)	-	60,554
	$25,707,168	$25,031,021

LIABILITIES AND SHAREHOLDER'S EQUITY

	2006	2005
Current Liabilities		
Accounts payable and accrued liabilities	$ 4,678,677	$ 4,798,980
Customer deposits (note 10)	897,320	655,407
Payments in lieu of income taxes payable	5,424	-
Due to related party (note 9)	3,545,195	3,013,669
	9,126,616	8,468,056
Long-term Debt (note 12)	8,038,524	8,038,524
Shareholder's Equity		
Share capital (note 11)	8,038,524	8,038,524
Retained earnings	503,504	485,917
	8,542,028	8,524,441
	$25,707,168	$25,031,021

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, 2006

	2006	2005
Balance, Beginning of year	$ 485,917	$ 753,463
Net Income	17,587	218,369
	503,504	971,832
Dividends	-	485,915
Balance, End of Year	$ 503,504	$ 485,917

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, 2006

	2006	%	2005	%
Electricity Revenue (note 13)	$36,851,307	100.00	$39,380,916	100.00
Cost of Power	31,378,239	85.15	33,932,978	86.17
Gross Margin	5,473,068	14.85	5,447,938	13.83
Expenses				
Billing and collecting	646,639	1.75	617,738	1.57
Community relations	36,709	0.10	24,210	0.06
Direct operation	2,912,878	7.90	2,982,088	7.57
Office and administration	374,315	1.02	310,821	0.79
Regulatory and professional	413,174	1.12	475,164	1.21
	4,383,715	11.89	4,410,021	11.20
Net Income from Operations Before Taxes, Interest & Amortization	1,089,353	2.96	1,037,917	2.63
Amortization	1,023,655	2.78	1,037,906	2.64
Interest income on regulatory assets	(151,460)	(0.41)	(349,154)	(0.89)
Interest	582,793	1.58	582,793	1.48
Net Income (Loss) from Operations Before Tax	(365,635)	(0.99)	(233,628)	(0.60)
Other Income				
Investment income	21,631	0.06	23,759	0.06
Miscellaneous	340,853	0.92	307,238	0.78
	362,484	0.98	330,997	0.84
Net Income (Loss) Before Income Tax	(3,151)	(0.01)	97,369	0.24
Payment in Lieu of Income Taxes				
Current	75,866	0.21	68,000	0.17
Future tax expense (benefit)	(96,604)	(0.26)	(189,000)	(0.48)
	(20,738)	(0.05)	(121,000)	(0.31)
Net Income	$ 17,587	0.04	$ 218,369	0.55

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, 2006

	2006	2005
Cash Flows from Operating Activities		
Net income	$ 17,587	$ 218,369
Items not requiring an outlay of cash:		
Amortization	1,023,655	1,037,906
Future payment in lieu of tax asset	(96,604)	(189,000)
	944,638	1,067,275
Changes in Non-Cash Working Capital Balances		
Accounts receivable	(828,774)	(613,971)
Regulatory assets	848,528	(691,564)
Prepaid expenses and deferred charges	33,866	(68,397)
Accounts payable and accrued liabilities	(120,305)	833,646
Payment in lieu of income taxes	11,390	37,170
Customer deposits	241,913	(185,887)
Due to related parties	531,526	1,713,837
Net Cash Provided by Operating Activities	1,662,782	2,092,109
Cash Flows from Financing Activities		
Dividends	-	(485,915)
Cash Flows from Investing Activities		
Additions to property, plant and equipment	(1,788,590)	(1,316,100)
Decrease in note receivable	29,304	-
Net Cash Used in Investing Activities	(1,759,286)	(1,316,100)
Net Increase (Decrease) in Cash	(96,504)	290,094
Cash, Beginning of Year	457,704	167,610
Cash, End of Year	$ 361,200	$ 457,704
Supplemental Cash Flow Information		
Interest paid	$ 702,715	$ 582,793
Income taxes paid	$ 64,476	$ 38,696

The attached Auditors' Report and notes form an integral part of these audited financial statements.

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 Erie Thames Power Corporation who, in turn is, 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 were to bill 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 kWh per year. The new block structure implemented in 2005 resulted in a change to the block structure for residential customers only. From November 1, 2005 to April 30, 2006 the first 1000 kWh's consumed per month were charged at 5.0 cents per kWh and the remaining consumption was billed at 5.8 cents per kWh. The rates from November 1, 2006 to April 30, 2007 were increased to 5.5 cents for the first 1000 kWhs and 6.4 cents for the remainder of the monthly consumption. Effective May 1, 2006 to October 31, 2006, the block structure was changed to 5.8 cents per kWh for the first 600 kWhs per month and 6.7 cents per kWh for the remainder.

Non-residential customers are charged based on a block structure of 750 kWhs per month and the structure remains consistent throughout the year. The rates up to May 1, 2007 are 5.5 cents per kWh on the first 750 kWh's and 6.4 cents per kWh for the remainder of the month's consumption.

1. Nature of Operations (cont.)

Further changes implemented by Bill 4 allowed Local Distribution Companies (LDCs) to apply to the OEB for rate adjustments. Specifically, LDCs began to recover the amounts deferred for regulatory purposes on April 1, 2004, and continued to recover these amounts through its April 1, 2005 rate approval. The 2006 rate process will further review the LDCs' deferral account balances and is anticipated to continue to permit LDCs to recover these amounts through their rate structure. In January of 2007, the OEB reviewed the rate structure and approved that all deferral amounts are available for recovery.

Through Bill 4, LDCs obtained approval to apply for a rate order that would allow the recovery of their full Market Based Rate of Return beginning March 1, 2005. This rate change is conditional on the LDC's reinvestment of one year's worth of the incremental rate of return in conservation and demand management initiatives over a three year period.

On December 18, 2003, the Ontario Energy Board renewed the LDC's distribution license for a 20 year period.

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 - 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.

(c) Financial Instruments

The Company's financial instruments consist of cash, accounts receivable, recoverable transition costs, accounts payable and accrued liabilities. Unless otherwise noted, it is management's opinion that the Company is not exposed to significant interest, currency or credit risk arising from these financial instruments except for the recoverable transition costs ("Regulatory assets"). The credit risk of the Regulatory assets is solely dependent upon future applications for rate increases by the Company and approval of such application by the OEB. The fair value of these financial instruments approximate their carrying values, unless otherwise noted.

(d) Payments in Lieu of Corporate Income Taxes

The Company uses the liability method for accounting for income taxes. Under this method, future 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 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 income tax asset, a valuation allowance reducing the future 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 flows 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.

3. Accounts Receivable

	2006	2005
Energy, water and sewer	$ 5,354,619	$ 3,718,527
Unbilled energy	1,584,352	2,227,239
Service revenues	138,886	303,316
	$ 7,077,857	$ 6,249,082

The amounts shown above are net of allowance for doubtful accounts.

4. Note Receivable

The note is non-interest bearing and repayable in monthly installments of $2,442 commencing February 2005 for a term of 48 months.

	2006	2005
Note Receivable	$ 58,608	$ 87,912
Less: current portion of note receivable	(29,304)	(29,304)
	$ 29,304	$ 58,608

5. Regulatory Assets

	2006	2005
Transition costs	$ 126,731	$ 296,854
Retail settlement variances	1,971,348	2,111,986
Pre-market opening cost of power variances	1,225,987	1,178,524
Demand side management expenses	184,732	53,849
	3,508,798	3,641,213
Recovery of regulatory assets	(2,051,155)	(1,158,696)
	$ 1,457,643	$ 2,482,517

(a) Transition costs represent specific and incremental costs incurred by the Company to prepare its systems and processes for the opening of the competitive electricity market in Ontario on May 1, 2002. These costs have been deferred pursuant to regulation underlying the Electricity Act and are subject to review and approval by the OEB. Expenditures determined to be ineligible for recovery will be expensed in the period of such determination. In January of 2007, the OEB reviewed the rate structure and approved that all these amounts are available for recovery.

(b) 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 settlement and transmission charges

In the absence of rate regulations these costs (revenues) would be charged to the period incurred. In 2006, revenues would have been $1,033,097 higher; in 2005, revenues would have been $517,584 lower.

(c) Pre-market opening cost of power variances, represent the excess cost of electricity to the Company over the amount billed to customers from January 1, 2001 until April 30, 2002.

In the absence of rate regulations, these costs would have been charged to the period incurred. In 2006, expenses would have been $47,463 higher; in 2005, expenses would have been $63,678 higher.

5. Regulatory Assets (cont.)

(d) Demand side management 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. The OEB has approved the company's final one third increase in market base rate of return with the requirement to spend one year's increase on demand side management projects before December 31, 2007.

In the absence of rate regulations, these costs would be charged to the period incurred. In 2006, expenses would have been $14,501 higher, in 2005 expenses would have been $43,516 higher.

(e) Amortization Policy

Transition costs will be amortized at an amount equal to the revenue collected from the approved rates over a period of four years, commencing on April 1, 2004, as set out in Bill 4.

During the year, the Company recorded amortization of $176,346 ($156,063 - 2005).

6. Property, Plant and Equipment

	Cost 2006	Accumulated Amortization	Net 2006	Net 2005
Land	$ 146,684	$ -	$ 146,684	$ 146,684
Building	114,317	27,708	86,609	91,182
Plant and equipment	558,508	207,913	350,595	345,357
Transmission and distribution system	19,592,538	3,772,606	15,819,932	14,855,246
	$20,412,047	$ 4,008,227	$16,403,820	$15,438,469

During the year, the Company recorded amortization of $823,239 ($755,425 - 2005).

7. Deferred Charges

	Cost 2006	Accumulated Amortization	Net 2006	Net 2005
Organizational	$ 512,813	$ 512,813	$ -	$ 36,485
Amalgamation and integration	290,130	290,130	-	24,069
	$ 802,943	$ 802,943	$ -	$ 60,554

Deferred charges represent costs incurred to facilitate the organization and incorporation of the Company and preparation for the opening of the electricity commodity market and in support of the deregulation of the electricity industry in Ontario. These amounts have been accumulated pursuant to regulations in the Electricity Act.

(a) Organizational Charges

Expenditures were incurred by the former Municipal Hydro Electric Commissions during the organization of the new business prior to the commencement of commercial operations. Commencing September 1, 2000, amortization is calculated on a straight-line basis over a period of five years.

(b) Amalgamation and Integration

Costs incurred by Erie Thames Power Corporation relating to the amalgamation and integration of the systems of the former Municipal Hydro Electric Commissions will be amortized over a period of five years commencing June 1, 2001.

During the year, the Company recorded amortization of $24,070 ($126,418 - 2005).

8. Intangible Assets

	Cost 2006	Accumulated Amortization	Net 2006	Net 2005
Goodwill	$ 100,000	$ 23,334	$ 76,667	$ 76,667

At year end, the Company tested goodwill in each of its reporting units using a discounted cash flow and cost methodology and determined that there was no impairment of goodwill.

9. Related Parties

The company has a contract with Erie Thames Power Corporation for management services and rental of facilities used by the company.

The Company has contracted its sister company, 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 of the Company's revenues and administrative services.

The contracts between the Company and Erie Thames Service Corporation and Erie Thames Power 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 distribution revenue for the sale of electricity to Erie Thames Power 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 $1,150,990 ($922,029 in 2005). These transactions are in the normal course of operations at rates approved by the Ontario Energy Board.

During the year, the Company purchased services from related parties amounting to the following:

Erie Thames Services Corporation	**2006**	**2005**
Purchase of capitalized items	$1,856,500	$1,189,206
Purchase of operations, maintenance and administrative services	2,979,797	3,150,939
	$4,836,297	$4,340,145

Erie Thames Power Corporation	**2006**	**2005**
Purchase of management services	$ 503,629	$ 495,000
Rent	219,536	220,011
	$ 723,165	$ 715,011

Shareholders of Erie Thames Power Corporation

Interest on long-term debt as set out in note 12.

The contracts with Erie Thames Power 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 of the Company's revenues and administrative services are automatically renewed every two years unless either party terminates the agreement with notice.

The attached Auditors' Report and notes form an integral part of these audited financial statements.

Accountants *with personality!*

9. Related Parties (cont.).

	2006	2005
Due to Erie Thames Services Corporation	$ 822,399	$ 542,340
Due to Erie Thames Power Corporation	2,611,758	2,324,434
Due to Shareholders of Parent Corporation (interest)	146,886	146,895
Due to (from) Erie Thames Solutions Corporation	(36,331)	-
Due to RDI Consulting Corporation	483	-
	$3,545,195	$3,013,669

These amounts represent funds owing to related parties. The amounts are non-interest bearing and payable in the normal course of business.

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. Amounts also include security deposits received for construction projects.

11. Capital Stock

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.

	2006	2005
Issued capital		
7 Class "A" shares	$ 7	$ 7
10,000 Class "B"shares	8,038,517	8,038,517
	$ 8,038,524	$ 8,038,524

12. Long-term Debt

Related Party Note Payable

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:

	2006	2005
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 2006, $582,793 was charged to interest expense for interest on related party long-term debt ($582,793 in 2005).

The Company has guaranteed the loans payable of its parent company Erie Thames Power Corporation. The loan is secured by a General Security Agreement covering accounts receivable, inventory and equipment, including motor cars. At December 31, 2006, the loans amount to $3,604,674 ($3,215,785 in 2005).

13. Electricity Revenue

	2006	%	2005	%
Sale of electricity	$24,438,596	66.32	$27,802,882	70.60
Distribution charges	5,473,068	14.85	5,447,938	13.83
Transmission charges	4,460,141	12.10	4,098,969	10.41
Retailer energy sales	2,479,502	6.73	2,031,127	5.16
	$36,851,307	100.00	$39,380,916	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 April 21, 2003, was $2,371,089 and had not changed as at December 31, 2006. The prudential support requirement will be honoured through long-term payment history, letter of credit or credit rating from an accredited rating agency.

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:

	2006	2005
Income from continuing operations before PILs	$ (3,151)	$ 97,369
Statutory Canadian federal and provincial income tax rate	36.12 %	36.12 %
Basic rate applied to income before PILs	(1,138)	35,170
Other	77,004	32,830
Provision for payment in lieu of income tax	$ 75,866	$ 68,000
Effective tax rate	(2,407.68)%	69.84 %

Provision for payments (recovery) in lieu of income taxes are made up of the following:

Current	$ 75,866	$ 68,000
Future tax expense (benefit)	(96,604)	(189,000)
	$ (20,738)	$ (121,000)

The Company as of December 31, 2006, has recorded a future income tax asset of $190,500 (2005 - $93,896), based on substantially enacted income tax rates of 36.12%. Such future income tax liabilities relate to the tax basis of depreciable assets being lower than the amounts recorded for accounting purposes.

16. Contingent Liabilities

A class action 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 challenging the validity of late payment penalties. 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.

After the release by the Supreme Court of Canada of its 2004 decision in the Enbridge Gas case, the plaintiffs in the Local Distribution Company (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.

At this time, it is not possible to quantify the effect, if any, on the financial statement of the Company.

17. Comparative Figures

Certain comparative figures have been reclassified to conform with the statement presentation adopted in the current year.

ERIE THAMES POWERLINES CORPORATION

ERIE THAMES POWERLINES CORPORATION
PROFORMA BALANCE SHEET
AS AT DECEMBER 31ST 2007

ASSETS

	YEAR ENDED 31-Dec-07
Current	
Bank	$ 361,200
Accounts Receivable (note 1)	8,084,752
Prepaid Expenses	80,873
	8,526,825
Capital Assets (note 2)	16,464,955
Regulatory Assets (note 3)	726,638
Note Receivable	58,608
Goodwill	76,667
	$ 25,853,693

LIABILITIES AND SHAREHOLDER'S EQUITY

Current	
Accounts Payable and Accrued Liabilities (note 5)	$ 4,180,430
PILS Payable	5,424
Due to Related Parties	3,046,948
Customer Deposits	897,320
	8,130,122
Long-term Debt	
Related Party Note Payable	8,038,524
Long Term Loan	-
Future PILS	-
	8,038,524
Shareholders' Equity	
Share Capital	8,038,524
Retained Earnings	1,646,523
	9,685,047
	$ 25,853,693

ERIE THAMES POWERLINES
CORPORATION

ERIE THAMES POWERLINES CORPORATION
PROFORMA STATEMENT OF INCOME
FOR THE TWELEVE MONTHS ENDED DECEMBER 31ST 2007

	YEAR ENDED 31-Dec-07
Electricity Revenue	$ 39,735,791
Cost of Power	32,512,213
Gross Margin	7,223,578
Miscellaneous Revenues	512,971
Total Revenues from Operations	7,736,549
Expenses	
Billing and Collecting	1,054,982
Community Relations	28,879
Regulatory and Professional	280,000
Office and Administration	1,505,091
Direct Operation	1,485,814
	4,354,766
Net Income from Operations Before Taxes, Interest & Amortization	3,381,783
Amortization	890,252
Shareholder Interest	582,793
Interest income on regulatory assets	(15,381)
Net Income from Operations Before Tax	1,924,119
Other Income	
Investment Income	-
Net Income Before Income Taxes	1,924,119
Current Taxes	-
PILS	781,100
Net Income (Loss)	1,143,019
Retained Earnings (deficit) Beginning of Period	503,504
Retained Earnings (deficit) End of Period	$ 1,646,523

ERIE THAMES POWERLINES CORPORATION
PROFORMA BALANCE SHEET
AS AT DECEMBER 31ST 2008

ASSETS

	YEAR ENDED 31-Dec-08
Current	
Bank	$ 361,200
Accounts Receivable	8,970,311
Prepaid Expenses	80,873
	9,412,384
Capital Assets	16,464,955
Regulatory Assets	137,048
Note Receivable	58,608
Goodwill	76,667
	$ 26,149,662

LIABILITIES AND SHAREHOLDER'S EQUITY

Current	
Accounts Payable and Accrued Liabilities	$ 3,732,450
PILS Payable	5,424
Due to Related Parties	2,598,968
Customer Deposits	897,320
	7,234,162
Long-term Debt	
Related Party Note Payable	8,038,524
	8,038,524
Shareholders' Equity	
Share Capital	8,038,524
Retained Earnings	2,838,451
	10,876,975
	$ 26,149,662

ERIE THAMES POWERLINES CORPORATION

ERIE THAMES POWERLINES CORPORATION
PROFORMA STATEMENT OF INCOME
FOR THE TWELEVE MONTHS ENDED DECEMBER 31ST 2008

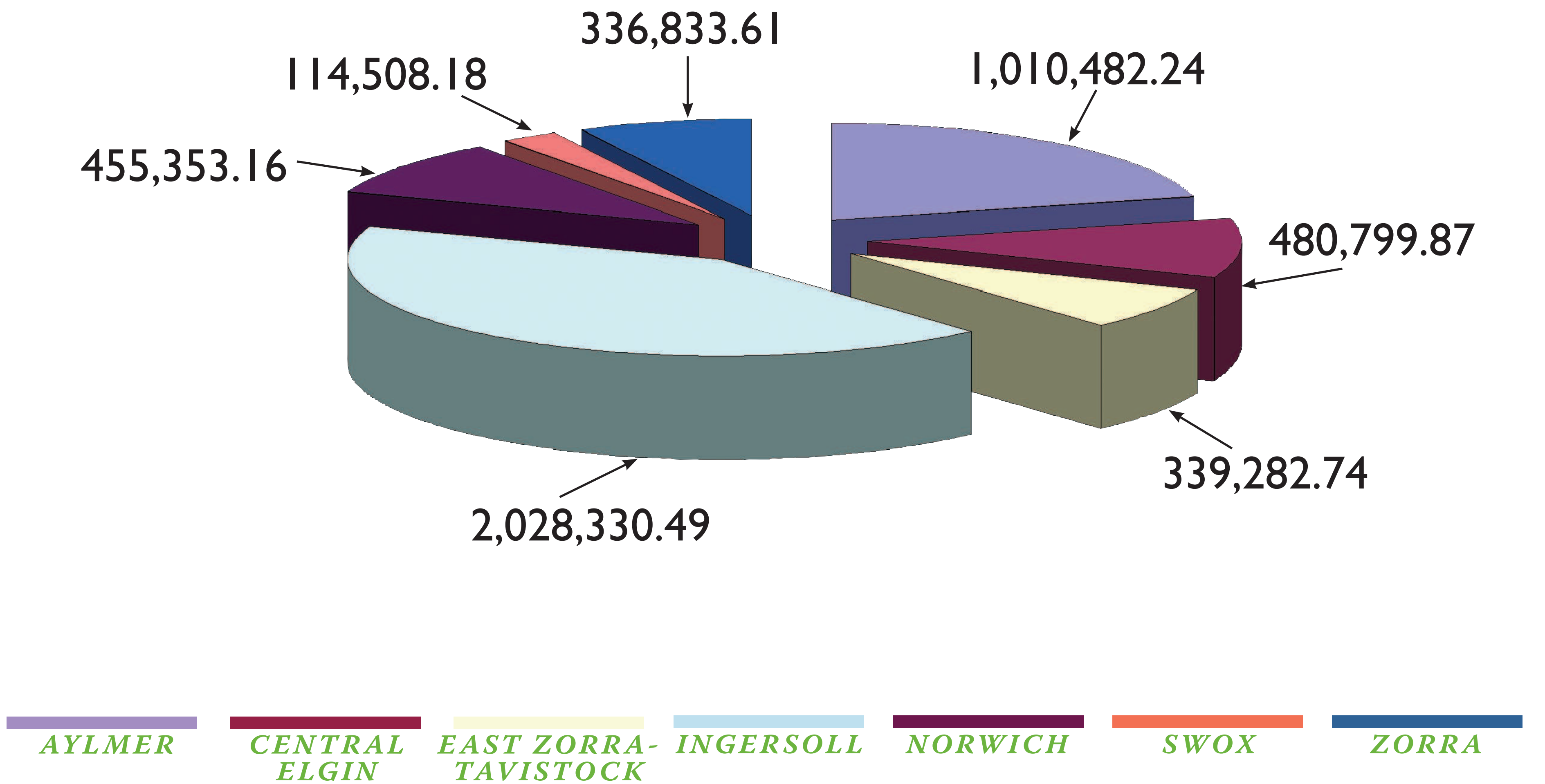
	YEAR ENDED 31-Dec-08
Electricity Revenue	$ 40,550,834
Cost of Power	33,436,279
Gross Margin	7,114,555
Miscellaneous Revenues	531,702
Total Revenues from Operations	7,646,257
Expenses	
Billing and Collecting	1,073,487
Community Relations	28,879
Regulatory and Professional	178,000
Office and Administration	1,651,740
Direct Operation	1,496,653
	4,428,759
Net Income from Operations Before Taxes, Interest & Amortization	3,217,498
Amortization	935,609
Shareholder Interest	792,683
Interest income on regulatory assets	(5,574)
Net Income from Operations Before Tax	1,494,780
Other Income	
Investment Income	-
Net Income Before Income Taxes	1,494,780
Current Taxes	
PILS	302,852
Net Income (Loss)	1,191,929
Retained Earnings (deficit) Beginning of Period	1,646,523
Retained Earnings (deficit) End of Period	$ 2,838,451

ERIE THAMES POWER CORPORATION

Annual Report 2006

payments...
to the SHAREHOLDERS

$4,792,595.79



message...
from the CEO

JEFF PETTIT
President & C.E.O.

The year 2006 is to be described as one of change, of growth, of challenges. In the words of Charlotte Perkins Gilman; "...while we flatter ourselves that things remain the same, they are changing under our very eyes from year to year, from day to day." In this industry sometimes things can change from hour to hour and minute to minute.

Erie Thames Power spent the majority of 2006 preparing for the change that can arrive unannounced. We invested time and resources to expand our services business as a means to have greater control over our own destiny and way to become increasingly independent from the regulated portion of the organization. This does not release us in any way from our original cornerstones of continued system reliability, customer service and safety. We are proud of our growth but those fundamentals remain true and our commitment to them is solid.

In 2006 we invested in a company called OUS Canada Inc., thus generating a partnership with Essex Power to form an Asset Management company named abicus (***a b****est* ***i****n* ***c****lass* ***u****tility* ***s****olution*), which balances safety, reliability and financial consideration. Asset Management (AM) is a key ingredient in managing infrastructure in a regulated environment that assists in making better, more informed decisions. It is our goal to expand AM into the water and municipal sectors, in the very near future.

Another area of importance for Erie Thames is our dedication to ISO 9000 – ***an international set of standards developed to provide a framework for a quality management system. Quality and customer service are hallmarks of ISO 9000***. I am thrilled to report that after undergoing a rigorous audit process, ET was re-certified company wide in 2006 with the ISO 9000 accreditation. This perpetuates a culture of quality improvement and customer service and Erie Thames takes very seriously our commitment to the ISO program.

Our investment in Utilismart Corporation continues to reap benefits since our involvement in 2005. As the number one independent settlement provider in the Ontario electricity market, Utilismart continued to gain market share throughout 2006. The Province's smart meter initiative will be a tremendous opportunity for Utilismart, and since they already hold the record for largest collector of consumption data, the transition will be seamless.

Our Powerlines division remains constant. For the second year in a row, the capital expenditures (CAPEX) investment within our licensed territory topped $1 million. For the Board of Directors and the senior management of the corporation, a main area of focus was to ensure that funds were reinvested in our distribution infrastructure for a more reliable supply of electricity to our valued customers. Unfortunately with the good came the not so good. Powerlines experienced some regulatory issues that ultimately impacted the bottom line; however, they have since been satisfactorily resolved and 2007 promises to be a year of improvement and recovery.

Keeping on the regulatory theme, the Province of Ontario has declared a transfer tax holiday on the mergers and acquisitions of Local Distribution Companies (LDC). It is expected that this will result in further amalgamations within our industry. It will be incumbent for Erie Thames to remain active and carefully consider potential opportunities regarding industry consolidation.

A hot topic throughout the electricity sector is that of conservation. Since August of 2003, the Province of Ontario and the Ministry of Energy have been focusing on preventing another significant blackout like the one that affected 10 million Ontario residents and 40 million people in the United States. Conservation and Demand Management (CDM) initiatives have been mandated by the Provincial Government, which is aimed at safeguarding our resources and pursuing alternate sources of power. In 2006, Erie Thames spent $124,455 on its CDM plan investing in a number of different projects that included:

- LED Christmas light exchange, where customers would bring in an old strand of Christmas lights and we provided them with a new strand of multi-coloured LED lights;
- Commercial and industrial CDM seminars and Utilismart offering, which included discussion on interval metering and the demonstration of the Utilismart product;
- Participation in the spring and fall "Every Kilowatt Counts" coupon program
- Upgrade of the eCare website so customers can go online and access a variety of tools in relation to their monthly bill

These initiatives resulted in savings of 299,050 kWh (the equivalent of 636 refrigerators running for an entire year) and 42 kW (the equivalent of shutting off 84 central air conditioning units). As the electricity market continues to "morph" and the Province's commitment to look for new and innovative ways to supply power increases, Erie Thames remains enthusiastic in our search to participate in opportunities to find alternate sources of energy.

Switching gears, 2006 was a year of new developments, thus the inception of Quadra software. This information technology (IT) solution was created because a need arose within Erie Thames, for a software tool, which could bridge the gap between the financial and operational aspects of organizations, and the marketplace had nothing to offer. After months of research and planning, Quadra is a tremendous success and another vital element in our growing suite of services. Many of our customers will benefit from this solution and I anticipate the demand for Quadra to grow significantly within our industry (and beyond) over the next few years.

Erie Thames experienced some wonderful successes in 2006. Negotiations with the union (Power Workers Union – PWU) were completed and a three-year deal was agreed upon, with a signed Collective Agreement in place, which expires December 2008. We are very pleased to have a good relationship with the PWU and our unionized employees, key partners and contributors to Erie Thames.

In the spring of 2006, we were recognized with an international award for best "outsourced customer care initiative" in the category for CIS/CRM Excellence. This award was part of the Electrical Planning Networks (EPN) utility awards program recognizing utilities for exceptional customer care and related IT initiatives. Erie Thames was chosen above utilities based in Europe, Africa, Australia and the US and a few others at home in Canada. The competition was great and Erie Thames is extremely proud of this accomplishment.

Last fall, Erie Thames was named Industry of the Year by the Ingersoll Chamber of Commerce, for their "superlative service and special contribution to the community". Being "*Your Hometown Utility*" remains important to Erie Thames as we continue to create a global footprint, as the local communities have been the cornerstone in the foundation of our success. It's only right that we give back as often as possible in whatever capacity we can.

I attribute the achievements of 2006 to the staff of Erie Thames, as the success was a result of a team effort. I feel blessed to say that I work alongside some of the best in the industry, who tirelessly continue to forge ahead in spite of the many challenges that arise. Our shared global vision will only continue to propel us towards opportunities that will strengthen and grow us to heights beyond the amalgamation imaginations of 2000.

I would like to take this opportunity to provide my thanks to the Board of Directors, the management team and the entire staff of Erie Thames Power Group of Companies for their ongoing commitment to our customers, their hard work, innovation, vision, and their trust in me, as we move forward into 2007 and beyond.

message...
from the CHAIR

I have remarked in the past that "CHANGE" is our stock in trade. That is to say, we will likely never see the end of change in our industry, ever. But change is not necessarily a bad thing. It can cause concern, anxiety, a sense of uncertainty but it also can be the driver of innovation and growth. If you fear change, you will suffer from the worst symptoms; however, if you accept change and look for ways to manage it, success, growth and prosperity can be the result.

In 2006, Erie Thames took the challenges that are associated with a changing market and embraced them. The outcome has been favourable and foundational as we continue to build upon the guiding principals that formed Erie Thames Power in 2000.

We have invested an additional one-third for a total of 67% holding in Utilismart Corporation. What was our reasoning? Well, at the start of Utilismart's life, they were new comers to the utility settlement field of expertise. They struggled their way into respectability by developing and selling a quality line of products and services to the industry. Slowly but surely they gained market share against some impressive competition. As we look back through the last 18 months since our initial investment, the company is now number one for total electrical companies served and is close to a potential major breakthrough that we believe will see their fortunes rise even higher.

As we know, the regulated side of our business, the LDC (or Local Distribution Company), is always going to be hampered by the government's efforts to crush down the cost of service delivery to the consumer and ensure all LDC's work diligently to produce effective delivery of services at the lowest possible costs. To rely on a future with only a regulated business such as a typical LDC, is to face the law of diminishing returns and ultimately suffer from increasing regulatory, financial, and operational pressures to the point of collapse. This is, of course why we developed our business model at the outset. Men of vision, such as our own Jeff Pettit, saw the reason for a multi-faceted business structure that would continue with the fundamental provision of electricity to our customers while striving to be trendsetters and innovators of true and effective cost containment strategies. But they also recognized that we needed the development of unregulated business enterprises that would someday provide the bulk of the profits for the new company in the years ahead. The original corporate enterprise had Erie Thames Power as our Holding Company with two subsidiary companies, Erie Thames Powerlines and Erie Thames Services as our starting point.

JEFF BROWN
Chairman of the Board

In the past year we have seen the development of Oncor Utility Services and Abicus (a partnership with Essex Power) come into reality in the marketplace. The investment in RDI Consulting Inc., a premiere consulting company within Ontario's electricity market and the capabilities of becoming even more important with international contracts.

Our own staff developed a work management software package called Quadra that can be used as an add-on to the existing Harris system we currently market to other utilities. There is also the continued growth of our meter shop and the implementation of new smart meter testing.

Because of our ability to adapt, we have become a forceful business enterprise with an impressive track record. As of December 31, 2006, Erie Thames paid their shareholders $4,792,592 in interest and dividend payments.

Embracing change not hiding from it, will continue to be the driving force for Erie Thames in innovation, growth, prosperity and success for 2007 and beyond.

Erie Thames SERVICES

IUS

Laurie Palmer

Jenn Start
Kim Ellis
Dana Schneider
Tom Sinnett
Kathleen Paddon
Carly Sherman
Heather Johnson
Els Ormston
Anne Broadworth
Ann Paquette
Sherri Vondervoort
Janice VanMaele
Laura Lee
Jill Beemer
Dave Perrault
Terry Stephenson
Chris Johnson
Kathy Killaire

MSP

Kevin Kew

Martin Ashby

OPERATIONS

Scott Garton

Sue Mann
Scott Brooks
Eric Hart
Lewy Underhill
Bart Scott
Mike Dodgson
Giulio Robles
Jeff Ellery
Ron Pazitka
Mike Cook
Jim Eaton
Bryan Snyder
Robert Triemstra
Ed Feick
Terry Horne
Nolann Martin
John Ellery

ENGINEERING

Jeff Nicholson

Jeff Bilyea
Mike Geboers

PURCHASING

Mary Gulliford

Dan Palmer

TRAFFIC

Brad Seward

Mike Stock
Carl McLellan
Nick Swartz

BUSINESS DEVELOPMENT

Todd Ross

Mike Dandy
Roberto Sebestyen
Andy Molnar

AMV

Jeff Quint

Tracy Collins
Mark Bax
Bob Giesbrecht
Joe Klassen

FINANCE

John Skeoch

Barb Lindsay
Graig Pettit
Trudy Wilkins
Anne Kupery
Melissa Labreche
Stacy Rau
Tammy Longworth

ERIE THAMES POWERLINES

Chris White

Pat Zimmer

ERIE THAMES POWER

Jeff Pettit

Cass Moore
John Skeoch
Todd Ross

ERIE THAMES POWER

Jeff Pettit, *President & CEO*
John Skeoch, *Chief Financial Officer*
Todd Ross, *Senior Vice President*
Cassandra Moore, *Executive Assistant/Marketing*

ERIE THAMES POWERLINES

Chris White, VP & GM Powerlines

ETS ERIE THAMES SERVICES

Laurie Palmer, VP & GM Customer Solutions
Scott Garton, VP & GM Field Services

ET Solutions inc.

Bruce Smith, Executive Vice President

- abicus Management Solutions Inc.
  - OUS Canada
- utilismart
- rdi consulting inc.
- coulter services inc.
- Quadra

JEFF PETTIT

President & Chief Executive Officer,
Erie Thames Power Group of Companies

As President and CEO of Erie Thames Power Group of Companies (ETPGC), Jeff's principles of value creation, global opportunity and entrepreneurial management permeate all the ongoing activities of ETPGC. His vision is to create an organization that is world leading in best-in-class services and solutions for the electricity and water sectors, being confident that ETPGC will reach new levels of profitability and growth, while expanding customer loyalty.

He is proud of the significant transformation that Erie Thames has undergone over the past seven years, and is excited to see how the company is going to change in years to come. He is thankful for the guidance and support of the Shareholders and Board of Directors, as they continue to trust his direction for the organization.

519.485.1820 ext. 226
jeffp@erie-thamespower.com

JOHN SKEOCH

Chief Financial Officer,
Erie Thames Power Group of Companies

Being responsible for the financial outcome of the company is no small feat, due in part to the many facets of the Erie Thames Power Group of Companies (ETPGC). John is closely linked with each of the ETPGC subsidiaries, where his extensive financial background provides valuable insight into their day-to-day fiscal operations.

John has been successful in the strategic planning and implementation of a common financial system throughout the company as well as providing sound leadership to the executive senior management team, the staff, the board of directors and the Shareholders of Erie Thames. His hard work and determination have given ETPGC a solid financial footing as we look to the future with confidence at the possibilities that lie ahead.

519.485.1820 ext. 264
johns@erie-thamespower.com

CASS MOORE

Executive Assistant, Erie Thames Power

Cassandra (Cass) is known for her strong commitment to the success of Erie Thames Power Group of Companies and those it employs. Her attention to detail and solid organizational skills provide the support necessary to alleviate the pressures faced by the Executive Management team as they continue to lead this organization into greater opportunities.

Also responsible for Marketing and Communications, Cass is working towards recreating the Erie Thames brand and what that means to our customers, our industry and our employees.

519.485.1820 ext 255
cassm@erie-thamespower.com

TODD ROSS

Senior Vice President, Erie Thames Power

Never content to remain exactly where we are today is what motivates Todd to seek out new prospects, which will cultivate and grow Erie Thames – the once insignificant Public Utility Commission (PUC) – to heights unknown. Over the past number of years, Todd has been instrumental in creating and developing the Integrated Utility Solutions department, *thus taking the company to another dimension*. Add to that his input and expertise in the development of our own Quadra software and his keen business savvy for recognizing the next great opportunity, you have a visionary who has helped shape Erie Thames into the solid organization it is today. The best is yet to be.

519.521.8411
toddr@erie-thamespower.com

LAURIE PALMER

Vice President & General Manager Customer Solutions,
Erie Thames Services

As head of the largest hosted solution for Customer Information System (CIS) in the Province, Laurie has her work cut out for her. Add to that the expansion of our product suite - financials, OMS, web presentment, disaster recovery, data conversions and support team; you have a highly skilled department that adds tremendous value to the organization. Since adding the Integrated Utility Solutions component to the company's suite of services in 2003, this business unit has only seen significant growth with an industry footprint of more than 153,000 customers. And that's just the beginning.

519.485.6038 ext 260
lauriep@erie-thamespower.com

SCOTT GARTON

Vice President & General Manager Field Services,
Erie Thames Services

As a 17-year veteran of the industry, Scott brings with him an extensive amount of experience and know-how. Leading a highly trained, highly skilled operations crew, Scott is responsible for a great number of things including but not limited to construction of capital projects for Erie Thames Powerlines and third parties, above and underground hydro operations, traffic signal installations and maintenance, purchasing, inventory, Health and Safety (First Aid & WHMIS) as well as ensuring that his journeymen and linemen are constantly being trained and developed. Scott's vision has put Erie Thames on the map as the "Go To" for all your traffic and construction needs.

519.485.6038 ext. 228
scottg@erie-thamespower.com

BRUCE SMITH

Executive Vice President,
Erie Thames Solutions Inc.

As no stranger to the electricity industry Bruce's experience brings tremendous value to the newest arm of the Erie Thames organization – Erie Thames Solutions Inc. This company is the information centre of the organization - consulting, settlement, asset management, Quadra software, etc. These business units assist our own Erie Thames Powerlines as well as other Local Distribution Companies (LDCs).

With over 17-years of experience in both public and private sectors, as well as his involvement on various board of directors, Bruce's strong analytical and leadership skills make him a valued asset as we introduce Erie Thames Solutions Inc. to the marketplace.

519.433.6002 ext. 223
bsmith@rdiconsulting.ca

CHRIS WHITE

Vice President & General Manager,
Erie Thames Powerlines

Wires, poles, transformers. That is the foundation for what we call the regulated part of the business. Translation – Erie Thames Powerlines. The Ontario Energy Board (OEB) is the Provinces' governing body which sets out regulations that each Local Distribution Company (LDC) is required by law to follow. They are many and they are detailed. Chris has spent 18 years becoming an expert in deciphering and keeping track of these regulations to help keep Erie Thames Powerlines in excellent condition.

Chris is also responsible for the many capital projects performed each year within our licensed territory. His goal is to provide our loyal customers with the best service at the best price.

519.773.2931
chrisw@erie-thamespower.com

update...
smart meter

Erie Thames Powerlines is moving forward with smart metering and has begun to implement a system that can quickly be scaled from targeted installations to full-scale deployments. In addition, the system can be expanded to handle water metering.

PHASE ONE, 2007 – Installation of 500 smart meters. This past April, 268 meters were deployed in residential areas throughout Ingersoll. An additional 238 meters will be installed on an as needed basis in locations where single-phase meters are due for reverification.

PHASE TWO, 2008 – Installation of 5,000 Smart Meters (location to be determined).

PHASE THREE, 2009 – Installation of 5,000 Smart Meters (location to be determined).

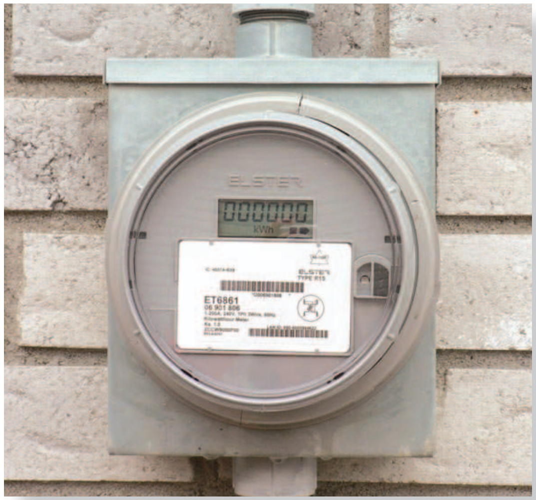
PHASE FOUR, 2010 – Installation of the remaining meters, approximately 3,500 (location to be determined).

Utilismart Corporation is reading the meters and providing billing data that will allow Erie Thames to test and modify their systems to ensure that time-of-use (TOU) billing is fully operational prior to implementing the rate structure.

The County of Oxford has recently agreed to pilot 20 Smart Water Meters. The meters will also be read via Utilismart. The addition of Smart Water Meters to the Smart Metering project will decrease the per meter cost of the system while driving efficiencies in the metering process.

old meter

smart meter



Auditors' Report
on summarized financial statements

Davis Martindale LLP
CHARTERED ACCOUNTANTS

Bruce Barran CA CFP
Mike Evans CA CFP
William Gohm CIRP*
Michael Koenig CGA CFP*
L Ron Martindale CA
Ron Martindale Jr CA CBV
Ian McIntosh FCA
Paul Panabaker CA CFP RFP
William Simpson CA CBV*
Brenda Walton CMA*
Michael Watson CA

To the Shareholders of:
Erie Thames Power Corporation

The accompanying summarized consolidated balance sheet and the consolidated statements of income and cash flows are derived from the complete consolidated financial statements of Erie Thames Power Corporation as at December 31, 2006 and for the year then ended on which we expressed an opinion without reservation in our report dated March 30, 2007. The fair summarization of the complete consolidated financial statements is the responsibility of management. Our responsibility, in accordance with the applicable Assurance Guideline of The Canadian Institute of Chartered Accountants, is to report on the summarized consolidated financial statements.

In our opinion, the accompanying consolidated financial statements fairly summarize, in all material respects, the related complete consolidated financial statements in accordance with the criteria described in the Guideline referred to above.

These summarized consolidated financial statements do not contain all the disclosures required by Canadian generally accepted accounting principles. Readers are cautioned that these statements may not be appropriate for their purposes. For more information on the entity's financial position, results of operations and cash flows, reference should be made to the related complete financial statements.

Davis Martindale LLP

London, Ontario
March 30, 2007

CHARTERED ACCOUNTANTS
Licensed Public Accountants

Accountants *with personality!*®
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ERIE THAMES POWER CORPORATION

CONSOLIDATED BALANCE SHEET
AS AT DECEMBER 31

Assets	2006	2005
Current	$9,345,968	$8,768,745
Note Receivable	68,263	58,608
Regulatory Assets (note 3)	1,457,643	2,482,517
Property, Plant & Equipment	21,076,566	18,866,647
Investments (note 4)	13,290	533,967
Deferred Charges	83,831	60,554
Future Income Tax Asset	53,000	179,000
Intangible Assets (note 5)	5,028,185	2,693,839
	$37,126,746	**$33,643,877**

Liabilities & Shareholders' Equity		
Current	$8,698,251	$9,559,120
Long-Term Debt (note 7)	15,394,566	11,383,143
Post-retirement Benefit Obligation	469,500	437,500
Non-controlling Interest	208,135	–
Share Capital	10,735,500	10,735,500
Retained Earnings	1,620,794	1,528,614
	$37,126,746	**$33,643,877**

Approved on behalf of the Board

Director

CONSOLIDATED STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31

	2006	2005
Cash Flows from Operating Activities		
Net Income	$360,568	339,984
Items not Requiring an Outlay of Cash	1,884,317	1,244,782
Changes in Non-Cash Working Capital Balances:	(517,419)	(265,385)
Net Cash Provided by Operating Activities	$1,727,466	1,319,381
Cash Flows from Financing Activities	3,066,280	808,903
Cash Flows from Investing Activities		
Net increase in Property, Plant & Equip.	(2,658,610)	(2,228,127)
Increase in Investments and Note Receivable	(29,906)	(17,448)
Acquisitions Net of Cash Acquired	(2,470,729)	–
Increase in Intangible Assets	(380,815)	(630,485)
Increase in Regulatory Assets	848,529	(655,079)
Net Cash Used in Investing Activities	(4,691,531)	(3,531,139)
Net Increase (Decrease) in Cash	102,215	(1,402,855)
Cash, Beginning of Year	(1,147,731)	255,124
Cash (Bank Indebtedness), End of Year	**$(1,045,516)**	**($1,147,731)**

Approved on behalf of the Board

Maureen Ralph

Director

The attached Auditors' Report and notes form an integral part of these summarized audited financial statements.

ERIE THAMES POWER CORPORATION

CONSOLIDATED STATEMENT OF INCOME (LOSS)
AS AT DECEMBER 31

Assets	2006	2005	2004	2003	2002
Electricity Revenue	$36,851,307	$39,380,916	$31,529,901	$30,100,625	$29,768,686
Cost of Power	31,378,239	33,932,978	26,490,207	25,258,871	25,271,722
Gross Margin	5,473,068	5,447,938	5,039,694	4,841,754	4,496,964
Service Revenue	7,808,087	6,808,887	5,630,725	4,259,588	2,657,448
Total Revenue from Operations	13,281,155	12,256,825	10,670,419	9,101,342	7,154,412
Operating Expenses	10,040,983	10,134,654	8,808,219	6,904,966	5,071,962
Net Income from Operations Before Taxes, Interest and Amortization	3,240,172	2,122,171	1,862,200	2,196,376	2,082,450
Amortization Expense	1,795,011	1,536,632	1,374,429	1,215,636	1,434,943
Interest Expense	939,627	561,898	394,297	492,626	928,972
Net Income (Loss) from Operations Before Tax	505,534	23,641	93,474	488,114	(281,465)
Other Income	92,035	130,983	58,584	700,677	80,000
Net Income (Loss) Before Tax	597,569	154,624	152,058	1,188,791	(201,465)
Payments (Recoveries) of Income Tax	191,003	(224,700)	165,463	77,785	(3,461)
Net Income (Loss) from Discontinued Operations	–	(39,340)	(47,109)	11,948	–
Non-Controlling Interest	45,998	–	–	–	–
Net Income (Loss)	$360,568	$339,984	$(60,514)	$1,122,954	$(198,004)
Interest and Dividends Paid to Shareholders	$1,046,712	$912,518	$912,518	$778,324	$912,518

The attached Auditors' Report and notes form an integral part of these summarized audited financial statements.

1. Description of Business

Erie Thames Power Corporation (the Company) was incorporated in 2000 pursuant to the Business Corporations Act (Ontario) as mandated by the Ontario government's Electricity Act, 1998 (Ontario) and Sections 71 and 73 of the Ontario Energy Board Act, 1998 (Ontario). Pursuant to this legislation, the shareholder municipalities of Erie Thames Power Corporation enacted by-laws, which transferred the assets, liabilities, rights and obligations of the Municipal Hydro Electric Commissions, in respect of the distribution of electricity, to the Company.

The principal business of the Company is the oversight of its wholly owned subsidiaries, which include:

Erie Thames Powerlines Corporation (Powerlines) - A regulated electricity distribution company that owns and operates electricity infrastructure for eleven communities in the counties of Oxford and Elgin.

Erie Thames Services Corporation (ETS) - ETS is an operating company that contracts for services in a number of areas:

(i) provide monthly, water, sewer and electricity billings for utilities companies
(ii) provide electricity grid expansion and maintenance services
(iii) provide electric meter calibration and maintenance services
(iv) provide support for Harris System conversions in addition to other utility software.

Erie Thames Solutions Inc. (ETSI) - Operates as a holding company. ETSI holds a 50% interest in Abicus Management Solutions Inc. (Abicus), which holds the Canadian rights to utility assets management software. Abicus holds a 100% interest in Oncor Utility Solutions (Canada) Company Limited (OUS), which provides asset management services to utility providers.

RDI Consulting Inc. - Operates as a provider of consulting services to various utilities.

Quadra Technology Services Inc. - Develops software add-ons for the Harris Utility Billing System.

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.

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 bill 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 kWh per year. The new block structure implemented in 2005 resulted in a change to the block structure for residential customers only. From November 1, 2005 to April 30, 2006, the first 1000 kWhs consumed per month were charged at 5.0 cents per kWh and the remaining consumption was billed at 5.8 cents per kWh. The rates from November 1, 2006 to April 30, 2007 were increased to 5.5 cents for the first 1000 kWhs and to 6.4 cents for the remainder of the monthly consumption. Effective May 1, 2006 to October 31, 2006, the block structure was changed to 5.8 cents per kWh for the first 600 kWhs per month and to 6.7 cents per kWh for the remainder.

Non-residential customers are charged based on a block structure of 750 kWhs per month and the structure remains consistent throughout the year. The rates up to May 1, 2007 are 5.5 cents per kWh on the first 750 kWhs and 6.4 cents per kWh for the remainder of the month's consumption.

Further changes implemented by Bill 4 allowed Local Distribution Companies (LDCs) to apply to the OEB for rate adjustments.

Specifically, LDCs began to recover the amounts deferred for regulatory purposes on April 1, 2004, and continued to recover these amounts through its April 1, 2005 rate approval. The 2006 rate process will further review the LDCs deferral account balances and it is anticipated to continue to permit LDCs to recover these amounts through their rate structure. In January 2007, the OEB reviewed the rate structure and approved that all deferral amounts are available for recovery.

Through Bill 4, LDCs obtained approval to apply for a rate order that would allow the recovery of their full Market Based Rate of Return beginning March 1, 2005. This rate change is conditional on the LDCs reinvestment of one year's worth of the incremental rate of return in conservation and demand management initiatives over a three year period.

On December 18, 2003, the Ontario Energy Board renewed the LDCs distribution license for a 20 year period.

3. Regulatory Assets

	2006	2005
Transition costs	$126,731	$296,854
Retail settlement variances	1,971,348	2,111,986
Pre-market opening cost of power variances	1,225,987	1,178,524
Demand side management expenses	184,732	53,849
	3,508,798	3,641,213
Recovery of regulatory assets	(2,051,155)	(1,158,696)
	$1,457,643	$2,482,517

(a) Transition costs represent specific and incremental costs incurred by the Company to prepare its systems and processes for the opening of the competitive electricity market in Ontario on May 1, 2002. These costs have been deferred pursuant to regulation underlying the Electricity Act and are subject to review and approval by the OEB. Expenditures determined to be ineligible for recovery will be expensed in the period of such determination. In January of 2007, the OEB reviewed the rate structure and approved these amounts for recovery.

(b) 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 various settlement and transmission charges.

In the absence of rate regulations, these costs (revenues) would be charged to the period incurred. In 2006, revenues would have been $1,033,097 higher; in 2005, revenues would have been $517,584 lower.

(c) Pre-market opening cost of power variances, represent the excess cost of electricity to the Company over the amount billed to customers from January 1, 2001 until April 30, 2002.

In the absence of rate regulations, these costs would have been charged to the period incurred. In 2006, expenses would have been $47,463 higher; in 2005, expenses would have been $63,678 higher.

(d) Demand side management 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. The OEB has approved the Company's final one third increase in market base rate of return with the requirement to spend one year's increase on demand side management projects before December 31, 2007.

In the absence of rate regulations, these costs would be charged to the period incurred. In 2006, expenses would have been $14,501 higher; in 2005, expenses would have been $43,516 higher.

(f) Amortization Policy

These amounts will be amortized at an amount equal to the revenue collected from the approved rates over a period of 4 years, commencing on April 1, 2004, as set out in Bill 4.

During the year, the Company recorded amortization of $176,346 ($156,063 - 2005).

4. Investments

	2006	2005
51 Common shares in Utilismart Corporation, representing 33 1/3% of the issued shares	$ –	$520,375
36,000 Partnership units in Enerconnect Limited Partnership, representing 1.2% ownership interest	13,289	13,591
1,426 Common shares in Sunlife Financial, at cost (FMV - $66,637)	1	1
	$ 13,290	$ 533,967

Investment in Enerconnect is accounted for using the equity method.

During the year, the company acquired controlling interest of Utilismart Corporation and has subsequently accounted for the acquisition using the step-consolidation method.

5. Intangible Assets

	2006	2005
Goodwill	$ 4,068,796	$ 2,099,839
Software Licenses	667,248	594,000
Quadra Software	262,631	–
Contracts	29,510	–
	$5,028,185	$2,693,839

Goodwill - At year end, the Company tested goodwill in each of its reporting units using a discounted cash flow and cost methodology and determined that there was no impairment of goodwill.

During the year, the company acquired Erie Thames Solutions Inc (ETSI) which resulted in an additional goodwill amount of $1,594,237. RDI Consulting Inc, a subsidiary of ETSI, holds a one third interest in Utilismart Corporation (Utilismart). An additional one third interest in Utilismart is held by another subsidiary of the Company. This

The attached Auditors' Report and notes form an integral part of these summarized audited financial statements.

resulted in a controlling interest being held by the Company at which time Utilismart was consolidated into the financial statements of the Company. This resulted in an additional $374,720 of goodwill. See note 10 for further information.

Software Licenses - The Company entered into an enterprise licence agreement for its accounting and billing software. The terms of the agreement are such that the life of the asset is indefinite. Based on the Company's ability to use this software to provide accounting and billing to third parties, it is management's opinion that the value of this license has not been impaired.

Quadra Software - The company is currently developing add-on software for the utility billing system.

Contracts - The contracts owned by Oncor Utility Solutions (Canada) Company Limited ("OUS Canada") are for the use of the asset management software. This intangible is being amortized over the life of the contract.

During the year, the Company recorded amortization of $1,600 ($NIL - 2005).

6. Demand Operating Loan

During 2006, the Company renewed its $2,500,000 demand operating loan with the bank to finance operating expenditures, bearing interest at TD Canada Trust Prime and due 364 days from issuance. As of December 31, 2006, $1,902,941of this loan facility has been drawn upon ($1,759,000 in 2005). The loan is secured by a first position General Security Agreement covering all Company assets excluding real property. The credit agreement includes covenants whereby an interest coverage ratio of at least 2:1 be maintained and a third party debt to capitalization ratio under 0.5:1 be maintained. The covenants are to be tested on a rolling four quarter basis. The company is in breach of the interest coverage ratio at December 31, 2006 but has obtained approval from the bank.

7. Long-term Debt

	2006	**2005**
Related party note payable	$10,735,500	$10,735,500
Capital lease obligation	962,376	570,875
Bank term loan	3,199,952	1,456,785
Notes payable	1,200,000	-
Future income tax liability	56,770	180,404
Less: current portion	(760,032)	(1,560,421)
	$15,394,566	$11,383,143

a) Related Party Note Payable

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:

	2006	**2005**
Alymer	$ 2,263,500	$ 2,263,500
Central Elgin	1,077,000	1,077,000
East Zorra Tavistock	760,000	760,000
Ingersoll	4,543,500	4,543,500
Norwich	1,020,000	1,020,000
Southwest Oxford	256,500	256,500
Zorra	815,000	815,000
	$ 10,735,500	$ 10,735,500

b) Capital Lease Obligation

The Company has under lease six Freightliner bucket trucks. The trucks are being leased for a period of seven years with varying terms commencing on 2001 to 2006. The interest rate imputed in these leases range from 5.8%-8.8%. Monthly payments ranging from $2,631 to $3,715, including finance charges, are required under the terms of the lease agreements. During the year, the Company entered into two additional lease agreements for Freightliner bucket trucks. These trucks are being leased for a period of seven years commencing September 2006 and October 2006. The interest rate imputed in these leases is 6.4% and 6.3%, respectively.

c) Term Loan

During 2006, the Company renewed its $5,800,000 term loan with the bank to finance upgrades at two locations and future expansion. The term loan bearing interest at TD Canada Trust Prime matures December 2009. As of December 31, 2006, $3,007,000 of this loan facility had been drawn upon ($1,456,785 - 2005). The loan is repayable at interest only per month with the balance due at maturity. At December 31, 2006, prime was 6.00%. For security and covenant requirements, see Note 6.

d) Notes Payable

Notes Payable accrue interest annually at a rate of TD Canada Trust Prime less 1%. Notes are repayable annually over 3 years at $400,000 plus accrued interest, and are secured by a $1,200,000 letter of credit.

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, 2007	$760,032
	December 31, 2008	566,524
	December 31, 2009	3,528,045
	December 31, 2010	129,886
	December 31, 2011	139,135
		$ 5,123,622

8. Segment Reporting

The company has two reportable segments:

a) Electricity Distribution - The regulated business which consists of the electricity distribution business

b) Non-regulated - The utility services businesses which consist of utility management services and electricity grid expansion and maintenance.

The designation of the segments has been based on a combination of the regulatory status and the nature of products and services provided.

Segment information on the above basis is as follows:

	2006			
	Electricity Distribution	Non-Regulated	Elimination Entry	Total
Revenues	$37,192,160	$10,613,183	$(3,145,949)	$44,659,394
Purchased power and other	31,378,239	–	–	31,378,239
Operating expenses	4,383,715	8,803,217	(3,145,949)	10,040,983
Income before interest other, amortization and provision for income taxes	1,430,206	1,809,966	–	3,240,172
Amortization	1,023,655	771,356	–	1,795,011
Interest income	(151,460)	–	–	(151,460)
Interest expense	582,793	508,294	–	1,091,087
Discontinued operations	–	–	–	–
Other	(21,631)	(24,406)	–	(46,037)
Income before taxes	(3,151)	554,722	–	551,571
Future income taxes	(96,604)	98,970	–	2,366
Income taxes	75,866	112,771	–	188,637
Net income	$17,587	$342,981	$ –	$360,568

	2005			
	Electricity Distribution	Non-Regulated	Elimination Entry	Total
Revenues	$39,688,154	$9,836,432	$(3,334,783)	$46,189,803
Purchased power and other	33,932,978	–	–	33,932,978
Operating expenses	4,410,021	9,059,416	(3,334,783)	10,134,654
Income before interest other, amortization and provision for income taxes	1,345,155	777,016	–	2,122,171
Amortization	1,037,906	498,726	–	1,536,632
Interest income	(349,154)	–	–	(349,154)
Interest expense	582,793	328,259	–	911,052
Discontinued operations	–	39,340	–	39,340
Other	(23,759)	(107,224)	–	(130,983)
Income before taxes	97,369	17,915	–	115,284
Future income taxes	(189,000)	(126,000)	–	(315,000)
Income taxes	68,000	22,300	–	90,300
Net income	$218,369	$121,615	$ –	$339,984

9. 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 April 21, 2003 was $2,371,089 and had not changed as at December 31, 2006. The prudential support requirement will be honoured through long-term payment history, letter of credit or credit rating from an accredited rating agency.

10. Business Acquisitions

The Company has made the following business acquisitions which have been accounted for using the purchase method. Earnings from the businesses acquired are included in the consolidated earnings from their respective dates of acquisition.

In July 2006, the Company purchased all of the issued and outstanding common shares of ETSI. ETSI held 100% of the issued and outstanding shares of RDI Consulting Inc. which in turn owned 33 1/3 % of Utilismart. This provided the Company with controlling interest in Utilismart. The acquisition was made for a total cash consideration of $2,150,000 including acquisition costs. The acquisition was financed by using the company's existing credit facility. Most of the goodwill related to this transaction is deductible for tax purposes.

In November 2006, the Company purchased 50% of the common shares of the newly formed company Abicus. Subsequently, Abicus purchased from UMS Group Inc. the Canadian rights to the Spend Optimization Tool and Project Entry Subsystem which is used to provide asset management services. UMS Group Inc. has granted the Company a non-transferable and non-exclusive perpetual license to use the software. The license allows the company or an affiliate, to provide asset management services to LDCs in Ontario having fewer than 50,000 customers and has a maximum number of customers per year of 300,000. Additionally, Abicus purchased 100% of the shares of OUS which is licensed by Abicus to license the use of the asset management software to LDCs. OUS' principal asset at the time of purchase by Abicus were the contracts for the use of this asset management software. This acquisition was made for a total cash consideration of $62,320 including acquisition costs. The acquisition was financed using the Company's existing credit facilities.

The net book value of the assets acquired and liabilities assumed from the acquisitions were as follows:

	ETSI	OUS	RDI	Total
Current assets	$ 31	$6,852	$139,856	$146,739
Property, plant and equipment	–	1,495	24,737	26,232
Goodwill	–	–	36,970	36,970
Investments	1,263,889	–	178,137	1,442,026
Other intangible assets	6,684	–	19,422	26,106
	$1,270,604	$8,347	$399,122	$1,678,073
Current liabilities assumed	8,670	5,307	27,111	41,088
Long-term debt assumed	193,000	–	–	193,000
	$201,670	$5,307	$27,111	$234,088
Net assets and total consideration	1,068,934	3 ,040	372,011	1,443,985
Less: Cash from the acquisition	(31)	–	(38,653)	(38,684)
Net assets less cash from Acquisition	$ 1,068,903	$ 3,040	$ 333,358	$ 1,405,301

11. Contingent Liabilities

An action 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 result 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 defense 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 defenses 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 challenging the validity of late payment penalties. 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 the settlement of the 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 Local Distribution Company (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.

At this time, it is not possible to quantify the effect, if any, on the financial statements of the Company.

12. 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, 2007	$92,443
	December 31, 2008	62,418
	December 31, 2009	38,907
	December 31, 2010	30,948
	December 31, 2011	30,948
		$255,664

13. Subsequent Event

Subsequent to year end, the Company acquired all of the issued and outstanding shares of Coulter Water Meter Service Inc. for a total purchase price of $900,000, consisting of $400,000 in cash and a note payable to the vendor for the remaining amount.

Coulter Water Meter Service Inc. provides water meter calibration and maintenance services.