LAKELAND POWER DISTRIBUTION LTD

APPLICATION FOR APPROVAL OF ELECTRICITY DISTRIBUTION RATES

EFFECTIVE MAY 1, 2013

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

AND IN THE MATTER OF an Application by Lakeland Power Distribution Ltd. 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, 2013.

Title of Proceeding:	An Application by Lakeland Power Distribution Ltd. for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2013.
Applicants Name:	**Lakeland Power Distribution Ltd.**
Applicants Address:	**200-395 Centre St. N** **Huntsville, ON** **P1H 2M2**
Applicants Contacts:	**Attention:** **Margaret Maw, CFO** **Telephone:** **705-789-5442** **Fax:** **705-789-3110** **E-mail:** **mmaw@lakelandholding.com**

APPLICATION:

Introduction

The Applicant is Lakeland Power Distribution Ltd. (LPDL). The Applicant is a corporation incorporated pursuant to the Ontario Business Corporations Act with its head office in the Town of Huntsville, ON. The Applicant carries on the business of distributing electricity within the Town of Bracebridge, Town of Huntsville, Village of Burk's Falls, Town of Sundridge and Municipality of Magnetawan.

The Applicant hereby applies to the Ontario Energy Board (the "OEB") pursuant to Section 78 of the Ontario Energy Board Act, 1998 ("the OEB Act") for approval of its proposed distribution rates and other charges, effective May 1, 2013. A list of requested approvals is set out below.

Except where specifically identified in the Application, the Applicant followed the OEB's Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, update issued June 28, 2012 (the "Filing Requirements") in order to prepare this application.

Proposed Distribution Rates and Other Charges

The Schedule of Proposed Tariff of Rates and Charges in this Application is set out in Appendix A of this Exhibit and in Exhibit 8. The material being filed in support of this Application sets out LPDL's approach to its distribution rates and charges.

Proposed Effective Date of Rate Order

The Applicant requests that the OEB make its Rate Order effective May 1, 2013 in accordance with the Filing Requirements.

The Proposed Distribution Rates and Other Charges are Just and Reasonable

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

- The proposed rates, as set out in Appendix A, for the distribution of electricity, have been prepared in accordance with the Filing Requirements and reflect traditional rate making and cost of service principles;

- The proposed and adjusted rates are necessary to ensure LPDL has sufficient funds to meet its capital expenditure obligations, fund OM&A expenses and provide for a reasonable Market Based Rate of Return ("MBRR") and Payments in Lieu of Taxes ("PILS");

- 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 the Applicant or the implementation of any other mitigation measures.

The other specific service charges proposed by the Applicant are the same as those previously approved by the OEB and such other grounds as may be set out in the material accompanying this Application Summary.

Relief Sought

The Applicant applies for an Order or Orders approving the proposed distribution rates and charges set out in Exhibit 8 to this Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2013.

The Applicant seeks approval of its Basic Green Energy Plan as part of this Application in accordance with the Deemed Conditions of License as reported by the OEB in its Distribution System Planning Guidelines G-2009-0087, issued June 16, 2009. The Applicants Basic Green Energy Plan has been prepared in accordance with the OEB's Filing Requirements as reported in

EB-2009-0397 – Distribution System Plans under the Green Energy Act issued on December 18, 2009.

Form of Hearing Requested

The Applicant requests that this Application be disposed of by way of a written hearing.

DATED at Huntsville, Ontario, this 6th day of September, 2012.

All of which is respectfully submitted,

Margaret Maw, CGA
Chief Financial Officer
Lakeland Power Distribution Ltd.

APPENDIX A

SCHEDULE OF PROPOSED RATES AND CHARGES

Lakeland Power Distribution Ltd.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2013

Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0145

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to residential customers residing in detached, semi detached, town house (freehold or condominium) dwelling units, duplexes or triplexes. Supply will be limited up to a maximum of 200 amp @ 240/120 volt. Further servicing details are available in our Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	20.19
Rate Rider for Stranded Meters - Effective until April 30, 2015	$	1.70
Distribution Volumetric Rate	$/kWh	0.0148
Low Voltage Service Rate - Effective Until	$/kWh	0.0034
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery - Effective Until April 30, 2013	$/kWh	0
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until April 30, 2014	$/kWh	0.0037
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014	$/kWh	-0.0035
Applicable only for Non-RPP Customers		
Retail Transmission Rate – Network Service Rate	$/kWh	0.0052
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0042

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Lakeland Power Distribution Ltd.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2013

Implementation Date May 1, 2013

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EB-2012-0145

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in our Conditions of Service

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	44.61
Rate Rider for Stranded Meters - Effective until April 30, 2015	$	3.09
Distribution Volumetric Rate	$/kWh	0.0092
Low Voltage Service Rate - Effective Until	$/kWh	0.003
Rate Rider for Tax Adjustments - Effective Until April 30, 2013	$/kWh	
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery - Effective Until April 30, 2013	$/kWh	0
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until April 30, 2014	$/kWh	0.0037
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014	$/kWh	-0.0035
Applicable only for Non-RPP Customers		
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Lakeland Power Distribution Ltd.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2013

Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0145

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in our Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	526.58
Distribution Volumetric Rate	$/kW	3.0048
Low Voltage Service Rate - Effective Until	$/kW	1.3960
Rate Rider for Tax Adjustments - Effective Until April 30, 2013	$/kW	
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery - Effective Until April 30, 2013	$/kW	0
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until April 30, 2014	$/kW	1.5362
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014	$/kW	-1.4292
Applicable only for Non-RPP Customers		
Retail Transmission Rate – Network Service Rate	$/kW	2.0358
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6356

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Lakeland Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2013
Implementation Date May 1, 2013

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EB-2012-0145

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 240/120 or 120 volts whose monthly peak demand is less than or expected to be less than 50 kW and is unmetered. A detailed calculation of the load will be calculated for billing purposes. Further servicing details are available in our Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	13.00
Distribution Volumetric Rate	$/kWh	0.0059
Low Voltage Service Rate - Effective Until	$/kWh	0.0030
Rate Rider for Tax Adjustments - Effective Until April 30, 2013	$/kWh	
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until April 30, 2014	$/kWh	0.0037
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014	$/kWh	-0.0035
Applicable only for Non-RPP Customers		
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Lakeland Power Distribution Ltd.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2013

Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0145

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in our Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	6.46
Distribution Volumetric Rate	$/kW	22.3710
Low Voltage Service Rate - Effective Until	$/kW	0.9588
Rate Rider for Tax Adjustments - Effective Until April 30, 2013	$/kW	
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until April 30, 2014	$/kW	1.3280
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	-1.2355
Retail Transmission Rate – Network Service Rate	$/kW	1.5212
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2053

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Lakeland Power Distribution Ltd.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2013

Implementation Date May 1, 2013

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EB-2012-0145

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times and the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in our Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	5.34
Distribution Volumetric Rate	$/kW	16.3439
Low Voltage Service Rate - Effective Until	$/kW	0.9390
Rate Rider for Tax Adjustments - Effective Until April 30, 2013	$/kW	
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until April 30, 2014	$/kW	1.3712
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014	$/kW	-1.2756
Applicable only for Non-RPP Customers		
Retail Transmission Rate – Network Service Rate	$/kW	1.4829
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1937

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Lakeland Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2013
Implementation Date May 1, 2013

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EB-2012-0145

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's micoFIT program and connected to the distribuor's distribution system. Further servicing details are available in the distributor's Condition of Service.

APPLICATION

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.25

Lakeland Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
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EB-2012-0145

ALLOWANCES

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

SPECIFIC SERVICE CHARGES

APPLICATION

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Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Request for other billing information	$	15.00
Income tax letter	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00

Non-Payment of Account

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

Temporary service install & remove - overhead - no transformer	$	500.00
Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00

Lakeland Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2013
Implementation Date May 1, 2013

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RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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

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

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factor will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0757
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0650

CONTACT INFORMATION:

LAKELAND POWER DISTRIBUTION LTD

Margaret Maw
Chief Financial Officer
200-395 Centre St. N
Huntsville, ON P1H 2M2

Telephone 705-789-5442
Fax 705-789-3110
E-mail mmaw@lakelandholding.com

APPLICANT'S COUNSEL:

LIST OF SPECIFIC APPROVALS REQUESTED:

In this proceeding, LPDL is requesting the following approvals:

- Approval to charge rates effective May 1, 2013 to recover a revenue requirement of $5,773,388 which includes a revenue deficiency of $392,906 as set out in Exhibit 6, Schedule 1, Tab 1; the schedule of proposed rates is set out in Exhibit 8 Schedule 6;

- Approval of the proposed loss factor as set out in Exhibit 8, Schedule 1;

- Approval of revised low voltage rates to be included in the standard distribution rates as proposed and described in Exhibit 8, Schedule 1;

- Approval to charge a Retail Transmission Network Service rate and a Retail Transmission Connection rate as proposed and described in Exhibit 8, Schedule 1;

- Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the OEB Decision and Order in the matter of LPDL's 2012 Distribution Rates (EB-2011-0180);

- Approval to continue the Specific Service Charges and Transformer Allowance approved in the OEB Decision and Order in the matter of LPDL's 2012 Distribution Rates (EB-EB-2011-0180);

- Approval to dispose of the following Deferral and Variance Account balances as at December 31, 2011 over a one year period using the method of recovery described in Exhibit 9, Tab 2, Schedule 1:

  1508 Other Regulatory Assets – Sub –account Hydro One Incremental Capital

  1518 Retail Cost Variance Account (Retail)

  1548 Retail Cost Variance Account (STR)

1550 Low Voltage Variance

1580 RSVA - Wholesale Market Service Charges

1584 RSVA - Transmission Network

1586 RSVA - Transmission Connection

1588 RSVA - Power

1588 RSVA – Power Sub-account Global Adjustment

1590 Recovery of Regulatory Asset Balances

1592 PILS and Tax Variances for 2006 and Subsequent Years – Sub-account HST

1595 Disposition and Recovery of Regulatory Balances (2008)

1595 Disposition and Recovery of Regulatory Balances (2009)

- Approval for the creation of a PP&E deferral account to record the difference in 2012 Net Book Value of Property, Plant and Equipment, as a result of the transition from financial reporting under Canadian Generally Accepted Accounting Principles (CGAAP) to reporting under Modified International Financial Reporting Standards (MIFRS), and the disposition of this account using the method of recovery described in Exhibit 9, Tab 4, Schedule 1;

- Approval to dispose of the following Deferral and Variance Account balances as at December 31, 2011 over a two year period using the method of recovery described in Exhibit 9, Tab 3, Schedule 1, for two specific classes – Residential and GS<50 kW:

1555 Stranded Meters

- In LPDL's 2010 IRM Decision (EB-2009-0234) the Board directed LPDL to record in account 1592, the incremental Input Tax Credit (ITC) it receives on distribution revenue requirement items that were previously subject to PST and become subject to HST.

LPDL has complied with this directive and has been recording these amounts as of July 1, 2010. The application LPDL is currently submitting is based on budgeted information net of any HST ITC's LPDL will receive. As a result, LPDL requests approval to discontinue recording these variances as of May 1, 2013.

PROPOSED ISSUES LIST:

The Applicant would expect, based on previous regulatory experience and other hearings, that the following matters pertaining to the 2013 Test Year may constitute issues in this Application:

GENERAL (Exhibit 1)

- Are the Applicant's overall economic and business planning assumptions for the Test Year appropriate?
- Is service quality, based on the Board specified performance indicators, acceptable?
- Is the proposed revenue requirement appropriate?

2. RATE BASE (Exhibit 2)

- Are the Applicant's asset planning assumptions (e.g. asset condition, economic conditions, etc.) appropriate?
- Is the Applicant's capitalization and depreciation policy appropriate?
- Are the capital expenditures appropriate?
- Are the in-service dates accurate for projects closed prior to the Test Year and are they appropriate for proposed projects?
- Is the working capital allowance for the test year appropriate?
- Is the proposed rate base for the test year appropriate?
- Is the accounting for smart meters in rate base appropriate?

- Is the accounting for stranded meters appropriate?

3. LOADS, CUSTOMERS - THROUGHPUT REVENUE (Exhibit 3)

- Is the load forecast methodology including weather normalization appropriate?
- Are the proposed customers/connections and load forecasts (both kWh and kW) for the test year appropriate?
- Is CDM appropriately reflected in the load forecast?
- Are the proposed revenue offsets appropriate?

4. OPERATING COSTS (Exhibit 4)

- Is the overall OM&A forecast for the test year appropriate?
- Are the methodologies used to allocate shared services and other costs appropriate?
- Is the proposed level of depreciation/amortization expense for the test year appropriate?
- Are the 2013 compensation costs and employee levels appropriate?
- Is the test year forecast of PILs appropriate?

5. COST OF CAPITAL AND RATE OF RETURN (Exhibit 5)

- Is the proposed capital structure appropriate?
- Is the cost of debt appropriate?

- Is the proposed return on equity appropriate?

6. CALCULATION OF REVENUE DEFICIENCY OR SURPLUS (Exhibit 6)

- Is the calculation of Revenue Deficiency accurate?

7. COST ALLOCATION (Exhibit 7)

- Is the Applicant's cost allocation appropriate?
- Are the proposed revenue-to-cost ratios appropriate?

8. RATE DESIGN (Exhibit 8)

- Are the customer charges and the fixed-variable splits for each class appropriate?
- Are the proposed Retail Transmission Service Rates appropriate?
- Are the proposed loss factors appropriate?
- Is the Applicant's proposed Tariff of Rates and Charges appropriate?
- Is the Applicant's rate mitigation plan appropriate?

9. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit 9)

- Are the account balances, cost allocation methodology and disposition plan appropriate?

PROCEDURAL ORDERS/MOTIONS/NOTICES:

On January 26, 2012, the Board issued its list of distributors that it anticipates will be filing a Cost of Service Application for 2013. LPDL was included on that list.

ACCOUNTING ORDERS REQUESTED:

LPDL is not requesting Accounting Orders in this proceeding.

COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS:

LPDL has followed the accounting principles and main categories of accounts as stated in the OEB's Accounting Procedures Handbook (the "APH") and the Uniform System of Accounts ("USoA") in the preparation of this Application.

DISTRIBUTION SERVICE TERRITORY AND DISTRIBUTION SYSTEM:

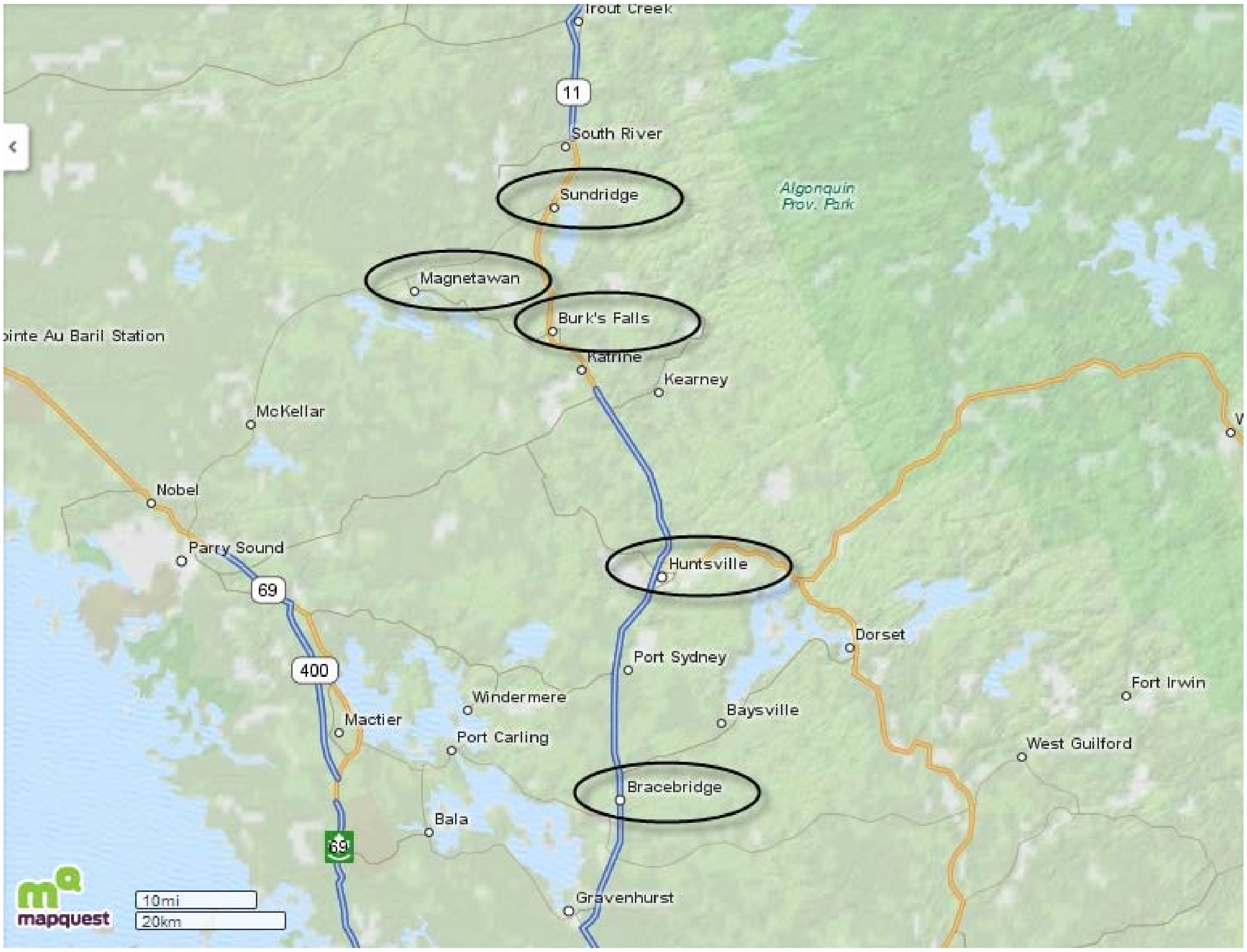
Description of Distributor:

COMMUNITY SERVED:	Town of Bracebridge Town of Huntsville Town of Sundridge Village of Burk's Falls Municipality of Magnetawan
TOTAL SERVICE AREA:	144 sq km
RURAL SERVICE AREA:	128 sq km
DISTRIBUTION TYPE:	Electricity distribution
SERVICE AREA POPULATION:	21,007
MUNICIPAL POPULATION:	36,500
BOUNDARIES:	A map of the Lakeland Power Distribution Ltd. Distribution Service Territory accompanies this Schedule as Appendix B. A schematic diagram of Lakeland Power Distribution Ltd.'s Distribution System is attached in Appendix C.

APPENDIX B

MAP OF DISTRIBUTION SERVICE TERRITORY

Lakeland Power Distribution Ltd. Service Area



Town of Bracebridge, Town of Huntsville, Municipality of Magnetawan, Village of Burk's Falls, Village of Sundridge

APPENDIX C

MAPS OF DISTRIBUTION SYSTEM

The maps attached represent the five municipalities that make up the service territory for Lakeland Power Distribution Ltd.

Lakeland Power Electrical Network
Bracebridge

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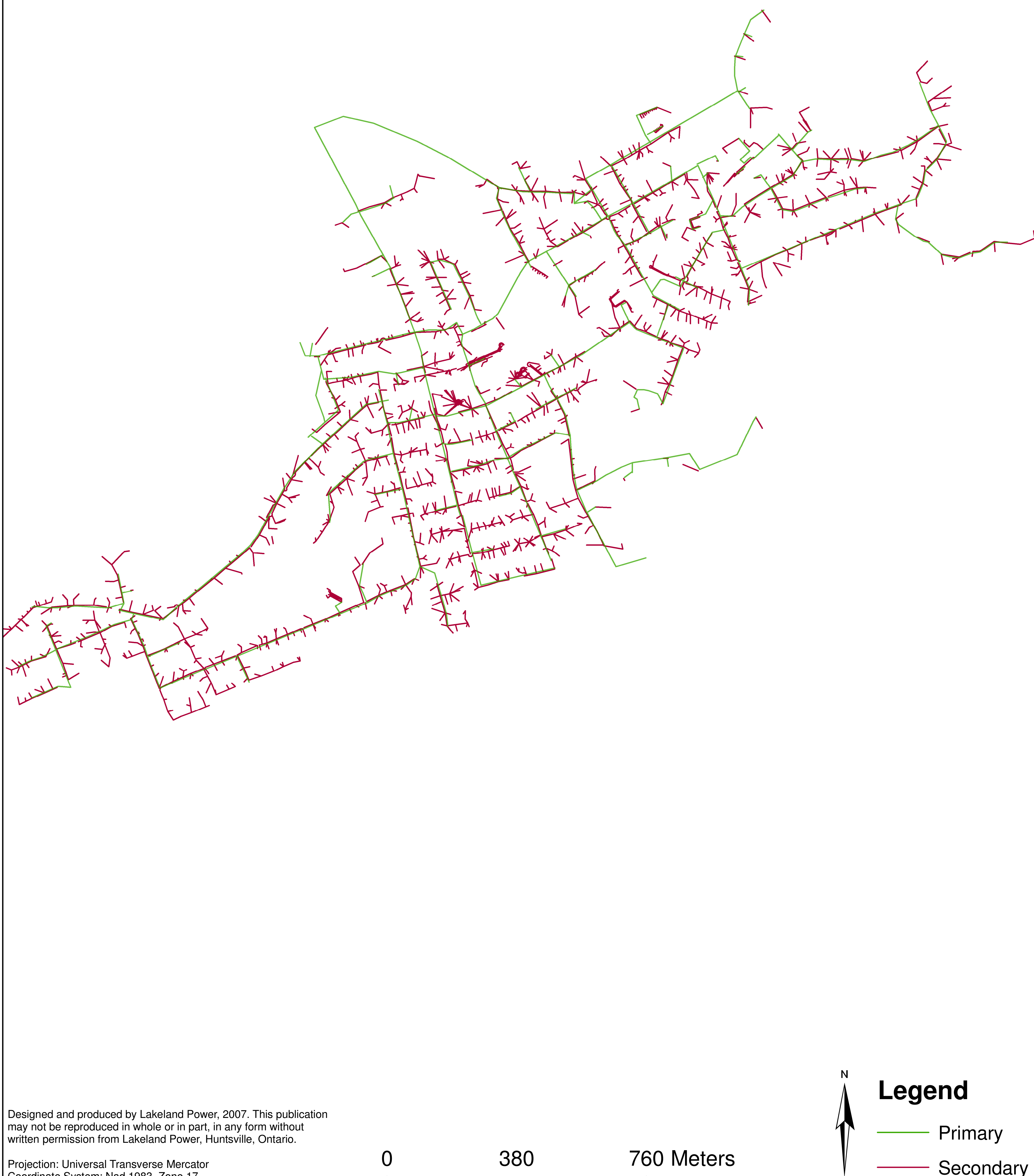
Projection: Universal Transverse Mercator
Coordinate System: Nad 1983, Zone 17

Created: January 10th 2007

Lakeland Power Electrical Network
Huntsville

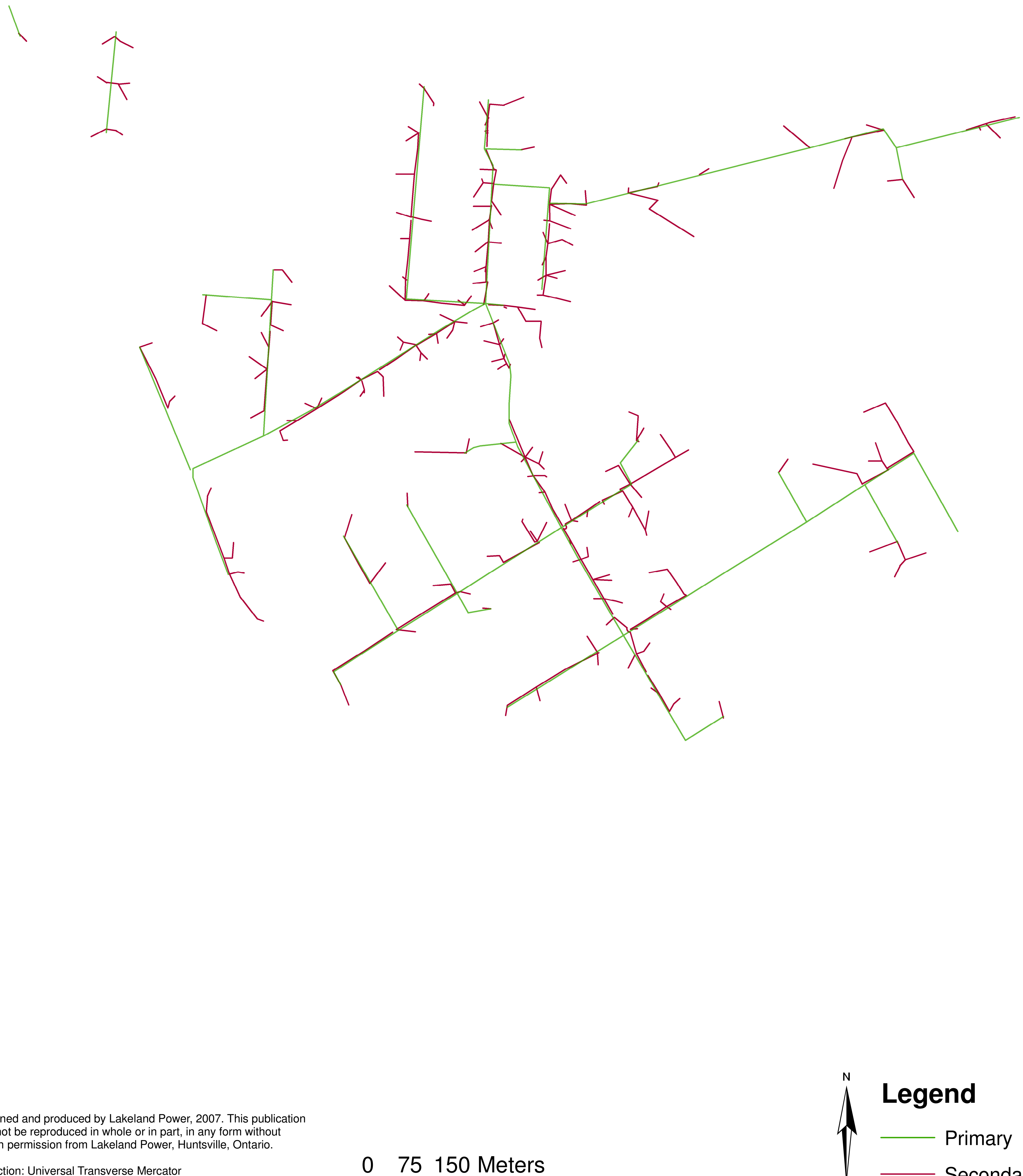


Projection: Universal Transverse Mercator
Coordinate System: Nad 1983, Zone 17

Created: January 10th 2007

LakelandPower

Lakeland Power Electrical Network
Magnetawan

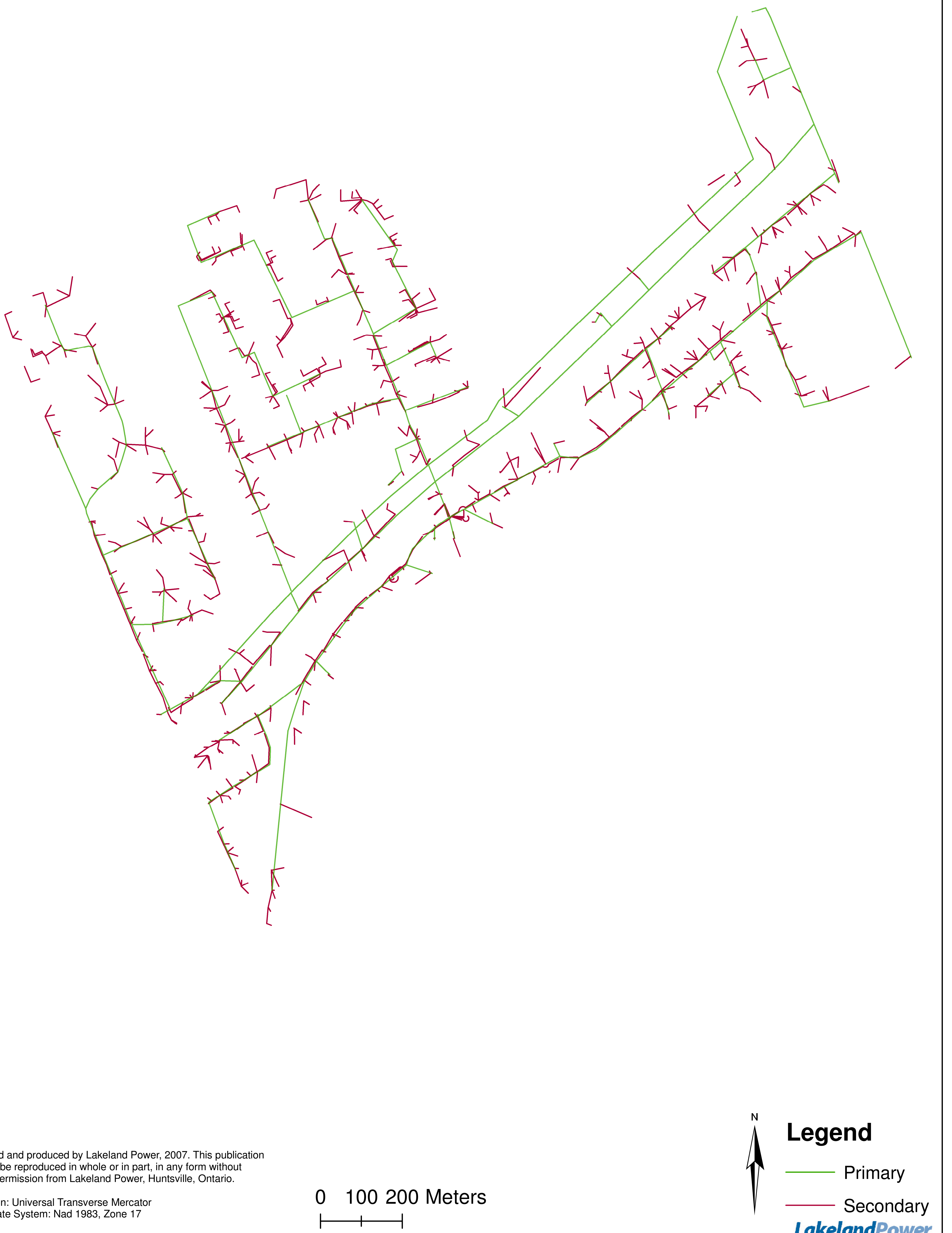


Projection: Universal Transverse Mercator
Coordinate System: Nad 1983, Zone 17

Created: January 10th 2007

LakelandPower

Lakeland Power Electrical Network
Sundridge



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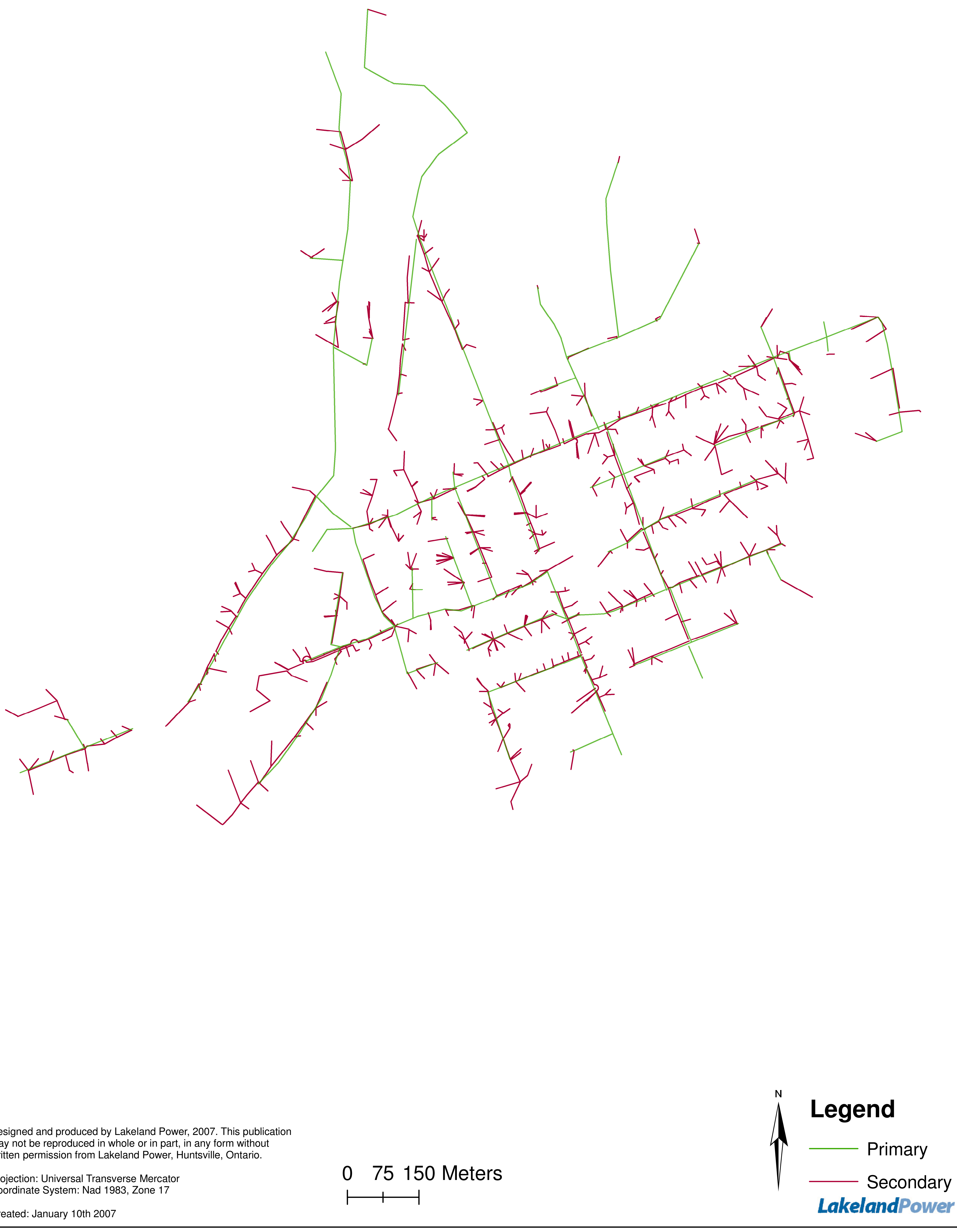
Projection: Universal Transverse Mercator
Coordinate System: Nad 1983, Zone 17

Created: January 10th 2007

LakelandPower

Lakeland Power Electrical Network
Burk's Falls



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Projection: Universal Transverse Mercator
Coordinate System: Nad 1983, Zone 17

Created: January 10th 2007

LIST OF NEIGHBOURING UTILITIES:

LPDL is bounded by the following utilities in each area:

- Town of Bracebridge - is bounded by Hydro One Networks Inc. on three sides of its service territory with Veridian Connections on the south side,

- Town of Huntsville - is bounded by Hydro One Networks Inc. on all sides of its service territory,

- Village of Sundridge - is bounded by Hydro One Networks Inc. on all sides of its service territory,

- Village of Burk's Falls - is bounded by Hydro One Networks Inc. on all sides of its service territory and,

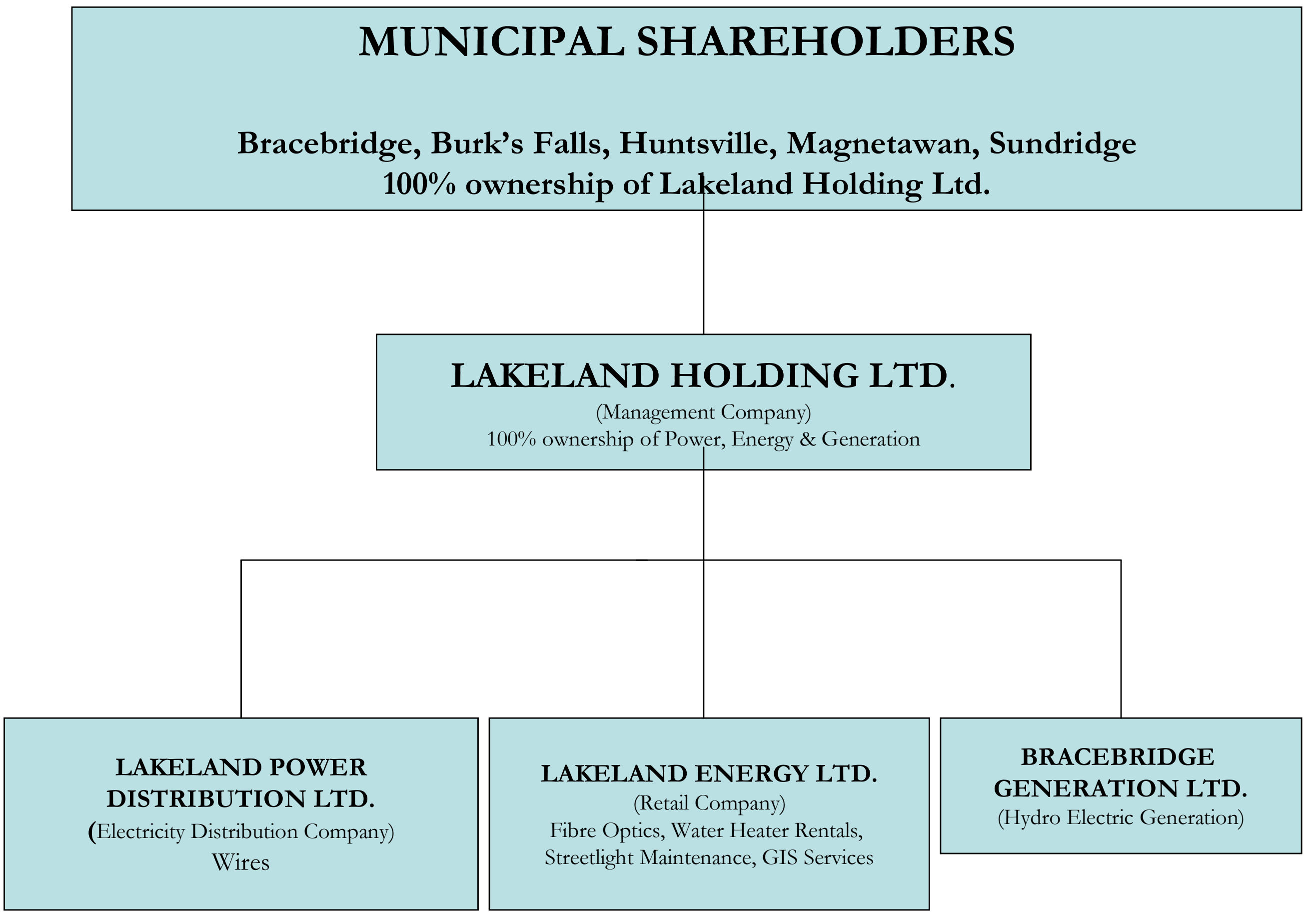
- Municipality of Magnetawan - is bounded by Hydro One Networks Inc. on all sides of its service territory.

EXPLANATION OF HOST AND EMBEDDED UTILITIES:

LPDL acts as an embedded utility to Hydro One Networks Inc. at the Muskoka Transformer Station in Utterson, Ontario. All areas are serviced from this transformer station.

UTILITY ORGANIZATION STRUCTURE:

CORPORATE ENTITIES RELATIONSHIPS CHART:



PLANNED CHANGES IN STRUCTURE:

No changes to LPDL’s corporate and operational structures are planned at the present time.

LPDL continues to be proactive in considering mergers and amalgamations.

STATUS OF BOARD DIRECTIVES FROM PREVIOUS BOARD DECISIONS:

Directive from 2009 Cost of Service Application (EB-2008-0234)

The Board prescribed a phase-in period to adjust its revenue-to-cost ratios, moving the Sentinel Lighting and Street Lighting from their 2009 positions to the bottom of the Board's target ranges during 2010 and 2011. LPDL has complied with this directive and as of its 2011 IRM application (EB-2010-0096), Sentinel Lighting and Street Lighting revenue-to-cost ratios have been moved to within the Board's target ranges.

PRELIMINARY LIST OF WITNESSES:

While LPDL requests that this Application be disposed of by way of a written hearing, should a technical conference or an oral hearing be necessary, LPDL will provide a list of potential witnesses as required.

SUMMARY OF THE APPLICATION:

Preamble

LPDL has submitted this Application in order to meet its Corporate Mission and Corporate Goals as outlined below. Current rates will result in actual Return on Equity in 2012 and 2013 below levels currently approved by the OEB. The increased rates are required to:

1) Maintain current capital investment levels in infrastructure to ensure a safe, reliable distribution system,
2) Continue with operating expenses necessary to maintain and operate the distribution system, meet customer service expectations and ensure regulatory compliance,
3) Maintain current staffing requirements, including training and preparing for succession planning,
4) To provide a reasonable rate of return to the Shareholder.

LPDL's mission statement is:

"Our mission is to provide safe, reliable,

and economic delivery of

electrical energy to our customers.

We are accountable to our shareholders:

Bracebridge, Burk's Falls, Huntsville,

Magnetawan and Sundridge.

(All with consideration of the Environment)

LPDL is an electricity distribution company licensed by the Ontario Energy Board to provide electricity distribution services to customers within the municipalities of Bracebridge, Huntsville, Sundridge, Burk's Falls, and Magnetawan.

LPDL's priorities are defined in its Vision Statement:

> *What we want to be:*
>
> *An organization that …*
>
> *Provides a safe environment for our employees*
>
> *Provides safe, reliable, and economic service to our customers,*
>
> *Continues to prosper and be a "good place to work"*
>
> *Provides a safe environment for and maintains good relations with the general public and suppliers.*
>
> *(All with consideration of the Environment)*

Purpose and Need

LPDL's requested revenue requirement for 2013, in the amount of $5,773,388 , includes the recovery of its costs to provide distribution services, its permitted Return on Equity ("ROE") and the funds necessary to service its debt.

When forecasted energy and demand levels for 2013 are considered, LPDL estimates that its present rates will produce a deficiency in gross distribution revenue of $392,906 for the 2013 Test Year.

The main items that have lead to this deficiency are the following: Smart Meter costs have been approved in Board Decision EB-2011-0413 and have been included in this application. The change in OM&A after excluding the costs specifically related to Smart Meters, $126 K, is 10% higher than 2011 actuals, which was an unusually low year in costs. In addition, the deficiency is a result of the 2009 load forecast. The 2009 load forecast was erroneously high as the historical kWh used for the regression analysis were uplifted in error (5% error) and the effect of CDM programs was not included. This resulted in an overall forecast that ended in being 9% higher than 2009 actuals. This effect continued through the remaining three years.

Therefore, LPDL seeks the OEB's approval to revise its electricity distribution rates. The rates proposed to recover its projected revenue requirement and other relief sought are set out in Exhibit 1, Tab 1, Schedule 2, Appendix A and Exhibit 8, Schedule 6 in this Application.

The information presented in this Application represents LPDL's forecasted results for its 2013 Test Year. LPDL is also presenting the forecasted results for 2012 Bridge Year and audited financial information for fiscal 2009, 2010 and 2011.

Timing

The financial information supporting the Test Year for this Application will be LPDL's fiscal year ending December 31, 2013 (the "2013 Test Year"). However, LPDL is requesting rates effective May 1, 2013, continuing through April 30, 2014.

Customer Impact

In preparing this application, LPDL has considered the impacts on its customers, with a goal of minimizing those impacts. With respect to cost allocation, LPDL notes that only the Unmetered Scattered Load and Sentinel Lighting classes fall outside the applicable threshold defined by the Board in the March 31, 2012 Report of the Board on Review of Electricity Distribution Cost Allocation Policy (EB-2011-0219). In this application the Unmetered Scattered Load and Sentinel Lighting classes have been brought within the Board's threshold with minimal impact to other classes.

Customer impacts, including the percentage average Total Bill Impact and Average Dollar Impact, which include revised distribution rates (monthly service charge and volumetric rates), revised low voltage rates, revised retail transmission rates, revised loss factors, LRAM and SSM rate riders, and regulatory asset rate riders to dispose of the balances in the Deferral and Variance Accounts requested in this Application are set out in Table 1.2.1 below, for typical Residential (800 kWh per month) and Commercial (2000 kWh per month) customers. A complete listing of bill impacts for all customer classes at various levels of consumption is provided in Exhibit 8, Schedule 8, Appendix A.

Transition to Modified International Financial Reporting Standards (MIFRS)

Consistent with the Board’s letter issued March 15, 2011 entitled *Use of Modified IFRS as a Basis for Filing Cost of Service Applications in 2012 Rates*, this application has been prepared using modified IFRS (MIFRS). To allow transparent and useful comparisons to historical expenses, the expenses approved in LPDL’s 2009 Cost of Service application, and to clearly illustrate the impact of the conversion to MIFRS, the forecasted 2013 Test Year has been prepared using both Canadian Generally Accepted Accounting Principles (CGAAP) and MIFRS.

The transition to MIFRS has impacted the calculation of the depreciation rates. These changes have impacted the 2013 rate base and the 2013 distribution revenue requirement. LPDL has provided detailed explanations of these changes in the applicable section of the application.

Table 1.2.1 - Bill Impact: Residential and Commercial

Appendix 2-W
Bill Impacts

Customer Class: Residential

Consumption 800 **kWh** ○ May 1 - October 31

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 15.3500	1	$ 15.35	$ 20.1900	1	$ 20.19	$ 4.84	31.53%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly	$ 3.5100	1	$ 3.51	$ -	1	$ -	-$ 3.51	-100.00%
Smart Meter Disposition Rider	Monthly	$ 1.1500	1	$ 1.15	$ -	1	$ -	-$ 1.15	-100.00%
Stranded Meter Disposition	Monthly	$ -	1	$ -	$ 1.6967	1	$ 1.70	$ 1.70	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0138	800	$ 11.04	$ 0.0148	800	$ 11.84	$ 0.80	7.25%
Smart Meter Disposition Rider		$ -	800	$ -	$ -	800	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0007	800	$ 0.56	$ -	800	$ -	-$ 0.56	-100.00%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A				$ 31.61			$ 33.73	$ 2.12	6.70%
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0001	800	$ 0.08	$ 0.0037	800	$ 2.98	$ 2.90	3621.49%
Tax Adjustment		-$ 0.0002	0	$ -	$ -	0	$ -	$ -	
		$ -	800	$ -	$ -	800	$ -	$ -	
		$ -	0	$ -	$ -	0	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0024	800	$ 1.92	$ 0.0034	800	$ 2.72	$ 0.80	41.67%
Smart Meter Entity Charge						0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				$ 33.61			$ 39.42	$ 5.81	17.30%
RTSR - Network	per kWh	$ 0.0051	847	$ 4.32	$ 0.0052	861	$ 4.47	$ 0.15	3.46%
RTSR - Line and Transformation Connection	per kWh	$ 0.0040	847	$ 3.39	$ 0.0042	861	$ 3.60	$ 0.21	6.15%
Sub-Total C - Delivery (including Sub-Total B)				$ 41.32			$ 47.49	$ 6.17	14.94%
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	847	$ 4.40	$ 0.0052	861	$ 4.47	$ 0.07	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	847	$ 0.93	$ 0.0011	861	$ 0.95	$ 0.02	1.62%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	847	$ 5.93	$ 0.0070	861	$ 6.02	$ 0.10	1.62%
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	247	$ 21.72	$ 0.0880	261	$ 22.93	$ 1.21	5.58%
TOU - Off Peak		$ 0.0650	542	$ 35.23	$ 0.0650	551	$ 35.80	$ 0.57	1.62%
TOU - Mid Peak		$ 0.1000	152	$ 15.24	$ 0.1000	155	$ 15.49	$ 0.25	1.62%
TOU - On Peak		$ 0.1170	152	$ 17.83	$ 0.1170	155	$ 18.12	$ 0.29	1.62%
Total Bill on RPP (before Taxes)				$ 119.55			$ 127.11	$ 7.57	6.33%
HST		13%		$ 15.54	13%		$ 16.52	$ 0.98	6.33%
Total Bill (including HST)				$ 135.09			$ 143.64	$ 8.55	6.33%
Ontario Clean Energy Benefit [1]				-$ 13.51			-$ 14.36	-$ 0.85	6.29%
Total Bill on RPP (including OCEB)				$ 121.58			$ 129.28	$ 7.70	6.33%
Total Bill on TOU (before Taxes)				$ 121.13			$ 128.60	$ 7.46	6.16%
HST		13%		$ 15.75	13%		$ 16.72	$ 0.97	6.16%
Total Bill (including HST)				$ 136.88			$ 145.31	$ 8.43	6.16%
Ontario Clean Energy Benefit [1]				-$ 13.69			-$ 14.53	-$ 0.84	6.14%
Total Bill on TOU (including OCEB)				$ 123.19			$ 130.78	$ 7.59	6.17%

Loss Factor (%) 5.85% (current) 7.57% (proposed)

Appendix 2-W
Bill Impacts

Customer Class: GS <50 kW

Consumption 2000 kWh ○ May 1 - October 31

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 36.6500	1	$ 36.65	$ 44.6100	1	$ 44.61	$ 7.96	21.72%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly	$ 4.2400	1	$ 4.24	$ -	1	$ -	-$ 4.24	-100.00%
Smart Meter Disposition Rider	Monthly	$ 2.8600	1	$ 2.86	$ -	1	$ -	-$ 2.86	-100.00%
Stranded Meter Disposition	Monthly	$ -	1	$ -	$ 3.0924	1	$ 3.09	$ 3.09	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0084	2000	$ 16.80	$ 0.0092	2000	$ 18.40	$ 1.60	9.52%
Smart Meter Disposition Rider		$ -	2000	$ -	$ -	2000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0001	2000	$ 0.20	$ -	2000	$ -	-$ 0.20	-100.00%
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Sub-Total A				$ 60.75			$ 66.10	**$ 5.35**	**8.81%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0001	2000	$ 0.20	$ 0.0037	2000	$ 7.44	$ 7.24	3621.49%
Tax Adjustment		-$ 0.0002	0	$ -	$ -	0	$ -	$ -	
		$ -	2000	$ -	$ -	2000	$ -	$ -	
		$ -	0	$ -	$ -	0	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0021	2000	$ 4.20	$ 0.0030	2000	$ 6.00	$ 1.80	42.86%
Smart Meter Entity Charge						0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 65.15**			**$ 79.55**	**$ 14.40**	**22.10%**
RTSR - Network	per kWh	$ 0.0047	2117	$ 9.95	$ 0.0048	2151	$ 10.29	$ 0.34	3.46%
RTSR - Line and Transformation Connection	per kWh	$ 0.0037	2117	$ 7.83	$ 0.0039	2151	$ 8.31	$ 0.48	6.15%
Sub-Total C - Delivery (including Sub-Total B)				**$ 82.93**			**$ 98.15**	**$ 15.22**	**18.35%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2117	$ 11.01	$ 0.0052	2151	$ 11.19	$ 0.18	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2117	$ 2.33	$ 0.0011	2151	$ 2.37	$ 0.04	1.62%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2117	$ 14.82	$ 0.0070	2151	$ 15.06	$ 0.24	1.62%
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	1517	$ 133.50	$ 0.0880	1551	$ 136.52	$ 3.03	2.27%
TOU - Off Peak		$ 0.0650	1355	$ 88.07	$ 0.0650	1377	$ 89.50	$ 1.43	1.62%
TOU - Mid Peak		$ 0.1000	381	$ 38.11	$ 0.1000	387	$ 38.73	$ 0.62	1.62%
TOU - On Peak		$ 0.1170	381	$ 44.58	$ 0.1170	387	$ 45.31	$ 0.72	1.62%
Total Bill on RPP (before Taxes)				**$ 289.83**			**$ 308.54**	**$ 18.71**	**6.45%**
HST		13%		$ 37.68	13%		$ 40.11	$ 2.43	6.45%
Total Bill (including HST)				$ 327.51			$ 348.65	$ 21.14	6.45%
Ontario Clean Energy Benefit [1]				-$ 32.75			-$ 34.87	-$ 2.12	6.47%
Total Bill on RPP (including OCEB)				**$ 294.76**			**$ 313.78**	**$ 19.02**	**6.45%**
Total Bill on TOU (before Taxes)				**$ 282.10**			**$ 300.55**	**$ 18.45**	**6.54%**
HST		13%		$ 36.67	13%		$ 39.07	$ 2.40	6.54%
Total Bill (including HST)				$ 318.77			$ 339.62	$ 20.85	6.54%
Ontario Clean Energy Benefit [1]				-$ 31.88			-$ 33.96	-$ 2.08	6.52%
Total Bill on TOU (including OCEB)				**$ 286.89**			**$ 305.66**	**$ 18.77**	**6.54%**

1 **Loss Factor (%)** | Current: 5.85% | Proposed: 7.57%

Smart Meters

2013 smart meter costs are included the 2013 rate base and revenue requirement. LPDL is also requesting the recovery of stranded meter amounts as outlined in Exhibit 9, Tab 3, Schedule 1 of this Application.

Capital Structure

LPDL is requesting the continuation of its current deemed capital structure of 40% Equity, 4% Short Term Debt and 56% Long Term Debt.

Return on Equity

LPDL has assumed a return on equity of 9.12% consistent with the Cost of Capital Parameter Updates for 2012 Cost of Service Applications issued by the OEB on March 2, 2012. LPDL understands the Board will be finalizing the cost of capital parameters for 2013 rates based on January 2013 market interest rate information, and that adjustments to the Application may be required as a result.

Capital Expenditures

LPDL continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory. Expenditures are also being made to meet regulations set out by both the OEB and IESO including load transfers and primary metering points.

BUDGET OVERVIEW:

LPDL compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budget forecast. This budget information is compiled for both the 2012 Bridge Year and the 2013 Test Year. Smart Meter costs have been approved in Board Decision EB-2011-0413 and have been included in this application. The change in OM&A after excluding the costs specifically related to Smart Meters, $126 K, is 10% higher than 2011 actuals, which was an unusually low year in costs.

Revenue Forecast

LPDL's energy sales and revenue forecast model were 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 2012 and 2013. The forecast is weather normalized as outlined in Exhibit 3, Tab 2, Schedule 1 and considers such factors as average weather conditions and economic conditions in the area serviced by LPDL. The 2009 load forecast was erroneously high as the historical kWh used for the regression analysis were uplifted in error (5% error) and the effect of CDM programs was not included. This resulted in an overall forecast that ended in being 9% higher than 2009 actuals. This error has been corrected in the current load forecast.

Operating Maintenance and Administration (“OM&A”) Expense Forecast

The OM&A expenses for the 2012 Bridge Year and the 2013 Test Year have been based on an in-depth review of operating priorities and requirements and are strongly influenced by prior year experience, year-to-date results and expected changes for the forecast periods. Each item is reviewed account by account for each of the forecast years. The change in OM&A after excluding the costs specifically related to Smart Meters, $126 K, is 10% higher than 2011 actuals, which was an unusually low year in costs.

Capital Budget

The capital budget forecast for 2012 and 2013 is influenced by, among other factors, the highest priority capital requirements and LPDL's capacity to finance capital projects. All proposed capital projects are assessed within the framework of their capital budget priority and are outlined in Exhibit 2, Tab 3. Annual capital budgets are approved by the Board of Directors.

LPDL has in 2012, developed an Asset Management Plan which accompanies this Application in Exhibit 2, Appendix A. Using current GIS and operational software, LPDL has completed a high level review of current assets and their age and has reviewed current strategies in dealing with maintenance and capital improvements. From this review and system inspection results, LPDL has identified various aged assets that require replacement to ensure safe and reliable delivery of electricity. As well, LPDL has identified various system voltage projects where 4.16kV and 12.5kV services will be upgraded to 27.6kV service to improve the quality and efficiency of electricity delivered. Some of these projects will allow LPDL to shift these loads to LPDL owned substations from Hydro One owned distribution stations thus reducing the reliance on and cost of Hydro One supply and improving system reliability. In the Asset Management Plan, LPDL has provided a forecasted capital project spending plan for a four year horizon covering 2013, 2014, 2015 and 2016. These forecasted project costs are engineering estimates only and the actual expenditure levels in the capital budgets could be adjusted based on project scope, prevailing construction costs and other outside influences (e.g. relocation requests, system expansions, etc.).

CHANGES IN METHODOLOGY:

LPDL is not requesting any changes in methodology in the current proceeding.

CALCULATION OF REVENUE DEFICIENCY:

LPDL has provided detailed calculations supporting its 2013 revenue deficiency. LPDL's net revenue deficiency is $288,786 and when grossed up for PILs LPDL's revenue deficiency is $392,906 . Table 1.2.2 on the following page provides the revenue deficiency calculations for the 2013 Test Year at Existing 2012 Board-approved rates and the 2013 Test Year Revenue Requirement.

Table 1.2.2 - Calculation of Revenue Deficiency

Particulars	At Current Approved Rates	At Proposed Rates
Revenue Deficiency from Below		$392,906
Distribution Revenue	$5,066,854	$5,066,854
Other Operating Revenue Offsets - net	$313,628	$313,628
Total Revenue	$5,380,482	$5,773,388
Operating Expenses	$4,279,610	$4,279,610
Deemed Interest Expense	$605,202	$605,202
Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	($15,517) **(2)**	($15,517)
Total Cost and Expenses	$4,869,295	$4,869,295
Utility Income Before Income Taxes	$511,187	$904,093
Tax Adjustments to Accounting Income per 2013 PILs model	($164,592)	($164,592)
Taxable Income	$346,595	$739,501
Income Tax Rate	26.50%	26.50%
Income Tax on Taxable Income	$91,848	$195,968
Income Tax Credits	($35,000)	($35,000)
Utility Net Income	$454,339	$743,125
Utility Rate Base	$20,370,760	$20,370,760
Deemed Equity Portion of Rate Base	$8,148,304	$8,148,304
Income/(Equity Portion of Rate Base)	5.58%	9.12%
Target Return - Equity on Rate Base	9.12%	9.12%
Deficiency/Sufficiency in Return on Equity	-3.54%	0.00%
Indicated Rate of Return	5.20%	6.62%
Requested Rate of Return on Rate Base	6.62%	6.62%
Deficiency/Sufficiency in Rate of Return	-1.42%	0.00%
Target Return on Equity	$743,125	$743,125
Revenue Deficiency/(Sufficiency)	$288,786	$ -
Gross Revenue Deficiency/(Sufficiency)	$392,906 **(1)**	

CAUSES OF REVENUE DEFICIENCY:

The revenue deficiency is primarily the result of:

- Increases in OM&A costs since LPDL's last Cost of Service application in 2009. For the 2013 Test Year, LPDL is forecasting OM&A expenses increasing at a compound annual growth rate of 3.9% per year since 2009 Board Approved, under CGAAP (the compound annual growth rate is 3.9% from 2009 actual). LPDL has provided a detailed explanation of changes in operating expenses in Exhibit 4. The increase in OM&A after excluding the effect of Smart Meter costs is 10% over 2011 actuals which was an unusally low cost year.

- Load forecast has been calculated based on correct historical data. The 2009 load forecast was erroneously high as the historical kWh used for the regression analysis were uplifted in error (5% error) and the effect of CDM programs was not included. This resulted in an overall forecast that ended in being 9% higher than 2009 actuals. This effect continued through the remaining three years.

- Capital Expenditures have exceeded depreciation levels resulting in an increased rate base on which the rate of return is calculated. LPDL is committed to ensuring the reliability of the distribution system and will continue to invest in capital infrastructure and equipment in 2012 and 2013 at a level exceeding depreciation. Changes in the Rate Base are discussed further in Exhibit 2.

FINANCIAL STATEMENTS – 2009, 2010 AND 2011:

LPDL's Audited Financial Statements accompany this Schedule as Appendix D.

APPENDIX D

COPY OF LPDL AUDITED FINANCIAL STATEMENTS

FOR 2009, 2010 AND 2011

Lakeland Power Distribution Ltd.
Financial Statements
For the year ended December 31, 2009

Contents

BDO

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BDO Canada LLP
239 Manitoba Street, Suite 1
Bracebridge ON P1L 1S2 Canada

Auditors' Report

To the Shareholder of
Lakeland Power Distribution Ltd.

We have audited the balance sheet of Lakeland Power Distribution Ltd. as at December 31, 2009 and the statements of operations, retained earnings, comprehensive income 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 Lakeland Power Distribution Ltd. as at December 31, 2009 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

BDO Canada LLP

Chartered Accountants, Licensed Public Accountants

Bracebridge, Ontario
February 24, 2010

Lakeland Power Distribution Ltd.
Balance Sheet

December 31	2009	2008
Assets		
Current		
Accounts receivable (Note 2)	$ **1,938,749**	$ 2,060,334
Unbilled service revenue	**2,662,505**	2,064,997
Inventory	**262,181**	264,390
Other current assets	**154,817**	106,046
Payments in lieu of income taxes recoverable	**-**	325,787
	5,018,252	4,821,554
Capital assets (Note 3)	**12,586,063**	11,908,541
Regulatory assets (Note 4)	**1,381,178**	69,055
Future income tax assets (Notes 1 & 5)	**757,631**	-
Other assets (Note 6)	**469,218**	462,498
	$ **20,212,342**	$ 17,261,648
Liabilities and Shareholder's Equity		
Current		
Bank overdraft	$ **264,186**	$ 168,903
Short-term bank loan (Note 7)	**890,000**	300,000
Accounts payable and accrued liabilities (Note 8)	**4,226,452**	3,242,438
Payments in lieu of income taxes payable	**38,304**	-
	5,418,942	3,711,341
Long-term debt (Note 9)	**3,487,500**	3,487,500
Customer deposits	**203,166**	212,237
Other non-current liabilities	**23,100**	23,100
	9,132,708	7,434,178
Contingent liability (Note 10)		
Shareholder's equity		
Share capital (Note 11)	**9,226,787**	9,226,787
Retained earnings	**1,852,847**	600,683
	11,079,634	9,827,470
	$ **20,212,342**	$ 17,261,648

On behalf of the Board:

______________________________ Director

______________________________ Director

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements

Lakeland Power Distribution Ltd.
Statement of Operations, Retained Earnings and Comprehensive Income

For the year ended December 31	2009	2008
Revenue	$ 20,649,853	$ 19,541,027
Direct costs (Note 12)	16,319,947	15,615,852
	4,329,906	3,925,175
Other revenues		
Investment income	36,587	53,990
Gain on disposal of capital assets	14,274	7,237
Other income	81,692	87,237
Other operating revenue (Schedule 1)	319,255	279,574
	4,781,714	4,353,213
Expenses		
Administration and general (Schedule 1)	1,218,758	1,054,419
Amortization (Note 13)	952,100	887,563
Billing and collecting (Schedule 1)	600,485	617,886
Community relations	25,980	25,443
Distribution (Schedule 1)	1,026,811	1,009,912
Interest	223,758	186,640
Payments in lieu of capital tax	14,733	2,893
Taxes other than income taxes	10,065	10,270
	4,072,690	3,795,026
Net income from operations for the year	709,024	558,187
Payments in lieu of income taxes (Note 5)		
Current payments in lieu of income taxes	214,491	171,483
Future payments in lieu of income taxes	160,905	-
	375,396	171,483
Net income and comprehensive income for the year	333,628	386,704
Retained earnings, beginning of year, as previously stated	600,683	1,701,479
Adjustment to recognize future income taxes (Note 1)	918,536	-
Retained earnings, as restated	1,519,219	1,701,479
Dividends paid	-	(1,487,500)
Retained earnings, end of year	$ 1,852,847	$ 600,683

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements

Lakeland Power Distribution Ltd.
Statement of Cash Flows

For the year ended December 31	2009	2008
Cash provided by (used in)		
Operating activities		
Net income for the year	**$ 333,628**	$ 386,704
Adjustments for		
Amortization (Note 13)	**1,080,564**	1,031,523
Future payments in lieu of income taxes	**160,905**	-
Gain on disposal of capital assets	**(14,274)**	(7,237)
	1,560,823	1,410,990
Changes in non-cash working capital balances		
Accounts receivable	**121,585**	222,657
Unbilled service revenue	**(597,509)**	67,126
Inventory	**2,209**	13,870
Other current assets	**(48,771)**	74,722
Accounts payable and accrued liabilities	**984,017**	(193,983)
Payments in lieu of income taxes recoverable	**364,091**	(449,851)
	2,386,445	1,145,531
Customer deposits	**(9,071)**	(23,976)
Retail settlement variance accounts	**525,371**	145,880
Smart meters	**(1,601,503)**	(35,380)
Other regulatory asset and liability accounts	**145,181**	(3,659)
	1,446,423	1,228,396
Investing activities		
Proceeds on sale of capital assets	**30,000**	7,237
Purchase of capital assets	**(2,119,998)**	(1,555,308)
Contributions received in aid of construction	**346,183**	479,066
Acquisition of intangible assets	**(6,720)**	-
Recovery of rate regulated assets	**(381,171)**	816,082
	(2,131,706)	(252,923)
Financing activities		
Increase in short-term bank loan	**590,000**	300,000
Dividends paid	**-**	(1,487,500)
	590,000	(1,187,500)
Decrease in cash and cash equivalents during the year	**(95,283)**	(212,027)
Cash and cash equivalents, beginning of year	**(168,903)**	43,124
Cash and cash equivalents, end of year	**$ (264,186)**	$ (168,903)
Represented by		
Bank overdraft	**$ (264,186)**	$ (168,903)

Supplementary information (Note 15)

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements

December 31, 2009

Nature of Business

The company is incorporated under the laws of Ontario and operates as a local distribution company distributing hydro electric power to users in Bracebridge, Huntsville, Sundridge, Burk's Falls and Magnetawan, Ontario.

The company is a municipally owned government business enterprise and is therefore exempt from income tax under the Income Tax Act of Canada.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand and bank balances (overdrafts).

Inventory

Inventory consists of repair parts, supplies and materials and is stated at the lower of average cost and net realizable value. Cost represents direct costs plus any related shipping and freight costs. Prior period write-downs can be reversed when the net realizable value of impaired inventory subsequently recovers.

Capital Assets

Capital assets are recorded at cost less accumulated amortization, which includes internal labour and allocated overhead. Amortization is provided on the straight line basis over the estimated useful life of the assets as follows:

Distribution Plant	
Buildings and fixtures	- 30 & 50 years
Conductors and devices	- 25 years
Distribution station equipment	- 25 years
Line transformers	- 25 years
Meters	- 25 years
New services distribution	- 25 years
Poles, towers and fixtures	- 25 years
Underground conduits	- 25 years
General Plant	
Buildings and fixtures	- 30 & 50 years
Communication equipment	- 10 years
Computer hardware and software	- 5 years
Office furniture and equipment	- 10 years
Stores equipment	- 10 years
Tools and garage equipment	- 10 years
Transportation equipment	- 5 & 8 years

Contributions in Aid of Construction

Certain capital assets may be acquired or constructed with financial assistance in the form of non-refundable contributions from customers. These contributions are netted against capital assets and amortized on the same basis as the capital assets to which they relate.

December 31, 2009

Impairment of Long-lived Assets

The company tests for impairment loss of long-lived assets whenever events or changes in circumstances occur, which may cause their carrying value to exceed the total undiscounted cash flows expected from their use and eventual disposition. An impairment loss, if any, is determined as the excess of the carrying value of the asset over its fair value.

Asset Retirement Obligations

The company recognizes asset retirement obligations in the period in which they are incurred if a reasonable estimate of fair value can be determined. While some of the company's long-lived tangible assets will have future legal retirement obligations, the date of removal of the assets cannot be reasonably determined at this time. An asset retirement obligation and offsetting capital asset will be recognized when the timing and amount can be reasonably determined. There are no asset retirement obligations to date.

Regulatory Assets

The rates of the company's electricity transmission and distribution businesses are subject to regulation by the Ontario Energy Board (OEB). The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets. The company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. The company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the company determines that it is no longer probable that the OEB will include a regulatory asset in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made. Specific regulatory assets are described below and disclosed in (Note 4).

Retail Settlement Variance Accounts

These accounts reflect the difference between the cost of electricity and the amounts billed to consumers beginning January 1, 2005. Amounts incurred prior to this date are currently being recovered in rates effective May 1, 2006 and May 1, 2009 and are included in the regulatory asset recovery accounts described below.

Regulatory Assets (continued)

Cash Pension Contributions
The pension contribution holiday for the Ontario Municipal Employees Retirement Fund (OMERS) ended on December 31, 2002. As a result of the holiday, pension costs were not included in current rates. January 2005 through to April 2006, cash pension costs were recorded as other regulatory assets. In May of 2006, cash pension costs were no longer allowed as regulatory assets, as they now formed part of the current rates. These costs were included in the OEB approved amounts for recovery, Regulatory Asset Recovery Account II.

Regulatory Asset Recovery Account I
The OEB approved amounts for recovery that were incurred prior to January 2005. These included qualifying transition costs, pre-market opening energy variance accounts and retail settlement variance amounts incurred prior to January 2005.

Regulatory Asset Recovery Account II
The OEB approved amounts for recovery that were incurred after January 2005 and prior to January 2008. These included retail settlement and cost variance amounts, distribution low-voltage service amounts and cash pension contributions, plus accrued interest.

Smart Meters
This amount consists of the net balance of capital and operating expenditures for smart meters, less recoveries received from the rate adder charged to customers. Effective May 1, 2009, the OEB increased the respective monthly rate adder to $1.00 per month per metered customer.

Other Assets

Intangible assets are recorded at cost less accumulated amortization and are amortized over the useful life of the asset. If the life of the asset is indefinite, no amortization is taken.

Income Taxes

Under the Electricity Act, 1998, the company is required to make payments in lieu of income taxes to Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with rules contained in the Income Tax Act, as modified by the Electricity Act, 1998, and related regulations.

Current Payments in Lieu of Income Taxes
The provision for current taxes and the assets and liabilities for the current and prior periods are measured at the amounts receivable or payable from/to the OEFC.

Future Payments in Lieu of Income Taxes
Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than not that they be realized from taxable income available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantively enacted by the balance sheet date. Future income taxes are charged or credited to the statement of operations and comprehensive income.

The carrying amount of future income tax assets is reviewed at each balance sheet date and reduced to the extent that all or part of the future income tax assets have not met the "more likely than not" criterion. Previously unrecognized future income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not of being recovered from future taxable income.

The company recognizes regulatory assets or liabilities which correspond to future income taxes that flow through the rate-making process. No amounts have been recognized in these financial statements as future income taxes have not been reflected in rate applications.

Revenue Recognition

Revenue is recognized, as power is transmitted and delivered to customers. Revenues are recognized on the accrual basis, which includes an estimate of electricity consumed by customers in the year, but billed subsequent to year end. This revenue is recorded as unbilled service revenue.

Contracted service revenue is recognized under the completed contract method whereby contract revenue billed and the related contract expenses are deferred until substantial completion of the contract. If losses are anticipated on contracts prior to substantial completion, full provision is made for such losses.

Cash received in advance of meeting the revenue recognition criteria described above is recorded as customer deposits.

Pension Plan

The company is an employer member of the Ontario Municipal Employees Retirement System (OMERS), which is a multi-employer, defined benefit pension plan. The Board of Trustees, representing plan members and employers, is responsible for overseeing the management of the pension plan, including investment of the assets and administration of the benefits. The company has adopted defined contribution plan accounting principles for this Plan because insufficient information is available to apply defined benefit plan accounting principles. The company records as pension expense the current service cost, amortization of past service costs and interest costs related to the future employer contributions to the Plan for past employee service.

Use of Estimates

The preparation of financial statements in accordance with Canadian generally accepted accounting principles, requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from management's best estimates as additional information becomes available in the future.

Financial Instruments

The company classifies its financial instruments into one of the following categories based on the purpose for which the asset was acquired. The company's accounting policy for each category is as follows:

Assets or liabilities held-for-trading

Financial instruments classified as assets or liabilities held-for-trading are reported at fair value at each balance sheet date, and any change in fair value is recognized in net income in the period during which the change occurs. Transaction costs are expensed when incurred.

Cash and bank overdrafts have been classified as held-for-trading.

Loans and receivables and other financial liabilities

Financial instruments classified as loans and receivables, and other financial liabilities are carried at amortized cost using the effective interest method. Interest income or expense is included in net income over the expected life of the instrument. Transaction costs are expensed when incurred.

Accounts receivable have been classified as loans and receivables.

Short-term bank loan, accounts payable and accrued liabilities and long-term debt have been classified as other financial liabilities.

New Accounting Pronouncements

Recent accounting pronouncements that have been issued but are not yet effective, and have a potential implication for the company, are as follows:

International Financial Reporting Standards (IFRS)
The Canadian Accounting Standards Board (AcSB) confirmed that the adoption of IFRS would be effective for interim and annual periods beginning on or after January 1, 2011 for Canadian publicly accountable profit-oriented enterprises. IFRS will replace Canada's current GAAP for these enterprises. Comparative IFRS information for the previous fiscal year will also have to be reported. These new standards will be effective in the fiscal year ended December 31, 2011.

The company is currently in the process of evaluating the potential impact of IFRS to the financial statements. This will be an ongoing process. The financial statements as disclosed under current GAAP may be significantly different when presented in accordance with IFRS.

1. Change in Accounting Policies

Effective January 1, 2009, the company adopted Canadian Institute of Chartered Accountants (CICA) Handbook Section 1000, Financial Statement Concepts. This section has been amended to focus on the capitalization of costs that truly meet the definition of an asset and de-emphasizes the matching principle. The adoption of this section had no impact on the financial statements.

Effective for year ends beginning on or after January 1, 2009, the CICA amended CICA Handbook Section 1100, Generally Accepted Accounting Principles, Section 3465, Income Taxes and Accounting Guideline 19 - Disclosures by Entities Subject to Rate-Regulation.

The revision to Section 1100 removed the temporary exemption pertaining to the application of that Section to the recognition and measurement of assets and liabilities arising from rate-regulation. Accounting Guideline 19 amended certain disclosures as a result of the changes to other Sections. Adoption of these amendments did not affect the company's results of operations and financial position.

The amendments to Section 3465 require rate-regulated enterprises to recognize future income tax liabilities and assets, as well as, a regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or returned to future customers and to present these amounts on a gross basis in the financial statements. Entities in this sector were previously exempted from the requirement to recognize future income taxes. The company adopted this new accounting recommendation without the restatement of the prior year's figures by making a cumulative catch-up adjustment of $918,536 to opening retained earnings in the current year and applying the new accounting policy to events and transactions occurring after the date of change.

Effective January 1, 2009, the company adopted CICA Handbook Section 3064, Goodwill and intangible assets, replacing Handbook Section 3062, Goodwill and other intangible assets and Handbook Section 3450, Research and development costs. The CICA also amended Handbook Section 1000, Financial Statement Concepts, to provide consistency with this new standard. Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. This section clarifies that costs can be deferred only when they relate to an item that meets the definition of an asset and as a result start-up costs must be expensed as incurred. The adoption of this section had no impact on the financial statements.

2. Accounts Receivable

	2009	2008
Electrical energy	**$ 1,688,551**	$ 1,928,446
Allowance for doubtful accounts	**(24,131)**	(33,753)
Net from LDC customers (Note 17)	**1,664,420**	1,894,693
GST receivable	**90,992**	35,505
Sundry (Note 14)	**183,337**	130,136
	$ 1,938,749	$ 2,060,334

December 31, 2009

3. Capital Assets

	2009		2008	
	Asset Cost	**Accumulated Amortization**	Asset Cost	Accumulated Amortization
Distribution Plant				
Buildings and fixtures	**$ 604,107**	**$ 118,978**	$ 604,107	$ 99,805
Conductors and devices	**4,410,201**	**1,166,166**	4,175,525	990,628
Distribution station equipment	**2,646,844**	**611,696**	1,434,423	512,986
Line transformers	**4,940,860**	**1,713,081**	4,479,935	1,467,143
Meters	**1,114,044**	**462,922**	1,109,842	411,195
New services distribution	**410,854**	**83,255**	366,831	67,702
Poles, towers and fixtures	**5,345,524**	**2,305,534**	5,131,378	2,039,665
Underground conduits	**2,937,369**	**1,214,512**	2,874,723	1,081,690
	22,409,803	**7,676,144**	20,176,764	6,670,814
General Plant				
Land	**278,455**	**-**	278,455	-
Buildings and fixtures	**176,006**	**35,395**	165,678	29,426
Communication equipment	**188,721**	**99,914**	185,693	81,000
Computer hardware	**357,391**	**292,114**	338,910	260,008
Computer software	**169,588**	**120,940**	136,627	102,552
Office furniture and equipment	**166,164**	**103,264**	161,887	89,668
Stores equipment	**10,960**	**6,936**	10,960	6,117
Tools and garage equipment	**235,440**	**141,061**	200,446	126,536
Transportation equipment	**1,058,226**	**582,131**	1,087,661	573,311
	2,640,951	**1,381,755**	2,566,317	1,268,618
Construction in progress	**-**	**-**	323,046	-
	25,050,754	**9,057,899**	23,066,127	7,939,432
Less contributions in aid of construction	**4,111,835**	**705,043**	3,765,651	547,497
	$ 20,938,919	**$ 8,352,856**	$ 19,300,476	$ 7,391,935
		$ 12,586,063		$ 11,908,541

4. Regulatory Assets

	2009	2008
Retail settlement variance accounts	**$ (625,028)**	$ (99,657)
Cash pension contributions	**-**	105,059
Regulatory asset recovery account I	**3,475,494**	3,475,494
Regulatory asset recovery account II	**152,151**	-
Smart meters	**1,636,883**	35,380
Conservation and Demand Management	**(40,122)**	-
	4,599,378	3,516,276
Recovery of regulatory assets account I	**(3,194,371)**	(3,447,221)
Recovery of regulatory assets account II	**(23,829)**	-
	$ 1,381,178	$ 69,055

The retail settlement variance accounts and the smart meter amounts above are expected to be recovered from future customers through future rate applications, which are subject to approval by the OEB.

The regulatory asset recovery account I amount was approved in rates effective May 1, 2006, which was expected to result in full recovery in 2008. During the current year, it was discovered that Hydro One Inc. over recovered rate regulated amounts of approximately $256,000 from the company. This overpayment by the company has been included as a reduction in the recovery of regulatory assets account I in accordance with the direction of the OEB, as the amounts are expected to be recovered in the future.

The regulatory asset recovery account II amount has been approved in rates effective May 1, 2009, which is expected to be fully recovered by 2011.

Retail settlement variance accounts reflect the difference between the cost of electricity and the amounts billed to consumers. During 2009, these variances resulted in a charge to reduce revenue of approximately $2,385,134 and a charge to reduce direct costs of approximately $1,949,039. In addition to retail settlement variances, carrying charges are also applied.

December 31, 2009

5. Future Income Tax Assets

Future income tax assets at December 31, 2009, which arise from differences between the carrying amounts and tax bases of the company's assets, are as follows:

	2009	2008
Future income tax assets		
Plant and equipment	$ 757,631	$ -

The provision for payments in lieu of income taxes differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

	2009	2008
Income before payments in lieu of income taxes	$ 709,024	$ 558,187
Statutory income tax rate	28.8 %	28.1 %
Expected payments in lieu of income taxes expense	204,199	156,851
Increase in taxes resulting from:		
Amortization in excess of capital cost allowance	-	22,119
Rate change	171,197	-
Other	-	(7,487)
Payments in lieu of income taxes expense	$ 375,396	$ 171,483
Payments in lieu of income taxes:		
Current payments in lieu of income taxes	$ 214,491	$ 171,483
Future payments in lieu of income taxes	160,905	-
	$ 375,396	$ 171,483

The provision for future payments in lieu of future income taxes of $160,905 reflects the decrease in the asset for payments in lieu of future income taxes that is not expected to be recovered from the company's customers through future rates.

December 31, 2009

6. Other Assets

	2009 Asset Cost	2009 Accumulated Amortization	2008 Asset Cost	2008 Accumulated Amortization
Intangible assets				
Land rights	**$ 484,365**	**$ 15,147**	$ 477,645	$ 15,147
		$ 469,218		$ 462,498

7. Short-term Bank Loan

The revolving facility available to the company is with a Chartered bank to assist with working capital requirements. Funds drawn on the facility at December 31, 2009 amount to $890,000 (2008 - $300,000). Funds available at December 31, 2009 amount to $2,110,000 (2008 - $1,700,000). Interest on this facility is at the bank's prime lending rate.

Security for the revolving facility is provided by a General Security Agreement, a floating and fixed charge over all assets and evidence of adequate liability insurance.

The agreement covering the above facility contains certain restrictions regarding interest coverage and debt capitalization tests.

8. Accounts Payable and Accrued Liabilities

	2009	2008
Accounts payable and accrued liabilities	**$ 815,045**	$ 750,661
Customer deposits	**294,726**	193,368
Power bill	**2,829,460**	1,833,096
Related company balances (Note 14)	**272,833**	450,176
Payroll deductions payable	**14,388**	15,137
	$ 4,226,452	$ 3,242,438

December 31, 2009

9. Long-Term Debt

	2009	2008
Chartered bank term loan, payments of interest only, payable monthly at 5.41% due March 2013	**$ 1,162,500**	$ 1,162,500
Chartered bank term loan, payments of interest only, payable monthly at 5.03% due March 2012	**2,325,000**	2,325,000
	$ 3,487,500	$ 3,487,500

Security for the chartered bank revolving loan is provided by a General Security Agreement conveying a first floating and fixed charge over all assets and evidence of adequate liability insurance.

The agreement covering the above facility contains certain restrictions regarding interest coverage and debt capitalization tests.

10. Contingent Liabilities

Legal Proceedings

The action known as Griffith at al. v. Toronto Hydro-Electric Commission et al. has been brought under the *Class Proceedings Act, 1992*. The plaintiff class seeks $500 million in restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities ("LDCs") who received late payment penalties which constitute interest at an effective rate in excess of 60% per year, contrary to section 347 of the *Criminal Code*. Pleadings have closed in this action. The action has not yet been certified as a class action and no discoveries have been held, as the parties were awaiting the outcome of a similar proceedings brought against Enbridge Gas Distribution Inc. (formerly Consumers Gas).

On April 22, 2004, the Supreme Court of Canada released a decision in the Consumers Gas case rejecting all of the defences which had been raised by 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 remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge and that settlement was approved by the Ontario Superior Court.

In 2007, Enbridge filed an application to the Ontario Energy Board (OEB) to recover the Court-approved amount and related amounts from ratepayers. On February 4, 2008 the OEB approved recovery of the said amounts from ratepayers over a five year period.

Subsequent to the year end, in March 2010, a settlement in principle has been reached on behalf of all LDCs. This tentative settlement requires the consent and approval of all LDCs and approval of the Ontario Superior Court of Justice in order to become effective. In summary the terms of the settlement are: a) LDCs collectively pay $17,000,000 (Lakeland Power Distribution Ltd. portion is approximately $31,600); b) payment is not due until June 30, 2011; c) amounts paid, after deduction of class counsel fees, will be paid to the Winter Warmth Fund or similar charities as agencies in each service territory; and d) LDCs are at liberty to seek OEB permission to recover settlement costs through rates.

Since the tentative settlement has not been approved yet and any liability is likely to be recovered through rate increases, the company has not reflected their portion of this settlement in these financial statements.

Environmental Contingency

On September 17, 2008, Environment Canada published its final regulations governing the management, storage and disposal of PCBs. The regulations impose timelines for disposal of PCBs based on certain criteria. It is management's plan to have all affected assets tested and removed by the end of 2011 to be in compliance with government requirements. No accrual has been reflected in these financial statements as these costs have not yet been determined.

December 31, 2009

11. Share Capital

Authorized

Unlimited Common shares

		2009	2008
Issued			
7,428	Common shares	**$ 9,226,787**	$ 9,226,787

12. Economic Dependence

During the year, the company purchased 88% (2008 - 86%) of its direct costs from Hydro One Inc. Should this supplier cease to operate, the company would need to explore alternative purchasing options to service its customers.

13. Amortization of Capital Assets

Total amortization of capital assets amounted to $1,080,564 for the year (2008 - $1,031,523). Transportation and communication equipment amortization of $128,464 (2008 - $143,960) has been expensed to operating lines where the equipment was used.

14. Related Party Transactions

The following table summarizes the company's related party transactions for the year:

	2009	2008
Revenue		
Other operating revenue received from Lakeland Energy Ltd.	$ 36,203	$ -
Other operating revenue received from Bracebridge Generation Ltd.	$ 25,192	$ 11,175
Expenses		
Purchase of electricity from Bracebridge Generation Ltd.	$ 2,045,456	$ 2,235,625
Management fees paid to Lakeland Holdings Ltd.	$ 651,585	$ 540,300
Information technology fees paid to Lakeland Energy Ltd.	$ 56,176	$ 58,353

These transactions are in the normal course of operations and are measured at the exchange value (the amount of consideration established and agreed to by the related parties), which approximates the arm's length equivalent value. Bracebridge Generation Ltd. (BGL), Lakeland Energy Ltd. (LEL) and Lakeland Power Distribution Ltd. (LPDL) are all wholly-owned subsidiaries of Lakeland Holding Ltd. (LHL) and are therefore, related by common control.

At the end of the year, amounts due from related parties are as follows and are included in sundry accounts receivable (Note 2):

	2009	2008
Accounts receivable from BGL	$ 7,440	$ 12,707
Accounts receivable from LEL	8,734	4,066
Accounts receivable from LHL	9,577	24,615
	$ 25,751	$ 41,388

At the end of the year, amounts due to related parties are as follows and are included in accounts payable and accrued liabilities (Note 8):

	2009	2008
Accounts payable to BGL	$ 214,629	$ 333,031
Accounts payable to LEL	23,275	38,485
Accounts payable to LHL	34,929	78,660
	$ 272,833	$ 450,176

During the year, Lakeland Power Distribution Ltd. purchased all of the electricity generated by Bracebridge Generation Ltd. on the same terms that it purchases electricity from third party suppliers.

December 31, 2009

15. Statement of Cash Flows Supplementary Information

During the year, the company paid (received) the following amounts in cash:

	2009	2008
Interest	$ 223,758	$ 186,640
Payments in lieu of income taxes paid	$ 190,940	$ 621,794
Payments in lieu of income taxes received	$ (325,770)	$ NIL

16. Capital Disclosures

The company defines its capital to be its long-term debt, share capital and retained earnings. The company's objective when managing its capital are:

- to safeguard its ability to continue as a going concern which will allow it to continue to service its customers
- to provide adequate returns to its shareholder
- to ensure ongoing access to funding to maintain and improve the electricity distribution system
- to ensure compliance with covenants related to its credit facilities.

Annual budgets are developed along with three year business plans and actual results are reviewed on a regular basis to monitor the company's capital and ensure it is maintained at an appropriate level. The company manages its capital structure and makes adjustments to it in light of changes in economic conditions. In order to maintain or adjust the capital structure, the company will adjust the amount of dividends paid to its shareholder. The company's externally imposed capital requirements consist of banking covenants related to its long-term debt (Note 9). One of the covenants limits the debt to 60% of the company's total capitalization.

There have been no changes in the company's capital management strategy in relation to the prior year.

17. Financial Instruments

i. Fair Values

The company's financial instruments are comprised of cash and cash equivalents, accounts receivable, short-term bank loan, accounts payable and accrued liabilities and long-term debt.

Cash and cash equivalents, accounts receivable, short-term bank loan and accounts payable and accrued liabilities are reported at their fair values on the balance sheet. The fair values are the same as the carrying values due to their short-term nature.

Fair value of long-term debt is the amount at which the instrument could be exchanged in a current transaction. In the past, the company has been able to renew its long-term debt at approximately prime less 0.7%. Given the current economic conditions, it is unlikely the long-term debt could be exchanged for prime less 0.7% and due to the volatility in the market place a current market rate is not determinable. For this reason, it is management's opinion that the fair value of long-term debt approximates the carrying value.

ii. Risks arising from financial instruments

Credit Risk

The company's cash is all held at a major institution. The company's credit risk associated with accounts receivable is related to payments from LDC customers. The company collects security deposits from customers in accordance with directions provided by the Ontario Energy Board. Current customer deposits total $203,166. In addition, the company holds credit risk insurance on all its commercial and industrial customers thereby minimizing its overall credit risk. The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the statement of operations. Subsequent recoveries of receivables previously provisioned are credited to the income statement.

At December 31, 2009, there were no significant concentrations of credit risk with respect to accounts receivable.

	2009	2008
Electrical energy	**$ 1,688,551**	$ 1,928,446
Allowance for doubtful accounts	**(24,131)**	(33,753)
Net from LDC customers (Note 2)	**1,664,420**	1,894,693
Of which:		
Outstanding for less than 30 days	**$ 1,634,022**	$ 1,875,262
Outstanding for 30 to 90 days	**29,498**	14,045
Outstanding for more than 90 days	**25,031**	39,139
Less: Allowance for doubtful accounts	**(24,131)**	(33,753)
	$ 1,664,420	$ 1,894,693

17. Financial Instruments (continued)

ii. Risks arising from financial instruments (continued)

Interest rate risk

The long-term debt bears fixed interest rates. Consequently, the long-term debt interest rate risk exposure is minimal.

Liquidity risk

The company manages its liquidity risk to ensure access to sufficient funds to meet operational needs. Liquidity risks are comprised of liabilities totaling $5,418,942 which are due within one year and long-term debt of $3,487,500 due between 3 and 4 years.

The company does not have commodity or foreign exchange risk.

18. Pension Plan

The company makes contributions to the Ontario Municipal Employees Retirement Fund (OMERS), which is a multi-employer plan, on behalf of substantially all full-time members of its staff. This plan is a defined benefit plan, which specifies the amount of the retirement benefit to be received by the employees based on the length of service and rates of pay. The Administration Corporation Board of Directors, representing plan members and employers, is responsible for overseeing the management of the pension plan, including investment of the assets and administration of the benefits. OMERS provides pension services to more than 390,000 active and retired members and approximately 921 employers.

Each year an independent actuary determines the funding status of OMERS Primary Pension Plan (the Plan) by comparing the actuarial value of invested assets to the estimated present value of all pension benefits that members have earned to date. The most recent actuarial valuation of the Plan was conducted at December 31, 2009. The results of this valuation disclosed total actuarial liabilities of $54,253 million in respect of benefits accrued for service with actuarial assets at that date of $52,734 million indicating an actuarial deficit of $1,519 million. Because OMERS is a multi-employer plan, any pension plan surpluses or deficits are a joint responsibility of Ontario municipal organizations and their employees. As a result, the company does not recognize any share of the OMERS pension surplus or deficit. Contributions made by the company to OMERS for 2009 was $61,375 (2008 - $56,432).

19. Comparative Figures

Certain comparative figures presented in the financial statements have been reclassified to conform to the presentation adopted for the current year.

Lakeland Power Distribution Ltd.
Schedule 1 - Other Revenues and Expenses

For the year ended December 31		2009		2008
Other Operating Revenue				
Late payment charges	$	108,675	$	125,130
Miscellaneous service revenues		101,803		68,400
Rent from electric property		108,777		86,044
	$	319,255	$	279,574
Administration and General Expense				
General and miscellaneous		877,037		803,845
Maintenance		128,537		99,494
Outside services		46,131		41,922
Regulatory expense		70,345		62,589
Rents		-		690
Salaries and related expenses		96,708		45,879
	$	1,218,758	$	1,054,419
Billing and Collecting Expense				
Collections	$	90,930	$	80,168
Retailer processing fees		36,776		64,316
Customer billing		274,051		249,853
Meter reading		116,926		119,263
Supervision		81,802		104,286
	$	600,485	$	617,886
Distribution Expense				
Maintenance	$	854,865	$	863,808
Operations		171,946		146,104
	$	1,026,811	$	1,009,912

Financial Statements

Lakeland Power Distribution Ltd.

December 31, 2010

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Grant Thornton

Independent Auditor's Report

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To the Directors of Lakeland Power Distribution Ltd.:

We have audited the accompanying financial statements of Lakeland Power Distribution Ltd., which comprise the balance sheet as at December 31, 2010, and the statement of earnings and retained earnings and cash flow statement for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Lakeland Power Distribution Ltd. as at December 31, 2010, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Other matter

The financial statements of Lakeland Power Distribution Ltd. for the year ended December 31, 2009, were audited by another auditor who expressed an unmodified opinion on those statements on February 24, 2010.

Grant Thornton LLP

Orillia, Canada
April 21, 2011

Chartered Accountants
Licensed Public Accountants

Lakeland Power Distribution Ltd.
Statements of Earnings and Retained Earnings

Year Ended December 31		2010		2009
Revenue	$	21,711,431	$	20,652,106
Power Purchased		17,170,452		16,319,947
		4,540,979		4,332,159
Other revenues				
Investment income		22,433		36,587
Gain on disposal of property and equipment		13,275		14,274
Other income		423,417		397,628
		5,000,104		4,780,648
Expenses				
Administration and general		1,334,598		1,218,758
Amortization (Note 12)		965,503		952,100
Billing and collecting		680,266		600,485
Operations and maintenance		959,009		1,051,725
Interest		209,252		223,758
Payments in lieu of capital tax		5,816		14,733
Taxes other than income taxes		10,549		10,065
		4,164,993		4,071,624
Earnings before payments in lieu of income taxes		835,111		709,024
Payments in lieu of income taxes (Note 7)		47,031		375,396
Net earnings	$	788,080	$	333,628

Retained earnings, beginning of year, as previously reported	$	1,852,847	$	600,683
Change in accounting policy, future income tax		-		918,536
		1,852,847		1,519,219
Net earnings		788,080		333,628
Retained earnings, end of year	$	2,640,927	$	1,852,847

See accompanying notes to the Financial Statements.

Lakeland Power Distribution Ltd.
Balance Sheet

December 31		2010		2009
Assets				
Current				
Receivables	$	**2,237,193**	$	1,836,926
Unbilled revenue		**2,355,046**		2,662,505
Inventory		**238,322**		262,181
Prepaids		**160,818**		150,006
Payments in lieu of income taxes recoverable		**15,651**		-
		5,007,030		4,911,618
Property and equipment (Note 4)		**13,385,931**		12,537,416
Intangible assets (Note 5)		**540,138**		517,866
Regulatory assets (Note 6)		**2,178,990**		2,046,327
Future income tax assets (Note 7)		**917,600**		757,631
	$	**22,029,689**	$	20,770,858
Liabilities and shareholders' equity				
Current				
Bank indebtedness (Note 8)	$	**767,371**	$	1,154,186
Payables and accruals		**5,055,002**		4,119,819
Payment in lieu of income taxes payable		**-**		38,304
		5,822,373		5,312,309
Long-term debt (Note 9)		**3,487,500**		3,487,500
Regulatory liabilities (Note 6)		**588,778**		665,149
Customer deposits		**240,224**		203,166
Other non-current liabilities		**23,100**		23,100
		10,161,975		9,691,224
Shareholder's equity				
Share capital (Note 11)		**9,226,787**		9,226,787
Retained earnings		**2,640,927**		1,852,847
		11,867,714		11,079,634
	$	**22,029,689**	$	20,770,858

Contingent liabilities (Note 10)

On behalf of the Board

_______________ Director _______________ Director

See accompanying notes to the Financial Statements

Lakeland Power Distribution Ltd.
Consolidated Statement of Cash Flows

Year Ended December 31	2010	2009
Increase (decrease) in cash and cash equivalents		
Operating activities		
Net earnings	$ **788,080**	$ 333,628
Amortization (Note 12)	**1,085,796**	1,080,564
Future (recovery) payments in lieu of income taxes	**(159,969)**	160,905
Gain on disposal of property and equipment	**(13,274)**	(14,274)
	1,700,633	1,560,823
Change in non-operating working capital		
Receivables	**(400,267)**	121,585
Unbilled revenue	**307,459**	(597,509)
Inventory	**23,859**	2,209
Prepaids	**(10,812)**	(48,771)
Payables and accruals	**935,187**	984,017
Payments in lieu of corporate taxes recoverable	**(53,955)**	364,091
	2,502,104	2,386,445
Customer deposits	**37,058**	(9,071)
Regulatory assets and liabilities	**(209,034)**	(1,312,122)
	2,330,128	1,065,252
Investing activities		
Proceeds from sale of property and equipment	**25,299**	30,000
Purchase of property and equipment	**(2,487,568)**	(2,119,998)
Contributions received in aid of construction	**560,961**	346,183
Acquisition of intangible assets	**(42,005)**	(6,720)
	(1,943,313)	(1,750,535)
Increase (decrease) in cash and cash equivalents	**386,815**	(685,283)
Cash and cash equivalents, beginning of year	**(1,154,186)**	(468,903)
Cash and cash equivalents, end of year	$ **(767,371)**	$ (1,154,186)

See accompanying notes to the Financial Statements.

1. Nature of operations

The Company is incorporated under the laws of Ontario and operates as a local distribution company distributing hydro electric power to users in Bracebridge, Huntsville, Sundridge, Burk's Falls and Magnetawan, Ontario. The Company distributes electricity under license from the Ontario Energy Board (OEB).

2. Summary of significant accounting policies

a) Cash and cash equivalents

Cash and cash equivalents consist of cash on hand, bank balances and bank indebtedness.

b) Inventory

Inventory consists of repair parts, supplies and materials and is stated at the lower of average cost and net realizable value. Costs include all direct costs plus any related shipping and freight costs. Net realizable value is the estimated selling price in the ordinary course of business less any applicable selling expenses. The Company classifies rebates received from vendors as a reduction to the cost of inventory. Amount of inventory expensed during the year was $ 287,288 (2009-$188,782)

c) Property and equipment

Property and equipment are recorded at cost less accumulated amortization, which includes internal labour and allocated overhead. Stranded meters have been taken out of service and are no longer being amortized. Amortization is provided on the straight line basis over the estimated useful life of the assets as follows:

Distribution plant	
Buildings and fixtures	30 & 50 years
Conductors and devices	25 years
Distribution station equipment	25 years
Line transformers	25 years
Meters	25 years
New services distribution	25 years
Poles, towers and fixtures	25 years
Underground conduits	25 years
General plant	
Building and fixtures	30 & 50 years
Communication equipment	10 years
Computer hardware	5 years
Office furniture and equipment	10 years
Stores equipment	10 years

2. Summary of significant accounting policies (continued)

c) Property and equipment (continued)

General plant (continued)

Tools and garage equipment	10 years
Transportation equipment	5 & 8 years

d) Contributions in aid of construction

Certain property and equipment may be acquired or constructed with financial assistance in the form of non-refundable contributions from customers. These contributions are netted against property and equipment and amortized on the same basis as the property and equipment to which they relate.

e) Impairment of long-lived assets

The Company tests for impairment loss of long-lived assets whenever events or changes in circumstances occur, which may cause their carrying value to exceed the total undiscounted cash flows expected from their use and eventual disposition. An impairment loss, if any, is determined as the excess of the carrying value of the asset over its fair value.

f) Property and equipment retirement obligations

Canadian generally accepted accounting principles require the Company to determine the fair value of the future expenditures required to settle legal obligations to remove property and equipment on retirement. If reasonably estimable, a liability is recognized equal to the present value of the estimated future removal expenditures. An equivalent amount is capitalized as an inherent cost of the associated property and equipment.

Some of the Company's assets may have asset retirement obligations. As the Company expects to use the majority of its property and equipment for an indefinite period, no removal date can be determined and, consequently, a reasonable estimate of the fair value of any asset retirement obligations has not been made at this time.

g) Intangible assets

Intangible assets consists of land rights and computer software, which are recorded at cost less accumulated amortization and are amortized over the useful life of the asset. Computer software is amortized on a straight line basis over 5 years and land rights have an indefinite life. Land rights are tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset might be impaired. The impairment test consists of a comparison of the fair value of the intangible asset with its carrying amount.

2. Summary of significant accounting policies (continued)

h) Regulatory assets and liabilities

The rates of the Company's electricity transmission and distribution businesses are subject to regulation by the Ontario Energy Board (OEB). The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets and liabilities that will be settled in future rates to customers.

Specific regulatory assets are described below and disclosed in (Note 6).

Smart meters

This amount consists of the net balance of capital and operating expenditures for smart meters, less recoveries received from the rate adder charged to customers.

Retail settlement variance accounts

These accounts reflect the difference between the cost of electricity and the amounts billed to consumers that have not yet been approved for recovery.

Regulatory assets approved for recovery

These assets have been approved for recovery by the OEB and are currently included in rates being charged to the customers.

i) Income taxes

Under the Electricity Act, 1998, the Company is required to make payments in lieu of income taxes to Ontario electricity Financial Corporation (OEFC). These payments are calculated in accordance with rules contained in the Income Tax Act, as modified by the electricity Act, 1998, and related regulations.

The Company follows the asset and liability method of accounting for payments in lieu of income taxes (PILs). Under this method, current PILs are recognized for the estimated PILs payable (receivable) for the current year. Future PILs assets and liabilities are recognized for temporary differences between the tax and accounting bases of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes, that are likely to be realized. Future PILs are measured using enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled.

2. Summary of significant accounting policies (continued)

i) Income taxes (continued)

Future payments in lieu of income taxes

Effective January 1, 2009, the amendments to Section 3465 required rate-regulated enterprises to recognize future income tax liabilities and assets. Entities in this sector were previously exempted from the requirement to recognize future income taxes. The Company adopted this new accounting recommendation in the prior year by making a cumulative catch-up adjustment of $918,536 to the 2009 opening retained earnings.

j) Revenue recognition

Revenue is recognized, as power is transmitted and delivered to customers. Revenue is recognized on the accrual basis, which includes an estimate of electricity consumed by customers in the year, but billed subsequent to year end. This revenue is recorded as unbilled revenue.

Contracted service revenue is recognized under the completed contract method, whereby contract revenue billed and the related contract expenses are deferred until substantial completion of the contract. If losses are anticipated on contracts prior to substantial completion, full provision is made for such losses.

Cash received in advance of meeting the revenue recognition criteria described above, is recorded as customer deposits.

Other revenue and investment income are recognized as revenue when they are earned. Gain on disposal of property and equipment is recognized when property and equipment is sold in excess of carrying cost of the assets corresponding net book value.

k) Pension plan

The Company is an employer member of the Ontario Municipal Employees Retirement System (OMERS), which is a multi-employer, defined benefit pension plan. The OMERS Board of Trustees, representing plan members and employers, is responsible for overseeing the management of the pension plan, including investment of the assets and administration of the benefits. The Company has adopted defined contribution plan accounting principles for this plan because insufficient information is available to apply defined benefit plan accounting principles. The Company recognizes the expense related to this plan as contributions are made. Contributions made by the Company to OMERS was $75,150 (2009 - $61,375).

2. Summary of significant accounting policies (continued)

l) Use of estimates

The preparation of financial statements 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 disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. These estimates and assumptions are based on management's historical experience, best knowledge of current events and actions that the Company may undertake in the future. Significant accounting estimates include allowance for doubtful accounts, unbilled revenue, inventory obsolescence, estimated useful lives of property and equipment and remaining recovery (settlement) period for regulated assets (liabilities). Actual results could differ from those estimates.

m) Financial instruments

i) Financial instrument categories

The Company classifies its financial instruments into one of the following categories, based on the purpose for which the asset was acquired. The fair value of these financial instruments approximates their carrying values, unless otherwise noted. The Company's accounting policy for each category is as follows:

Assets or liabilities held-for-trading
Cash and cash equivalents have been classified as "held-for-trading". They are reported at fair value at each balance sheet date, and any change in fair value is recognized in net income in the period during which the change occurs. Transaction costs are expensed when incurred.

Loans and receivables
Receivables are classified under "loans and receivables". They are recorded at cost, which, upon their initial measurement, is equal to their fair value. Subsequent measurements of accounts receivable are recorded at amortized cost which usually corresponds to the amount initially recorded less any allowance for doubtful accounts.

Other financial liabilities
Bank indebtedness, payables and accruals and long term debt are classified as "other financial liabilities". They are initially measured at fair value and the gains and losses resulting from their subsequent measurement at amortized cost, at the end of each period, are recognized in net income.

2. Summary of significant accounting policies (continued)

m) Financial instruments (continued)

ii) Risks arising from financial instruments

Credit risk
The Company's cash is all held at a major institution. The Company's credit risk associated with accounts receivable is related to payments from LDC customers. The Company collects security deposits from customers in accordance with directions provided by the Ontario Energy Board. Current customer deposits total $240,224 (2009 - $203,166). In addition, the Company holds credit risk insurance on all its commercial and industrial customers thereby minimizing its overall credit risk. The carrying amount of receivables is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the statement of operations. Subsequent recoveries of receivables previously provisioned are credited to the statement of operations.

Interest rate risk
The long-term debt bears fixed interest rates. Consequently, the long-term interest rate risk exposure is minimal. The bank indebtedness bear interest at floating rates which gives rise to a risk that the Company's income (loss) and cash flows may be adversely impacted by fluctuations in interest rates.

Liquidity risk
The Company manages its liquidity risk to ensure access to sufficient funds to meet operational needs. Liquidity risks are comprised of liabilities totaling $5,822,373 which are due within one year and long-term debt of $3,487,500 due by March 2013.

3. New accounting pronouncements

International financial reporting standards (IFRS)

In 2008, the Canadian Accounting Standards Board (AcSB) confirmed that the adoption of IFRS would be effective for interim and annual periods beginning on or after January 1, 2011 for Canadian publicly accountable profit-oriented enterprises. In September 2010, the AcSB decided to permit rate regulated entities to defer their IFRS implementation date to January 1, 2012. IFRS will replace Canada's current GAAP for these enterprises upon adoption. Comparative IFRS information for the previous fiscal year will also have to be reported. As such, the Company will apply IFRS to its financial statements ending December 31, 2012.

The Company is currently in the process of evaluating the potential impact of IFRS on the future financial statements. This will be an ongoing process. The financial statements as disclosed under current GAAP may be significantly different when presented in accordance with IFRS.

Lakeland Power Distribution Ltd.
Notes to the Financial Statements
December 31, 2010

3. New accounting pronouncements (continued)

One area that is expected to change will be that regulatory assets and liabilities will not be permitted for separate treatment under IFRS. This would have resulted in an increase of earnings of $53,641 (2009 - $(262,899)), and increase of property and equipment of $244,995 (2009 - $1,575,023).

4. Property and equipment

	2010 Asset Cost	2010 Accumulated Amortization	2009 Asset Cost	2009 Accumulated Amortization
Distribution Plant				
Buildings and fixtures	$ 652,936	$ 135,437	$ 604,107	$ 118,978
Conductors and devices	4,820,122	1,354,596	4,410,201	1,166,166
Distribution station equipment	3,174,761	745,212	2,646,844	611,696
Line transformers	5,520,518	1,979,831	4,940,860	1,713,081
Meters	193,262	49,747	1,114,044	462,922
Stranded meters	1,006,849	419,887	-	-
New services distribution	484,652	101,164	410,854	83,255
Poles, towers and fixtures	5,556,074	2,579,897	5,345,524	2,305,534
Underground conduits	3,036,781	1,350,576	2,937,369	1,214,512
	24,445,955	8,716,347	22,409,803	7,676,144
General Plant				
Land	278,455	-	278,455	-
Buildings and fixtures	174,386	45,062	176,006	35,395
Communication equipment	188,721	114,459	188,721	99,914
Computer hardware	360,301	319,252	357,391	292,114
Office furniture and equipment	166,164	115,135	166,164	103,264
Store equipment	10,960	7,756	10,960	6,936
Tools and garage equipment	238,014	157,183	235,440	141,061
Transportation equipment	1,175,512	640,551	1,058,226	582,131
	2,592,513	1,399,398	2,471,363	1,260,815
Construction in progress	255,271	-	-	-
	27,293,739	10,115,745	24,881,166	8,936,959
Less contributions in aid of construction	4,672,796	880,733	4,111,835	705,044
	$ 22,620,943	$ 9,235,012	$ 20,769,331	$ 8,231,915
		$ 13,385,931		$ 12,537,416

5. Intangible assets

	2010		2009	
	Asset Cost	**Accumulated Amortization**	Asset Cost	Accumulated Amortization
Land rights	**$ 493,354**	**$ 15,147**	$ 484,365	$ 15,147
Computer software	**202,603**	**140,672**	169,588	120,940
	$ 695,957	**$ 155,819**	$ 653,953	$ 136,087
		$ 540,138		$ 517,866

6. Regulatory assets and liabilities

	2010	2009
Regulatory assets		
Smart meters	**$ 1,965,730**	$ 1,636,883
Regulatory assets approved for recovery	**213,260**	409,444
	$ 2,178,990	$ 2,046,327
Regulatory liabilities		
Other	**200,081**	231,157
Retail settlement variances	**388,697**	433,992
	$ 588,778	$ 665,149

7. Future income tax assets

Future income tax assets, which arise from differences between the carrying amounts and tax bases of the Company's assets, are as follows:

	2010	2009
Future income tax assets		
Regulatory assets and liabilities	**$ (87,000)**	$ -
Difference of tax basis of property and equipment and intangibles from the carrying value	**1,004,600**	757,631
	$ 917,600	$ 757,631
Payments in lieu of income taxes:		
Current payments in lieu of income taxes	**$ 207,000**	$ 214,491
Future payments (recovery) in lieu of income taxes	**(159,969)**	160,905
	$ 47,031	$ 375,396

8. Bank indebtedness

The revolving facility available to the Company is with a Chartered bank to assist with working capital requirements. Funds available on the facility are up to $3,000,000 and interest is at the bank's prime lending rate.

Security for the revolving facility is provided by a General Security Agreement with the TD bank, a floating and fixed charge over all assets and evidence of adequate liability insurance.

The agreement covering the above facility contains certain restrictions regarding interest coverage and debt capitalization tests, which have been met.

9. Long-term debt

	2010	2009
Chartered bank term loan, payments of interest only only, payable monthly at 5.41% due March 2013	$ 1,162,500	$ 1,162,500
Chartered bank term loan, payments of interest only, payable monthly at 5.03%, due March 2012	2,325,000	2,325,000
	$ 3,487,500	$ 3,487,500

Security for chartered bank term loans is provided by a General Security Agreement with the TD Bank, conveying a first floating and fixed charge over all assets and evidence of adequate liability insurance.

The agreement covering the above facility contains certain restrictions regarding interest coverage and debt capitalization tests, which have been met.

10. Contingent liability

Environmental contingency
On September 17, 2008, Environment Canada published its final regulations governing the management, storage and disposal of PCBs by 2014. The regulations impose timelines for disposal of PCBs based on certain criteria. It is management's plan to have all affected assets tested and removed by the end of 2011 to be in compliance with government requirements. No accrual has been reflected in these financial statements as these costs have not yet been determined.

11. Share capital

		2010	2009
Authorized			
Unlimited	Common shares		
Issued			
7,428	Common shares	$ 9,226,787	$ 9,226,787

12. Amortization of property and equipment

The amortization of property and equipment amounted to $1,085,796 for the year (2009 - $1,080,564). The statement of earnings reflects $965,503 (2009 - $952,100) because the transportation and communication equipment amortization of $120,293 (2009 - $128,464) has been allocated to operating lines where the equipment was used. In 2010, $41,038 was capitalized in property and equipment, $4,240 was allocated to smart meters in regulatory assets, and $75,015 was expensed in other accounts.

13. Related party transactions

These transactions are in the normal course of operations and are measured at the exchange value (the amount of consideration established and agreed to by the related parties) which approximates the arm's length equivalent value. Bracebridge Generation Ltd. (BGL), Lakeland Energy Ltd. (LEL) and Lakeland Power Distribution Ltd. (LPDL) are all wholly-owned subsidiaries of Lakeland Holding Ltd. (LHL) and are therefore, related by common control. During the year, Lakeland Power Distribution Ltd. purchased all of the electricity generated by Bracebridge Generation Ltd. on the same terms that it purchases electricity from third party suppliers.

The following table summarizes the Company's related party transactions for the year:

		2010		2009
Lakeland Energy Ltd.				
Other operating revenue received	$	**13,707**	$	36,203
Information technology expenses, in adminstration and general		**166,027**		56,176
Communication expenses, in adminstration and general		**13,860**		-
Other operating and maintenance		**94,304**		-
Bracebridge Generation Ltd				
Other operating revenue	$	**22,404**	$	25,192
Cash proceeds on disposal of property and equpment		**12,025**		-
Power purchased		**2,128,851**		2,045,456
Other operating and maintenance expenses		**330**		-
Lakeland Holdings Limited				
Management fees paid, in adminstration and general	$	**698,341**	$	651,585
Shareholders of Lakeland Holdings Ltd, the parent company				
Purchases				
Town of Bracebridge	$	29,111	$	11,545
Town of Huntsville		4,398		4,555

13. Related party transactions (continued)

Sales				
Town of Bracebridge	$	1,116,256	$	966,397
Town of Huntsville		595,439		301,038
Village of Burk's Falls		107,652		117,476
Village of Sundridge		104,660		104,417
Municipality of Magnetawan		27,812		24,403

At the end of the year, amounts due from/to related parties are as follows and are included in receivables and payables and accruals:

		2010		2009
Accounts receivable from BGL	$	**19,167**	$	7,440
Accounts receivable from LEL		**12,211**		8,734
Accounts receivable from LHL		**22,195**		9,577
	$	**53,572**	$	25,751
Account payable to BGL	$	**246,502**	$	214,629
Accounts payable to LEL		**29,639**		23,275
Accounts payable to LHL		**49,705**		34,929
	$	**325,846**	$	272,833

14. Statement of cash flows supplementary information

During the year, the Company paid (received) the following amounts in cash:

		2010		2009
Interest received	$	**22,433**	$	36,587
Interest paid	$	**209,252**	$	223,758
Payments in lieu of income taxes	$	**268,960**	$	190,940
Refunds received in lieu of income taxes	$	**(2,209)**	$	(325,770)

15. Capital disclosures

The Company defines its capital to be its long-term debt, share capital and retained earnings. The Company's objectives when managing its capital are:

- To safeguard its ability to continue as a going concern which will allow it to continue to service its customers
- To provide adequate returns to its shareholder
- To ensure ongoing access to funding to maintain and improve the electricity distribution system
- To ensure compliance with covenants related to its credit facilities.

Annual budgets are developed along with three year business plans and actual results are reviewed on a regular basis to monitor the Company's capital and ensure it is maintained at an appropriate level. The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions. In order to maintain or adjust the capital structure, the Company will adjust the amount of dividends paid to its shareholders. The Company's externally imposed capital requirements consist of banking covenants related to its long-term debt and bank indebtedness (Notes 8 and 9). One of the covenants limits the debt to 60% of the Company's total capitalization.

There have been no changes in the Company's capital management strategy in relation to the prior year.

16. Comparative figures

Certain comparative figures presented in the financial statements have been reclassified to conform to the presentation adopted for the current year.

LakelandPower

Financial Statements

Lakeland Power Distribution Ltd.

December 31, 2011

Contents

Grant Thornton

Independent Auditor's Report

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To the Directors of Lakeland Power Distribution Ltd.:

We have audited the accompanying financial statements of Lakeland Power Distribution Ltd., which comprise the balance sheet as at December 31, 2011, and the statement of earnings and retained earnings and cash flow statement for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Lakeland Power Distribution Ltd. as at December 31, 2011, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Grant Thornton LLP

Orillia, Canada
April 26, 2012

Chartered Accountants
Licensed Public Accountants

Lakeland Power Distribution Ltd.
Statements of Earnings and Retained Earnings

Year Ended December 31	2011	2010
Revenue	$ 23,155,056	$ 21,711,431
Power Purchased	18,600,838	17,170,452
	4,554,218	4,540,979
Other revenues		
Investment income	48,188	22,433
Gain on disposal of property and equipment	-	13,275
Late payment/Collection charges	148,522	168,252
Utility service revenue	168,041	187,031
Non-utility service revenue	48,796	68,134
	4,967,765	5,000,104
Expenses		
Administration and general	1,243,836	1,334,598
Amortization (Note 12)	1,033,587	965,503
Billing and collecting	606,599	680,266
Operations and maintenance	980,306	959,009
Interest	266,615	209,252
Payments in lieu of capital tax	32	5,816
Taxes other than income taxes	9,773	10,549
	4,140,748	4,164,993
Earnings before payments in lieu of income taxes	827,017	835,111
Payments in lieu of income taxes (Note 7)		
Current-Payments In Lieu of income taxes (PILs)	190,548	207,000
Future-Payments In Lieu of income taxes (PILs)	(50,000)	(159,969)
	140,548	47,031
Net earnings	$ 686,469	$ 788,080

Retained earnings, beginning of year	$ 2,640,927	$ 1,852,847
Net earnings	686,469	788,080
Retained earnings, end of year	$ 3,327,396	$ 2,640,927

See accompanying notes to the financial statements.

Lakeland Power Distribution Ltd.
Balance Sheet

December 31	2011	2010
Assets		
Current		
Receivables	$ **2,681,536**	$ 2,183,621
Intercompany receivables (Note 13)	**86,442**	53,572
Unbilled revenue	**2,262,157**	2,355,046
Inventory	**184,200**	238,322
Prepaids	**173,632**	160,818
Payments in lieu of income taxes (PILs) recoverable	**32,615**	15,651
	5,420,582	5,007,030
Property and equipment (Note 4)	**14,376,167**	13,385,930
Intangible assets (Note 5)	**602,840**	540,139
Regulatory assets (Note 6)	**2,576,365**	2,178,990
Future income tax assets (Note 7)	**967,600**	917,600
	$ **23,943,554**	$ 22,029,689
Liabilities		
Current		
Bank indebtedness (Note 8)	$ **1,338,359**	$ 767,371
Payables and accruals	**5,218,222**	4,742,485
Intercompany payables (Note 13)	**994,700**	312,517
	7,551,281	5,822,373
Long-term debt (Note 9)	**3,487,500**	3,487,500
Regulatory liabilities (Note 6)	**121,681**	588,778
Customer deposits	**205,809**	240,224
Other non-current liabilities	**23,100**	23,100
	11,389,371	10,161,975
Shareholder's equity		
Share capital (Note 11)	**9,226,787**	9,226,787
Retained earnings	**3,327,396**	2,640,927
	12,554,183	11,867,714
	$ **23,943,554**	$ 22,029,689

Contingent liability (Note 10)

On behalf of the Board

T. Peggett _______ Director   P B Matthews _______ Director

See accompanying notes to the financial statements

Lakeland Power Distribution Ltd.
Consolidated Statement of Cash Flows

Year Ended December 31	2011	2010
Increase (decrease) in cash and cash equivalents		
Operating activities		
Net earnings	$ 686,469	$ 788,080
Amortization (Note 12)	1,157,908	1,085,796
Future recovery of payments in lieu of income taxes (Note 7)	(50,000)	(159,969)
Gain on disposal of property and equipment	-	(13,274)
	1,794,377	1,700,633
Change in non-cash working capital		
Receivables	(530,785)	(400,267)
Unbilled revenue	92,889	307,459
Inventory	54,122	23,859
Prepaids	(12,814)	(10,812)
Payables and accruals	1,157,920	935,187
Payments in lieu of income taxes recoverable	(16,964)	(53,955)
	2,538,745	2,502,104
Customer deposits	(34,415)	37,058
Regulatory assets and liabilities	(864,472)	(209,034)
	1,639,858	2,330,128
Investing activities		
Proceeds from sale of property and equipment		25,299
Purchase of property and equipment	(2,446,533)	(2,487,568)
Contributions received in aid of construction	324,442	560,961
Acquisition of intangible assets	(88,755)	(42,005)
	(2,210,846)	(1,943,313)
(Decrease) increase in cash and cash equivalents	(570,988)	386,815
Cash and cash equivalents, beginning of year	(767,371)	(1,154,186)
Cash and cash equivalents, end of year	$ (1,338,359)	$ (767,371)

See accompanying notes to the financial statements.

1. Nature of operations

The Company is incorporated under the laws of Ontario and operates as a local distribution company distributing hydro electric power to users in Bracebridge, Huntsville, Sundridge, Burk's Falls and Magnetawan, Ontario. The Company distributes electricity under license from the Ontario Energy Board (OEB).

2. Summary of significant accounting policies

a) Cash and cash equivalents

Cash and cash equivalents consist of cash on hand, bank balances and bank indebtedness.

b) Inventory

Inventory consists of repair parts, supplies and materials and is stated at the lower of average cost and net realizable value. Costs include all direct costs plus any related shipping and freight costs. Net realizable value is the estimated selling price in the ordinary course of business less any applicable selling expenses. The Company classifies rebates received from vendors as a reduction to the cost of inventory. Amount of inventory expensed during the year was $ 295,823 (2010-$287,288)

c) Property and equipment

Property and equipment are recorded at cost less accumulated amortization, which includes internal labour and allocated overhead. Stranded meters have been taken out of service and are no longer being amortized. Amortization is provided on the straight line basis over the estimated useful life of the assets as follows:

<u>Distribution plant</u>	
Buildings and fixtures	30 & 50 years
Conductors and devices	25 years
Distribution station equipment	25 years
Line transformers	25 years
Meters	25 years
New services distribution	25 years
Poles, towers and fixtures	25 years
Underground conduits	25 years
<u>General plant</u>	
Building and fixtures	30 & 50 years
Communication equipment	10 years
Computer hardware	5 years
Office furniture and equipment	10 years
Stores equipment	10 years

2. Summary of significant accounting policies (continued)

c) Property and equipment (continued)

General plant (continued)

Tools and garage equipment	10 years
Transportation equipment	5 & 8 years

d) Contributions in aid of construction

Certain property and equipment may be acquired or constructed with financial assistance in the form of non-refundable contributions from customers. These contributions are netted against property and equipment and amortized on the same basis as the property and equipment to which they relate.

e) Impairment of long-lived assets

The Company tests for impairment loss of long-lived assets whenever events or changes in circumstances occur, which may cause their carrying value to exceed the total undiscounted cash flows expected from their use and eventual disposition. An impairment loss, if any, is determined as the excess of the carrying value of the asset over its fair value.

f) Property and equipment retirement obligations

Canadian generally accepted accounting principles require the Company to determine the fair value of the future expenditures required to settle legal obligations to remove property and equipment on retirement. If reasonably estimable, a liability is recognized equal to the present value of the estimated future removal expenditures. An equivalent amount is capitalized as an inherent cost of the associated property and equipment.

Some of the Company's assets may have asset retirement obligations. As the Company expects to use the majority of its property and equipment for an indefinite period, no removal date can be determined and, consequently, a reasonable estimate of the fair value of any asset retirement obligations has not been made at this time.

g) Intangible assets

Intangible assets consists of land rights and computer software, which are recorded at cost less accumulated amortization and are amortized over the useful life of the asset. Computer software is amortized on a straight line basis over 5 years and land rights have an indefinite life. Land rights are tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset might be impaired. The impairment test consists of a comparison of the fair value of the intangible asset with its carrying amount and no impairment has been recorded to date.

2. Summary of significant accounting policies (continued)

h) Regulatory assets and liabilities

The rates of the Company's electricity transmission and distribution businesses are subject to regulation by the Ontario Energy Board (OEB). The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets and liabilities that management believes will be settled in future rates to customers.

Specific regulatory assets and liabilities are described below and disclosed in Note 6.

Smart meters

This amount consists of the net balance of capital and operating expenditures for smart meters, less recoveries received from the rate adder charged to customers.

Retail settlement variance accounts

These accounts reflect the difference between the cost of electricity and the amounts billed to consumers that have not yet been approved for recovery.

Renewable generation

These assets relate to the Green Energy Act with the distributor being responsible for the cost of expansion up to the value of the generators renewable energy expansion cost of $90,000 per MW generation capacity. These amounts have not yet been submitted for recovery.

Regulatory assets and liabilities approved for recovery

These assets and liabilities have been approved for recovery by the OEB and are currently included in rates being charged to the customers.

i) Income taxes

Under the Electricity Act, 1998, the Company is required to make payments in lieu of income taxes to Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with rules contained in the Income Tax Act, as modified by the electricity Act, 1998, and related regulations.

2. Summary of significant accounting policies (continued)

i) Income taxes (continued)

The Company follows the asset and liability method of accounting for payments in lieu of income taxes (PILs). Under this method, current PILs are recognized for the estimated PILs payable (receivable) for the current year. Future PILs assets and liabilities are recognized for temporary differences between the tax and accounting bases of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes, that are likely to be realized. Future PILs are measured using enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled.

j) Revenue recognition

Revenue is recognized, as power is transmitted and delivered to customers. Revenue is recognized on the accrual basis, which includes an estimate of electricity consumed by customers in the year, but billed subsequent to year end. This revenue is recorded as unbilled revenue.

Utility service revenue on customer owned property is recognized under the completed contract method, whereby contract revenue billed and the related contract expenses are deferred until substantial completion of the contract. If losses are anticipated on contracts prior to substantial completion, full provision is made for such losses

Gain on disposal of property and equipment is recognized when property and equipment is sold in excess of carrying cost of the asset's corresponding net book value.

Investment, late payment and other income are recognized as revenue when they are earned. Carrying charges on Regulatory Assets, at prescribed interest rates by the Ontario Energy Board, are also included in investment income.

k) Pension plan

The Company is an employer member of the Ontario Municipal Employees Retirement System (OMERS), which is a multi-employer, defined benefit pension plan. The OMERS Board of Trustees, representing plan members and employers, is responsible for overseeing the management of the pension plan, including investment of the assets and administration of the benefits. The Company has adopted defined contribution plan accounting principles for this plan because insufficient information is available to apply defined benefit plan accounting principles. The Company recognizes the expense related to this plan as contributions are made. The required contributions made by the Company to OMERS was $83,900 (2010 - $75,150).

2. Summary of significant accounting policies (continued)

l) Use of estimates

The preparation of financial statements 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 disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. These estimates and assumptions are based on management's historical experience, best knowledge of current events and actions that the Company may undertake in the future. Significant accounting estimates include allowance for doubtful accounts, unbilled revenue, inventory obsolescence, estimated useful lives of property and equipment and remaining recovery (settlement) period for regulated assets (liabilities). Actual results could differ from those estimates.

m) Financial instruments

i) Financial instrument categories

The Company classifies its financial instruments into one of the following categories, based on the purpose for which the asset was acquired. The fair value of these financial instruments approximates their carrying values, unless otherwise noted. The Company's accounting policy for each category is as follows:

Assets or liabilities held-for-trading
Cash and cash equivalents have been classified as "held-for-trading". They are reported at fair value at each balance sheet date, and any change in fair value is recognized in net income in the period during which the change occurs. Transaction costs are expensed when incurred.

Loans and receivables
Receivables and unbilled revenue are classified under "loans and receivables". They are recorded at cost, which, upon their initial measurement, is equal to their fair value. Subsequent measurements of receivables are recorded at amortized cost which usually corresponds to the amount initially recorded less any allowance for doubtful accounts.

Other financial liabilities
Bank indebtedness, payables and accruals and long term debt are classified as "other financial liabilities". They are initially measured at fair value and the gains and losses resulting from their subsequent measurement at amortized cost, at the end of each period, are recognized in net income.

2. Summary of significant accounting policies (continued)

m) Financial instruments (continued)

ii) Risks arising from financial instruments

Credit risk
The Company's cash is all held at The Toronto-Dominion Bank (TD Bank). The Company's credit risk associated with accounts receivable is related to payments from LDC customers. The Company collects security deposits from customers in accordance with directions provided by the Ontario Energy Board. Current customer deposits total $205,809 (2010 - $240,224). In addition, the Company holds credit risk insurance on all its commercial and industrial customers thereby minimizing its overall credit risk. The carrying amount of receivables is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the statement of operations. Subsequent recoveries of receivables previously provisioned are credited to the statement of operations.

Interest rate risk
The long-term debt bears fixed interest rates. Consequently, the long-term interest rate risk exposure is minimal. The bank indebtedness bear interest at floating rates which gives rise to a risk that the Company's future income (loss) and cash flows may be adversely impacted by fluctuations in interest rates.

Liquidity risk
The Company manages its liquidity risk to ensure access to sufficient funds to meet operational needs. Liquidity risks are comprised of liabilities totaling $7,551,281 which are due within one year and long-term debt of $3,487,500 due by March 2013.

3. New accounting pronouncements

International financial reporting standards (IFRS)

In 2008, the Canadian Accounting Standards Board (AcSB) confirmed that the adoption of IFRS would be effective for interim and annual periods beginning on or after January 1, 2012 for Canadian publicly accountable profit-oriented enterprises. In September 2010, the AcSB decided to permit rate regulated entities to defer their IFRS implementation date to January 1, 2013. IFRS will replace Canada's current GAAP for these enterprises upon adoption. Comparative IFRS information for the previous fiscal year will also have to be reported. As such, the Company will apply IFRS to its financial statements ending December 31, 2013.

The Company is currently in the process of evaluating the potential impact of IFRS on the future financial statements. This will be an ongoing process. The financial statements as disclosed under current GAAP may be significantly different when presented in accordance with IFRS.

3. New accounting pronouncements (continued)

One area that is expected to change will be regulatory assets and liabilities will not be permitted for separate balance sheet treatment under IFRS. If these items don't qualify as assets or liabilities under IFRS they will be recorded on the statement of earnings. This would have resulted in increased of earnings of $156,992 (2010 - $53,641), and an increase of property and equipment of $320,053 (2010 - $244,995).

4. Property and equipment

	2011		2010	
	Asset Cost	**Accumulated Amortization**	Asset Cost	Accumulated Amortization
Distribution Plant				
Buildings and fixtures	$ 1,840,984	$ 176,034	$ 652,936	$ 135,437
Conductors and devices	5,246,219	1,559,747	4,820,122	1,354,596
Distribution station equipment	3,222,714	890,246	3,174,761	745,212
Line transformers	5,913,575	2,266,034	5,520,518	1,979,831
Meters	266,941	59,653	193,262	49,747
Stranded meters	1,006,849	419,887	1,006,849	419,887
New services distribution	561,603	122,088	484,652	101,164
Poles, towers and fixtures	5,892,793	2,865,206	5,556,074	2,579,897
Underground conduits	3,110,633	1,490,104	3,036,781	1,350,576
	27,062,311	9,848,999	24,445,955	8,716,347
General Plant				
Land	278,455	-	278,455	-
Buildings and fixtures	174,386	51,204	174,386	45,062
Communication equipment	188,721	128,762	188,721	114,459
Computer hardware	366,140	339,051	360,301	319,252
Office furniture and equipment	232,043	126,099	166,164	115,135
Store equipment	10,960	8,576	10,960	7,756
Tools and garage equipment	251,749	173,429	238,014	157,183
Transportation equipment	1,175,512	764,873	1,175,512	640,551
	2,677,966	1,591,994	2,592,513	1,399,398
Construction in progress	-	-	255,271	-
	29,740,277	11,440,993	27,293,739	10,115,745
Less contributions in aid of construction	4,997,238	1,074,121	4,672,796	880,732
	$ 24,743,039	$ 10,366,872	$ 22,620,943	$ 9,235,013
		$ 14,376,167		$ 13,385,930

Lakeland Power Distribution Ltd.
Notes to the Financial Statements
December 31, 2011

5. Intangible assets

	2011 Asset Cost	2011 Accumulated Amortization	2010 Asset Cost	2010 Accumulated Amortization
Land rights	$ 516,004	$ 15,147	$ 493,354	$ 15,147
Computer software	268,708	166,725	202,603	140,671
	$ 784,712	$ 181,872	$ 695,957	$ 155,818
		$ 602,840		$ 540,139

6. Regulatory assets and liabilities

	2011	2010
Regulatory assets		
Smart meters	$ 1,893,095	$ 1,965,730
Other	32,582	2,807
Renewable generation	249,798	(2,801)
Retail settlement variances	400,890	-
Regulatory assets approved for recovery	-	213,260
	$ 2,576,365	$ 2,178,990
Regulatory liabilities		
Regulatory liabilities approved for recovery	121,681	-
Retail settlement variances	-	588,778
	$ 121,681	$ 588,778

7. Future income tax assets

Future income tax assets, which arise from differences between the carrying amounts and tax bases of the Company's assets, are as follows:

	2011	2010
Future income tax assets		
Regulatory assets and liabilities (tax effective)	$ -	$ (87,000)
Difference of tax basis of property and equipment and intangibles from the carrying value	967,600	1,004,600
	$ 967,600	$ 917,600
Payments in lieu of income taxes:		
Current payments in lieu of income taxes	$ 190,548	$ 207,000
Future recovery of payments in lieu of income taxes	(50,000)	(159,969)
	$ 140,548	$ 47,031

8. Bank indebtedness

The revolving facility available to the Company is with TD Bank to assist with working capital requirements. Funds available on the facility are up to $4,000,000 and interest is at the bank's prime lending rate.

Security for the revolving facility is provided by a General Security Agreement with the TD bank, a floating and fixed charge over all assets and evidence of adequate liability insurance.

The agreement covering the above facility contains certain restrictions regarding interest coverage and debt capitalization tests, which have been met.

9. Long-term debt

	2011	2010
TD Bank term loan, payments of interest only only, payable monthly at 5.41% due March 2013	$ 1,162,500	$ 1,162,500
TD bank term loan, payments of interest only, payable monthly at 5.03%, due March 2013	2,325,000	2,325,000
	$ 3,487,500	$ 3,487,500

Security for chartered bank term loans is provided by a General Security Agreement with the TD Bank, conveying a first floating and fixed charge over all assets and evidence of adequate liability insurance.

The agreement covering the above facility contains certain restrictions regarding interest coverage and debt capitalization tests, which have been met.

10. Contingent liability

Environmental contingency

On September 17, 2008, Environment Canada published its final regulations governing the management, storage and disposal of PCBs by 2020. The regulations impose timelines for disposal of PCBs based on certain criteria. It is management's plan to have all affected assets tested and removed by the end of 2012 to be in advance of government requirements. No accrual has been reflected in these financial statements as these costs have not yet been determined.

11. Share capital

		2011	2010
Authorized			
Unlimited	Common shares		
Issued			
7,428	Common shares	$ 9,226,787	$ 9,226,787

12. Amortization of property and equipment

The amortization of property and equipment amounted to $1,157,908 for the year (2010 - $1,085,796). The line item *Amortization* on the statement of earnings reflects $1,033,587 (2010 - $965,503) because the transportation and communication equipment amortization of $124,321 (2010 - $120,293) has been allocated to operating lines where the equipment was used. In 2011, $52,124 was capitalized in property and equipment, $933 was allocated to smart meters in regulatory assets, and $71,264 was expensed in other accounts.

13. Related party transactions

These transactions are in the normal course of operations and are measured at the exchange value (the amount of consideration established and agreed to by the related parties) which approximates the arm's length equivalent value. Bracebridge Generation Ltd. (BGL), Lakeland Energy Ltd. (LEL) and Lakeland Power Distribution Ltd. (LPDL) are all wholly-owned subsidiaries of Lakeland Holding Ltd. (LHL) and are therefore, related by common control. During the year, Lakeland Power Distribution Ltd. purchased all of the electricity generated by Bracebridge Generation Ltd. on the same terms that it purchases electricity from third party suppliers.

The following table summarizes the Company's related party transactions for the year:

		2011		2010
Lakeland Energy Ltd.				
Other operating revenue received	$	**8,117**	$	13,707
Information technology expenses, in adminstration and general		**167,508**		166,027
Communication expenses, in adminstration and general		**13,860**		13,860
Other operating and maintenance		**74,753**		94,304
Bracebridge Generation Ltd				
Other operating revenue	$	**21,952**	$	22,404
Cash proceeds on disposal of property and equipment		**-**		12,025
Power purchased		**1,926,830**		2,128,851
Other operating and maintenance expenses		**-**		330
Lakeland Holding Limited				
Management fees paid, in adminstration and general	$	**668,974**	$	698,341
Shareholders of Lakeland Holding Ltd, the parent company				
Purchases				
Town of Bracebridge	$	**51,856**	$	29,111
Town of Huntsville		**4,635**		4,398
Village of Burk's Falls		**145**		-
Town of Sundridge		**45**		-

13. Related party transactions (continued)

	2011	2010
Sales		
Town of Bracebridge	$ **952,915**	$ 1,116,256
Town of Huntsville	**391,831**	595,439
Village of Burk's Falls	**108,046**	107,652
Village of Sundridge	**105,235**	104,660
Municipality of Magnetawan	**29,247**	27,812

At the end of the year, amounts due from/to related parties are as follows and are included in receivables and payables and accruals:

	2011	2010
Accounts receivable from BGL	$ **20,277**	$ 19,167
Accounts receivable from LEL	**15,358**	12,210
Accounts receivable from LHL	**50,807**	22,195
	$ **86,442**	$ 53,572
Account payable to BGL	$ **952,792**	$ 246,502
Accounts payable to LEL	**12,334**	16,310
Accounts payable to LHL	**29,575**	49,705
	$ **994,701**	$ 312,517

14. Statement of cash flows supplementary information

During the year, the Company paid (received) the following amounts in cash:

	2011	2010
Interest received	$ **48,188**	$ 22,433
Interest paid	$ **266,586**	$ 209,252
Payments in lieu of income taxes	$ **219,064**	$ 268,960
Refunds received in lieu of income taxes	$ **(11,491)**	$ (2,209)

15. Capital disclosures

The Company defines its capital to be its long-term debt, share capital and retained earnings. The Company's objectives when managing its capital are:

- To safeguard its ability to continue as a going concern which will allow it to continue to service its customers
- To provide adequate returns to its shareholder
- To ensure ongoing access to funding to maintain and improve the electricity distribution system
- To ensure compliance with covenants related to its credit facilities.

Annual budgets are developed along with three year business plans and actual results are reviewed on a regular basis to monitor the Company's capital and ensure it is maintained at an appropriate level. The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions. In order to maintain or adjust the capital structure, the Company will adjust the amount of dividends paid to its shareholders. The Company's externally imposed capital requirements consist of banking covenants related to its long-term debt and bank indebtedness (Notes 8 and 9). One of the covenants limits the debt to 60% of the Company's total capitalization.

There have been no changes in the Company's capital management strategy in relation to the prior year.

16. Comparative figures

Certain comparative figures presented in the financial statements have been reclassified to conform to the presentation adopted for the current year.

RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND REGULATORY ACCOUNTING:

The only reconciliation required between financial statements and regulatory accounting relate to those expenses which the OEB has disallowed for rate application purposes. These have been identified in Table 1.3.1 below. These expenses have been removed from requested OM&A expenses for 2013 Test Year in Exhibit 4 of this application.

Table 1.3.1 – Reconciliation from Audited OM&A Expense to Regulatory OM&A Expense

	Last Rebasing Year (Approved)	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual[2]	Bridge Year 2012[3] CGAAP & MIFRS and MIFRS
OM&A on Financial Statements	$ 2,846,013	$ 2,872,034	$ 2,973,873	$ 2,830,741	$ 3,274,647
5681 - Special Purpose Charge Expense	$ -	$ -	$ -	$ -	$ -
6205 - Donations (not including LEAP)	$ -	$ -	$ -	$ 2,913	$ 6,033
5695 OM&A Contra Account for Smart Meter OM&A costs	$ -	-$ 95,447	-$ 166,182	-$ 71,609	$ -
5330 - Collection charges (included in Other Income)	$ -	$ 30,030	$ 33,965	$ 14,970	$ -
4380 - Expenses of Non-utility Operations (included in Operation)	$ -	$ 17,435	$ -	$ -	$ -
Total	**$ 2,846,013**	**$ 2,920,016**	**$ 3,106,090**	**$ 2,884,467**	**$ 3,268,614**

PRO FORMA FINANCIAL STATEMENTS - 2012 AND 2013:

The Pro Forma Financial Statements for the 2012 Bridge Year and the 2013 Test Year accompany this Schedule as Appendix E.

APPENDIX E

COPY OF LPDL 2012 PRO FORMA FINANCIAL STATEMENTS – CGAAP AND MIFRS

AND

2013 PRO FORMA FINANCIAL STATEMENTS - MIFRS

Lakeland Power Distribution Ltd.
2012 STATEMENT OF INCOME AND RETAINED EARNINGS (CGAAP)

Commodity Sales	$	21,312,493
Distribution Revenues		5,084,801
Other Revenues		335,000
Total Revenues		**26,732,294**
Cost of Power		21,312,493
Operating Expenses		207,888
Maintenance Expenses		887,385
Billing & Collecting Expenses		783,033
Community Relations Expenses		21,000
General & Administrative Expenses		1,362,540
Amortization & Depreciation Expense		1,497,835
Interest Expense		265,892
Taxes Other Than Income Tax		10,290
Total Expenses		**26,348,356**
Net Income Before Taxes		**383,938**
Income Tax		59,510
Net Income	**$**	**324,428**

Lakeland Power Distribution Ltd.
2012 BALANCE SHEET (CGAAP)

Cash	$	510
Accounts Receivable		4,657,409
Prepaid Expenses		245,000
Inventory		200,000
Total Current Assets	**$**	**5,102,919**
Propery, Plant & Equipment		16,525,700
Regulatory Assets		1,060,643
Other Long-term Assets		967,600
TOTAL ASSETS	**$**	**23,656,862**
Accounts Payable		7,075,056
Current portion of Long-term Debt		-
Total Current Liabilities	**$**	**7,075,056**
Employee Future Benefits		
Non-current Liabilities		215,692
Long-term Debt		3,487,500
Total Long-Term Liabilities	**$**	**3,703,192**
TOTAL LIABILITIES	**$**	**10,778,248**
Common Shares		9,226,787
Paid-in Capital		-
Retained Earnings		3,651,827.43
TOTAL SHAREHOLDER EQUITY	**$**	**12,878,615**
TOTAL LIABILITY & SHAREHOLDER EQUITY	**$**	**23,656,863**

Lakeland Power Distribution Ltd.
2012 STATEMENT OF INCOME AND RETAINED EARNINGS (MIFRS)

Commodity Sales	$	21,312,493
Distribution Revenues		5,084,801
Other Revenues		259,571
Total Revenues		**26,656,865**
Cost of Power		21,312,493
Operating Expenses		207,888
Maintenance Expenses		887,385
Billing & Collecting Expenses		783,033
Community Relations Expenses		21,000
General & Administrative Expenses		1,362,540
Amortization & Depreciation Expense		1,225,639
Interest Expense		265,892
Taxes Other Than Income Tax		10,290
Total Expenses		**26,076,160**
Net Income Before Taxes		**580,705**
Income Tax		90,009
Net Income	**$**	**490,696**

Lakeland Power Distribution Ltd.
2012 BALANCE SHEET (MIFRS)

Cash	$	510
Accounts Receivable		4,657,409
Prepaid Expenses		245,000
Inventory		200,000
Total Current Assets	**$**	**5,102,919**
Propery, Plant & Equipment		16,760,041
Regulatory Assets		1,060,591
Other Long-term Assets		967,600
TOTAL ASSETS	**$**	**23,891,151**
Accounts Payable		7,143,078
Current portion of Long-term Debt		-
Total Current Liabilities	**$**	**7,143,078**
Employee Future Benefits		
Non-current Liabilities		215,692
Long-term Debt		3,487,500
Total Long-Term Liabilities	**$**	**3,703,192**
TOTAL LIABILITIES	**$**	**10,846,270**
Common Shares		9,226,787
Paid-in Capital		-
Retained Earnings		3,818,095.33
TOTAL SHAREHOLDER EQUITY	**$**	**13,044,883**
TOTAL LIABILITY & SHAREHOLDER EQUITY	**$**	**23,891,153**

Lakeland Power Distribution Ltd.
2013 STATEMENT OF INCOME AND RETAINED EARNINGS (MIFRS)

Commodity Sales	$	21,044,660
Distribution Revenues		5,476,660
Other Revenues		284,098
Total Revenues		**26,805,418**
Cost of Power		21,044,660
Operating Expenses		197,000
Maintenance Expenses		908,546
Billing & Collecting Expenses		798,025
Community Relations Expenses		21,000
General & Administrative Expenses		1,384,756
Amortization & Depreciation Expense		1,010,680
Interest Expense		266,392
Taxes Other Than Income Tax		10,702
Total Expenses		**25,641,760**
Net Income Before Taxes		**1,163,658**
Income Tax		273,369
Net Income	**$**	**890,289**

Lakeland Power Distribution Ltd.
2013 BALANCE SHEET (MIFRS)

Cash	$	510
Accounts Receivable		4,657,409
Prepaid Expenses		245,000
Inventory		200,000
Total Current Assets	**$**	**5,102,919**
Propery, Plant & Equipment		17,644,710
Regulatory Assets		1,066,676
Other Long-term Assets		967,600
TOTAL ASSETS	**$**	**24,781,905**
Accounts Payable		7,309,813
Current portion of Long-term Debt		-
Total Current Liabilities	**$**	**7,309,813**
Employee Future Benefits		
Non-current Liabilities		215,692
Long-term Debt		3,487,500
Total Long-Term Liabilities	**$**	**3,703,192**
TOTAL LIABILITIES	**$**	**11,013,005**
Common Shares		9,226,787
Paid-in Capital		-
Retained Earnings		4,542,115.08
TOTAL SHAREHOLDER EQUITY	**$**	**13,768,902**
TOTAL LIABILITY & SHAREHOLDER EQUITY	**$**	**24,781,907**

RECONCILIATION BETWEEN PRO FORMA STATEMENTS AND REVENUE DEFICIENCY STATEMENTS:

No reconciliation is required between the 2013 Pro Forma statement and the revenue deficiency statement.

INFORMATION ON AFFILIATES:

Lakeland Holding Ltd. is the parent company of LPDL. It is wholly owned by the municipalities listed in Tab 1, Schedule 13. A copy of Lakeland Holding Ltd.'s consolidated 2011 Audited financial statements accompany this Schedule as Appendix F. Neither Lakeland Holding Ltd. nor LPDL produces an annual report.

Two other companies, Bracebridge Generation Ltd. and Lakeland Energy Ltd., are also wholly owned by Lakeland Holding Ltd..

APPENDIX F

2011 ANNUAL STATEMENTS – PARENT COMPANY

LAKELAND HOLDING LTD. CONSOLIDATED

FOR THE YEAR ENDED DECEMBER 31, 2011

Consolidated Financial Statements

Lakeland Holding Ltd.

December 31, 2011

Contents

Grant Thornton

Independent Auditor's Report

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To the Shareholders of Lakeland Holding Ltd.:

We have audited the accompanying consolidated financial statements of Lakeland Holding Ltd., which comprise the consolidated balance sheet as at December 31, 2011, and the consolidated statement of earnings and retained earnings and cash flow statement for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Lakeland Holding Ltd. as at December 31, 2011, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Grant Thornton LLP

Orillia, Canada
April 26, 2012

Chartered Accountants
Licensed Public Accountants

Lakeland Holding Ltd.
Consolidated Statements of Earnings and Retained Earnings

Year Ended December 31	2011	2010
Revenue	$ 23,155,056	$ 21,711,431
Power purchased	18,600,838	17,170,452
	4,554,218	4,540,979
Other revenues		
Generation	1,926,830	2,128,851
Energy	1,260,727	900,839
Late Payment/Collection charges	148,522	168,252
Utility service on customer owned property	168,041	187,031
Other income	21,726	34,198
Gain on disposal of property and equipment	-	13,275
Investment income	73,609	34,162
	8,153,673	8,007,587
Expenses		
Administration and general	1,402,424	1,470,262
Amortization (Note 12)	1,722,864	1,598,079
Billing and collecting	613,349	683,266
Taxes other than income taxes	87,463	104,436
Interest (Note 13)	273,917	225,571
Operations and maintenance	2,248,692	2,145,356
Payments in lieu of capital tax	276	6,432
	6,348,985	6,233,402
Earnings before payments in lieu of income taxes	1,804,688	1,774,185
Payments in Lieu of income taxes (Note 7)		
Current-Payments in Lieu of income taxes (PILs)	292,004	225,814
Future-Payments in Lieu of income taxes (PILs)	113,000	67,167
	405,004	292,981
Net earnings	$ 1,399,684	$ 1,481,204

Retained earnings, beginning of year	$ 10,085,721	$ 9,104,517
Net earnings	1,399,684	1,481,204
Dividends (Note 14)	(500,000)	(500,000)
Retained earnings, end of year	$ 10,985,405	$ 10,085,721

See accompanying notes to the consolidated financial statements.

Lakeland Holding Ltd.
Consolidated Balance Sheet

December 31		2011		2010
Assets				
Current				
Cash and cash equivalents	$	**492,980**	$	1,081,951
Receivables		**3,335,548**		2,663,417
Unbilled revenue		**2,262,157**		2,355,046
Inventory		**205,739**		255,726
Prepaids		**234,667**		217,533
Payments in lieu of income taxes recoverable		**-**		47,330
		6,531,091		6,621,003
Property and equipment (Note 4)		**40,856,401**		27,426,423
Intangible assets (Note 5)		**994,000**		949,259
Regulatory assets (Note 6)		**2,576,365**		2,178,990
Future income tax assets (Note 7)		**931,074**		1,044,074
	$	**51,888,931**	$	38,219,749
Liabilities and shareholders' equity				
Current				
Construction loan (Note 8)	$	**16,107,899**	$	4,901,624
Payables and accruals		**7,894,262**		5,749,610
Payments in lieu of income taxes payable		**13,449**		-
Deferred revenue		**218,760**		167,837
Current portion of long-term debt (Note 9)		**221,416**		144,289
		24,455,786		10,963,360
Long-term debt (Note 9)		**3,487,500**		3,708,916
Customer deposits		**205,809**		240,224
Regulatory liabilities (Note 6)		**121,681**		588,778
Other non-current liabilities		**23,100**		23,100
		28,293,876		15,524,378
Shareholders' equity				
Share capital (Note 11)		**12,609,650**		12,609,650
Retained earnings		**10,985,405**		10,085,721
		23,595,055		22,695,371
	$	**51,888,931**	$	38,219,749

Contingent liabilities (Note 10)

On behalf of the Board

T. Pegguitt Director P B Matthews Director

See accompanying notes to the consolidated financial statements

Lakeland Holding Ltd.
Consolidated Statement of Cash Flows

Year Ended December 31	2011	2010
Increase (decrease) in cash and cash equivalents		
Operating activities		
Net earnings	**$ 1,399,684**	$ 1,481,204
Amortization (Note 12)	**1,868,923**	1,734,783
Gain on disposal of capital assets	**-**	(13,274)
Future payments in lieu of income taxes	**113,000**	67,167
	3,381,607	3,269,880
Change in non-cash working capital		
Receivables	**(672,131)**	(756,471)
Unbilled revenue	**92,889**	307,459
Inventory	**49,987**	25,954
Prepaids	**(17,134)**	(45,040)
Payables and accruals	**2,144,652**	1,542,460
Deferred revenue	**50,923**	(49,494)
Payment in lieu of income taxes	**60,779**	(56,247)
	5,091,572	4,238,501
Customer deposits	**(34,415)**	37,058
Regulatory assets and liabilities	**(864,472)**	(209,033)
	4,192,685	4,066,526
Financing activities		
Construction loan advances	**11,206,275**	4,901,624
Repayment of long-term debt	**(144,289)**	(144,284)
Dividends paid	**(500,000)**	(500,000)
	10,561,986	4,257,340
Investing activities		
Proceeds from sale of property and equipment	**-**	13,274
Purchase of property and equipment	**(15,561,181)**	(8,152,882)
Contributions received in aid of construction	**324,442**	560,961
Acquisition of intangible assets	**(106,903)**	(92,337)
	(15,343,642)	(7,670,984)
(Decrease) increase in cash and cash equivalents	**(588,971)**	652,882
Cash and cash equivalents, beginning of year	**1,081,951**	429,069
Cash and cash equivalents, end of year	**$ 492,980**	$ 1,081,951

See accompanying notes to the consolidated financial statements.

Lakeland Holding Ltd.
Notes to the Consolidated Financial Statements
December 31, 2011

1. Nature of operations

The Company is incorporated under the laws of Ontario. Two of the subsidiaries are also incorporated under the laws of Ontario and operate as local utility companies producing and distributing hydro electric power to users in Bracebridge, Huntsville, Sundridge, Burk's Falls and Magnetawan, Ontario. These businesses are granted license to operate and are regulated by the Ontario Energy Board (OEB). A third subsidiary is incorporated under the laws of Ontario and sells utility related products and services.

2. Summary of significant accounting policies

a) Reporting entity

The consolidated financial statements include all transactions of the companies in which the Company has a controlling interest. All significant intercompany transactions and balances have been eliminated on consolidation.

The assets, liabilities and operations of the following subsidiaries are included in these consolidated financial statements:

Bracebridge Generation Ltd.
Lakeland Energy Ltd.
Lakeland Power Distribution Ltd.

b) Cash and cash equivalents

Cash and cash equivalents consist of cash on hand, bank balances, and bank indebtedness.

c) Inventory

Inventory consists of repair parts, supplies and materials valued at the lower of average cost and net realizable value. Cost includes all direct costs plus any related shipping and freight costs. Net realizable value is the estimated selling price in the ordinary course of business, less any applicable selling expenses. The company classifies rebates received from vendors as a reduction to the cost of inventory. Amount of inventory expensed during the year was $295,823 (2010 - $287,288).

d) Property and equipment

Property and equipment are recorded at cost less accumulated amortization which includes internal labour and allocated overhead. Stranded meters have been taken out of service and are no longer being amortized. Amortization is provided on the straight line basis over the estimated useful life of the assets as follows:

2. Summary of significant accounting policies (continued)

d) Property and equipment (continued)

Distribution plant

Buildings and fixtures	30 & 50 years
Conductors and devices	25 years
Distribution station equipment	25 years
Line transformers	25 years
Meters	25 years
New services distribution	25 years
Poles, towers and fixtures	25 years
Underground conduits	25 years

General plant

Building and fixtures	30 & 50 years
Communication equipment	10 years
Computer hardware and software	5 years
Office furniture and equipment	10 years
Stores equipment	10 years
Tools and garage equipment	10 years
Transportation equipment	5 & 8 years
Leasehold improvements	5 years

Generation plants

Buildings and fixtures	5 to 25 years
Generation plants	25 years
Transportation equipment	5 to 8 years
Fibre optics	10 years
Water heaters and sentinel lights	10 years

e) Contributions in aid of construction

Certain property and equipment may be acquired or constructed with financial assistance in the form of non-refundable contributions from customers. These contributions are netted against property and equipment and amortized on the same basis as the capital assets to which they relate.

f) Impairment of long-lived assets

The Company tests for impairment loss of long-lived assets whenever events or changes in circumstances occur, which may cause their carrying value to exceed the total undiscounted cash flows expected from their use and eventual disposition. An impairment loss, if any, is determined as the excess of the carrying value of the asset over its fair value.

2. Summary of significant accounting policies (continued)

g) Property and equipment retirement obligations

Canadian generally accepted accounting principles require the Company to determine the fair value of the future expenditures required to settle legal obligations to remove property and equipment on retirement. If reasonably estimable, a liability is recognized equal to the present value of the estimated future removal expenditures. An equivalent amount is capitalized as an inherent cost of the associated property and equipment.

Some of the Company's assets may have asset retirement obligations. As the Company expects to use the majority of its property and equipment for an indefinite period, no removal date can be determined and, consequently, a reasonable estimate of the fair value of any asset retirement obligations has not been made at this time.

h) Intangible assets

Intangible assets consists of land rights, waterpower lease and computer software, which are recorded at cost less accumulated amortization and are amortized over the useful life of the asset. Computer software is amortized on a straight line basis over 5 years. Land rights and waterpower lease both have an indefinite life and are tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset might be impaired. The impairment test consists of a comparison of the fair value of the intangible asset with its carrying amount and no impairment has been recorded to date.

i) Regulatory assets and liabilities

The rates of the Company's electricity transmission and distribution businesses are subject to regulation by the Ontario Energy Board (OEB). The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets and liabilities that management believes will be settled in future rates to customers.

Specific regulatory assets and liabilities are described below and disclosed in (Note 6).

Smart meters

This amount consists of the net balance of capital and operating expenditures for smart meters, less recoveries received from the rate adder charged to customers. Effective May 1, 2010, the OEB increased the respective monthly rate adder to $2.50 per month per metered customers.

Renewable generation

These assets relate to the Green Energy Act with the distributor being responsible for the cost of expansion up to the value of the generators renewable energy expansion cost of $90,000 per MW generation capacity. These amounts have not yet been submitted for recovery.

2. Summary of significant accounting policies (continued)

i) Regulatory assets and liabilities (continued)

Retail settlement variance accounts

These accounts reflect the difference between the cost of electricity and the amounts billed to consumers that have not yet been approved for recovery.

Regulatory assets and liabilities approved for recovery

These assets and liabilities have been approved for recovery by the OEB and are currently included in rates being charged to the customers.

j) Income taxes

Under the Electricity Act, 1998, the Company is required to make payments in lieu of income taxes to Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with rules contained in the Income Tax Act, as modified by the electricity Act, 1998, and related regulations.

The Company follows the asset and liability method of accounting for payments in lieu of income taxes (PILs). Under this method, current PILs are recognized for the estimated PILs payable (receivable) for the current year. Future PILs assets and liabilities are recognized for temporary differences between the tax and accounting bases of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes, that are likely to be realized. Future PILs are measured using enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled.

k) Revenue recognition

Revenue is recognized as power is transmitted and delivered to customers. Revenue is recognized on the accrual basis, which includes an estimate of electricity consumed by customers in the year, but billed subsequent to year end. This revenue is recorded as unbilled service revenue.

Generation revenues are recognized in the period power is generated based on fixed rate contracts which have a CPI index included.

Energy revenues are recognized over the term of the lease as they are earned. Initial setup revenues on monthly contracts are recognized over a twelve month period.

Utility service revenue on customer owned property is recognized under the completed contract method, whereby contract revenue billed and the related contract expenses are deferred until substantial completion of the contract. If losses are anticipated on contracts prior to substantial completion, full provision is made for such losses.

2. Summary of significant accounting policies (continued)

k) Revenue recognition (continued)

Gain on disposal of property and equipment is recognized when property and equipment is sold in excess of carrying cost of the asset's corresponding net book value.

Investment, late payment/collection charges and other income are recognized as revenue when they are earned. Carrying charges on Regulatory Assets, at prescribed interest rates by the Ontario Energy Board, are also included in investment income.

l) Pension plan

The Company is an employer member of the Ontario Municipal Employees Retirement System (OMERS), which is a multi-employer, defined benefit pension plan. The OMERS Board of Trustees, representing plan members and employers, is responsible for overseeing the management of the pension plan, including investment of the assets and administration of the benefits. The Company has adopted defined contribution plan accounting principles for this plan because insufficient information is available to apply defined benefit plan accounting principles. The Company recognizes the expense related to this plan as contributions are made. The required contributions made by the Company to OMERS were $201,838 (2010 - $172,030).

m) Use of estimates

The preparation of consolidated financial statements 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 disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. These estimates and assumptions are based on management's historical experience, best knowledge of current events and actions that the Company may undertake in the future. Significant accounting estimates include allowance for doubtful accounts, unbilled revenue, inventory obsolescence, estimated useful lives of property and equipment and remaining recovery (settlement) period for regulated assets (liabilities). Actual results could differ from those estimates.

2. Summary of significant accounting policies (continued)

n) Financial instruments

i) Financial instrument categories

The Company classifies its financial instruments into one of the following categories, based on the purpose for which the asset was acquired. The fair value of these financial instruments approximates their carrying values, unless otherwise noted. The Company's accounting policy for each category is as follows:

Assets or liabilities held-for-trading
Cash and cash equivalents have been classified as "held-for-trading". They are reported at fair value at each balance sheet date, and any change in fair value is recognized in net income in the period during which the change occurs. Transaction costs are expensed when incurred.

Loans and receivables
Receivables are classified under "loans and receivables". They are recorded at cost, which, upon their initial measurement, is equal to their fair value. Subsequent measurements of accounts receivable are recorded at amortized cost which usually corresponds to the amount initially recorded less any allowance for doubtful accounts.

Other financial liabilities
Bank indebtedness, the construction loan, payables and accruals and long term debt are classified as "other financial liabilities". They are initially measured at fair value and the gains and losses resulting from their subsequent measurement at amortized cost, at the end of each period, are recognized in net income.

ii) Risks arising from financial instruments

Credit risk
The Company's cash is all held at The Toronto-Dominion Bank (TD Bank). The Company's credit risk associated with receivables is related to payments from LDC customers. The Company collects security deposits from customers in accordance with directions provided by the Ontario Energy Board. Current customer deposits total $205,809 (2010 - $240,224). In addition, the Company holds credit risk insurance on all its commercial and industrial customers thereby minimizing its overall credit risk. The carrying amount of receivables is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the consolidated statement of operations. Subsequent recoveries of receivables previously provisioned are credited to the statement of operations.

Interest rate risk
The long-term debt bears fixed interest rates. Consequently, the long-term interest rate risk exposure is minimal. The bank indebtedness and construction loan bear interest at floating rates which gives rise to a risk that the Company's future income (loss) and cash flows may be adversely impacted by fluctuations in interest rates.

2. Summary of significant accounting policies (continued)

n) Financial instruments (continued)

ii) Risks arising from financial instruments (continued)

Liquidity risk
The Company manages its liquidity risk to ensure access to sufficient funds to meet operational needs. Liquidity risks are comprised of liabilities totaling $24,455,786 which are due within one year and long-term debt of $3,487,500 to be repaid over the next 3 years. Included in this amount is a construction loan of $16,107,899 that has been converted to a long-term debt instrument on March 30, 2012 as a 10 yr term swap loan, 3.74% fixed interest, 20 yr amortization.

3. New accounting pronouncements

International financial reporting standards (IFRS)

In 2008, the Canadian Accounting Standards Board (AcSB) confirmed that the adoption of IFRS would be effective for interim and annual periods beginning on or after January 1, 2012 for Canadian publicly accountable profit-oriented enterprises. In March 2012, the AcSB decided to permit rate regulated entities to defer their IFRS implementation date to January 1, 2013. IFRS will replace Canada's current GAAP for these enterprises upon adoption. Comparative IFRS information for the previous fiscal year will also have to be reported. As such, the Company will apply IFRS to its consolidated financial statements ending December 31, 2013.

The Company is currently in the process of evaluating the potential impact of IFRS on the future consolidated financial statements. This will be an ongoing process. The consolidated financial statements as disclosed under current GAAP may be significantly different when presented in accordance with IFRS.

One area that is expected to change will be that regulatory assets and liabilities will not be permitted for separate treatment under IFRS. If these items do not qualify as assets or liabilities under IFRS they will be recorded on the statement of earnings. This would have resulted in increased earnings of $156,992 (2010 - $53,641), and an increase of property and equipment of $320,053 (2010 - $244,995).

4. Property and equipment

	2011		2010	
	Asset Cost	**Accumulated Amortization**	Asset Cost	Accumulated Amortization
Distribution Plant				
Buildings and fixtures	**$ 1,840,984**	**$ 176,034**	$ 652,936	$ 135,437
Conductors and devices	**5,246,219**	**1,559,747**	4,820,122	1,354,596

4. Property and equipment (continued)

	2011 Asset Cost	2011 Accumulated Amortization	2010 Asset Cost	2010 Accumulated Amortization
Distribution Plant (continued)				
Distribution station equipment	3,222,714	890,246	3,174,761	745,212
Line transformers	5,913,575	2,266,034	5,520,518	1,979,831
Meters	266,941	59,653	193,262	49,747
Stranded meters	1,006,849	419,887	1,006,849	419,887
New services distribution	561,603	122,088	484,652	101,164
Poles, towers and fixtures	5,892,793	2,865,206	5,556,074	2,579,897
Underground conduits	3,110,633	1,490,104	3,036,781	1,350,576
	27,062,311	9,848,999	24,445,955	8,716,347
General Plant				
Land	278,455	-	278,455	-
Buildings and fixtures	174,386	51,204	174,386	45,062
Communication equipment	188,721	128,762	188,721	114,459
Computer hardware	622,994	447,140	510,796	388,144
Office furniture and equipment	232,043	126,099	166,164	115,135
Store equipment	10,960	8,576	10,960	7,756
Tools and garage equipment	251,749	173,429	238,014	157,183
Transportation equipment	1,345,326	863,229	1,316,643	720,570
Leasehold improvements	193,371	131,954	193,371	93,280
	3,298,005	1,930,393	3,077,510	1,641,589
Construction in progress	18,228,261	-	6,115,364	-
Generation Plants and Other				
Land	54,646	-	51,723	-
Buildings and fixtures	254,857	131,508	250,384	109,327
Generation plants	8,896,117	2,602,953	8,824,223	2,248,560
Fibre optics	1,739,372	488,026	1,260,938	338,011
Water heaters/sentinel lights	649,645	401,817	608,354	362,130
	11,594,637	3,624,304	10,995,622	3,058,028
	60,183,214	15,403,696	44,634,451	13,415,964
Less contributions in Aid of construction	4,997,238	1,074,121	4,672,796	880,732
	$ 55,185,976	$ 14,329,575	$ 39,961,655	$ 12,535,232
		$ 40,856,401		$ 27,426,423

5. Intangible assets

	2011 Asset Cost	2011 Accumulated Amortization	2010 Asset Cost	2010 Accumulated Amortization
Computer software	$ 536,671	$ 299,965	$ 439,997	$ 225,382
Land rights	516,004	15,147	493,354	15,147
Waterpower lease	256,437	-	256,437	-
	$ 1,309,112	$ 315,112	$ 1,189,788	$ 240,529
		$ 994,000		$ 949,259

In 2005, the Company acquired a Water Power Lease Agreement with the Ministry of natural Resources through the acquisition of Burk's Falls Waterpower Corporation. The lease provides access to crown lands and water beds and is considered to have an indefinite life. The lease has been in existence since 1985.

6. Regulatory assets and liabilities

	2011	2010
Regulatory assets		
Smart meters	$ 1,893,095	$ 1,965,730
Other	32,582	-
Renewable generation	249,798	-
Retail settlement variances	400,890	-
Regulatory assets approved for recovery	-	213,260
	$ 2,576,365	$ 2,178,990
Regulatory liabilities		
Regulatory liabilities approved for recovery	121,681	-
Retail settlement variances	-	588,778
	$ 121,681	$ 588,778

7. Future income tax assets

Future income tax assets at December 31, 2011, which arise from differences between the carrying amounts and tax bases of the Company's assets, are as follows:

	2011	2010
Future income taxes assets		
Difference of tax basis of property and equipment and intangibles from the carrying value	$ 780,504	$ 929,500
Regulatory assets and liabilities (tax effective)	-	(87,000)
Corporate minimum tax credit carry forward	112,326	112,048
Tax losses for carryforward	7,524	30,726
Transitional credit	30,720	58,800
	$ 931,074	$ 1,044,074

Reconciliation of total payments in lieu of income taxes

	2011	2010
Earnings before payments in lieu of income taxes	$ 1,804,688	$ 1,774,185
Current effective tax rate	28.25%	29.95%
Expected payments	509,824	531,368
Tax rate change	24,813	(151,734)
Regulatory asset and liabilities (tax effective)	(87,000)	-
Small business deduction	(36,240)	(48,018)
Difference in current effective tax rate with expected future tax rates	-	(55,886)
Manufacturing and processing deduction	(24,063)	-
Other	17,670	17,251
	405,004	292,981
Payments in lieu of income taxes		
Current payments in lieu of income taxes	292,004	225,814
Future payments in lieu of income taxes	113,000	67,167
	$ 405,004	$ 292,981

The "transitional credit" of $22,433 was utilized during 2011, leaving $30,720 available to reduce tax per year from 2009 until 2013. Any credit amount that is not required to reduce taxes in a particular year will be available to claim in a subsequent year. Any credit amounts not required to reduce taxes left in 2013 will expire.

8. Construction loan

The demand loan is with a TD bank to assist with the construction of new generation stations. Interest is at the bank's prime lending rate.

Security for the revolving facility is provided by a General Security Agreement with the TD Bank, a floating and fixed charge over all assets and evidence of adequate liability insurance.

The agreement covering the above facility contains certain restrictions regarding interest coverage and debt capitalization tests, which have been met.

On March 8, 2012 an agreement was made to convert the construction loan into an interest rate swap effective March 31, 2012. Terms are 10 yr loan, 3.74% fixed interest, 20 yr. amortization.

9. Long-term debt

	2011	2010
TD bank committed installment loan, interest payable monthly at 2.48% annual, due April 2012	$ **221,416**	$ 365,705
TD bank term loan, payments of interest only, payable monthly at 5.41%, due March 2013	**1,162,500**	1,162,500
TD bank term loan, payments of interest only, payable monthly at 5.03%, due March 2013	**2,325,000**	2,325,000
	3,708,916	3,823,205
Less current portion	**221,416**	144,289
	$ **3,487,500**	$ 3,708,916

Principal payments required on long-term debt for the next two years are due as follows:

2012	$ 221,416
2013	3,487,500
	$ 3,708,916

The TD bank committed installment loan was renewed in 2011 at the same terms as are currently in place.

Security for TD bank term loans is provided by a General Security Agreement with the TD Bank, conveying a first floating and fixed charge over all assets of Lakeland Power Distribution Ltd. and Bracebridge Generation Ltd. and evidence of adequate liability insurance.

The agreement covering the above facility contains certain restrictions regarding interest coverage and debt capitalization tests, which have been met.

10. Contingent liability

Environmental contingency

On September 17, 2008, Environment Canada published its final regulations governing the management, storage and disposal of PCBs by 2020. The regulations impose timelines for disposal of PCBs based on certain criteria. It is management's plan to have all affected assets tested and removed by the end of 2012 to be in advance of government requirements. No accrual has been reflected in these financial statements as these costs have not yet been determined.

Legal contingency

The Company is involved in potential litigation regarding a July 2008 drowning at a generation station. In respect to any potential claim, the Company believes that insurance coverage is adequate and that no material exposure exists. No further action has been taken at this time.

The Company has invoked liquidated damages against the civil contractor on the generation upgrade projects for late start-up. The Company does not feel that the outcome will have any adverse effect on these statements.

11. Share capital

		2011	2010
Authorized			
Unlimited	Common shares		
Issued			
10,000	Common shares	$ **12,609,650**	$ 12,609,650

12. Amortization of property and equipment

The amortization of property and equipment amounted to $1,868,923 for the year (2010 - $1,734,783). The lime item *Amortization* on the statement of earnings reflects $1,722,864 (2010 - $1,598,079) because the transportation and communication equipment amortization of $146,059 (2010 - $136,704) has been expensed and capitalized to operating lines where the equipment was used.

13. Statement of cash flow supplementary information

During the year, the Company paid (received) the following amounts in cash:

		2011		2010
Interest	$	**273,917**	$	225,571
Payments (refunds) in lieu of income taxes	$	**251,540**	$	282,061

14. Related party transactions

These transactions are in the normal course of operations and are measured at the exchange value (the amount of consideration established and agreed to by the related parties) which approximates the arm's length equivalent value.

The following table summarizes the Company's related party shareholder transactions for the year:

		2011		2010
Purchases				
Town of Bracebridge				
Dividends	$	**325,548**	$	325,548
Operating expenses		**51,910**		65,174
Town of Huntsville				
Dividends		**125,648**		125,648
Operating expenses		**4,635**		5,398
Village of Burk's Falls				
Dividends		**19,800**		19,800
Operating expenses		**1,181**		1,033
Village of Sundridge				
Dividends		**21,652**		21,652
Operating expenses		**45**		-
Municipality of Magnetawan				
Dividends		**7,352**		7,352
Sales				
Town of Bracebridge	$	**1,051,156**	$	1,197,591
Town of Huntsville		**458,953**		668,341
Village of Burk's Falls		**117,231**		114,925
Village of Sundridge		**125,011**		116,639
Municipality of Magnetawan		**32,403**		34,797

15. Capital disclosures

The Company defines its capital to be its long-term debt, share capital and retained earnings. The Company's objectives when managing its capital are:

- To safeguard its ability to continue as a going concern which will allow it to continue to service its customers
- To provide adequate returns to its shareholders
- To ensure ongoing access to funding to maintain and improve the electricity distribution system
- To ensure compliance with covenants related to its credit facilities.

Annual budgets are developed along with three year business plans and actual results are reviewed on a regular basis to monitor the Company's capital and ensure it is maintained at an appropriate level. The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions. In order to maintain or adjust the capital structure, the Company will adjust the amount of dividends paid to its shareholders. The Company's externally imposed capital requirements consist of banking covenants related to its long-term debt (Note 9). One of the covenants limits the debt to 60% of the Company's total capitalization.

There have been no changes in the Company's capital management strategy in relation to the prior year.

16. Comparative figures

Certain comparative figures presented in the financial statements have been reclassified to conform to the presentation adopted for the current year.

MATERIALITY THRESHOLDS:

Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, issued by the Board June 28, 2012 states the relevant default materiality threshold as: “$50,000 for distributors with a revenue requirement less than $10 million”.

All variances greater than $50,000 have been analyzed.

Exhibit	Tab	Schedule	Appendix	Contents
2 – Rate Base				
	1			**Overview**
		1		Overview
		2		Variance Analysis of Rate Base
	2			**Gross Assets – Property, Plant and Equipment and Accumulated Amortization**
		1		Continuity Statements for Gross Assets – Property, Plant & Equipment and Accumulated Amortization
		2		Gross Assets Table
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	3			**Capital Budget**
		1		Introduction – Capital Budget
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		1		Overview and Calculation by Account – Allowance for Working Capital
	5			**Conversion to Modified International Financial Reporting Standards (MIFRS)**
		1		Impact on Fixed Assets – Conversion to MIFRS
		2		Impact on Capital Budgets
		3		PP&E Deferral Account and Request for

OVERVIEW:

Rate Base Overview

The rate base used for the purpose of calculating the revenue requirement used in this Application is the average of the balances at the beginning and the end of the 2013 Test Year, both on a MIFRS basis, plus a working capital allowance, which is 13% of the sum of the cost of power and controllable expenses.

The net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. LPDL's rate base calculation excludes any non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

LPDL has provided its rate base calculations for the years 2009 OEB Approved, 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year (CGAAP and MIFRS) and 2013 Test Year (MIFRS) in Table 2.1.1 (a) below. LPDL has calculated its 2013 rate base as 20,370,760 under MIFRS, which will be used to determine the proposed revenue requirement.

Table 2.1.1 (a) – Summary of Rate Base – 2013 Test Year (MIFRS)

Description	2009 OEB Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge CGAAP	2012 Bridge MIFRS	2013 Test MIFRS
Gross Fixed Assets	21,438,673	21,423,286	23,061,632	26,799,933	28,387,201	28,260,840	30,033,741
Accumulated Depreciation	8,538,320	8,368,003	9,390,834	10,453,632	11,861,554	11,500,799	12,389,031
Net Book Value	12,900,353	13,055,283	13,670,798	16,346,301	16,525,646	16,760,041	17,644,710
Average Net Book Value	12,577,880	12,551,638	13,363,040	15,008,549	16,435,973	16,553,171	17,202,376
Working Capital	22,489,355	19,154,580	20,120,909	21,423,501	24,591,397	24,591,397	24,372,189
Working Capital Allowance	3,373,403	2,873,187	3,018,136	3,213,525	3,688,709	3,688,709	3,168,385
Rate Base	15,951,283	15,424,825	16,381,177	18,222,074	20,124,683	20,241,880	20,370,760

Table 2.1.1(b) below is a summary of LPDL's cost of power and controllable expenses used in calculating working capital for 2009 Board Approved, 2009 Actual to 2011 Actual, as well as 2012 Bridge Year (CGAAP and MIFRS) and 2013 Test Year (MIFRS).

Table 2.1.1 (b) – Summary of Working Capital Calculation

Description	2009 OEB Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge CGAAP	2012 Bridge MIFRS	2013 Test MIFRS
Cost of Power	19,632,370	16,319,947	17,170,452	18,600,838	21,312,493	21,312,493	21,044,660
Operations	223,674	196,371	164,974	156,712	207,888	207,888	197,000
Maintenance	927,043	832,493	764,547	808,995	900,185	900,185	921,046
Billing & Collecting	655,137	644,517	798,870	650,758	783,034	783,034	798,025
Community Relations	11,255	25,980	32,988	20,952	21,000	21,000	21,000
Administration & General Expense	1,028,905	1,110,474	1,172,712	1,175,441	1,356,507	1,356,507	1,379,756
Property Taxes	10,972	24,798	16,365	9,805	10,290	10,290	10,702
Working Capital	22,489,355	19,154,580	20,120,909	21,423,501	24,591,397	24,591,397	24,372,189

The changes in working capital are primarily due to the annual changes in cost of power. The working capital allowance in the 2009 OEB Approved, 2009, 2010, 2011 Actual and 2012 Bridge years are based on 15% of cost of power and controllable expenses in accordance with the Filing Requirements. As indicated above, the working capital allowance for the 2013 Test Year has been reduced to 13% of the cost of power and controllable expenses as set out in the Board's letter of April 12, 2012.

This exhibit will compare historical data with the 2012 Bridge Year and 2013 Test Year. Changes to capital spending, working capital, fixed assets and rate base due to the conversion from CGAAP to MIFRS will be discussed in Tab 5 – Conversion to MIFRS, of this exhibit.

LPDL Distribution System

LPDL owns and operates the electricity distribution system in its licensed service area in the Town of Bracebridge, Town of Huntsville, Village of Burk's Falls, Village of Sundridge and the Municipality of Magnetawan, serving approximately 9,700 Residential, General Service and Unmetered Scattered Load customers as well as Street Light and Sentinel Light connections.

LPDL is supplied through the Hydro One transmission system at voltages of 44kv and distribution voltages of 12.5kV. LPDL owns distribution stations at voltages of 27.6kV and

4.16kV. Electricity is then distributed through LPDL's service area of 144 square kilometres, consisting of 128 square kilometres of rural area and 16 square kilometres of urban area. LPDL's distribution system is made up of over 75 kilometres of primary underground cable, including 5 kilometres of submarine cable, over 221 kilometres of primary overhead conductor and 4,661 poles. LPDL not only delivers electricity at its supply voltage of 44kV to industrial customers as well as at 27.6kV and 12.5kV but also owns 4 distribution stations stepping voltage down to 4.16kV and 3 distribution stations stepping voltage down to 27.6kV. Voltage is further stepped down in order to supply individual customers through approximately 2,231 transformers. The above count of primary overhead conductor of 221 kilometres is lower than the last RRR submission by 36 kilometres due to the erroneous inclusion of a number of Hydro One owned lines which will be adjusted for in the next RRR submission.

LPDL owns and maintains approximately 9,700 meters installed on its customers' premises for the purpose of measuring consumption of electricity for billing purposes. Smart meters are installed on all residential and General Service < 50 kW customers' premises and interval meters are installed on all General Service > 50 kW customers' premises. The above meters vary in type depending on the customer size and connection and include meters capable of measuring kWh consumption, kW and kVA demand as well as hourly interval data.

LPDL monitors its distribution system through a control centre in its Bracebridge operations centre. In managing its distribution system assets, LPDL's main objective is to optimize performance of assets at a reasonable cost with due regard for system reliability, public & worker safety and customer service expectations. This Application incorporates LPDL's 2013 Capital and Expense Budgets in determining the revenue requirement to bring these plans to fruition. Further information will be provided later in this Application.

LPDL considers performance-related asset information including, but not limited to, data on reliability, asset age and condition, loading, customer connection requirements, system configuration, line loss reduction, outage mitigation and procuring the lowest cost of commodity to determine investment needs in the system.

On an annual basis, LPDL reviews capital projects for potential implementation and prioritizes each project based on past trouble calls/problem areas and available funding. LPDL recognizes that a prudent capital spending program should be at a minimum, reflective of the depreciation level of the distribution system in order to maintain an efficient system. In the years leading up to and including 2009, the majority of LPDL's resources were consumed by new connections/expansions. From 2010 and onward into future years, LPDL's capital spending has shifted to focus on replacing aging assets and voltage conversion projects to improve system reliability and customer satisfaction.

Various program inspections and assessments of LPDL's assets are used to determine project priorities. For example LPDL conducts regular inspections of substations, including oil tests on substation transformers and infrared thermography scans of substation and switch equipment, pole integrity tests and visual inspections of all plant assets, which allows LPDL the opportunity to identify any distribution plant assets that are in poor condition and require priority replacement before they fail and cause power outages or damage. As well, LPDL's GIS database, in sync with the implementation of the asset management software system, tracks and maintains the location, age, type and other characteristics of each distribution plant asset. This data provides LPDL with an up to date snapshot of service areas that have older plant equipment thus aiding in prioritizing replacement plans. In addition, priorities may be affected by outside regulatory requirements as with an obligation to relocate a pole line to accommodate a municipal road widening or meter replacements in adherence with Measurement Canada standards.

In addition to the capital needs of the network, LPDL provides and plans for system maintenance of the network on a priority basis. LPDL maintenance practices and programs are focused on Tree Trimming, due to the geographic location in one of the most heavily forested areas of the province and Distribution Station Maintenance, for system reliability. Further information on LPDL's Capital and Operation, Maintenance & Administration amounts will follow later in this Application.

Capital Asset Categories:

DISTRIBUTION PLANT		**GENERAL PLANT**	
Accounts:	1611 - 1860 and 1995	Accounts:	1908 - 1985
Project Type:	Customer Demand	Asset Type:	Building and Fixtures
	Aging Asset		Office Furniture and Equipment
	Security		Computer Hardware
	Capacity		Computer Software
	Reliability		Transportation Equipment
	Regulatory Requirements		Tools and Equipment
	Substations		Communication/SCADA
	Metering		

LPDL's assets fall into two broad categories. The first is ***distribution plant*** which includes assets such as poles, conductor, overhead and underground electricity distribution infrastructure, transformers, meters and substation equipment. The second is ***general plant*** which includes assets such as buildings, office furniture and equipment, transportation equipment, communications equipment, computer hardware and software and tools and general equipment. A more detailed list of distribution and general plant categories can be found in Table 2.2.6 (Gross Assets) in Exhibit 2, Tab 2, Schedule 2.

Distribution Plant Capital Projects

LPDL's distribution plant capital project categories include:

- **Customer Demand**

These are projects that LPDL undertakes to meet its customer service obligations in accordance with the OEB's Distribution System Code (the "DSC") and LPDL's Conditions of Service. Activities include connecting new customers and building distribution systems for new subdivisions. Capital contributions toward the cost of these projects are collected by LPDL in accordance with the DSC and the provisions of its Conditions of Service. LPDL uses the economic evaluation methodology prescribed by the DSC to determine the level of capital contribution for each project. LPDL has not included any of these types of customer demand subdivision projects in its 2012 or 2013 Capital Budget.

- **Aging Asset**

Aging Asset projects are completed when assets reach the end of their useful life and must be replaced. LPDL completes visual inspections of its plant and performs predictive testing on certain assets where such testing is available and replaces assets based on these inspection and testing activities if warranted and resources are available. In adherence with the OEB guidelines, LPDL inspects its distribution plant assets over a three year cycle. In some cases the projects involve spot replacement of assets; in others, the projects involve complete asset replacement within a geographic area. When a geographic area is being replaced, consideration is given to converting the distribution voltage from 4.16kV or 12.5kV to a higher voltage level of 27.6 kV. Converting voltage levels while replacing the assets does not increase the cost of the project but delivers added benefits including reductions in substation maintenance and capital expenditures as well as reduced system losses. New assets require less maintenance, deliver better reliability and reduce safety risks to the general public.

- **Security**

The probability and impact of asset failure are considered at peak load to determine the risk the failure creates. In these cases, projects are developed to add switching devices or create a backup feeder supply to reduce the risk of power outages and to reduce restoration times.

- **Capacity**

Load growth caused by new customer connections and increased demand of existing customers over time can result in a need for capacity improvements on the system. Projects can take the form of new or upgraded feeders, transformers or voltage conversion projects, substations or transformer stations additions or upgrades. These projects are not customer-specific, but rather, they benefit many customers.

- **Reliability**

The main driver for these investments is an analysis of what measures could be undertaken to improve LPDL's reliability performance as measured by outage and reliability statistics (System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI)) and investigating problematic areas. These activities will support maintenance of, or improvement to, the Service Quality Indices measured and submitted to the OEB each year by LPDL. The Asset Management Plan Summary provided in Exhibit 2, Tab 3, Schedule 3 supports the capital and maintenance programs needed to maintain and enhance the reliability of LPDL's distribution system.

- **Regulatory Requirements**

These projects are system capital investments which are being driven by regulatory requirements. These requirements may include, among others, directions from the OEB, the IESO, ESA, Measurement Canada, the Ministry of Energy or the Ministry of Environment. Regulatory requirement projects can include relocating system plant for roadway reconstruction work, the removal and replacement of PCB transformers by 2012 and the replacement of meters to remain compliant with Measurement Canada standards.

- **Substations**

Distribution substations (DS) are used to transfer power received from the transformer stations via primary distribution feeders to 4.16 kV, 12.5kV or 27.6kV for further distribution. Investments are undertaken to improve or maintain reliability to a large number of customers and to maintain security and safety at the substations. LPDL has been expanding their 27.6 kV system for several years with the objective of eliminating some of the 4.16 kV and 12.5kV network in some service areas, which will eventually lead to a reduction in the number of distribution stations, a reduction of the reliance on certain Hydro One distribution stations and improved electricity distribution efficiency.

- **Metering**

Capital expenditures in this category include meter installations, meter upgrades and the capital components of wholesale and retail meter verification activities. LPDL began the installation of smart meters in 2009 and completed the mass deployment and cutover to Time of Use billing in 2011. LPDL's smart meter costs have been approved for disposition into rate base with rate recovery effective May 1, 2012 and thus are not included as part of this Application.

General Plant Capital Projects

LPDL's general plant capital projects have been categorized based on the accounts in the Accounting Procedures Handbook and include:

- **Building/Fixtures and Office Furniture/Equipment**

These capital expenditures are associated with the maintenance of LPDL's buildings and other facilities. (Account 1808, 1908, 1915)

- **Computer Hardware and Software**

These capital expenditures pertain to the acquisition of new and replacement computer hardware and new and upgraded computer software applications, based on a three year life cycle. (Account 1920, 1925)

- **Transportation Equipment**

These capital expenditures pertain to the acquisition and modification of new vehicles to support the construction and maintenance of the electricity distribution system for LPDL. (Account 1930)

- **Tools and Equipment**

These capital expenditures pertain to the replacement of tools and equipment that are worn or have come to the end of their useful life, with newer and more ergonomically friendly tools and equipment. (Account 1940)

- **Communication Equipment and SCADA**

These capital expenditures pertain to the purchase of telephone equipment, meter reading and mobile communication equipment, fibre communication and Supervisory Control and Data Acquisition (SCADA) system application and equipment. (Account 1955, 1980)

LPDL's capital projects for the 2013 Test Year are discussed in further detail in Exhibit 2, Tab 3, Schedule 2. LPDL has provided project-specific justifications for 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and 2013 Test Year.

LPDL does not capitalize interest nor does it capitalize, through internal cost allocations, indirect administrative supports costs such as Finance or Engineering.

Gross Assets – Property, Plant and Equipment and Accumulated Amortization

The 2012 Bridge and 2013 Test Years' gross asset balances reflect the capital expenditure programs forecast for both years. Analyses of 2009 to 2013 capital programs are described in detail in LPDL's written evidence in Exhibit 2, Tab 3, Schedule 2.

LPDL Budget Process

LPDL's Asset Management Plan, which sets out processes for determining the necessary distribution system investments to ensure safe and reliable delivery of electricity to its customers, accompanies this Exhibit as Appendix A.

- **Overall Budget Process**

The budget is prepared annually by management and is reviewed and approved by LPDL's Board of Directors. The budget is prepared before the start of each fiscal year. Once approved, it typically does not change but provides a plan against which actual results may be evaluated.

- **Responsibilities**

  - It is the responsibility of the Finance department to co-ordinate the development of and review of the operating budget, capital budget and forecast processes.
  - Each department manager is responsible for preparing its respective operating budget and capital budget.
  - The CEO, CFO and COO are responsible for presenting and recommending the budget to the Board of Directors for approval.
  - It is the responsibility of the Board of Directors, on behalf of the shareholders, to approve the budget.

The budget is an important planning tool for LPDL. It puts capital and operational plans into a common financial plan. The final document provides a comprehensive package of departmental budgets that collectively ensure that appropriate resources are designated for the various capital and operational needs of the utility for the coming year.

The departmental Budget Plans represent the output of detailed work plans based on required activities for the year. LPDL notes that these Budget Plans address both capital and operating requirements.

- **Budget Review Process**

LPDL budget review process is as follows:

  - Each department budget is reviewed and approved by the corresponding manager and submitted to the Finance department.

- The Finance department consolidates all departmental work plan budgets to produce budget reports by functional areas to be reviewed by the corresponding Executive Team member(s).
- The Executive Team member(s) will then have an opportunity to make recommendations to the consolidated budgets.
- A final budget package is produced to present to the Executive Team for its review and approval.

- **The Actual-to-Budget Review Process**

Once the budget is final, each department reviews and tracks progress against the budget on a monthly basis. This review process involves the following activities:

- All Managers review budget progress on a monthly basis.
- All Managers review year-to-date ("YTD") operating results for their area(s) of responsibility on a monthly basis.
- Significant variances in capital and operating expenditures based on YTD results are reviewed along with work plans in order to identify any changes that may have an impact on actual expenditures.
- All significant variances are reported to the Board of Directors on a monthly basis by the CFO
- A revised forecast is produced each month to account for major changes in operational assumptions or new customer demand projects.

VARIANCE ANALYSIS OF RATE BASE:

Table 2.1.2 - 2009 Approved Rate Base vs. 2009 Actual

Description	2009 OEB Approved*	2009 Actual	Variance
Gross Fixed Assets	21,438,673	21,423,286	(15,387)
Accumulated Depreciation	8,538,320	8,368,003	(170,317)
Net Book Value	12,900,353	13,055,283	154,930
Average Net Book Value	12,577,880	12,551,638	(26,242)
Working Capital	22,489,355	19,154,580	(3,334,775)
Working Capital Allowance	3,373,403	2,873,187	(500,216)
Rate Base	15,951,283	15,424,825	(526,458)

The 2009 Approved Gross Fixed Assets and Accumulated Amortization amounts were slightly higher than LPDL's 2009 audited actuals. The 2009 actual rate base of $15,424,825 was $(526,458) lower than the 2009 Board Approved rate base of $15,951,283. Capital spending in 2009 was only $(15,387) lower than approved however the capital was spent on longer life projects (account 1820 vs account 1930) than was forecasted in the 2009 Cost of Service application. This resulted in a lower accumulated depreciation than was submitted, a decrease of $(170,317). This impact on Average Net Book Value for 2009 Actuals was only a slight decrease of $(26,242) to rate base, in addition to a lower than anticipated allowance on working capital expenses of $(500,216), mainly due to a lower than expected cost of power in 2009 than was included in 2009 Board Approved, a decrease of $(3,312,423) (WCA 15% =$496,863). Detailed calculations for the Working Capital Allowance are available in Exhibit 2, Tab 1, Schedule 1 Table 2.1.1 (a) and Table 2.1.1 (b).

Table 2.1.3 - 2009 Actual vs. 2010 Actual

Description	2009 Actual	2010 Actual	Variance
Gross Fixed Assets	21,423,286	23,061,632	1,638,347
Accumulated Depreciation	8,368,003	9,390,834	1,022,832
Net Book Value	13,055,283	13,670,798	615,515
Average Net Book Value	12,551,638	13,363,040	811,403
Working Capital	19,154,580	20,120,909	966,329
Working Capital Allowance	2,873,187	3,018,136	144,949
Rate Base	15,424,825	16,381,177	956,352

The rate base of $16,381,177 for 2010 was an increase of $956,352 over 2009. This increase is primarily the result of an increase in average net fixed assets of $811,403, due to capital expenditures in 2010, as well as an increase in working capital allowance of $144,949, mainly due to increased cost of power in 2010. Detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2. Detailed calculations for the Working Capital Allowance are available in Exhibit 2, Tab 1, Schedule 1 Table 2.1.1 (a) and Table 2.1.1 (b).

Table 2.1.4a - 2010 Actual vs. 2011 Actual

Description	2010 Actual	2011 Actual	Variance
Gross Fixed Assets	23,061,632	26,799,933	3,738,300
Accumulated Depreciation	9,390,834	10,453,632	1,062,798
Net Book Value	13,670,798	16,346,301	2,675,503
Average Net Book Value	13,363,040	15,008,549	1,645,509
Working Capital	20,120,909	21,423,501	1,302,591
Working Capital Allowance	3,018,136	3,213,525	195,389
Rate Base	16,381,177	18,222,074	1,840,898

Table 2.1.4b - Gross Fixed Assets and Accumulated Depreciation with Approved Smart Meter Disposition to Fixed Assets

Description	2010 Actual	2011 Actual	Variance
Gross Fixed Assets	23,061,632	25,527,750	2,466,117
Add: Smart Meter Disposition to 1860		1,619,923	1,619,923
Less: Stranded Assets from 1860		(1,006,849)	(1,006,849)
Add: Smart Meter Disposition to 1611		202,361	202,361
Add: Smart Meter Disposition to 1920		46,164	46,164
Add: Smart Meter Disposition to 1955		410,583	410,583
Smart Meter Disposition to Fixed Assets	0	1,272,183	1,272,183
Gross Fixed Assets with Smart Meters	23,061,632	26,799,933	3,738,300
Accumulated Depreciation	9,390,834	10,548,742	1,157,908
Add: Smart Meter Disposition on 1860		127,044	127,044
Less: Stranded Assets from 1860		(419,887)	(419,887)
Add: Smart Meter Disposition on 1611		60,708	60,708
Add: Smart Meter Disposition on 1920		13,849	13,849
Add: Smart Meter Disposition on 1955		123,175	123,175
Smart Meter Disposition to Accum Deprec	0	(95,110)	(95,110)
Accumulated Depcrec with Smart Meters	9,390,834	10,453,632	1,062,798

Gross fixed assets increased in 2011 by $3,738,300. As can be seen in Table 2.1.4b above, this was partially due to 2011 capital spending of $2,466,117, of which $1,188,048 was due to the expansion of LPDL's operation facility. As well, LPDL's smart meter disposition reclass to fixed assets in 2012, approved as per Board File No. EB-2011-0413, is reflected in the adjusted ending balance of 2011 Gross Fixed Assets with an increase of $1,272,183 (net of Stranded Meters of $(1,006,849)). This has resulted in an increase to Average Net Book Value of $1,645,509. In addition to this increase, the working capital allowance increased in 2011 by $195,389, mainly due to an increase in cost of power over 2010, resulting in a total increase to 2011 rate base of $1,840,898. Exhibit 2, Tab 3, Schedule 2 provides details of the capital projects in 2011. Detailed calculations for the Working Capital Allowance are available in Exhibit 2, Tab 1, Schedule 1 Table 2.1.1 (a) and Table 2.1.1 (b).

Table 2.1.5a - 2011 Actual vs. 2012 Bridge Year (CGAAP)

Description	2011 Actual	2012 Bridge CGAAP	Variance
Gross Fixed Assets	26,799,933	28,387,201	1,587,268
Accumulated Depreciation	10,453,632	11,861,554	1,407,922
Net Book Value	16,346,301	16,525,646	179,346
Average Net Book Value	15,008,549	16,435,973	1,427,424
Working Capital	21,423,501	24,591,397	3,167,896
Working Capital Allowance	3,213,525	3,688,709	475,184
Rate Base	18,222,074	20,124,683	1,902,608

In the 2012 Bridge Year (CGAAP), rate base is forecasted to increase by $1,902,608. This increase is primarily the result of an increase in average net fixed assets of $1,427,424, due to capital expenditures in 2012, as well as an increase in working capital allowance of $475,184, mainly due to increases in 2012 in cost of power, billing and collecting and administration and general expenses. Detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2. Detailed calculations for the Working Capital Allowance are available in Exhibit 2, Tab 1, Schedule 1 Table 2.1.1 (a) and Table 2.1.1 (b).

Table 2.1.5b - 2011 Actual vs. 2012 Bridge Year (MIFRS)

Description	2011 Actual	2012 Bridge MIFRS	Variance
Gross Fixed Assets	26,799,933	28,260,840	1,460,907
Accumulated Depreciation	10,453,632	11,500,799	1,047,167
Net Book Value	16,346,301	16,760,041	413,740
Average Net Book Value	15,008,549	16,553,171	1,544,621
Working Capital	21,423,501	24,591,397	3,167,896
Working Capital Allowance	3,213,525	3,688,709	475,184
Rate Base	18,222,074	20,241,880	2,019,806

In the 2012 Bridge Year (MIFRS), the forecasted rate base has now increased by $2,019,806 compared to 2011 Actuals. This increase is primarily the result of an increase in gross fixed assets of $1,460,907, due to capital expenditures in 2012 offset by additional asset disposals written off as per MIFRS requirements in 2012, of $126,361. The Average Net Book Value has increased by $1,544,621, which is a greater increase than when compared to 2012 Bridge Year (CGAAP) due to the reduction of accumulated depreciation due to longer useful lives as per MIFRS (MIFRS impact of $117,197). The working capital allowance increase of $475,184, is again mainly due to increases in 2012 in cost of power, billing and collecting and administration and general expenses. Detailed information on the capital projects for 2012 can be found in Exhibit 2, Tab 3, Schedule 2. Detailed calculations for the Working Capital Allowance are available in Exhibit 2, Tab 1, Schedule 1 Table 2.1.1 (a) and Table 2.1.1 (b).

Table 2.1.6 - 2012 Bridge Year (MIFRS) vs. 2013 Test Year (MIFRS)

Description	2012 Bridge MIFRS	2013 Test MIFRS	Variance
Gross Fixed Assets	28,260,840	30,033,741	1,772,901
Accumulated Depreciation	11,500,799	12,389,031	888,232
Net Book Value	16,760,041	17,644,710	884,670
Average Net Book Value	16,553,171	17,202,376	649,205
Working Capital	24,591,397	24,372,189	(219,207)
Working Capital Allowance	3,688,709	3,168,385	(520,325)
Rate Base	20,241,880	20,370,760	128,880

In the 2013 Test Year (MIFRS), the overall rate base is projected to increase by $128,880. This increase is the result of an increase in average net fixed assets of $649,205, due to capital expenditures in 2013 offset by the write off of net asset disposals, offset by a large decrease in working capital allowance of $(520,325). This large decrease is mainly due to the reduction of the working capital allowance rate from 15% to 13% in 2013 in addition to the slight decrease in cost of power. Detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2. Detailed calculations for the Working Capital Allowance are available in Exhibit 2, Tab 1, Schedule 1 Table 2.1.1 (a) and Table 2.1.1 (b).

Stranded Meters

Per The Board's 'Guideline: Smart Meter Funding and Cost Recovery (G-2008-0002)', LPDL had chosen option one in accounting for stranded meters and left the value of the stranded meters in rate base (Account 1860). In the fall of 2011, LPDL had filed for rate recovery of smart meter costs as per the latest guidance issued in 'Guideline: G2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition'. LPDL received approval for smart meter disposition and rate recovery by the Board effective for May 1, 2012. This smart meter filing and approved rate recovery did not include stranded meter disposal and recovery, as they are to be included as part of LPDL's 2013 Cost of Service Application.

Table 2.1.7 - NBV of Stranded Meters for 2012

Description	
Stranded Meters as of Dec/09	1,006,849
Accumulated Amortization as of Dec/09	- 419,887
NBV of Stranded Meters as of Dec/09	586,962
Amortization to be taken for 2010 in 2012	- 46,851
Amortization to be taken for 2011 in 2012	- 46,851
Amortization to be taken for 2012 in 2012	- 46,851
NBV of Stranded Meters for Disposal in 2012	446,409

After 2009, LPDL had stranded meter assets of $ 1,006,849 and had stopped recording amortization on these assets. At December 31, 2009 the net book value of the stranded meters was $ 586,962 as shown in Table 2.1.7 above. No capital contributions or proceeds from disposal were applicable to LPDL's stranded meters as they consisted of residential and general service <50kW customers who are not charged for the cost of meters. To reflect the adjusted net book value of these assets for 2012, LPDL has recorded an amortization expense in 2012 of 140,553 ($46,851 per year for 2010, 2011 and 2012). This adjusted 2012 net book value of $446,409 has been removed from rate base for 2012 and reclassed to Account 1555 'Sub-Account Stranded Meters', as approved in LPDL's smart meter decision Board File No. EB-2011-0413.

The proposed treatment for recovery of stranded meter assets (via rate rider), disposition period and associated bill impacts will be explained in Section 2.12.6 Smart Meters with Exhibit 9 Disposition of Deferral and Variance Accounts.

CONTINUITY STATEMENTS FOR GROSS ASSETS – PROPERTY, PLANT & EQUIPMENT AND ACCUMULATED AMORTIZATION:

The Fixed Asset Continuity Schedules for 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year (CGAAP and MIFRS) and 2013 Test Year (MIFRS) are included below in Tables 2.2.1 to 2.2.5 (accounts used in accordance with APH). The variances of Gross Assets and Accumulated Amortization for the same above noted periods are provided below in Tables 2.2.6 and 2.2.7 respectively.

As stated, the Fixed Asset Schedules, Gross Assets and Accumulated Amortization tables for the 2012 Bridge Year are presented on both CGAAP and MIFRS. The 2013 Test Year tables are presented on MIFRS. The conversion from CGAAP to MIFRS has resulted in some changes to LPDL's accounting for Property, Plant and Equipment (PP&E).

LPDL has elected to take the IFRS 1 Exemption for rate regulated entities, which allows for the use of the net book value of assets as at the date of transition as the deemed cost of the asset. This change has been reflected in the continuity statements provided below for the 2012 Bridge Year (MIFRS) and the 2013 Test Year.

IAS 16 requires each part of an item of PP&E with a cost that is significant in relation to the total cost to be depreciated separately. In addition IAS 16 requires that entities perform a review of its useful lives, amortization methods and residual values on an annual basis. With the engagement of a third party asset valuation firm along with the aid of the Jul 8, 2010 Kinetrics Report entitled "Asset Depreciation Study for the Ontario Energy Board", LPDL has reviewed the useful lives of its assets and established remaining useful lives and net book values of assets at December 2010. LPDL has restated its continuity statements for the 2012 Bridge Year and 2013 Test Year to include these changes as presented under the MIFRS schedules below.

Table 2.2.1 - Fixed Asset Continuity Schedule - 2009

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 136,627	$ 32,961		$ 169,588	$ 102,552	$ 18,387		$ 120,939	$ 48,649
12	1611	Computer Software (Formally known as Account 1925) - Smart Meters					$ -				$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ 477,645	$ 6,720		$ 484,365	$ 15,147			$ 15,147	$ 469,218
N/A	1805	Land					$ -				$ -	$ -
47	1808	Buildings		$ 604,107			$ 604,107	$ 96,273	$ 19,173		$ 115,446	$ 488,661
13	1810	Leasehold Improvements					$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV					$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 1,434,423	$ 1,212,421		$ 2,646,844	$ 512,986	$ 98,710		$ 611,696	$ 2,035,148
47	1825	Storage Battery Equipment					$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 5,131,378	$ 214,146		$ 5,345,524	$ 2,039,665	$ 265,869		$ 2,305,534	$ 3,039,990
47	1835	Overhead Conductors & Devices		$ 2,779,360	$ 122,595		$ 2,901,955	$ 662,542	$ 116,389		$ 778,931	$ 2,123,024
47	1840	Underground Conduit		$ 2,874,723	$ 62,646		$ 2,937,369	$ 1,081,690	$ 132,822		$ 1,214,512	$ 1,722,857
47	1845	Underground Conductors & Devices		$ 1,396,165	$ 112,081		$ 1,508,246	$ 328,086	$ 59,149		$ 387,235	$ 1,121,011
47	1850	Line Transformers		$ 4,479,935	$ 460,925		$ 4,940,860	$ 1,467,143	$ 245,938		$ 1,713,081	$ 3,227,779
47	1855	Services (Overhead & Underground)		$ 366,831	$ 44,022		$ 410,853	$ 67,702	$ 15,553		$ 83,255	$ 327,598
47	1860	Meters		$ 1,109,842	$ 4,202		$ 1,114,044	$ 411,195	$ 51,728		$ 462,923	$ 651,121
47	1860	Meters (Stranded Meters)					$ -				$ -	$ -
47	1860	Meters (Smart Meters)					$ -				$ -	$ -
N/A	1905	Land		$ 278,455			$ 278,455				$ -	$ 278,455
47	1908	Buildings & Fixtures		$ 165,678	$ 10,328		$ 176,006	$ 32,951	$ 5,969		$ 38,920	$ 137,086
13	1910	Leasehold Improvements					$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 161,887	$ 4,277		$ 166,164	$ 89,668	$ 13,596		$ 103,264	$ 62,900
8	1915	Office Furniture & Equipment (5 years)					$ -				$ -	$ -
10	1920	Computer Equipment - Hardware		$ 175,959			$ 175,959	$ 175,959			$ 175,959	-$ 0
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ 105,477			$ 105,477	$ 71,616	$ 18,763		$ 90,379	$ 15,098
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ 57,475	$ 18,481		$ 75,956	$ 12,433	$ 13,343		$ 25,776	$ 50,180
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07) - Smart Meters					$ -				$ -	$ -
10	1930	Transportation Equipment		$ 1,087,661	$ 105,935	-$ 135,370	$ 1,058,226	$ 573,311	$ 128,464	-$ 119,644	$ 582,131	$ 476,095
8	1935	Stores Equipment		$ 10,960			$ 10,960	$ 6,124	$ 820		$ 6,944	$ 4,016
8	1940	Tools, Shop & Garage Equipment		$ 200,446	$ 34,994		$ 235,440	$ 126,535	$ 14,524		$ 141,059	$ 94,381
8	1945	Measurement & Testing Equipment					$ -				$ -	$ -
8	1950	Power Operated Equipment					$ -				$ -	$ -
8	1955	Communications Equipment		$ 185,693	$ 3,028		$ 188,721	$ 81,000	$ 18,914		$ 99,914	$ 88,807
8	1955	Communication Equipment (Smart Meters)					$ -				$ -	$ -
8	1960	Miscellaneous Equipment					$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises					$ -				$ -	$ -
47	1980	System Supervisor Equipment					$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets					$ -				$ -	$ -
47	1995	Contributions & Grants		-$ 3,765,651	-$ 346,183		-$ 4,111,834	-$ 547,497	-$ 157,546		-$ 705,043	-$ 3,406,791
	etc.						$ -				$ -	$ -
		Total		**$ 19,455,075**	**$ 2,103,579**	**-$ 135,370**	**$ 21,423,284**	**$ 7,407,081**	**$ 1,080,565**	**-$ 119,644**	**$ 8,368,002**	**$ 13,055,282**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 128,464
Stores Equipment	
Net Depreciation	$ 952,101

Table 2.2.2 - Fixed Asset Continuity Schedule - 2010

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 169,588	$ 33,016		$ 202,604	$ 120,939	$ 19,732		$ 140,671	$ 61,933
12	1611	Computer Software (Formally known as Account 1925) - Smart Meters		$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ 484,365	$ 8,989		$ 493,354	$ 15,147			$ 15,147	$ 478,207
N/A	1805	Land		$ -			$ -	$ -			$ -	$ -
47	1808	Buildings		$ 604,107	$ 48,829		$ 652,936	$ 115,446	$ 19,987		$ 135,433	$ 517,503
13	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 2,646,844	$ 527,917		$ 3,174,761	$ 611,696	$ 133,516		$ 745,212	$ 2,429,549
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 5,345,524	$ 210,551		$ 5,556,075	$ 2,305,534	$ 274,363		$ 2,579,897	$ 2,976,178
47	1835	Overhead Conductors & Devices		$ 2,901,955	$ 218,685		$ 3,120,640	$ 778,931	$ 123,215		$ 902,146	$ 2,218,494
47	1840	Underground Conduit		$ 2,937,369	$ 99,412		$ 3,036,781	$ 1,214,512	$ 136,063		$ 1,350,575	$ 1,686,206
47	1845	Underground Conductors & Devices		$ 1,508,246	$ 191,236		$ 1,699,482	$ 387,235	$ 65,216		$ 452,451	$ 1,247,031
47	1850	Line Transformers		$ 4,940,860	$ 579,658		$ 5,520,518	$ 1,713,081	$ 266,750		$ 1,979,831	$ 3,540,687
47	1855	Services (Overhead & Underground)		$ 410,853	$ 73,798		$ 484,651	$ 83,255	$ 17,909		$ 101,164	$ 383,487
47	1860	Meters		$ 107,195	$ 86,067		$ 193,262	$ 43,036	$ 6,712		$ 49,748	$ 143,514
47	1860	Meters (Stranded Meters)		$ 1,006,849			$ 1,006,849	$ 419,887			$ 419,887	$ 586,962
47	1860	Meters (Smart Meters)		$ -			$ -	$ -			$ -	$ -
N/A	1905	Land		$ 278,455			$ 278,455	$ -			$ -	$ 278,455
47	1908	Buildings & Fixtures		$ 176,006	-$ 1,620		$ 174,386	$ 38,920	$ 6,141		$ 45,061	$ 129,325
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 166,164			$ 166,164	$ 103,264	$ 11,871		$ 115,135	$ 51,029
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 175,959			$ 175,959	$ 175,959			$ 175,959	-$ 0
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ 105,477			$ 105,477	$ 90,379	$ 11,656		$ 102,035	$ 3,441
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ 75,956	$ 2,910		$ 78,866	$ 25,776	$ 15,483		$ 41,259	$ 37,607
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07) - Smart Meters		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 1,058,226	$ 192,275	-$ 74,989	$ 1,175,512	$ 582,131	$ 121,384	-$ 62,964	$ 640,551	$ 534,961
8	1935	Stores Equipment		$ 10,960			$ 10,960	$ 6,944	$ 820		$ 7,764	$ 3,196
8	1940	Tools, Shop & Garage Equipment		$ 235,440	$ 2,574		$ 238,014	$ 141,059	$ 16,123		$ 157,182	$ 80,832
8	1945	Measurement & Testing Equipment		$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ 188,721			$ 188,721	$ 99,914	$ 14,545		$ 114,459	$ 74,262
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		-$ 4,111,834	-$ 560,961		-$ 4,672,795	-$ 705,043	-$ 175,689		-$ 880,732	-$ 3,792,063
	etc.						$ -	$ -			$ -	$ -
		Total		**$ 21,423,284**	**$ 1,713,336**	**-$ 74,989**	**$ 23,061,631**	**$ 8,368,002**	**$ 1,085,797**	**-$ 62,964**	**$ 9,390,835**	**$ 13,670,796**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 120,293
Stores Equipment	
Net Depreciation	$ 965,504

Table 2.2.3 - Fixed Asset Continuity Schedule – 2011

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 202,604	$ 66,105		$ 268,709	$ 140,671	$ 26,053		$ 166,724	$ 101,985
12	1611	Computer Software (Formally known as Account 1925) - Smart Meters		$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ 493,354	$ 22,650		$ 516,004	$ 15,147			$ 15,147	$ 500,857
N/A	1805	Land		$ -			$ -	$ -			$ -	$ -
47	1808	Buildings		$ 652,936	$ 1,188,048		$ 1,840,984	$ 135,433	$ 40,601		$ 176,034	$ 1,664,950
13	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 3,174,761	$ 47,952		$ 3,222,713	$ 745,212	$ 145,034		$ 890,246	$ 2,332,467
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 5,556,075	$ 336,718		$ 5,892,793	$ 2,579,897	$ 285,308		$ 2,865,205	$ 3,027,588
47	1835	Overhead Conductors & Devices		$ 3,120,640	$ 257,034		$ 3,377,674	$ 902,146	$ 132,729		$ 1,034,875	$ 2,342,799
47	1840	Underground Conduit		$ 3,036,781	$ 73,853		$ 3,110,634	$ 1,350,575	$ 139,529		$ 1,490,104	$ 1,620,530
47	1845	Underground Conductors & Devices		$ 1,699,482	$ 169,062		$ 1,868,544	$ 452,451	$ 72,422		$ 524,873	$ 1,343,671
47	1850	Line Transformers		$ 5,520,518	$ 393,057		$ 5,913,575	$ 1,979,831	$ 286,204		$ 2,266,035	$ 3,647,540
47	1855	Services (Overhead & Underground)		$ 484,651	$ 76,951		$ 561,602	$ 101,164	$ 20,924		$ 122,088	$ 439,514
47	1860	Meters		$ 193,262	$ 73,679		$ 266,941	$ 49,748	$ 9,906		$ 59,654	$ 207,287
47	1860	Meters (Stranded Meters)		$ 1,006,849			$ 1,006,849	$ 419,887			$ 419,887	$ 586,962
47	1860	Meters (Smart Meters)		$ -			$ -	$ -			$ -	$ -
N/A	1905	Land		$ 278,455			$ 278,455	$ -			$ -	$ 278,455
47	1908	Buildings & Fixtures		$ 174,386			$ 174,386	$ 45,061	$ 6,141		$ 51,202	$ 123,184
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 166,164	$ 65,879		$ 232,043	$ 115,135	$ 10,964		$ 126,099	$ 105,944
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 175,959			$ 175,959	$ 175,959			$ 175,959	-$ 0
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ 105,477			$ 105,477	$ 102,035	$ 3,441		$ 105,476	$ 0
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ 78,866	$ 5,839		$ 84,705	$ 41,259	$ 16,358		$ 57,617	$ 27,088
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07) - Smart Meters		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ 1,175,512			$ 1,175,512	$ 640,551	$ 124,321		$ 764,872	$ 410,640
8	1935	Stores Equipment		$ 10,960			$ 10,960	$ 7,764	$ 820		$ 8,584	$ 2,376
8	1940	Tools, Shop & Garage Equipment		$ 238,014	$ 13,734		$ 251,748	$ 157,182	$ 16,247		$ 173,429	$ 78,319
8	1945	Measurement & Testing Equipment		$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ 188,721			$ 188,721	$ 114,459	$ 14,302		$ 128,761	$ 59,960
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		-$ 4,672,795	-$ 324,443		-$ 4,997,238	-$ 880,732	-$ 193,397		-$ 1,074,129	-$ 3,923,109
	etc.						$ -	$ -			$ -	$ -
		Total		**$ 23,061,631**	**$ 2,466,118**	**$ -**	**$ 25,527,749**	**$ 9,390,835**	**$ 1,157,907**	**$ -**	**$ 10,548,742**	**$ 14,979,007**
	1555	**Smart Meters - Meters**					**$ 1,619,923**				**$ 127,044**	**$ 1,492,880**
	1555	**Smart Meters - Software**					**$ 202,361**				**$ 60,708**	**$ 141,653**
	1555	**Smart Meters - Hardware**					**$ 46,164**				**$ 13,849**	**$ 32,315**
	1555	**Smart Meters - Communication**					**$ 410,583**				**$ 123,175**	**$ 287,408**
	1555	**Smart Meters - Stranded meters**					**-$ 1,006,849**				**-$ 419,887**	**-$ 586,962**
							$ 26,799,932				$ 10,453,632	$ 16,346,300

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	$ 124,321
Stores Equipment	
Net Depreciation	$ 1,033,586

Table 2.2.4(a) - Fixed Asset Continuity Schedule – 2012 (CGAAP)

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 268,709	$ 108,600		$ 377,309	$ 166,724	$ 39,718		$ 206,442	$ 170,867
12	1611	Computer Software (Formally known as Account 1925) - Smart Meters		$ 202,361			$ 202,361	$ 60,708	$ 40,472		$ 101,181	$ 101,181
CEC	1612	Land Rights (Formally known as Account 1906)		$ 516,004	$ 5,000		$ 521,004	$ 15,147			$ 15,147	$ 505,857
N/A	1805	Land		$ -			$ -	$ -			$ -	$ -
47	1808	Buildings		$ 1,840,984			$ 1,840,984	$ 176,034	$ 60,402		$ 236,436	$ 1,604,548
13	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 3,222,713	$ 105,000		$ 3,327,713	$ 890,246	$ 148,093		$ 1,038,339	$ 2,289,374
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 5,892,793	$ 224,750		$ 6,117,543	$ 2,865,205	$ 296,538		$ 3,161,743	$ 2,955,800
47	1835	Overhead Conductors & Devices		$ 3,377,674	$ 174,750		$ 3,552,424	$ 1,034,875	$ 141,365		$ 1,176,240	$ 2,376,184
47	1840	Underground Conduit		$ 3,110,634	$ 86,750		$ 3,197,384	$ 1,490,104	$ 142,741		$ 1,632,845	$ 1,564,539
47	1845	Underground Conductors & Devices		$ 1,868,544	$ 210,500		$ 2,079,044	$ 524,873	$ 80,013		$ 604,886	$ 1,474,158
47	1850	Line Transformers		$ 5,913,575	$ 288,750		$ 6,202,325	$ 2,266,035	$ 299,840		$ 2,565,875	$ 3,636,450
47	1855	Services (Overhead & Underground)		$ 561,602	$ 74,500		$ 636,102	$ 122,088	$ 23,953		$ 146,041	$ 490,061
47	1860	Meters		$ 266,941	$ 90,000		$ 356,941	$ 59,654	$ 14,379		$ 74,034	$ 282,908
47	1860	Meters (Stranded Meters)		$ -			$ -	$ -			$ -	$ -
47	1860	Meters (Smart Meters)		$ 1,619,923			$ 1,619,923	$ 127,044	$ 107,995		$ 235,039	$ 1,384,885
N/A	1905	Land		$ 278,455			$ 278,455	$ -			$ -	$ 278,455
47	1908	Buildings & Fixtures		$ 174,386			$ 174,386	$ 51,202	$ 6,141		$ 57,343	$ 117,043
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 232,043	$ 10,000		$ 242,043	$ 126,099	$ 14,758		$ 140,857	$ 101,186
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 175,959			$ 175,959	$ 175,959			$ 175,959	-$ 0
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ 105,477			$ 105,477	$ 105,476			$ 105,476	$ 0
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ 84,705	$ 10,000		$ 94,705	$ 57,617	$ 14,598		$ 72,215	$ 22,490
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07) - Smart Meters		$ 46,164			$ 46,164	$ 13,849	$ 9,233		$ 23,082	$ 23,082
10	1930	Transportation Equipment		$ 1,175,512	$ 115,000	-$ 76,332	$ 1,214,180	$ 764,872	$ 116,436	-$ 65,796	$ 815,512	$ 398,667
8	1935	Stores Equipment		$ 10,960			$ 10,960	$ 8,584	$ 820		$ 9,404	$ 1,556
8	1940	Tools, Shop & Garage Equipment		$ 251,748	$ 60,000		$ 311,748	$ 173,429	$ 17,211		$ 190,640	$ 121,108
8	1945	Measurement & Testing Equipment		$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ 188,721			$ 188,721	$ 128,761	$ 13,447		$ 142,208	$ 46,513
8	1955	Communication Equipment (Smart Meters)		$ 410,583			$ 410,583	$ 123,175	$ 82,117		$ 205,292	$ 205,292
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ -	$ 100,000		$ 100,000	$ -	$ 3,333		$ 3,333	$ 96,667
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		-$ 4,997,238			-$ 4,997,238	-$ 1,074,129	-$ 199,886		-$ 1,274,015	-$ 3,723,223
	etc.						$ -	$ -			$ -	$ -
		Total		**$ 26,799,932**	**$ 1,663,600**	**-$ 76,332**	**$ 28,387,200**	**$ 10,453,632**	**$ 1,473,717**	**-$ 65,796**	**$ 11,861,554**	**$ 16,525,647**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 116,436
Stranded Meters (in 1555)	-$ 140,553
Net Depreciation	$ 1,497,834

Table 2.2.4(b) - Fixed Asset Continuity Schedule – 2012 (MIFRS)

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 268,709	$ 108,600		$ 377,309	$ 166,724	$ 112,845		$ 279,569	$ 97,740
12	1611	Computer Software (Formally known as Account 1925) - Smart Meters		$ 202,361	$ -		$ 202,361	$ 60,708	$ 70,826		$ 131,535	$ 70,826
CEC	1612	Land Rights (Formally known as Account 1906)		$ 516,004	$ 5,000		$ 521,004	$ 15,147	$ -		$ 15,147	$ 505,857
N/A	1805	Land		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1808	Buildings		$ 1,840,984	$ -		$ 1,840,984	$ 176,034	$ 76,374		$ 252,408	$ 1,588,576
13	1810	Leasehold Improvements		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 3,222,713	$ 105,000		$ 3,327,713	$ 890,246	$ 73,037		$ 963,283	$ 2,364,430
47	1825	Storage Battery Equipment		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 5,892,793	$ 224,750	-$ 16,191	$ 6,101,352	$ 2,865,205	$ 206,375	-$ 9,020	$ 3,062,560	$ 3,038,792
47	1835	Overhead Conductors & Devices		$ 3,377,674	$ 174,750	-$ 12,715	$ 3,539,709	$ 1,034,875	$ 152,605	-$ 7,502	$ 1,179,978	$ 2,359,731
47	1840	Underground Conduit		$ 3,110,634	$ 86,750		$ 3,197,384	$ 1,490,104	$ 46,275		$ 1,536,379	$ 1,661,005
47	1845	Underground Conductors & Devices		$ 1,868,544	$ 210,500	-$ 22,250	$ 2,056,794	$ 524,873	$ 66,323	-$ 13,128	$ 578,068	$ 1,478,725
47	1850	Line Transformers		$ 5,913,575	$ 288,750	-$ 29,929	$ 6,172,396	$ 2,266,035	$ 192,015	-$ 15,361	$ 2,442,689	$ 3,729,707
47	1855	Services (Overhead & Underground)		$ 561,602	$ 74,500		$ 636,102	$ 122,088	$ 13,222		$ 135,310	$ 500,792
47	1860	Meters		$ 266,941	$ 90,000	-$ 24,576	$ 332,365	$ 59,654	$ 18,355	-$ 2,458	$ 75,551	$ 256,814
47	1860	Meters (Stranded Meters)		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1860	Meters (Smart Meters)		$ 1,619,923	$ -	-$ 20,700	$ 1,599,223	$ 127,044	$ 110,584	-$ 2,070	$ 235,557	$ 1,363,666
N/A	1905	Land		$ 278,455	$ -		$ 278,455	$ -	$ -		$ -	$ 278,455
47	1908	Buildings & Fixtures		$ 174,386	$ -		$ 174,386	$ 51,202	$ 5,651		$ 56,853	$ 117,533
13	1910	Leasehold Improvements		$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 232,043	$ 10,000		$ 242,043	$ 126,099	$ 21,647		$ 147,746	$ 94,297
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware		$ 175,959	$ -		$ 175,959	$ 175,959	$ -		$ 175,959	-$ 0
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ 105,477	$ -		$ 105,477	$ 105,476	$ -		$ 105,476	$ 0
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ 84,705	$ 10,000		$ 94,705	$ 57,617	$ 28,088		$ 85,705	$ 9,000
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07) - Smart Meters		$ 46,164	$ -		$ 46,164	$ 13,849	$ 10,772		$ 24,621	$ 21,543
10	1930	Transportation Equipment		$ 1,175,512	$ 115,000	-$ 76,332	$ 1,214,180	$ 764,872	$ 77,415	-$ 65,796	$ 776,491	$ 437,689
8	1935	Stores Equipment		$ 10,960	$ -		$ 10,960	$ 8,584	$ 697		$ 9,281	$ 1,679
8	1940	Tools, Shop & Garage Equipment		$ 251,748	$ 60,000		$ 311,748	$ 173,429	$ 22,778		$ 196,207	$ 115,541
8	1945	Measurement & Testing Equipment		$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1950	Power Operated Equipment		$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment		$ 188,721	$ -		$ 188,721	$ 128,761	$ 13,944		$ 142,705	$ 46,016
8	1955	Communication Equipment (Smart Meters)		$ 410,583	$ -		$ 410,583	$ 123,175	$ 33,813		$ 156,988	$ 253,596
8	1960	Miscellaneous Equipment		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment		$ -	$ 100,000		$ 100,000	$ -	$ 2,500		$ 2,500	$ 97,500
47	1985	Miscellaneous Fixed Assets		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants		-$ 4,997,238	$ -		-$ 4,997,238	-$ 1,074,129	-$ 193,638		-$ 1,267,767	-$ 3,729,471
	etc.				$ -		$ -	$ -	$ -		$ -	$ -
									0			
		Total		**$ 26,799,932**	**$ 1,663,600**	**-$ 202,693**	**$ 28,260,840**	**$ 10,453,632**	**$ 1,162,500**	**-$ 115,334**	**$ 11,500,798**	**$ 16,760,042**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 77,415
Stranded Meters (in 1555)	-$ 140,553
Net Depreciation	$ 1,225,638

Table 2.2.5 - Fixed Asset Continuity Schedule – 2013 (MIFRS)

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 377,309	$ 10,000		$ 387,309	$ 279,569	$ 22,720		$ 302,289	$ 85,020
12	1611	Computer Software (Formally known as Account 1925) - Smart Meters		$ 202,361			$ 202,361	$ 131,535	$ 70,826		$ 202,361	$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ 521,004	$ 5,000		$ 526,004	$ 15,147	$ -		$ 15,147	$ 510,857
N/A	1805	Land		$ -			$ -	$ -	$ -		$ -	$ -
47	1808	Buildings		$ 1,840,984		-$ 1,111	$ 1,839,873	$ 252,408	$ 76,374	-$ 441	$ 328,341	$ 1,511,532
13	1810	Leasehold Improvements		$ -			$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -	$ -		$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 3,327,713	$ 150,000		$ 3,477,713	$ 963,283	$ 76,224		$ 1,039,507	$ 2,438,206
47	1825	Storage Battery Equipment		$ -			$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 6,101,352	$ 147,400	-$ 7,373	$ 6,241,379	$ 3,062,560	$ 210,027	-$ 3,884	$ 3,268,704	$ 2,972,676
47	1835	Overhead Conductors & Devices		$ 3,539,709	$ 123,000	-$ 3,972	$ 3,658,738	$ 1,179,978	$ 154,749	-$ 2,565	$ 1,332,163	$ 2,326,575
47	1840	Underground Conduit		$ 3,197,384	$ 155,500		$ 3,352,884	$ 1,536,379	$ 49,303		$ 1,585,682	$ 1,767,202
47	1845	Underground Conductors & Devices		$ 2,056,794	$ 404,500	-$ 27,724	$ 2,433,569	$ 578,068	$ 72,902	-$ 18,718	$ 632,253	$ 1,801,317
47	1850	Line Transformers		$ 6,172,396	$ 297,800		$ 6,470,196	$ 2,442,689	$ 198,595		$ 2,641,284	$ 3,828,913
47	1855	Services (Overhead & Underground)		$ 636,102	$ 111,800		$ 747,902	$ 135,310	$ 15,292		$ 150,603	$ 597,299
47	1860	Meters		$ 332,365	$ 84,500	-$ 49,152	$ 367,713	$ 75,551	$ 22,533	-$ 8,192	$ 89,892	$ 277,821
47	1860	Meters (Stranded Meters)		$ -			$ -	$ -	$ -		$ -	$ -
47	1860	Meters (Smart Meters)		$ 1,599,223	$ 15,500	-$ 2,700	$ 1,612,023	$ 235,557	$ 109,720	-$ 450	$ 344,828	$ 1,267,196
N/A	1905	Land		$ 278,455			$ 278,455	$ -	$ -		$ -	$ 278,455
47	1908	Buildings & Fixtures		$ 174,386			$ 174,386	$ 56,853	$ 5,651		$ 62,503	$ 111,883
13	1910	Leasehold Improvements		$ -			$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 242,043	$ 10,000		$ 252,043	$ 147,746	$ 22,647		$ 170,392	$ 81,651
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware		$ 175,959			$ 175,959	$ 175,959	$ -		$ 175,959	-$ 0
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ 105,477			$ 105,477	$ 105,476	$ -		$ 105,476	$ 0
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ 94,705			$ 94,705	$ 85,705	$ 2,000		$ 87,705	$ 7,000
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07) - Smart Meters		$ 46,164			$ 46,164	$ 24,621	$ 10,772		$ 35,392	$ 10,772
10	1930	Transportation Equipment		$ 1,214,180	$ 395,000	-$ 190,067	$ 1,419,113	$ 776,491	$ 101,869	-$ 190,067	$ 688,293	$ 730,820
8	1935	Stores Equipment		$ 10,960			$ 10,960	$ 9,281	$ 697		$ 9,978	$ 982
8	1940	Tools, Shop & Garage Equipment		$ 311,748	$ 45,000		$ 356,748	$ 196,207	$ 28,028		$ 224,234	$ 132,514
8	1945	Measurement & Testing Equipment		$ -			$ -	$ -	$ -		$ -	$ -
8	1950	Power Operated Equipment		$ -			$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment		$ 188,721			$ 188,721	$ 142,705	$ 13,944		$ 156,649	$ 32,072
8	1955	Communication Equipment (Smart Meters)		$ 410,583			$ 410,583	$ 156,988	$ 33,813		$ 190,800	$ 219,783
8	1960	Miscellaneous Equipment		$ -			$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment		$ 100,000	$ 100,000		$ 200,000	$ 2,500	$ 7,500		$ 10,000	$ 190,000
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants		-$ 4,997,238			-$ 4,997,238	-$ 1,267,767	-$ 193,638		-$ 1,461,405	-$ 3,535,833
	etc.						$ -	$ -	$ -		$ -	$ -
									0			
		Total		**$ 28,260,840**	**$ 2,055,000**	**-$ 282,099**	**$ 30,033,741**	**$ 11,500,798**	**$ 1,112,547**	**-$ 224,317**	**$ 12,389,029**	**$ 17,644,712**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 101,869
Deferred PP&E	$ 58,599
Net Depreciation	$ 952,080

GROSS ASSETS TABLE:

Table 2.2.6 - Gross Asset Table

Description	2009 Board Approved ($)	2009 Actual ($)	Variance from 2009 Board Approved	2010 Actual ($)	Variance from 2009 Actual	2011 Actual ($)	Variance from 2010 Actual	2012 Bridge CGAAP ($)	Variance from 2011 Actual	2012 Bridge MIFRS ($)	Variance from 2011 Actual	2013 Test MIFRS ($)	Variance from 2012 Bridge (MIFRS)
Land and Buildings													
1612-Land Rights	477,645	484,365	6,720	493,354	8,989	516,004	22,650	521,004	5,000	521,004	5,000	526,004	5,000
1808-Buildings and Fixtures	611,163	604,107	(7,056)	652,936	48,829	1,840,984	1,188,048	1,840,984	0	1,840,984	0	1,839,873	(1,111)
1905-Land	278,455	278,455	0	278,455	0	278,455	0	278,455	0	278,455	0	278,455	0
Sub-Total-Land and Buildings	**1,367,263**	**1,366,927**	**(336)**	**1,424,745**	**57,818**	**2,635,443**	**1,210,698**	**2,640,443**	**5,000**	**2,640,443**	**5,000**	**2,644,332**	**3,889**
DS													
1820-Distribution Station Equipment - Normally Primary below 50 kV	1,934,423	2,646,844	712,421	3,174,761	527,917	3,222,714	47,952	3,327,714	105,000	3,327,714	105,000	3,477,714	150,000
Sub-Total-DS	**1,934,423**	**2,646,844**	**712,421**	**3,174,761**	**527,917**	**3,222,714**	**47,952**	**3,327,714**	**105,000**	**3,327,714**	**105,000**	**3,477,714**	**150,000**
Poles and Wires													
1830-Poles, Towers and Fixtures	5,487,061	5,345,524	(141,537)	5,556,074	210,551	5,892,793	336,718	6,117,543	224,750	6,101,352	208,559	6,241,379	140,027
1835-Overhead Conductors and Devices	2,934,942	2,901,954	(32,987)	3,120,640	218,685	3,377,674	257,034	3,552,424	174,750	3,539,709	162,035	3,658,738	119,028
1840-Underground Conduit	3,017,365	2,937,369	(79,996)	3,036,781	99,412	3,110,633	73,853	3,197,383	86,750	3,197,383	86,750	3,352,883	155,500
1845-Underground Conductors and Devices	1,480,616	1,508,247	27,631	1,699,483	191,236	1,868,545	169,062	2,079,045	210,500	2,056,794	188,250	2,433,570	376,776
Sub-Total-Poles and Wires	**12,919,983**	**12,693,094**	**(226,889)**	**13,412,978**	**719,884**	**14,249,644**	**836,667**	**14,946,394**	**696,750**	**14,895,238**	**645,594**	**15,686,570**	**791,331**
Line Transformers													
1850-Line Transformers	4,429,249	4,940,860	511,611	5,520,518	579,658	5,913,575	393,057	6,202,325	288,750	6,172,396	258,821	6,470,196	297,800
Sub-Total-Line Transformers	**4,429,249**	**4,940,860**	**511,611**	**5,520,518**	**579,658**	**5,913,575**	**393,057**	**6,202,325**	**288,750**	**6,172,396**	**258,821**	**6,470,196**	**297,800**
Services and Meters													
1855-Services	382,551	410,854	28,302	484,652	73,798	561,603	76,951	636,103	74,500	636,103	74,500	747,903	111,800
1860-Meters	1,139,825	1,114,044	(25,781)	1,200,111	86,067	1,273,790	73,679	1,976,864	703,075	1,931,588	657,799	1,979,736	48,148
Sub-Total-Services and Meters	**1,522,376**	**1,524,898**	**2,522**	**1,684,763**	**159,865**	**1,835,392**	**150,629**	**2,612,967**	**777,575**	**2,567,691**	**732,299**	**2,727,639**	**159,948**
General Plant													
1908-Buildings and Fixtures	158,565	176,006	17,441	174,386	(1,620)	174,386	0	174,386	0	174,386	0	174,386	0
Sub-Total-General Plant	**158,565**	**176,006**	**17,441**	**174,386**	**(1,620)**	**174,386**	**0**	**174,386**	**0**	**174,386**	**0**	**174,386**	**0**
IT Assets													
1920-Computer Equipment - Hardware	408,814	357,391	(51,422)	360,301	2,910	366,140	5,839	422,304	56,164	422,304	56,164	432,304	10,000
1611-Computer Software	208,777	169,588	(39,189)	202,603	33,016	268,708	66,105	579,670	310,961	579,670	310,961	589,670	10,000
Sub-Total-IT Assets	**617,590**	**526,979**	**(90,611)**	**562,905**	**35,925**	**634,848**	**71,944**	**1,001,973**	**367,125**	**1,001,973**	**367,125**	**1,021,973**	**20,000**
Equipment													
1915-Office Furniture and Equipment	150,610	166,164	15,554	166,164	0	232,043	65,879	242,043	10,000	242,043	10,000	242,043	0
1930-Transportation Equipment	1,225,672	1,058,226	(167,445)	1,175,512	117,286	1,175,512	0	1,214,180	38,668	1,214,180	38,668	1,419,113	204,933
1935-Stores Equipment	17,960	10,960	(7,000)	10,960	0	10,960	0	10,960	0	10,960	0	10,960	0
1940-Tools, Shop and Garage Equipment	223,001	235,440	12,439	238,014	2,574	251,749	13,734	311,749	60,000	311,749	60,000	356,749	45,000
1955-Communication Equipment	158,566	188,721	30,155	188,721	0	188,721	0	599,304	410,583	599,304	410,583	599,304	0
Sub-Total-Equipment	**1,775,809**	**1,659,512**	**(116,297)**	**1,779,372**	**119,860**	**1,858,985**	**79,613**	**2,378,236**	**519,251**	**2,378,236**	**519,251**	**2,628,169**	**249,933**
Other Distribution Assets													
1980-System Supervisory Equipment		0	0	0	0	0	0	100,000	100,000	100,000	100,000	200,000	100,000
1995-Contributions and Grants - Credit	(3,286,585)	(4,111,835)	(825,249)	(4,672,796)	(560,961)	(4,997,238)	(324,443)	(4,997,238)	0	(4,997,238)	0	(4,997,238)	0
Sub-Total-Other Distribution Assets	**(3,286,585)**	**(4,111,835)**	**(825,249)**	**(4,672,796)**	**(560,961)**	**(4,997,238)**	**(324,443)**	**(4,897,238)**	**100,000**	**(4,897,238)**	**100,000**	**(4,797,238)**	**100,000**
GROSS ASSET TOTAL	**21,438,673**	**21,423,286**	**(15,388)**	**23,061,632**	**1,638,347**	**25,527,750**	**2,466,117**	**28,387,201**	**2,859,451**	**28,260,840**	**2,733,090**	**30,033,741**	**1,772,901**

VARIANCE ANALYSIS ON GROSS ASSETS:

The Gross Asset Variance analysis for the variances highlighted in Table 2.2.6 of Exhibit 2, Tab 2, Schedule 2 is provided as follows.

2009 Board Approved vs. 2009 Actual

The variances in gross assets for 2009 Board Approved compared to 2009 Actual is an immaterial decrease of $(15,388), with the capital spending just reallocated amongst different projects than was submitted in the 2009 Cost of Service Application.

2009 Actual vs. 2010 Actual

The variance of $1,638,347 in gross assets for 2009 Actual compared to 2010 Actual is the result of capital expenditures in 2010 of $ $1,713,336 offset by the disposal of vehicles sold during the year (total gross book value of -$74,989).

2010 Actual vs. 2011 Actual

The variance of $2,466,117 in gross assets for 2010 Actual compared to 2011 Actual is the result of capital expenditures in 2011.

2011 Actual vs .2012 Bridge Year (CGAAP)

The increase of $2,859,451 for the 2012 Bridge Year (CGAAP) is the result of capital spending during the year of $ $1,663,600 as well the beginning balance adjustment to reflect the reclass of the approved smart meter disposition to capital of $2,279,032 offset by the stranded meter disposal (gross book value of $(1,006,849)) and disposal of vehicles sold during the year (gross book value of -$76,332).

2011 Actual vs .2012 Bridge Year (MIFRS)

The increase of $2,733,090 for the 2012 Bridge Year (MIFRS) is the result of capital spending during the year of $ $1,663,600 as well the beginning balance adjustment to reflect the reclass of the approved smart meter disposition to capital of $2,279,032 offset by the stranded meter disposal (gross book value of $(1,006,849)), disposal of vehicles sold during the year (gross book value of -$76,332) and disposal of other distribution plant equipment per MIFRS requirements (gross book value of $126,331).

2012 Bridge Year (MIFRS) vs. 2013 Test Year (MIFRS)

The variance of $1,772,901 in gross assets for the 2012 Bridge Year compared to the 2013 Test Year, both on MIFRS, are the result of capital expenditures of $2,055,000 in 2013 offset by the disposal of vehicles sold during the year (gross book value of -$190,067) and disposal of other distribution plant equipment per MIFRS requirements (gross book value of $92,032).

ACCUMULATED AMORTIZATION TABLE:

Table 2.2.7 - Accumulated Amortization Table

Description	2009 Board Approved ($)	2009 Actual ($)	Variance from 2009 Board Approved	2010 Actual ($)	Variance from 2009 Actual	2011 Actual ($)	Variance from 2010 Actual	2012 Bridge CGAAP ($)	Variance from 2011 Actual	2012 Bridge MIFRS ($)	Variance from 2011 Actual	2013 Test MIFRS ($)	Variance from 2012 Bridge (MIFRS)
Land and Buildings													
1612-Land Rights	15,147	15,147	0	15,147	0	15,147	0	15,147	0	15,147	0	15,147	0
1808-Buildings and Fixtures	119,331	115,446	(3,885)	135,433	19,987	176,034	40,601	236,436	60,402	252,408	76,374	328,341	75,933
Sub-Total-Land and Buildings	**134,478**	**130,592**	**(3,885)**	**150,579**	**19,987**	**191,181**	**40,601**	**251,583**	**60,402**	**267,555**	**76,374**	**343,488**	**75,933**
DS													
1820-Distribution Station Equipment - Normally Primary below 50 kV	597,448	611,696	14,248	745,212	133,516	890,246	145,034	1,038,339	148,093	963,283	73,037	1,039,507	76,224
Sub-Total-DS	**597,448**	**611,696**	**14,248**	**745,212**	**133,516**	**890,246**	**145,034**	**1,038,339**	**148,093**	**963,283**	**73,037**	**1,039,507**	**76,224**
Poles and Wires													
1830-Poles, Towers and Fixtures	2,234,912	2,305,534	70,622	2,579,897	274,363	2,865,206	285,308	3,161,744	296,538	3,062,561	197,355	3,268,704	206,143
1835-Overhead Conductors and Devices	777,014	778,931	1,917	902,146	123,215	1,034,875	132,729	1,176,239	141,365	1,179,978	145,103	1,332,163	152,185
1840-Underground Conduit	1,216,938	1,214,512	(2,426)	1,350,576	136,063	1,490,104	139,529	1,632,845	142,741	1,536,379	46,275	1,585,682	49,303
1845-Underground Conductors and Devices	387,654	387,235	(419)	452,450	65,216	524,872	72,422	604,885	80,013	578,067	53,195	632,251	54,184
Sub-Total-Poles and Wires	**4,616,518**	**4,686,213**	**69,695**	**5,285,069**	**598,857**	**5,915,057**	**629,988**	**6,575,713**	**660,656**	**6,356,985**	**441,928**	**6,818,800**	**461,815**
Line Transformers													
1850-Line Transformers	1,698,021	1,713,081	15,060	1,979,830	266,750	2,266,034	286,204	2,565,874	299,840	2,442,688	176,654	2,641,283	198,595
Sub-Total-Line Transformers	**1,698,021**	**1,713,081**	**15,060**	**1,979,830**	**266,750**	**2,266,034**	**286,204**	**2,565,874**	**299,840**	**2,442,688**	**176,654**	**2,641,283**	**198,595**
Services and Meters													
1855-Services	82,113	83,255	1,142	101,164	17,909	122,088	20,924	146,041	23,953	135,310	13,222	150,602	15,292
1860-Meters	464,037	462,922	(1,115)	469,633	6,711	479,540	9,906	309,071	(170,468)	311,107	(168,433)	434,718	123,612
Sub-Total-Services and Meters	**546,150**	**546,177**	**27**	**570,797**	**24,621**	**601,628**	**30,830**	**455,113**	**(146,515)**	**446,417**	**(155,211)**	**585,321**	**138,904**
General Plant													
1908-Buildings and Fixtures	38,393	38,921	528	45,062	6,141	51,204	6,141	57,345	6,141	56,855	5,651	62,506	5,651
Sub-Total-General Plant	**38,393**	**38,921**	**528**	**45,062**	**6,141**	**51,204**	**6,141**	**57,345**	**6,141**	**56,855**	**5,651**	**62,506**	**5,651**
IT Assets													
1920-Computer Equipment - Hardware	304,237	292,114	(12,123)	319,252	27,139	339,051	19,799	376,731	37,680	391,760	52,709	404,532	12,772
1611-Computer Software	134,289	120,940	(13,349)	140,672	19,732	166,725	26,053	307,624	140,899	411,105	244,379	504,650	93,546
Sub-Total-IT Assets	**438,526**	**413,054**	**(25,472)**	**459,924**	**46,871**	**505,776**	**45,852**	**684,355**	**178,579**	**802,865**	**297,089**	**909,182**	**106,318**
Equipment													
1915-Office Furniture and Equipment	100,559	103,264	2,705	115,135	11,871	126,099	10,964	140,858	14,758	147,746	21,647	170,393	22,647
1930-Transportation Equipment	793,732	582,131	(211,601)	640,551	58,420	764,873	124,321	815,513	50,640	776,492	11,619	688,293	(88,199)
1935-Stores Equipment	7,986	6,944	(1,042)	7,764	820	8,584	820	9,404	820	9,281	697	9,978	697
1940-Tools, Shop and Garage Equipment	140,193	141,059	866	157,182	16,123	173,429	16,247	190,640	17,211	196,207	22,778	224,235	28,028
1955-Communication Equipment	95,694	99,914	4,220	114,459	14,545	128,762	14,302	347,501	218,739	299,693	170,932	347,450	47,757
Sub-Total-Equipment	**1,138,164**	**933,313**	**(204,851)**	**1,035,092**	**101,779**	**1,201,747**	**166,655**	**1,503,915**	**302,168**	**1,429,420**	**227,673**	**1,440,351**	**10,931**
Other Distribution Assets													
1980-System Supervisory Equipment		0	0	0	0	0	0	3,333	3,333	2,500	2,500	10,000	7,500
1995-Contributions and Grants - Credit	(669,376)	(705,043)	(35,667)	(880,733)	(175,689)	(1,074,130)	(193,397)	(1,274,016)	(199,886)	(1,267,768)	(193,638)	(1,461,406)	(193,638)
Sub-Total-Other Distribution Assets	**(669,376)**	**(705,043)**	**(35,667)**	**(880,733)**	**(175,689)**	**(1,074,130)**	**(193,397)**	**(1,270,683)**	**(196,553)**	**(1,265,268)**	**(191,138)**	**(1,451,406)**	**(186,138)**
ACCUMULATED DEPRECIATION TOTAL	**8,538,322**	**8,368,003**	**(170,319)**	**9,390,834**	**1,022,832**	**10,548,742**	**1,157,908**	**11,861,554**	**1,312,812**	**11,500,799**	**952,057**	**12,389,031**	**888,232**

VARIANCE ANALYSIS ON ACCUMULATED AMORTIZATION:

Changes in accumulated amortization are directly affected by changes in fixed assets due to additions, the removal of fully depreciated assets from the grouped asset classes, and the disposition of identifiable assets.

Table 2.2.7 shows the changes in accumulated amortization from 2009 Actual to the 2013 Test Year. The change in accumulated amortization is a result of capital expenditures, amortization expense each year, and write-offs of fully-amortized assets as appropriate over the four year period. The variance from 2009 Board Approved to 2009 Actual is due to the capital budget having been allocated to projects different than those submitted in the 2009 Cost of Service Application. Capital was spent on asset classes that had longer useful lives thus resulting in lower amortization (capital was spent on long term assets (account 1820) in place of short term assets (account 1930)). From 2011 to 2012, the impact to accumulated amortization relating to smart meter capital transferred to rate base as of January 1, 2012 was a decrease of $95,111 (representing $127,044 of smart meter accumulated amortization offset by the $419,887 of stranded meter accumulated amortization written off for account 1860; $60,708 for account 1611; $13,849 for account 1920; and $123,175 for account 1955) offset by the addition of the current year’s amortization expense. In 2012 Bridge Year (MIFRS) and 2013 Test Year (MIFRS), useful lives have been revised per MIFRS requirements which has reduced the amortization recorded on these assets each year. Please refer to Exhibit 4, Tab 2, Schedule 7 for details of annual amortization expense for each asset account.

INTRODUCTION - CAPITAL BUDGET:

LPDL's Asset Management Plan identifies the capital projects, spanning a four year horizon (2013-2016), based on the best available information for each year (see Appendix A for details). The capital budget forecast is influenced significantly by condition data that is collected each year on aging infrastructure and as such, LPDL may be required to adjust the capital project forecast as the knowledge of its system needs changes. As provided in Exhibit 2, Tab 3, Schedule 2, a significant portion of LPDL's capital investments are focused on replacing aging assets or voltage conversion projects to improve system reliability, which was identified through the asset management program. All proposed capital projects for the 2012 Bridge Year and 2013 Test Year will be completed and in service in that year. Details of LPDL's capital budget for these periods are provided in Table 2.3.2 below.

Provincial Sales Tax Impact

As a result of the implementation of HST in the province of Ontario on July 1, 2010, the 8% PST portion, previously included as part of the capital cost, has become an input tax credit (ITC). Thus LPDL has considered this reduction in capital expenditures relating to the purchase of products. Capital expenditures do not include tax on purchases of products or services made after July 1, 2010 for either the 2012 Bridge Year forecast or the 2013 Test Year budget.

Introduction

LPDL has been, and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers through effective capital spending. Table 2.3.1 below provides an analysis of LPDL's capital spending from 2007 to 2013.

Table 2.3.1 - Capital Spending Summary 2007 to 2013

Year	Total Distribution Plant	Capital Contributions	Net Distribution Plant	General Plant	Total Capital Spending Net of Contributions	Disposals	Total Capital Net of Contributions & Disposals	$ Inc/(Dec)	% Inc/(Dec)
2007	1,392,998	(774,248)	618,750	225,533	844,283	0	844,283	(846,968)	-50.1%
2008	914,087	(479,066)	435,020	318,176	753,196	(76,847)	676,349	(167,934)	-19.9%
2009	2,239,759	(346,183)	1,893,576	210,004	2,103,580	(135,370)	1,968,210	1,291,861	191.0%
2010	2,045,143	(560,961)	1,484,182	229,154	1,713,336	(74,989)	1,638,347	(329,863)	-16.8%
2011	2,639,004	(324,443)	2,314,561	151,557	2,466,118	0	2,466,118	827,770	50.5%
2012 CGAAP	1,260,000	0	1,260,000	403,600	1,663,600	(76,332)	1,587,268	(878,850)	-35.6%
2012 MIFRS	1,260,000	0	1,260,000	403,600	1,663,600	(202,693)	1,460,907	(1,005,211)	-40.8%
2013	1,495,000	0	1,495,000	560,000	2,055,000	(282,099)	1,772,901	311,994	21.4%

The updated filing requirements for Exhibit 2 (Rate Base) request actual summary information for the past five historical years. Note that 2007 and 2008 capital expenditures will not be discussed in detail in this Application as they are presented for informational purposes only. The capital spending in 2009, 2010, 2011, 2012 Bridge Year and 2013 Test year is broken down by project by year in Exhibit 2, Tab 3, Schedule 2.

In 2009, the main driver of the 191.0% increase over 2008 spending levels was an increase in expenditures of $1,212,000 relating to distribution stations (mainly new Centennial MS station). In addition, there was an increase in expenditures of $148,000 on distribution plant (mainly decrease in capital contributions) and $113,000 on transformers (mainly backup generator) offset by a decrease on general plant expenditures of $167,000 (mainly office furniture/equipment and vehicles).

In 2010, the main driver of the -16.8% decrease from 2009 spending levels was a decrease in expenditures of $685,000 in distribution stations (mainly attributable to the smaller rebuild project of the Huntsville MS2 station in 2010 for $400 K compared to the construction of Centennial MS in 2009 for $1,200 K). As can be seen in Table 2.3.1a below, this was offset by various increases in capital expenditures on building and fixtures of $49,000 (operations storage yard improvements), distribution plant of $142,000 (poles, conductors, cable, transformers, services), meter capital of $82,000 (General Service >50 kW meter upgrade) and general plant of $82,000 (mainly increase in vehicle expenditures offset by decrease in computer software and tools/shop equipment).

Table 2.3.1a – Capital Spending Change between 2009 and 2010

		$ 000
2009 Capital Spending	$	1,968
Distribution Stations - Difference in Project Size	-$	685
Storage Yard Improvements	$	49
Distribution Plant	$	142
Meters	$	82
General Plant	$	82
2010 Capital Spending	$	1,638

In 2011, LPDL's capital expenditures increased by 50.5% due mainly to the expansion of the operations building facility, an increase in building and fixtures of $1,139,000. In addition, there was an increase in expenditures of $170,000 on distribution plant (poles, conductors, cable, transformers, services) offset by a decrease in capital expenditures of $480,000 on distribution stations (minimal spending on substations in 2011).

For 2012 and 2013, LPDL is planning a number of capital projects to replace its aging infrastructure and improve system reliability via voltage conversion upgrades as identified through inspection programs and analysis of improved GIS data conducted as part of the asset management program.

In 2012, capital spending on MIFRS basis is forecasted to be lower than 2011 spending levels by -40.8%. This decrease is mainly due to a decrease in building and fixtures expenditures of $1,189,000 offset by increases in capital expenditures on distribution stations of $57,000 (minimal station upgrades in 2012), distribution plant of $78,000 (poles, conductors, cable, transformers) and general plant of $252,000 (mainly vehicles, storage equipment and SCADA system). The above noted decrease in spending is also attributable to an increase in disposals of $202,693, for vehicles and distribution plant, recorded in 2012 as per MIFRS requirements.

The capital spending for 2013 MIFRS is forecasted to increase by 21.4% over 2012 MIFRS forecasted spending levels. This increase is due mainly to increases in capital expenditures on distribution plant of $180,000 (poles, conductors, cable, transformers) as well as on distribution stations of $45,000 (feeder replacements) and general plant of $156,000 (mainly increase in vehicle spending offset by decrease in computer software and tools/shop equipment). The above noted increase is offset by the reduction of capital spending due to higher disposals of $80,000 for vehicles and distribution plant in 2013 MIFRS over 2012 MIFRS ($282,099 versus $202,693 respectively).

The capital spending numbers reported in Table 2.3.1 above exclude all amounts regarding smart meter spending, as they have been handled through LPDL's Approved Smart Meter Cost Recovery Application Board File No. EB-2011-0413 for revenue requirement purposes (discussed with Variance Analysis on Rate Base in Exhibit 2, Tab 1, Schedule 2) and stranded meters, as they are discussed later in this application in Exhibit 9, Tab 3. The figures in Table 2.3.1 are also exclusive of spending required to meet the needs of the Green Energy Act. These costs, which are tracked in account 1531 and not included for recovery approval in this Application, are discussed as part of LPDL's Green Energy Plan which can be found in Exhibit 2, Appendix C.

ASSIGNMENT OF CAPITAL PROJECTS BY YEAR:

Table 2.3.2 below summarizes LPDL's actual investment in capital projects for the years 2007, 2008, 2009, 2010, 2011 as well as forecasted projects for the 2012 Bridge and 2013 Test Years, which are based on inspection results and analysis of distribution asset attributes conducted as part of the asset management plan program. Descriptions of 2009-2013 projects are also provided below which identify the cost, need and scope of each project over the materiality threshold of $50,000.

Table 2.3.2 - 2007-2013 Capital Projects

Projects	2007	2008	2009	2010	2011	2012 Bridge Year	2013 Test Year	Gross Capital TOTAL	Contributed Capital	Net Capital TOTAL
DISTRIBUTION PLANT	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**			
Building General Plant										
Project 1 - Backup Generator at Huntsville Administration Facility	0	0	128,294	0	0	0	0	128,294	0	128,294
Project 2 - Storage Yard Improvements at Operations Facility	0	0	0	50,637	0	0	0	50,637	0	50,637
Project 3 - Expand Bracebridge Operations Facility	0	0	0	0	1,208,165	0	0	1,208,165	0	1,208,165
Sub-Total: Building General Plant	0	0	128,294	50,637	1,208,165	0	0	1,387,097	0	1,387,097
Distribution Station										
Project 4 - Construct New 27.6kV 10MVA Centennial MS	0	0	1,131,560	96,079	24,698	0	0	1,252,337	-30,340	1,221,996
Project 5 - Install F35 Relays in Substations	0	0	75,663	6,512	0	0	0	82,174	0	82,174
Project 6 - Rebuild Huntsville MS2	0	0	0	397,567	5,528	0	0	403,095	0	403,095
Project 7 - Install Vacuum Reclosure Douglas MS5	0	0	0	0	0	50,000	0	50,000	0	50,000
Project 8 - Replace Feeder Cable Huntsville MS1	0	0	0	0	0	55,000	150,000	205,000	0	205,000
Sub-Total: Distribution Station	0	0	1,207,223	500,157	30,226	105,000	150,000	1,992,606	-30,340	1,962,265
Distribution Plant - Overhead										
Project N/A - Rebuild Wellington St	60,000	0	0	0	0	0	0	60,000	0	60,000
Project 9 - Relocate Pole Line for High Falls Road Widening	0	5,897	120,006	0	0	0	0	125,903	-112,169	13,734
Project 10 - Rebuild Centre St, Florence St and Brunel Rd	0	0	332,976	151,446	0	0	0	484,421	-222,559	261,863
Project 11 - Extend Cedar Lane 27.6kV	0	0	5,902	94,420	0	0	0	100,322	0	100,322
Project 12 - Rebuild Wilsons Falls to 27.6kV Golden Beach MS	0	0	0	10,629	526,642	0	0	537,271	-42,710	494,561
Project 13 - Rebuild Spencer St	0	0	0	98,469	92,845	0	0	191,314	0	191,314
Project 14 - Rebuild West Rd to Huntsville MS2	0	0	0	165,221	1,197	0	0	166,418	0	166,418
Project 15 - Rebuild Dill St and Victoria St	0	0	0	0	30,271	350,000	0	380,271	0	380,271
Project 16 - Reinsulate Poles and Convert to 27.6kV Aubrey St	0	0	0	0	0	150,000	0	150,000	0	150,000
Project 17 - Rebuild Armstrong St and Maple St	0	0	0	0	0	0	244,000	244,000	0	244,000
Project 18 - Miscellaneous Pole Replacements	141,145	175,443	32,635	81,877	120,459	0	0	551,559	0	551,559
Project 19 - Miscellaneous Projects	0	94,575	39,141	61,431	67,259	0	0	262,406	-14,712	247,694
Sub-Total: Distribution Plant - Overhead	201,145	275,915	530,659	663,493	838,673	500,000	244,000	3,253,885	-392,149	2,861,736
Distribution Plant - Underground										
Project N/A - Rebuild Morrow Dr	25,000	0	0	0	0	0	0	25,000	0	25,000
Project 20 - Replace Oakwood Heights	0	0	0	34,707	66,463	445,000	0	546,170	0	546,170
Project 21 - Rebuild Andrea Dr	0	0	0	43,381	73,206	0	0	116,587	0	116,587
Project 22 - Rebuild Fairlawn Blvd	0	0	0	105,309	6,216	0	0	111,525	0	111,525
Project 23 - Replace Curling Rd	0	0	0	0	0	0	435,000	435,000	0	435,000
Project 24 - Replace Wilshire Blvd	0	0	0	0	0	0	261,000	261,000	0	261,000
Project 25 - Replace Submarine Cable Bracebridge Bay	0	0	0	0	0	0	200,000	200,000	0	200,000
Project 26 - Replace Submarine Cable Lake Muskoka Caisse Island	0	0	0	0	0	50,000	0	50,000	0	50,000
Project 27 - Build Third Feeder to Centennial MS	0	0	0	0	0	0	100,000	100,000	0	100,000
Project 28 - Miscellaneous Projects	0	5,046	4,312	3,464	24,583	0	0	37,406	0	37,406
Sub-Total: Distribution Plant - Underground	25,000	5,046	4,312	186,862	170,468	495,000	996,000	1,882,688	0	1,882,688
Transformers										
Project N/A - Stock Replacement (after 2006 storm)	225,000	0	0	0	0	0	0	225,000	0	225,000
Project 29 - PCB Removal/Replacement	75,000	94,436	48,352	184,042	39,692	65,000	0	506,521	0	506,521
Sub-Total: Transformers	300,000	94,436	48,352	184,042	39,692	65,000	0	731,521	0	731,521
Connection and New Services										
Project 30 - Inverary Subdivision	119,178	144,701	2,053	20,450	5,352	0	0	291,734	-289,536	2,199
Project 31 - Greystone Condo Development	0	34,304	80,017	16,857	25,053	0	0	156,231	-120,521	35,710
Project 32 - Rivers Edge Subdivision	0	9,862	85,141	26,475	3,538	0	0	125,016	-76,567	48,450
Project 33 - Clearbrook Subdivision	97,521	44,478	11,888	3,097	0	0	0	156,984	-154,618	2,366
Project 34 - New Bracebridge Sewage Plant	0	0	11,509	84,001	0	0	0	95,510	-89,734	5,776
Project 35 - Douglas Dr Seniors Residence	0	0	8,181	23,687	55,019	0	0	86,887	-44,987	41,900
Project 36 - New Services and Services Upgrade	557,549	283,575	114,965	189,683	190,717	0	0	1,336,488	-1,286,449	50,039
Sub-Total: Connections and New Services	774,248	516,920	313,754	364,251	279,678	0	0	2,248,851	-2,062,412	186,439
Meters										
Project N/A - Replace Meters	92,605	0	0	0	0	0	0	92,605	0	92,605
Project 37 - Install New Smart Meters	0	0	0	0	0	15,000	15,000	30,000	0	30,000
Project 38 - Replace GS>50 Interval Meters	0	6,826	446	86,711	72,101	75,000	85,000	326,084	0	326,084
Sub-Total: Meters	92,605	6,826	446	86,711	72,101	90,000	100,000	448,689	0	448,689
Miscellaneous										
Project N/A - Land Rights	0	0	6,720	8,989	0	5,000	5,000	25,709	0	25,709
Project N/A - Miscellaneous Building & Fixtures	0	14,944	0	0	0	0	0	14,944	0	14,944
Sub-Total: Miscellaneous	0	14,944	6,720	8,989	0	5,000	5,000	40,653	0	40,653
Sub-Total: Distribution Plant	1,392,998	914,087	2,239,759	2,045,143	2,639,004	1,260,000	1,495,000	11,985,990	-2,484,901	9,501,089
Contributed Capital	-774,248	-479,066	-346,183	-560,961	-324,443	0	0	-2,484,901		
Total: Distribution Plant	**618,750**	**435,020**	**1,893,576**	**1,484,182**	**2,314,561**	**1,260,000**	**1,495,000**	**9,501,089**		

GENERAL PLANT	2007	2008	2009	2010	2011	2012 Bridge Year	2013 Test Year	Gross Capital TOTAL
Project 39 - Buildings & Fixtures	49,691	7,113	10,328	-1,620	0	0	0	65,512
Project 40 - Office Furniture and Equipment	20,262	37,277	4,277	0	65,879	10,000	0	137,695
Project 41 - Computer Equipment - Hardware	33,428	24,047	18,481	2,910	5,839	10,000	10,000	104,704
Project 42 - Computer Software	15,322	4,550	32,961	33,016	66,105	108,600	10,000	270,554
Project 43 - Transportation Equipment	34,837	188,836	105,935	192,275	0	115,000	395,000	1,031,884
Project 44 - Tools, Shop and Garage Equipment	13,230	29,226	34,994	2,574	13,734	60,000	45,000	198,758
Project N/A - Communication Equipment	58,763	27,127	3,028	0	0	0	0	88,918
Project 45 - SCADA	0	0	0	0	0	100,000	100,000	200,000
Total: General Plant	**225,533**	**318,176**	**210,004**	**229,154**	**151,557**	**403,600**	**560,000**	**2,098,024**
TOTAL CAPITAL SPENDING (Disposals NOT Included)	**844,283**	**753,196**	**2,103,580**	**1,713,336**	**2,466,118**	**1,663,600**	**2,055,000**	**11,599,113**

DISTRIBUTION PLANT PROJECTS

BUILDING GENERAL PLANT

Project #1: General Plant and Security – Backup Generator at Huntsville Administration Facility

Cost: $128,294 (2009)

Need: A backup generator was purchased and installed at the administration office in Huntsville, to ensure the availability of continuous operation during power outages. This allows LPDL's customer service staff to maintain contact with customers at all times during any power outages via uninterrupted access to the phone system and Customer Information System software.

Scope: A 250kW Generac natural gas generator was installed onsite to provide uninterrupted power to the administration office in the event of any power outages.

Project #2: General Plant – Storage Yard Improvements at Operations Facility

Cost: $50,637 (2010)

Need: There was an old water tower foundation located in the centre of the operations storage yard which needed to be removed in order to improve water drainage and outside storage capacity in the yard.

Scope: This project included contractor costs to remove the old foundation and to regrade the storage yard to meet the storm water management plan at the Bracebridge operations facility.

Project #3: General Plant – Expand Bracebridge Operations Facility

Cost: $1,208,165 (2011)

Need: Due to company growth and space limitations for increasing IT system requirements, space in the operations facility had become inadequate thus requiring an expansion to LPDL's existing operations centre in Bracebridge. The existing facility was lacking secure and sufficient IT server space, a lunch room, a meeting room and sufficient office space for all personnel. A portable trailer had been moved onsite to provide space for a meeting room and one office in the interim which was quickly outgrown by the time the facility expansion was completed.

Scope: This expansion to the operations facility included additional office space, a meeting room, a lunch room, washroom facilities, two vehicle bays, correction of structural deficiencies (roof replacement), energy efficiency enhancements (heating/cooling and lighting changes), paving of the front lot and removal of the portable trailer. Tender bids were put out to contractors and two competitive bids were received and assessed. Affiliate companies operating from this facility are required to pay monthly rental charges, based on square footage market price, which are included in LPDL's revenue offsets.

DISTRIBUTION SUBSTATIONS

Project #4: Customer Demand and System Reliability – Distribution Station: Construct New 27.6kV 10MVA Centennial MS

Cost:	$1,252,337 Gross	(2009 = $1,131,560; 2010 = $96,079; 2011 = $24,698)
	$1,221,996 Net	(Contributed Capital Offset = $30,340)

Need: LPDL constructed and energized in 2009, a new 27.6kV 10MVA substation in Bracebridge to accommodate customer growth in new subdivision developments and voltage conversion projects from 4.16kv and 12.5kv to 27.6kV in Bracebridge. Through careful investigation, LPDL determined that in order to meet this growth need, the best economical decision was to replace the existing 4MVA substation with a new 10MVA station rather than repairing the existing old small station as well as constructing another new small substation at another site location. Due to limited capacity on the existing 4.16kV and 12.5kV circuits a new substation was warranted.

Scope: The construction and energization of this substation in 2009 included a 44kV to 27.6kV substation transformer and two feeders, each with vacuum reclosures, with room in the switch gear for a third feeder to accommodate future growth. Expenditures in 2010 and 2011 included the purchase and installation of the switch cabinet for the future third feeder, a spare reclosure, soil testing at the substation site and final commissioning and testing of the substation by the contractor.

Project #5: System Reliability – Distribution Station: Install F35 Relays in Substations

Cost: $82,174 (2009 = $75,663; 2010 = $6,511)

Need: F35 relays were installed at each substation in Bracebridge and Huntsville providing LPDL with the ability to identify faults and monitor and record loading at each station and feeder to improve the reliability of LPDL's service. These relays are smart grid ready allowing compatibility with any future smart grid development.

Scope: An F35 relay was installed at each LPDL owned substation in Bracebridge and Huntsville (seven in total) and connected to the operation's centre in Bracebridge via a fibre communication network.

Project #6: System Reliability and Aging Asset – Distribution Station: Rebuild Huntsville MS2

Cost: $403,095 (2010 = $397,567; 2011 = $5,528)

Need: The 5MVA substation transformer at Huntsville MS2 substation, built in 1974 and nearly forty years old, was showing signs of insulation breakdown during the annual inspection and oil analyses. A third substation was investigated to allow for redundancy and load switching due to Huntsville MS2 requiring replacement. After comparing costs, upgrading the existing substation was deemed to be the most cost effective.

Scope: The old 5MVA substation transformer was removed and replaced with a new 8MVA substation transformer. This provided LPDL with the ability to feed the customer base in Huntsville from this one station at any given time, whereas in the past, LPDL could only switch out substations during low peak seasons. This upgrade included spill containment to mitigate any future environmental concerns due to transformer oil spills.

Project #7: System Reliability – Distribution Station: Install Vacuum Reclosure at Douglas MS5

Cost: $50,000 (2012 Estimate)

Need: Currently there are two feeders out of Douglas MS5 substation in Bracebridge. One feeder has hydraulic reclosures and the other feeder is protected by fuses. The feeder currently protected by fuses will be upgraded with the installation of vacuum reclosures to enhance the protection at this substation.

Scope: This project involves the installation of a padmounted SEL Viper reclosure and a rework of the cables at the substation.

Project #8: Aging Asset – Distribution Station: Replace Feeder Cable at Huntsville MS1

Cost:	$205,000	(2012 Estimate = $55,000; 2013 Estimate = $150,000)
	$(473)	2012 Loss on Disposal (2011 NBV)
	$(1,158)	2013 Loss on Disposal (2012 NBV)

Need: Huntsville MS1 substation currently has five 4.16kV feeders and all of the cables and equipment are at or near the end of life and require replacement, as identified in the asset management plan review of GIS distribution asset ages. This replacement is in preparation of the planned upgrade to a higher capacity transformer at this substation in 2015.

Scope: This project involves the phased replacement of underground feeder cables connected to Huntsville MS1 substation. Two feeders, F1 and F2, will be replaced in 2012. In 2013, the remaining three feeders, F3, F4 and F5, are planned to be replaced as well as the refurbishment of the existing switch gear at Huntsville MS1 substation.

OVERHEAD DISTRIBUTION PLANT

Project #9: Regulatory – Overhead: Relocate Pole Line for High Falls Road Widening

Cost: $125,903 Gross (2008 = $5,897; 2009 = $120,006)
$ 13,734 Net (Contributed Capital Offset = $112,169)

Need: The District of Muskoka reconstructed High Falls Rd in Bracebridge in order to widen to the road between Highway 11 and Manitoba St. Due to this reconstruction, poles and conductors needed to relocated and replaced in several locations to accommodate this road widening project.

Scope: This phased relocation and replacement project required the installation of new poles (approximately 15 poles), conductor and transformers to accommodate the new road path. A small stretch of poles, conductor and transformers were replaced in the fall of 2008. The following spring (2009), when the District was able to begin construction again after the thaw, LPDL replaced the remaining poles, conductor and transformers as required to accommodate the new road path.

Project #10: Customer Demand and System Reliability – Overhead: Rebuild Centre St, Florence St and Brunel Rd

Cost: $484,421 Gross (2009 = $332,975; 2010 = $151,446)
$261,863 Net (Contributed Capital Offset = $222,558)

Need: A new feeder from Huntsville MS1 substation was required to replace existing overloaded circuits and allow for new load. The pole lines on Centre St and Florence St in Huntsville were in extremely poor condition with inadequate conductor size and required replacement. These lines were both upgraded with new poles and larger conductor. Brunel Rd in Huntsville also had inadequate conductor size which was replaced and upgraded with larger conductor. This pole line rebuild also improved redundancy by providing LPDL with the ability to loop feed the town core of Huntsville.

Scope: This rebuild included the replacement of poles (approximately 29 poles) and larger size conductor on Centre St and Florence St (2009) and the replacement of conductor with larger size conductor on Brunel Rd (2010) to accommodate the new load.

Project #11: System Reliability – Overhead: Extend Cedar Lane 27.6kV

Cost: $100,322 (2009 = $5,902; 2010 = $94,420)

Need: LPDL installed 27.6kV overhead conductor on Cedar Lane to upgrade the service from the existing Hydro One fed 12.5kV circuit to the 27.6kV circuit supplied by LPDL's Centennial MS. These customers on Cedar Lane, which were fed from Hydro One's Taylor DS, were experiencing voltage spikes thus affecting LPDL's system performance. This upgrade reduced the bulk of the system performance issues and also allowed for future expansion of the 27.6kV circuit to the remaining few customers to further improve LPDL's service reliability.

Scope: This installation included new overhead conductor and the replacement of 12.5kV transformers with higher voltage 27.6kV transformers.

Project #12: System Reliability and Aging Asset – Overhead: Rebuild Wilsons Falls to 27.6kV Golden Beach MS

Cost: $537,271 Gross (2010 = $10,629; 2011 = $526,642)
$494,561 Net (Contributed Capital Offset = $42,710)

Need: This pole line was rebuilt to provide LPDL with the ability to parallel two 27.6kV stations in Bracebridge and to have local generation plants run on one or both of the 27.6kV substations thus optimizing the system. This provides LPDL with a more reliable system as full backup/loop feed is provided by the one substation if the other is down for maintenance. During the process, LPDL also upgraded this service to 27.6kV from 4.16kV in an effort to reduce system losses over time and improve system reliability to customers.

Scope: The poles (approximately 24 poles), conductor and transformers were replaced on Hiram St, McDonald St, Monck Rd and Ann St with higher voltage 27.6kV conductor and transformers to accommodate the new loop feed.

Project #13: System Reliability – Overhead: Rebuild Spencer St

Cost: $191,314 (2010 = $98,469; 2011 = $92,845)

Need: This pole line rebuild on Spencer St in Bracebridge, gives LPDL the ability to parallel the F1 Feeder and F2 Feeder out of Centennial MS substation in Bracebridge thus providing a loop feed and the ability to switch out feeders during maintenance or unplanned outages (storms) when required. LPDL upgraded the existing 12.5kV service with 27.6kV overhead service thus reducing the Hydro One feed from Beaumaris DS. This upgrade also allows for future expansion of the 27.6kV circuit throughout Bracebridge to improve LPDL's service reliability.

Scope: This involved the phased replacement of the poles (approximately 16 poles in total), conductor and transformers with higher voltage 27.6kV conductor and transformers to accommodate the new loop feed. In 2010, North St was replaced and in 2011, Spencer St from North St to Santa's Village Rd, was replaced.

Project #14: Aging Asset – Overhead: Rebuild West Rd to Huntsville MS2

Cost: $166,418 (2010 = $165,221; 2011 = $1,197)

Need: During the annual plant inspection, the pole line on West Rd from Shaw Rd to Huntsville MS2 substation in Huntsville was found to be very deteriorated as it is over forty years old. This line is a critical piece of infrastructure as it is a 44kV feed as well as a 4.16kV feeder out of Huntsville MS2.

Scope: This project involved the replacement of all poles (approximately 9 poles) between Shaw Rd and Huntsville MS2 as well as the replacement of all insulators on the 4.16kV and 44kV lines.

Project #15: Aging Asset and Customer Demand – Overhead: Rebuild Dill and Victoria St

Cost:	$380,271	(2011 = $30,271; 2012 Estimate = $350,000)
	$(10,506)	2012 Loss on Disposal (2011 NBV)

Need: Centennial MS substation in Bracebridge currently has two feeders and is being prepped for a third feeder planned for 2013. The pole lines on Dill St and Victoria St in Bracebridge are currently 4.16kV and will be replaced and upgraded to 27.6kV to be connected to this future third feeder. This pole line is nearing end of life and requires replacement. This upgraded service will also provide a loop feed and additional capacity for any future growth in South Bracebridge.

Scope: In 2011, the switchgear was purchased to accommodate this upgraded build. The rebuild in 2012 will include new poles on Dill St (approximately 19 poles) and new higher voltage 27.6kV conductor and transformers on Dill St between Wellington St and Ontario St and on Victoria St between Dill St and Quebec St. No pole replacements are required for Victoria St as the conductor is connected to joint use poles owned by Bell.

Project #16: System Reliability – Overhead: Reinsulate Poles and Convert to 27.6kV Aubrey St

Cost:	$150,000	(2012 Estimate)
	$(1,878)	2012 Loss on Disposal (2011 NBV)

Need: The pole line on Aubrey St in Bracebridge is currently a 4.16kV service (double circuit). The insulators, transformers and secondary buss will be replaced and upgraded to 27.6kV service. This upgrade will complete the loop feed to the Oakwood Heights area in Bracebridge.

Scope: This replacement will include all new insulators and secondary buss (approximately 400 m) as well as new higher voltage 27.6kV transformers on Aubrey St from Ann St to Liddard St. In addition, the second 4.16kV circuit will be removed as it will no longer be required with the new upgraded single circuit service.

<u>Project #17: System Reliability and Aging Asset – Overhead: Rebuild Armstrong St and Maple St</u>

Cost:	$244,000	(2013 Estimate)
	$(4,896)	2013 Loss on Disposal (2012 NBV)

Need: The pole lines on Armstrong St and Maple St in Bracebridge, were identified in our routine distribution plant inspection program as becoming deteriorated and nearing end of life thus requiring replacement. The Armstrong St pole line will be replaced and upgraded from existing 4.16kV service to 27.6kV service thus reducing load from the 4.16kV Bracebridge MS2 substation. The Maple St pole line will be replaced and upgraded from existing 12.5kV service to 27.6kV service thus reducing load from the Hydro One owned Taylor DS. This switch will improve the service reliability to these customers and in time reduce shared distribution charges to LPDL as reliance on Hydro One stations is reduced.

Scope: This replacement will include new poles on Armstrong St (approximately 7 poles) as well as new higher voltage 27.6kV conductor and transformers on Armstrong St and Maple St. No pole replacements are required for Maple St as the conductor is connected to joint use poles owned by Bell.

<u>Project #18: Aging Asset – Overhead: Miscellaneous Pole Replacements</u>

Cost: $551,559 (2007 = $141,145; 2008 = $175,443; 2009 = $32,635; 2010 = $81,877; 2011 = $120,459)

Need: During LPDL's routine pole inspection program conducted throughout each year, poles were identified as being deteriorated and requiring replacement. These poles were replaced to prevent them from becoming a safety hazard to the public, causing plant failures and/or unplanned power outages.

Scope: All poles replaced in this pole replacement program (each job was under the materiality threshold of $50,000) were installed to meet standards as per ESA Regulation 22/04.

<u>Project #19: System Reliability – Overhead: Miscellaneous Projects</u>

Cost: $262,406 Gross (2008 = $94,575; 2009 = $39,141; 2010 = $61,431; 2011 $67,259)
$247,694 Net (Contributed Capital Offset = $14,712)

Need: There are a number of miscellaneous services identified through LPDL's routine system inspection conducted each year and/or customer service calls received throughout each year, that have voltage issues/deteriorated equipment and require replacement. These poles/services were replaced/upgraded to prevent them from becoming a safety hazard to the customer and/or causing voltage issues or unplanned power outages.

Scope: All poles/equipment replaced in these miscellaneous construction jobs (each of these are under the materiality threshold of $50,000) were installed to meet standards as per ESA Regulation 22/04.

<u>UNDERGROUND DISTRIBUTION PLANT</u>

Project #20: Aging Asset – Underground: Replace Oakwood Heights

Cost: $546,170 (2010 = $34,707; 2011 = $66,463; 2012 Estimate = $445,000)
$(7,257) 2012 Loss on Disposal (2011 NBV)

Need: The underground cable servicing the Oakwood Heights subdivision in Bracebridge is over forty years old and reaching end of life. Major outages have been experienced in this area due to faulty cables thus requiring replacement. This old, direct-buried service, built as a 12.5kV radial feed, is being replaced and upgraded to 27.6kV in phases. Following these phased rebuilds, the upgraded service will also provide a loop feed to the 27.6kV system thus improving service reliability for these customers.

Scope: The 2010 and 2011 replacement of Oakwood Heights to Curling Rd (first phase) included new 28kV underground primary cable (approximately 450m times three wires), vaults and higher voltage 27.6kV transformers. The 2012 replacement of Oakwood Heights to Liddard St (second phase) will also include new 28kV underground primary cable (approximately 780m times three wires), vaults and higher voltage 27.6kV transformers.

Project #21: System Reliability and Aging Asset – Underground: Rebuild Andrea Dr

Cost: $116,587 (2010 = $43,381; 2011 = $73,206)

Need: The underground cable servicing Andrea Dr in Bracebridge was over forty years old and reaching end of life. This old, direct-buried service was built as a 12.5kV radial feed which was upgraded during this build and reconnected as a loop feed to the 27.6kV system in an effort to improve service reliability to these customers.

Scope: 2010 expenditures covered the cost of directional drilling contract from Wellington St to Andrea Dr. In 2011, this replacement project included new 28kV underground cable (approximately 400m single phase wire), vaults and higher voltage 27.6kV transformers.

<u>Project #22: System Reliability and Aging Asset – Underground: Rebuild Fairlawn Blvd</u>

Cost: $111,525 (2010 = $105,309; 2011 = $6,216)

Need: During the routine annual plant inspection, Fairlawn Blvd in Bracebridge, which was being fed by an overhead back lot construction system, was found to be grown in by trees and the poles and conductor were deteriorated. As well, the poles were rock mounted. To be cost effective and to increase reliability and safety of the feed, LPDL decided to replace this line with an underground feed from the front lot.

Scope: This involved the installation of 28kV underground cable (approximately 450m single phase wire) as a loop feed, two underground padmount transformers and underground secondary to ten houses on Fairlawn Blvd. As well, the old 12.5kV overhead line located on the back lot was removed.

<u>Project #23: System Reliability and Aging Asset – Underground: Replace Curling Rd</u>

Cost: $435,000 (2013 Estimate)
$(4,948) 2013 Loss on Disposal (2012 NBV)

Need: The underground cable servicing Curling Rd in Bracebridge is over forty years old and reaching end of life, as identified in the asset management plan review of GIS distribution asset ages. This old, direct-buried service was built as a 12.5kV radial feed which should be upgraded during this rebuild and reconnected as a loop feed to the 27.6kV system. Major outages have been experienced in this area due to faulty cables thus requiring replacement in an effort to improve system reliability and redundancy.

Scope: The replacement of Curling Rd will involve new 28kV underground primary cable to form a new loop feed (approximately 800m times two wires), vaults and higher voltage 27.6kV transformers.

<u>Project #24: System Reliability and Aging Asset – Underground: Replace Wilshire Blvd</u>

Cost: $261,000 (2013 Estimate)
$(1,930) 2013 Loss on Disposal (2012 NBV)

Need: The underground cable servicing Wilshire Blvd in Bracebridge is over forty years old and reaching end of life, as identified in the asset management plan review of GIS distribution asset ages. This old, direct-buried service was also built as a 12.5kV radial feed which should be upgraded during this rebuild and reconnected as a loop feed to the 27.6kV system. This upgraded build will also reduce 12.5kV load from the Hydro One owned Taylor DS which will improve the service reliability to these customers and in time reduce shared distribution charges to LPDL as reliance on Hydro One stations is reduced.

Scope: The replacement of Wilshire Blvd will involve new 28kV underground primary cable (approximately 150m times three wires), vaults and higher voltage 27.6kV transformers.

Project #25: Aging Asset and Capacity – Underground: Replace Submarine Cable at Bracebridge Bay

Cost: $200,000 (2013 Estimate)
$(971) 2013 Loss on Disposal (2012 NBV)

Need: The existing submarine cable, located along the bottom of the Muskoka River crossing Bracebridge Bay, is over forty years old and reaching end of life, as identified in the asset management plan review of GIS distribution asset ages. This old cable currently services the 4.16kV system in Bracebridge and will be replaced with new 28kV submarine cable. This will accommodate the future 27.6kV service to South Bracebridge and reduce 4.16kV load in Bracebridge.

Scope: This project will include the replacement and installation of 28kV submarine cable (approximately 120m times three wires) under the Muskoka River in Bracebridge.

Project #26: Aging Asset – Underground: Replace Submarine Cable at Lake Muskoka Caisse Island

Cost: $50,000 (2012 Estimate)

$(1,393) 2012 Loss on Disposal (2011 NBV)

Need: The existing submarine cable, located along the bottom of Lake Muskoka, connecting Caisse Island to Beaumont Farm Rd in Bracebridge, is over forty years old and was ruined when struck by lightning in August 2012. This old cable is currently connected to the 12.5kV system in Bracebridge and was replaced with new submarine cable.

Scope: This project included the replacement and installation of new 28kV submarine cable (approximately 500m) under Lake Muskoka to reconnect Caisse Island to Beaumont Farm Rd in Bracebridge.

Project #27: Capacity – Underground: Build Third Feeder to Centennial MS

Cost: $100,000 (2013 Estimate)

Need: To accommodate growth in South Bracebridge, a third 27.6kV feeder out of Centennial MS substation in Bracebridge will be built to eventually service this area.

Scope: This first phase, of five phases spanning 2013 to 2017, involves the installation of a three phase vacuum reclosure and underground cabling to connect the feeder to the distribution system.

Project #28: System Reliability – Underground: Miscellaneous Projects

Cost: $37,406 (2008 = $5,046; 2009 = $4,312; 2010 = $3,464; 2011 $24,584)

Need: There are a number of miscellaneous underground services identified through LPDL's routine system inspection conducted each year and/or customer service calls received throughout each year, that have voltage issues/deteriorated equipment and require replacement. These services were replaced/upgraded to prevent them from becoming a safety hazard to the customer and/or causing voltage issues or unplanned power outages.

Scope: All cable/equipment replaced in these miscellaneous construction jobs (each of these are under the materiality threshold of $50,000) were installed to meet standards as per ESA Regulation 22/04.

TRANSFORMERS

Project #29: Regulatory – Transformer: PCB Removal/Replacement

Cost: $506,521 (2007 = $75,000; 2008 = $94,435; 2009 = $48,352; 2010 = $184,042; 2011 $39,692; 2012 Estimate = $65,000)

$(14,567) 2012 Loss on Disposal (2011 NBV)

Need: As required by the federal Environment Protection Act – Reg. 347, all PCB transformers were required to be changed out by 2010, which was later extended to 2020. LPDL has been working towards changing out all of these PCB contaminated transformers in service to ensure safety, environmental and regulatory compliance is achieved. As part of good governance, the Board of Directors required these to be replaced as soon as possible.

Scope: This plan includes the replacement and disposal of all PCB contaminated transformers which LPDL will have completed by the end of 2012. During these PCB transformer change outs, some poles were replaced as well to meet new standards as per ESA Regulation 22/04.

NEW CONNECTIONS

Project #30: Customer Demand – Connection – Inverary Subdivision Development

Cost: $291,734 Gross (2007 = $119,178; 2008 = $144,701; 2009 = $2,053; 2010 = $20,450; 2011 $5,352)

$ 2,199 Net (Contributed Capital Offset = $289,535)

Need: LPDL is obligated under the DSC to provide and connect distribution systems for new subdivisions that are partially funded through contributed capital via the economic evaluation process. These projects represent the cost of line extensions and plant alterations to connect the new subdivision.

Scope: The costs to connect these services include the cost of cable, poles, conductor and transformers required for the requested services. This subdivision located in Bracebridge was developed in phases beginning with the overhead build from Monck Rd to Wellington St in 2007 and on Santa's Village Rd from Wellington St to Gainsborough Rd in 2008. The underground connections on Gainsborough Rd and Argyll Court were then serviced and connected over the following years as the homes were built in phases (28 connections to date).

Project #31: Customer Demand – Connection – Greystone Condo Development

Cost: $156,231 Gross (2008 = $34,304; 2009 = $80,017; 2010 = $16,857; 2011 $25,053)
$ 35,710 Net (Contributed Capital Offset = $120,521)

Need: LPDL is obligated under the DSC to provide and connect distribution systems for new subdivisions that are partially funded through contributed capital. These projects represent the cost of line extensions and plant alterations to connect the new subdivision.

Scope: The costs to connect these services included the cost of cable, poles, conductor and transformers required for the requested services. This condominium development located in Bracebridge was developed in phases beginning with the overhead extension on Manitoba St to the underground service site on Manitoba St in 2008. The first twelve unit condominium was developed and connected in 2009, the second twelve unit building connected in 2010 and a pool recreation building in 2011.

<u>Project #32: Customer Demand – Connection – Rivers Edge Subdivision Development</u>

Cost: $125,016 Gross (2008 = $9,862; 2009 = $85,141; 2010 = $26,475; 2011 $3,538)
$ 48,450 Net (Contributed Capital Offset = $76,566)

Need: LPDL is obligated under the DSC to provide and connect distribution systems for new subdivisions that are partially funded through contributed capital via the economic evaluation process. These projects represent the cost of line extensions and plant alterations to connect the new subdivision.

Scope: The costs to connect these services included the cost of transformers for the most part plus additional cable, poles and conductor as required for the requested services. This townhouse development located in Bracebridge was developed in phases beginning with the overhead line connection from Wellington St to the underground service site on Spencer St in 2008. The underground transformers for the planned development were installed and the first six unit townhouse was developed and connected on Spencer St in 2009. Three more four to six unit townhouse buildings were developed and connected in 2010 on Durham Rd , Prescott Ct and Stormont Ct. One six unit townhouse building was developed and connected in 2011 on Stormont Ct.

<u>Project #33: Customer Demand – Connection – Clearbrook Subdivision Development</u>

Cost: $156,984 Gross (2007 = $97,521; 2008 = $44,478; 2009 = $11,888; 2010 = $3,097)
$ 2,366 Net (Contributed Capital Offset = $154,618)

Need: LPDL is obligated under the DSC to provide and connect distribution systems for new subdivisions that are partially funded through contributed capital via the economic evaluation process. These projects represent the cost of line extensions and plant alterations to connect the new subdivision.

Scope: The costs to connect these services included the cost of cable and transformers required for the requested services. This subdivision located in Bracebridge was developed in several phases beginning with the overhead build from Douglas Dr in the years before this cost of service period. In this first phase of development, 103 homes were connected throughout 2007 and 2008 on Clearbrook Trail, Clearstream Court, Windsong Crescent and Heron's Hill. In the second phase, Pheasant Run, Rosemead Close and Fieldstream Chase were developed and 24 more homes were connected in 2009. In the last phase, Whitehorn Park was developed and 18 more homes were connected in 2010.

Project #34: Customer Demand – Connection – New Bracebridge Sewage Plant

Cost:	$95,510 Gross	(2009 = $11,509; 2010 = $84,001)
	$ 5,776 Net	(Contributed Capital Offset = $89,734)

Need: LPDL is obligated under the DSC to provide and connect new services and upgrade existing services as required to meet customer demand. Capital contributions may apply for connections as per LPDL's Conditions of Service

Scope: The costs to connect this new sewage plant, built by the District of Muskoka to service Bracebridge and surrounding areas, included new poles and conductor to feed the customer owned 44kV substation transformer. This installation also required Hydro One to replace a number of Hydro One owned poles as they did not meet the required clearances.

Project #35: Customer Demand – Connection – Douglas Dr Seniors Residence

Cost:	$86,887 Gross	(2009 = $8,181; 2010 = $23,687; 2011 $55,019)
	$41,900 Net	(Contributed Capital Offset = $44,987)

Need: LPDL is obligated under the DSC to provide and connect new services and upgrade existing services as required to meet customer demand. Capital contributions may apply for connections as per LPDL's Conditions of Service.

Scope: In preparation of this build in 2009, a cooling fan package was installed at the Douglas MS5 substation to increase the available capacity required to service this new senior's residence development in Bracebridge. In 2010, the padmount transformer was purchased for this service and in 2011 the installation included new poles, wires and metering equipment.

Project #36: Customer Demand – Connection – New Services and Service Upgrades

Cost: $1,336,488 Gross (2007 = $557,549; 2008 = $283,574; 2009 = $114,965; 2010 = $189,683; 2011 $190,717)

$ 50,039 Net (Contributed Capital Offset = $1,286,449)

Need: LPDL is obligated under the DSC to provide and connect new services and upgrade existing services as required to meet customer demand. Capital contributions may apply for connections as per LPDL's Conditions of Service.

Scope: These new overhead and underground service and upgrade connections included the cost of poles, conductor, cable and transformers required for the requested service. In 2007 and 2008, the years prior to this cost of service period, there were approximately 250 new customers connected. In the subsequent years, there were approximately 90 new connections in 2009, 100 new connections in 2010 and 156 connections in 2011.

METERS

Project #37: Meters – Customer Demand – Install New Smart Meters

Cost: $30,000 (2012 Estimate = $15,000; 2013 Estimate = $15,000)

Need: Supply and install smart meters on new residential and GS<50 connections as requested.

Scope: Purchase and install smart meters as required to meet customer demand.

<u>Project #38: Meters – Regulatory – Replace GS>50 Interval Meters</u>

Cost: $326,084 (2008 = $6,826; 2009 = $446; 2010 = $86,711; 2011 $72,101;
2012 Estimate = $75,000; 2013 Estimate = $85,000)
$(40,748) 2012 Loss on Retirement Net of Salvage Proceeds (Account 4362)
$(43,210) 2013 Loss on Retirement Net of Salvage Proceeds (Account 4362)

Need: By 2009, most of LPDL's GS>50 meters (not smart meters) were past their seal date and needed to be replaced as per Measurement Canada requirements. LPDL had been delaying the replacement of these meters while investigating technologies that would best suit the developing smart meter communication network. As well, following LPDL's Measurement Canada audit in 2011, it was identified that any of the new 2 and 2.5 element meters and delta on the block meters should be phased out and replaced with 3 element meters as per the Electricity and Gas Inspection Regulations. LPDL plans to replace these delta on the block meters in 2012 and the 2 and 2.5 element meters in phases throughout 2013 and 2014 thus allowing LPDL the opportunity to carry one standard type of 3 element meter which will reduce the range of meter stock required and to be compliant with the regulation.

Scope: In 2010, LPDL replaced all GS>50 non-interval meters with new interval meters (of the same size and voltage as the removed meters) equipped with new SmartSynch technology. In 2011, LPDL replaced GS>50 existing interval meters that had an expired seal date, with new interval meters (of the same size and voltage as the removed meters) equipped with new SmartSynch technology. The installation of these new meters provided compliance with the Measurement Canada seal date standards as well as provided LPDL with the opportunity to automate the collection of all interval meter data and eliminate manual onsite downloads. In 2012 LPDL plans to replace these delta on the block meters with new 3 element meters that will be integrated with the existing network communication technology, as recommended in the 2011 Measurement Canada audit (39 meters). Phased throughout 2013 and 2014, LPDL plans to replace any of the above 2 and 2.5 element meters with new 3 element meters that will be integrated with the existing network communication technology, as recommended in the 2011

Measurement Canada audit (35 and 100 respectively). All of the above meters include CT's and PT's where required by the size of service.

GENERAL PLANT PROJECTS:

Project #39: A/C 1908 - Building & Fixtures

Cost: $65,512 (2007 = $49,691; 2008 = $7,113; 2009 = $10,328; 2010 = $-1,620)

Need: As per LPDL's 2009 cost of service filing, various building and fixture upgrades were required in 2007 and 2008 to accommodate new staff and to update antiquated systems.

Scope: Replaced various fixtures and equipment as required (each under materiality), including a new air conditioner at the administration office in 2009.

Project #40: A/C 1915 - Office Furniture & Equipment

Cost: $137,695 (2007 = $20,262; 2008 = $37,277; 2009 = $4,277; 2010 = $0; 2011 = $65,879; 2012 Estimate = $10,000)

Need: Each year, various pieces of office furniture and equipment require replacement that is old and in poor condition, is no longer functional or is required to accommodate new staff.

Scope: Replaced various office furniture and equipment as required (each under materiality). In 2009, filing cabinets and tables were purchased to provide extra storage capacity in the operations center and meeting functionality in the temporary trailer. In 2011, new work stations and meeting room furniture and equipment were purchased to replace obsolete furniture and furnish new office space with the Bracebridge operations building expansion. In 2012 is a provision to replace furniture (ie chairs and workstations) that is obsolete and not ergonomically conducive to safe and healthy work practices.

Project #41: A/C 1920 - Computer Equipment - Hardware

Cost: $104,704 (2007 = $33,428; 2008 = $24,047; 2009 = $18,481; 2010 = $2,910; 2011 = $5,838; 2012 Estimate = $10,000; 2013 Estimate = $10,000)

Need: LPDL recognizes the need to stay current with computer technology in order to meet operating requirements. A three to five year life cycle is utilized for computer hardware driven by increased incidence of hardware failure, reduced technical support and higher performance requirements of current operating and application systems. Computer equipment that is obsolete and inadequate for required applications is replaced and new equipment is purchased to accommodate staff requirements.

Scope: In 2009, a call tracking phone system and server were purchased and programmed to gather data required to meet OEB customer service reporting requirements ($13,650) as well as replacement of computers/laptops for personnel ($4,831). In 2010 and 2011, computers and laptops were replaced for personnel that had failing and inefficient equipment. In 2012 and 2013 is a provision for the replacement of laptops and computers that have become obsolete and no longer operate effectively and efficiently for the applications required.

Project #42: A/C 1925 - Computer Software

Cost: $270,554 (2007 = $15,322; 2008 = $4,550; 2009 = $32,961; 2010 = $33,016; 2011 = $66,105; 2012 Estimate = $108,600; 2013 Estimate = $10,000)

Need: Adding and replacing computer software systems is necessary to support the running of all application programs and provides the support necessary for computers to interact with each other. This also includes vendor software upgrades, as well as user license fees where required, to ensure the latest versions are being utilized to maintain optimum system performance.

Scope: In 2009, computer software purchases included Dell server software licences for the call tracking system ($8,990) and new Great Plains financial system module software ($26,521). In

2010, additional Great Plains modules were implemented ($8,900) as well as the purchase of the Worktech asset management software ($24,116). In 2011, the asset management software was programmed and integrated to LPDL's GIS software ($55,145) in addition to the implementation of a new customer service online bill presentment platform ($10,960). In 2012 is a provision for various software upgrades including Asset Management integration and implementation to other systems ($28,600), GIS ArcView seats and ARCFM licences ($12,500), Microsoft Windows update rollout to all computers/laptops ($20,000), customer service Northstar V6 version upgrade ($25,000), File Nexus pdf module ($15,000) and customer service IVR program ($7,500). In 2013 is a provision for new software version and integration upgrades as required for various operating and application systems.

Project #43: A/C 1930 – Transportation Equipment

Cost: $1,031,884 (2007 = $34,837; 2008 = $188,836; 2009 = $105,935; 2010 = $192,275; 2011 = $0; 2012 Estimate = $115,000; 2013 Estimate = $395,000)

Need: LPDL requires a reliable and cost effective fleet of work platforms and vehicles in order to perform field work and respond to emergencies as required. LPDL generally plans to replace two vehicles per year and considers the age of the vehicle, kilometers used and amount of repairs and maintenance incurred or required when making vehicle replacement decisions.

Scope: In 2009, a 2010 Freightliner cab and chassis was purchased ($85,417) to replace the 2002 bucket truck that was sold in 2009 for $30,000 (disposal of $135,370) as well as a 2009 Yamaha Rhino to gain full season off road access to several areas of the distribution plant that pass through heavily forested terrain ($20,518). In 2010, the Altec AM50E Aerial Device was purchased and installed on the 2010 Freightliner cab and chassis ($154,490) as well as the purchase of a 2010 Ford Transit for engineering staff ($30,819) and a cargo trailer for transporting equipment to and from job sites ($6,966). In 2010, the above purchases were offset by the sale of two vehicles: 1992 bucket truck (disposal of $34,906) and 2006 Toyota Tacoma for $12,025 (disposal of $40,084). In 2012 is a provision to replace two vehicles used by operations personnel ($45,000) and engineering personnel ($45,000) that are over six years old and have high kilometers as well as the purchase of a wire reel trailer ($25,000). In 2013 is a provision for a new RBD digger truck to replace the existing digger that is twelve years old and incurring increasing maintenance costs ($300,000) as well as a new cargo van for the metering department ($45,000) and pickup truck for operations personnel ($40,000) that will each be over nine years old and incurring increasing maintenance costs. Bids were requested from three vendors for the RBD Digger Truck and one supplier replied back.

<u>Project #44: A/C 1940 – Tools, Shop and Garage Equipment</u>

Cost: $198,758 (2007 = $13,230; 2008 = $29,226; 2009 = $34,994; 2010 = $2,574; 2011 = $13,734; 2012 Estimate = $60,000; 2013 Estimate = $45,000)
$(670) 2013 Loss on Disposal (2012 NBV)

Need: LPDL recognizes the importance and need for timely replacement of tools and equipment that are worn or have come to the end of their useful life with newer and more ergonomically friendly tools and equipment that support a safe work environment for LPDL's employees. As well, stock transformers are currently stored outside where they are difficult to access and susceptible to damage from weather, equipment and environmental hazards, thus require a more accessible and secure storage structure. The existing storage shed structures located at the operations facility are also in poor condition and in need of replacement to allow for increased storage capacity and better protection of larger stock and equipment.

Scope: In 2009, a new forklift was purchased for moving stock and heavy equipment around the shop and yard ($31,590) as well as various small tools, shop and garage equipment and measurement and testing equipment ($3,404). In 2010, a defibrillator was purchased for the operations centre ($1,615) as well as various small tools and shop and garage equipment ($959). In 2011, various lines testing and work protection equipment was purchased including jumper kit for underground temporary power, secondary cable faults, grounding kit for underground and overhead work protection and underground cable fault troubleshooting device ($11,417) in addition to other miscellaneous shop and garage equipment ($2,317). In 2012 is a provision to build and install an outside racking structure that will allow LPDL to store and shelter the stock transformers off of the ground, safe from hazards and allow for easy access and retrieval ($50,000) as well as a provision for various small tools and garage and testing equipment as needed ($10,000). In 2013 is a provision to remove the old shed and build a new outside shed and storage structure at the operations facility to allow for more secure and increased storage capacity ($35,000) as well as a provision for various small tools and garage and testing equipment as needed ($10,000).

<u>Project #45: A/C 1980 – SCADA System</u>

Cost: $200,000 (2012 Estimate = $100,000; 2013 Estimate = $100,000)

Need: LPDL is planning to purchase a SCADA system that will track and manage station performance to improve LPDL's distribution system management. This will improve LPDL's service reliability by identifying high load areas and outage causes sooner thus providing the ability to restore power sooner.

Scope: This will involve the purchase and implementation of a SCADA software system. This is a multiyear project intended to enhance system monitoring and outage management with the addition and implementation of supplemental modules over time. In 2012 is a provision for the purchase and implementation of the SCADA software platform. This software would be functional in 2012, providing operations staff with the ability to communicate with remote terminal units installed in distribution system assets in the field to retrieve historical and live system load details. In 2013 is a provision for the implementation of enhanced SCADA communication to mobile operations and integration with other software systems.

ASSET MANAGEMENT PLAN SUMMARY:

LPDL has in 2012, developed an Asset Management Plan which accompanies this Schedule as Appendix A. This is an evolving document which LPDL plans to review annually and revise accordingly as system requirements and priorities change and improved data becomes more available with the further development and updating of asset information systems.

Asset management is the professional management of physical infrastructure with a systematic methodology integrating best practices in all aspects of selection, design, construction, operation, maintenance, replacement and disposition. The goal is to develop an Asset Management Plan that allows LPDL the opportunity to optimize the whole life business impact of costs, performance and risk exposures of LPDL's physical assets. Currently LPDL's distribution assets range in age from new to over 60 years old. Optimal performance of these assets is critical to ensure that safe, efficient and reliable electricity is delivered to maximize customer satisfaction and achieve regulatory performance standards.

Using current GIS and operational software, LPDL has completed a high level review of current assets and their age and has reviewed current strategies in dealing with maintenance and capital improvements. From this review and system inspection results, LPDL has identified various aged assets that require replacement to ensure safe and reliable delivery of electricity. As well, LPDL has identified various system voltage projects where 4.16kV and 12.5kV services will be upgraded to 27.6kV service to improve the quality and efficiency of electricity delivered. Some of these projects will allow LPDL to shift these loads to LPDL owned substations from Hydro One owned distribution stations thus reducing the reliance on Hydro One supply and improving system reliability.

In the Asset Management Plan, LPDL has provided a forecasted capital project spending plan for a four year horizon covering 2013, 2014, 2015 and 2016 as provided in Appendix A of this Exhibit. These projects are identified by year of expenditure, type of asset, need for expenditure, scope of project and cost estimate. These forecasted project costs are engineering estimates only and the actual expenditure levels in the capital budgets could be adjusted based on project scope, prevailing construction costs and other outside influences (e.g. relocation requests, system expansions, etc.).

CAPITALIZATION POLICY:

LPDL has historically applied the following general capitalization policies and principles based on CGAAP, as well as guidelines set out by the Ontario Energy Board, where applicable. Going forward capitalization will conform to MIFRS. The information found in this section applies to capitalization under CGAAP only. There are no changes to the capitalization policy under MIFRS for capital additions. Amortization and disposals are calculated and recorded differently under MIFRS and are described in Tab 5 – Conversion to MIFRS.

- The amount to be capitalized is the cost to acquire or construct a capital asset, including any ancillary costs incurred to place a capital asset into its intended state of operation. LPDL does not capitalize interest on funds for construction.
- Assets that are intended to be used on an on-going basis and are expected to provide future economic benefit (generally considered to be greater than one year) will be capitalized.
- Individual items with an estimated useful life greater than one year and valued at greater than $1,000 will be capitalized.
- Expenditures that create a physical betterment or improvement of the asset (i.e. there is a significant increase in the physical output or service capacity; or the useful life of the capital asset is extended) will be capitalized.
- With respect to transportation equipment (i.e. vehicles), all costs associated with placing a vehicle into service are capitalized.

GUIDELINES FOR CAPITALIZATION

Capital Assets

Capital Assets include tangible assets which include property, plant, and equipment provided they are held for use in the production or supply of goods and services. A capital expenditure must provide a benefit lasting beyond one year. Capital expenditures also include the improvement or "betterment" of existing assets. Intangible assets are also considered capital assets and are identified as assets that lack physical substance.

Betterment

A "betterment" is a cost which enhances the service potential of a capital asset and is therefore capitalized. A "betterment" includes expenditures which increase the capacity of the asset, lower associated operating costs of the asset, improve the quality of output or extend the asset's useful life.

Repair

A repair is a cost incurred to maintain the service potential of a capital asset. Expenditures for repairs are expensed to the current operating period. Expenditures for repairs and/or maintenance designed to maintain an asset in its original state are not capital expenditures and should be charged to an operating account.

CAPITAL ASSET COST

Cost

Cost is the amount of consideration given up to acquire, construct, develop or better a capital asset.

Amortization

Capital assets are amortized based on a method and life set by the OEB which is considered a suitable indicator of estimated useful life for the electrical distribution industry. A full years amortization is calculated on a straight line basis over estimated useful life of the asset. For the purposes of this rate application, LPDL used the half year rule for calculating depreciation expense for the 2013 Test Year.

Capital Spares

Spare transformers and meters will be accounted for as capital assets since they form an integral part of the reliability program for a distribution system. These spares are held for the purpose of backing up transformers and meters in-service for a distribution system.

Disposals

Prior to the conversion to MIFRS for 2013, LPDL was using the pooled asset methodology for disposals. From 2013 onward, individual assets that are disposed of will be identified individually and removed from fixed assets and accumulated amortization to Account 4362 ‘Loss on Retirement’.

SERVICE QUALITY & RELIABILITY PERFORMANCE:

LPDL tracks service reliability statistics SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index) including and excluding loss of supply related incidents. Table 2.3.3 below shows these statistic reporting results for the past three years.

Table 2. 3.3 - Service Reliability Statistics

Year	SAIDI	SAIFI	CAIDI
With Loss of Supply:			
2009	3.40	1.40	2.43
2010	3.62	0.83	4.36
2011	4.20	1.35	3.10
Excluding Loss of Supply			
2009	1.96	0.56	3.49
2010	3.27	0.66	4.96
2011	1.85	0.35	5.33

LPDL is committed to the reliability of the distribution system and is working towards continuously improving the above statistics. LPDL has set 2012 target indices for SAIDI and SAIFI (excluding Loss of Supply), developed at budget time before the 2011 year end results were available, as follows:

Table 2.3.4 - Target Indices for 2012

Year	SAIDI	SAIFI	CAIDI
2012 Target	1.29	0.49	2.62

In order to meet these targets, LPDL will continue to invest in capital projects that focus on the replacement of aging assets that have a high probability of failure and tree trimming maintenance programs that reduce the outages caused by tree interference. Renewal of these assets and continued maintenance programs reduce the risk to reliability and safety that would otherwise be unacceptable.

In addition to the above service reliability indicators, LPDL also measures service quality indicators, now referred to as Electricity Service Quality Requirements. LPDL continues to review and modify business and system processes to continuously improve these statistics. Table 2.3.5 below summarizes LPDL's reported Service Quality Requirements for the past three years.

Table 2.3.5 - Reported Service Quality Requirements

Indicator	OEB Minimum Standard	2009	2010	2011
Connection of New Services - Low Voltage	90% within 5 days	89.4%	97.6%	96.8%
Connection of New Services - High Voltage	90% within 10 days	100.0%	100.0%	n/a
Appointments Scheduled/Completed	90%	98.3%	97.9%	98.1%
Appointments Met	90%	98.9%	97.4%	96.9%
Appointments Rescheduled	100%	100.0%	100.0%	100.0%
Telephone Calls Answered	65% within 30 seconds	81.2%	80.9%	82.6%
Telephone Calls Abandoned	Less than 10%	3.5%	4.2%	2.5%
Written Responses to Enquiries	80% within 10 days	99.1%	98.3%	99.0%
Emergency Response - Urban	80% within 60 minutes	100.0%	100.0%	100.0%
Emergency Response - Rural	80% within 120 minutes	100.0%	100.0%	n/a
Reconnected Customers	85% within 2 days	n/a	n/a	100.0%

<u>OVERVIEW AND CALCULATION BY ACCOUNT - ALLOWANCE FOR WORKING CAPITAL:</u>

Overview and Calculation by Account

LPDL's working capital allowance is forecasted to be $3,168,385 for the 2013 Test Year (MIFRS) based on the methodology outlined on page 17 of Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 28, 2012. Namely, 13% of the sum of Cost of Power and Controllable Expenses (Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General), as illustrated in Table 2.4.1 below. LPDL's Cost of Power calculations for 2012 and 2013 are provided as Appendix B to this Exhibit.

Table 2.4.1 - Working Capital Calculation for 2013 (MIFRS)

Description	2013 Test Year
Cost of Power	21,044,660
Operations	197,000
Maintenance	921,046
Billing & Collecting	798,025
Community Relations	21,000
Administration & General Expense	1,379,756
Property Taxes	10,702
Working Capital Base	24,372,189
Working Capital Allowance Rate	13%
Working Capital Allowance	3,168,385

IMPACT ON FIXED ASSETS - CONVERSION TO MIFRS:

Overview

The Canadian Accounting Standards Board ("AcSB") adopted a strategic plan that will have Canadian GAAP (CGAAP) transitioned to International Financial Reporting Standards (IFRS), effective January 1, 2013 and which will require entities to restate, for comparative purposes, their 2012 interim and annual financial statements and their opening 2013 financial position.

In October 2010, the AcSB approved the incorporation of IFRS into Part 1 of the Canadian Institute of Chartered Accountants ("CICA") Handbook for qualifying entities with activities subject to rate regulation. Part 1 of the CICA Handbook specifies that first-time adoption is mandatory for interim and annual financial statements relating to annual periods beginning on or after January 1, 2011. The AcSB has proposed that qualifying entities with rate regulated activities be permitted, but not required, to continue applying the accounting standards in Part V of the CICA Handbook for an additional two years. This amendment also requires entities that do not prepare their interim and annual financial statements in accordance with Part 1 of the Handbook during the annual period beginning on or after January 1, 2011 to disclose that fact.

LPDL has deferred implementation of IFRS to January 1, 2013.

Transitional Analysis and Findings

Standard: IAS 16 – Property, Plant and Equipment
Topic: Componentization and Depreciation
Objective: To document LPDL's accounting policy on componentization and depreciation of property, plant and equipment.

Background: Each part of an item of property, plant and equipment (PP&E) with a cost that is significant in relation to the total cost of the item, shall be depreciated separately.

Using the April 2010 Kinetrics Inc. Asset Amortization Study, prepared for the Ontario Energy Board, LPDL has adopted the Typical Useful Life (TUL) for fixed assets in accordance with this study.

Depreciation is to be calculated on the basis of the estimated useful life of the item after deducting its residual value when fully depreciated. In practice, the residual value of an asset is often insignificant and therefore immaterial in the calculation of the depreciable amount.

The residual value and the useful life of an asset shall be reviewed at least at each financial year-end and, if expectations differ from previous estimates, the change(s) shall be accounted for as a change in an accounting estimate in accordance with IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors.

Depreciation of an asset begins when it is available for use (i.e. when it is in the location and in the condition necessary for it to be capable of operating in the manner as intended). Depreciation of an asset ceases, at the earlier of the date that the asset is classified as held for Sale, in accordance with IFRS 5, and the date that the asset is derecognized.

Considerations

Significant components of PP&E will be separately accounted for under IFRS. Each significant component, and their estimated useful lives, for purposes of computing depreciation expense under IFRS, will be tracked in a sub account.

Table 2.5.1 below, provides details of the conclusions from this transition and provides a comparison of PP&E's useful life as it was assigned under CGAAP and the revised TUL under MIFRS.

Table 2.5.1 - Schedule of PP&E Useful Life Assets

Component	Previous Component	Proposed Useful Life	Existing Useful Life	Kinetrics Study
Overhead System				
Wood Poles	Poles, Towers, Fixtures	45	25	45
Concrete Poles	Poles, Towers, Fixtures	60	25	60
Steel Poles	Poles, Towers, Fixtures	60	25	60
Conductors	Poles, Towers, Fixtures	60	25	60
Transformers (Pole) & Voltage Regulators	Poles, Towers, Fixtures	40	25	40
Underground System				
Padmount Transformers	Transformers	40	25	40
Ducts	Underground Conduit	50	25	50
Primary Non-TR XLPE Cables Direct Buried	Underground Conductor	25	25	25
Transformer & Municipal Station				
Power Transformers	Distribution Station Equipment	45	25	45
Station Metal Clad Switchgear	Distribution Station Equipment	40	25	40
Steel Structure	Distribution Station Equipment	50	25	50
DS Equipment - Other Components	Distribution Station Equipment	30	25	n/a
Civil Work, Site	Distribution Station - Parking, Fencing, Roof	30	25	25-30
Monitoring and Control				
Remote SCADA		20	15	20
Other Assets				
Office Equipment	Office Equipment	10	10	5-15
Vehicles - Trucks & Buckets	Vehicles	10	10	5-15
Vehicles - Trailers	Vehicles	10	10	5-20
Vehicles - Vans/Cars	Vehicles	5	5	5-10
Administrative Buildings	Buildings	50	30	50-75
Computer Hardware	Computer Hardware	5	5	3-5
Computer Software	Computer Software	5	5	2-5
Equipment - Power, Stores, Tools, Shop, Measure, Test	Tools, Shop and Garage Equipment	10	10	5-10
Residential Energy Meters	Meters	n/a	25	25-35
Industrial/Commercial Energy Meters	Meters	15	25	15-30
Wholesale Energy Meters	Meters	15	25	15-30
Smart Meters	Meters	15	15	5-10

LPDL has adopted the Kinetric's Report Typical Useful Life (TUL) in all asset categories.

LPDL retained the auditing firm, Grant Thornton, to provide assistance in the transition of financial records from CGAAP to IFRS. The assignment of useful lives to the asset base and net book value by asset component was provided by Suncorp Valuations, a third party asset valuation firm. The new levels of componentization and the corresponding useful lives will be applied beginning January 1, 2013.

The 2012 Rate Base has been restated as part of this Rate Application, in MIFRS format as required by the Addendum to the Report of the Board (EB-2008-0408) issued June 13, 2011 on Implementing IFRS, Appendix A, Issue 2.

Standard: IAS 16 – Property, Plant and Equipment:
Topic: Capitalization - Overheads
Objective: To document the accounting policy on the capitalization of overheads.
Core Principle: The cost of an item of PP&E is recognized as an asset if and only if:

a) It is probable that future economic benefits will flow to the company; and;
b) The cost of the item can be measured reliably.

The cost of an item of PP&E includes any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended.

Certain costs are explicitly prohibited from inclusion as costs of an item of PP&E:

a) Costs of opening a new facility;
b) Costs of introducing a new product or service (including advertising and promotion);
c) Costs of conducting business in a new location or with a new class of customer (including costs of staff training);
d) Administration and other general overhead costs; and
e) Day-to-day servicing costs.

IAS 16 does not indicate what constitutes an item of PP&E. Judgment is required when applying the core principle.

LPDL's Observations and Conclusions - Under IFRS the following costs will be capitalized:

- Directly Attributable:

  The cost must be directly attributed to a specific item of PP&E at the time it is incurred. The incurrence of that cost should aid directly in the construction effort making the asset more capable of being used than if the cost had not been incurred.

- Payroll Burden:

  Payroll allocation consists of the following benefits paid to or for employees: health benefits, WSIB, and the company portion of OMERS, CPP and EI. IAS 16 specifically allows for benefits as defined in IAS 19 to be included as a directly attributable cost. The payroll burden is allocated to capital based upon payroll dollars charged to capital.

- Rolling Stock (Vehicle Burden):

  The vehicle burden is allocated to capital based on the time that the vehicle is used on the job site, thus establishing the fact that the use of the vehicle is directly attributable to an item of PP&E.

Under IFRS the following costs will **not** be Capitalized:

- General and administrative overhead.
- Day-to-day servicing costs which are defined as costs of labour and consumables and may include the cost of small parts. The purpose of these expenditures is often described as for the "repairs and maintenance" of the item of PP&E.
- Under IFRS, training costs cannot be capitalized, but training on how to use a piece of equipment can be capitalized.

Conclusion

LPDL has determined that there are only a few minor changes required to LPDL's processes under MIFRS going forward, those involving useful life and depreciation expense and disposal of individual assets. The 2012 Bridge Year on MIFRS calculates depreciation on the adjusted 2011 Net Book Value over the adjusted remaining useful lives, established via the Suncorp valuation study. As well, individual assets that have been disposed of are removed from fixed assets and accumulated amortization with a gain/loss on retirement or disposal being recognized when applicable. For 2013 Test Year, assets will be depreciated over their new extended useful lives as well as any disposals being removed from fixed assets and accumulated amortization with a gain/loss on retirement or disposal being recognized when applicable. LPDL does not capitalize overhead allocations and is thus already IFRS compliant and requires no change to processes in this manner.

For depreciation, LPDL will need to track costs in sub accounts for componentization, because of different Typical Useful Life (TUL) periods and resulting differing depreciation rates.

Impact on Fixed Assets

LPDL has elected to take the IFRS 1 Exemption for rate regulated entities, which allows the use of the net book value of assets as at the date of transition as the deemed cost of the asset. This change has been reflected in the continuity statements provided in Exhibit 2, Tab 2, Schedule 1 which are reproduced below for the 2012 Bridge Year (Table 2.2.4(b)) and the 2013 Test Year (Table 2.2.5). The opening balance of the gross fixed assets for the 2012 Bridge year is the net book value of the assets for the same date under CGAAP.

The OEB commissioned a depreciation study to assist electricity distributors in their transition to IFRS. In the Report of the Board, Transition to IFRS (EB-2008-0408) the Board stated: “While utilities remain solely responsible for complying with financial reporting requirements, the Board notes that generic depreciation study could assist with IFRS compliance in addition to providing considerable regulatory benefits. The study should provide a good starting point for the determination of service lives for distribution assets that may be both acceptable to the Board and useful for financial reporting purposes. Distributors will remain responsible for review and updates of the services life for their particular assets for financial reporting and regulatory requirements."

LPDL has reviewed the useful life of its assets with the aid of the Asset Depreciation Study by Kinetrics (Kinetrics Report). LPDL has used the mid-range typical useful life for its assets, except for the items described above (as illustrated in Table 2.5.1 above) as described in the Kinetrics Study. Consequently, the useful lives have been extended causing net depreciation (depreciation expense to the income statement) to be reduced in the 2013 Test Year. This change has been reflected in the Continuity Statements provided below for the 2012 Bridge Year and 2013 Test Year.

Table 2.2.4(b) - Fixed Asset Continuity Schedule – 2012 (MIFRS)

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 268,709	$ 108,600		$ 377,309	$ 166,724	$ 112,845		$ 279,569	$ 97,740
12	1611	Computer Software (Formally known as Account 1925) - Smart Meters		$ 202,361	$ -		$ 202,361	$ 60,708	$ 70,826		$ 131,535	$ 70,826
CEC	1612	Land Rights (Formally known as Account 1906)		$ 516,004	$ 5,000		$ 521,004	$ 15,147	$ -		$ 15,147	$ 505,857
N/A	1805	Land		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1808	Buildings		$ 1,840,984	$ -		$ 1,840,984	$ 176,034	$ 76,374		$ 252,408	$ 1,588,576
13	1810	Leasehold Improvements		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 3,222,713	$ 105,000		$ 3,327,713	$ 890,246	$ 73,037		$ 963,283	$ 2,364,430
47	1825	Storage Battery Equipment		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 5,892,793	$ 224,750	-$ 16,191	$ 6,101,352	$ 2,865,205	$ 206,375	-$ 9,020	$ 3,062,560	$ 3,038,792
47	1835	Overhead Conductors & Devices		$ 3,377,674	$ 174,750	-$ 12,715	$ 3,539,709	$ 1,034,875	$ 152,605	-$ 7,502	$ 1,179,978	$ 2,359,731
47	1840	Underground Conduit		$ 3,110,634	$ 86,750		$ 3,197,384	$ 1,490,104	$ 46,275		$ 1,536,379	$ 1,661,005
47	1845	Underground Conductors & Devices		$ 1,868,544	$ 210,500	-$ 22,250	$ 2,056,794	$ 524,873	$ 66,323	-$ 13,128	$ 578,068	$ 1,478,725
47	1850	Line Transformers		$ 5,913,575	$ 288,750	-$ 29,929	$ 6,172,396	$ 2,266,035	$ 192,015	-$ 15,361	$ 2,442,689	$ 3,729,707
47	1855	Services (Overhead & Underground)		$ 561,602	$ 74,500		$ 636,102	$ 122,088	$ 13,222		$ 135,310	$ 500,792
47	1860	Meters		$ 266,941	$ 90,000	-$ 24,576	$ 332,365	$ 59,654	$ 18,355	-$ 2,458	$ 75,551	$ 256,814
47	1860	Meters (Stranded Meters)		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1860	Meters (Smart Meters)		$ 1,619,923	$ -	-$ 20,700	$ 1,599,223	$ 127,044	$ 110,584	-$ 2,070	$ 235,557	$ 1,363,666
N/A	1905	Land		$ 278,455	$ -		$ 278,455	$ -	$ -		$ -	$ 278,455
47	1908	Buildings & Fixtures		$ 174,386	$ -		$ 174,386	$ 51,202	$ 5,651		$ 56,853	$ 117,533
13	1910	Leasehold Improvements		$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 232,043	$ 10,000		$ 242,043	$ 126,099	$ 21,647		$ 147,746	$ 94,297
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware		$ 175,959	$ -		$ 175,959	$ 175,959	$ -		$ 175,959	-$ 0
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ 105,477	$ -		$ 105,477	$ 105,476	$ -		$ 105,476	$ 0
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ 84,705	$ 10,000		$ 94,705	$ 57,617	$ 28,088		$ 85,705	$ 9,000
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07) - Smart Meters		$ 46,164	$ -		$ 46,164	$ 13,849	$ 10,772		$ 24,621	$ 21,543
10	1930	Transportation Equipment		$ 1,175,512	$ 115,000	-$ 76,332	$ 1,214,180	$ 764,872	$ 77,415	-$ 65,796	$ 776,491	$ 437,689
8	1935	Stores Equipment		$ 10,960	$ -		$ 10,960	$ 8,584	$ 697		$ 9,281	$ 1,679
8	1940	Tools, Shop & Garage Equipment		$ 251,748	$ 60,000		$ 311,748	$ 173,429	$ 22,778		$ 196,207	$ 115,541
8	1945	Measurement & Testing Equipment		$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1950	Power Operated Equipment		$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment		$ 188,721	$ -		$ 188,721	$ 128,761	$ 13,944		$ 142,705	$ 46,016
8	1955	Communication Equipment (Smart Meters)		$ 410,583	$ -		$ 410,583	$ 123,175	$ 33,813		$ 156,988	$ 253,596
8	1960	Miscellaneous Equipment		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment		$ -	$ 100,000		$ 100,000	$ -	$ 2,500		$ 2,500	$ 97,500
47	1985	Miscellaneous Fixed Assets		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants		-$ 4,997,238	$ -		-$ 4,997,238	-$ 1,074,129	-$ 193,638		-$ 1,267,767	-$ 3,729,471
	etc.				$ -		$ -	$ -	$ -		$ -	$ -
									0			
		Total		**$ 26,799,932**	**$ 1,663,600**	**-$ 202,693**	**$ 28,260,840**	**$ 10,453,632**	**$ 1,162,500**	**-$ 115,334**	**$ 11,500,798**	**$ 16,760,042**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 77,415
Stranded Meters (in 1555)	-$ 140,553
Net Depreciation	$ 1,225,638

Table 2.2.5 - Fixed Asset Continuity Schedule – 2013 (MIFRS)

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 377,309	$ 10,000		$ 387,309	$ 279,569	$ 22,720		$ 302,289	$ 85,020
12	1611	Computer Software (Formally known as Account 1925) - Smart Meters		$ 202,361			$ 202,361	$ 131,535	$ 70,826		$ 202,361	$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ 521,004	$ 5,000		$ 526,004	$ 15,147	$ -		$ 15,147	$ 510,857
N/A	1805	Land		$ -			$ -	$ -	$ -		$ -	$ -
47	1808	Buildings		$ 1,840,984		-$ 1,111	$ 1,839,873	$ 252,408	$ 76,374	-$ 441	$ 328,341	$ 1,511,532
13	1810	Leasehold Improvements		$ -			$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -	$ -		$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 3,327,713	$ 150,000		$ 3,477,713	$ 963,283	$ 76,224		$ 1,039,507	$ 2,438,206
47	1825	Storage Battery Equipment		$ -			$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 6,101,352	$ 147,400	-$ 7,373	$ 6,241,379	$ 3,062,560	$ 210,027	-$ 3,884	$ 3,268,704	$ 2,972,676
47	1835	Overhead Conductors & Devices		$ 3,539,709	$ 123,000	-$ 3,972	$ 3,658,738	$ 1,179,978	$ 154,749	-$ 2,565	$ 1,332,163	$ 2,326,575
47	1840	Underground Conduit		$ 3,197,384	$ 155,500		$ 3,352,884	$ 1,536,379	$ 49,303		$ 1,585,682	$ 1,767,202
47	1845	Underground Conductors & Devices		$ 2,056,794	$ 404,500	-$ 27,724	$ 2,433,569	$ 578,068	$ 72,902	-$ 18,718	$ 632,253	$ 1,801,317
47	1850	Line Transformers		$ 6,172,396	$ 297,800		$ 6,470,196	$ 2,442,689	$ 198,595		$ 2,641,284	$ 3,828,913
47	1855	Services (Overhead & Underground)		$ 636,102	$ 111,800		$ 747,902	$ 135,310	$ 15,292		$ 150,603	$ 597,299
47	1860	Meters		$ 332,365	$ 84,500	-$ 49,152	$ 367,713	$ 75,551	$ 22,533	-$ 8,192	$ 89,892	$ 277,821
47	1860	Meters (Stranded Meters)		$ -			$ -	$ -	$ -		$ -	$ -
47	1860	Meters (Smart Meters)		$ 1,599,223	$ 15,500	-$ 2,700	$ 1,612,023	$ 235,557	$ 109,720	-$ 450	$ 344,828	$ 1,267,196
N/A	1905	Land		$ 278,455			$ 278,455	$ -	$ -		$ -	$ 278,455
47	1908	Buildings & Fixtures		$ 174,386			$ 174,386	$ 56,853	$ 5,651		$ 62,503	$ 111,883
13	1910	Leasehold Improvements		$ -			$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 242,043	$ 10,000		$ 252,043	$ 147,746	$ 22,647		$ 170,392	$ 81,651
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware		$ 175,959			$ 175,959	$ 175,959	$ -		$ 175,959	-$ 0
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ 105,477			$ 105,477	$ 105,476	$ -		$ 105,476	$ 0
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ 94,705			$ 94,705	$ 85,705	$ 2,000		$ 87,705	$ 7,000
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07) - Smart Meters		$ 46,164			$ 46,164	$ 24,621	$ 10,772		$ 35,392	$ 10,772
10	1930	Transportation Equipment		$ 1,214,180	$ 395,000	-$ 190,067	$ 1,419,113	$ 776,491	$ 101,869	-$ 190,067	$ 688,293	$ 730,820
8	1935	Stores Equipment		$ 10,960			$ 10,960	$ 9,281	$ 697		$ 9,978	$ 982
8	1940	Tools, Shop & Garage Equipment		$ 311,748	$ 45,000		$ 356,748	$ 196,207	$ 28,028		$ 224,234	$ 132,514
8	1945	Measurement & Testing Equipment		$ -			$ -	$ -	$ -		$ -	$ -
8	1950	Power Operated Equipment		$ -			$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment		$ 188,721			$ 188,721	$ 142,705	$ 13,944		$ 156,649	$ 32,072
8	1955	Communication Equipment (Smart Meters)		$ 410,583			$ 410,583	$ 156,988	$ 33,813		$ 190,800	$ 219,783
8	1960	Miscellaneous Equipment		$ -			$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment		$ 100,000	$ 100,000		$ 200,000	$ 2,500	$ 7,500		$ 10,000	$ 190,000
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants		-$ 4,997,238			-$ 4,997,238	-$ 1,267,767	-$ 193,638		-$ 1,461,405	-$ 3,535,833
	etc.						$ -	$ -	$ -		$ -	$ -
									0			
		Total		**$ 28,260,840**	**$ 2,055,000**	**-$ 282,099**	**$ 30,033,741**	**$ 11,500,798**	**$ 1,112,547**	**-$ 224,317**	**$ 12,389,029**	**$ 17,644,712**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 101,869
Deferred PP&E	$ 58,599
Net Depreciation	$ 952,080

<u>IMPACT ON CAPITAL BUDGETS – CONVERSION TO MIFRS:</u>

Componentization and Amortization

IAS 16 requires each part of an item of PP&E with a cost that is significant in relation to the total cost of the time to be depreciated separately. In addition, IAS 16 requires entities perform a review of its useful lives, amortization methods and residual values on an annual basis.

LPDL has reviewed the useful life of its assets with the aid of the Kinetrics report and the Suncorp asset valuation study. Exhibit 4, Tab 4, Schedule 2 outlines the amortization expense based on the new useful lives of the assets. LPDL has changed the useful life of its assets to the “Projected Useful Life” as shown in Table 2.5.1 defined within the ranges in the Kinetrics study. LPDL has restated its continuity statements for the 2012 Bridge Year and the 2013 Test Year to include these changes.

PP&E DEFERRAL ACCOUNT AND REQUEST FOR DISPOSITION:

The conversion from CGAAP to MIFRS has resulted in some changes to LPDL's accounting for Plant, Property and Equipment (PP&E).

Table 2.5.2 IFRS-CGAAP Transitional PP&E Amounts below illustrates LPDL's forecast of the PP&E Deferral account as a result of transition from CGAAP to MIFRS, with MIFRS incorporating the revised componentized Typical Useful Life as previously stated in Table 2.5.1

Table 2.5.2 - IFRS-CGAAP Transitional PP&E Amounts

	2009 Rebasing Year	2010	2011	2012	2013 Rebasing Year	2014	2015	2016
Reporting Basis	CGAAP	IRM	IRM	IRM	MIFRS	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast			
			$	$	$	$	$	$
PP&E Values under CGAAP								
Opening net PP&E - Note 1				16,346,300				
Additions				1,587,268				
Depreciation (amounts should be negative)				-1,407,922				
Closing net PP&E (1)				16,525,647				
PP&E Values under MIFRS (Starts from 2012, the transition year)								
Opening net PP&E - Note 1				16,346,300				
Additions				1,460,907				
Depreciation (amounts should be negative)				-1,047,166				
Closing net PP&E (2)				16,760,042				
Difference in Closing net PP&E, CGAAP vs. MIFRS (Shown as adjustment to rate base on rebasing)				-234,395				
Account 1575 - IFRS-CGAAP Transitional PP&E Amounts								
Opening balance				0	-234395	-175796	-117198	-58599
Amounts added in the year				-234395				
Sub-total				-234395	-234395	-175796	-117198	-58599
Amount of amortization, included in depreciation expense - Note 2					58599	58599	58599	58599
Closing balance in deferral account				-234395	-175796	-117198	-58599	0

Effect on Revenue Requirement

Amortization of deferred balance as above - Note 2	-58599	**WACC**	6.62%
Return on Rate Base Associated with deferred PP&E balance at WACC - Note 3	-15517	**Disposition Period - Note 4**	4
Amount included in Revenue Requirement on rebasing	-74116		

Table 2.5.2 above illustrates that through the transition from CGAPP to MIFRS, with MIFRS incorporating the revised componentized Useful Life as previously stated, the calculated difference in closing net PP&E for 2013 Test Year is changed by $-234,395. As LPDL transitions from CGAAP to MIFRS for January 1, 2013, it is anticipated that this variance will need to be recorded and tracked in the Deferral / Variance account which has been identified as a request to the OEB in Exhibit 9.

Based on the Addendum Report of the Board "Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment (EB-2009-0408)" dated June 13, 2012, LPDL requests this amount be moved to a PPE deferral account for disposition to customers. LPDL requests a four year disposition period. As directed, this amount will not attract carrying charges but will attract the same level of return as used in determining revenue requirement for this cost of service application as shown on Table 2.5.2.

IAS 16 – Property, Plant and Equipment – Measurement after Recognition.

For subsequent periods following the initial recognition of an asset, IAS 16 permits the choice of using either the Cost Model or the Revaluation Model for valuing PP&E. LPDL will continue to use the Cost Model to measure PP&E.

IMPACT ON RATE BASE – CONVERSION TO MIFRS:

Table 2.5.3 below provides a comparison of rate base between CGAAP and MIFRS for the 2012 Bridge Year. The change in Net Book Value has been described above. The working capital allowance has not increased as there are no changes to OM&A expenses under MIFRS.

Table 2.5.3 - Impact of MIFRS – Rate Base

	2012 Bridge Year (CGAAP)	2013 Test Year (CGAAP)	2012 Bridge Year (MIFRS)	2013 Test Year (MIFRS)	Variance
Gross Fixed assets	$ 28,387,201	$ 30,252,134	$ 28,260,840	$ 30,033,741	
Accum. Dep'n	$ 11,861,554	$ 13,247,375	$ 11,500,799	$ 12,389,031	
Net Book Value	$ 16,525,646	$ 17,004,759	$ 16,760,041	$ 17,644,710	
Average NBV	$ 16,435,973	$ 16,765,202	$ 16,553,171	$ 17,202,376	
Working Capital Allow	$ 3,688,709	$ 3,168,385	$ 3,688,709	$ 3,168,385	
Rate Base	$ 20,124,683	$ 19,933,587	$ 20,241,880	$ 20,370,760	$ 437,173

Table 2.5.4 provides details of the impact of MIFRS on the revenue requirement for the 2013 Test Year which results in an overall variance of -$600,940 . This variance is made up of a reduction in amortization, and increase in the regulated return on capital and a reduction in PILs. In addition revenue offsets have decreased as a result of capital disposal recognition and one-fourth of the PP&E deferral account balance and associated rate of return.

Table 2.5.4 – Impact of MIFRS on Revenue Requirement

	2013 Test Year (CGAAP)	2013 Test Year (MIFRS)	Variance
OM&A	$ 3,327,529	$ 3,327,529	$ -
Amortization	$ 1,428,232	$ 1,010,680	-$ 417,552
Amortization on PP&E Adjustment	$ -	-$ 58,599	-$ 58,599
Return on PP&E Adjustment	$ -	-$ 15,517	-$ 15,517
Regulated Return on Capital	$ 1,348,327	$ 1,348,327	$ -
PILS	$ 328,022	$ 160,968	-$ 167,054
Service Revenue Requirement	$ 6,432,110	$ 5,773,388	-$ 658,722
Less: Revenue Offsets	$ 371,410	$ 313,628	-$ 57,782
Base Revenue Requirement	$ 6,060,700	$ 5,459,760	-$ 600,940

Tables 2.5.5 and 2.5.6 below provide details of the revenue deficiency for the 2013 Test Year under CGAAP and MIFRS.

Table 2.5.5 – Revenue Deficiency (CGAAP)

Description	2012 Bridge Actual (CGAAP)	2013 Test Existing Rates (CGAAP)	2013 Test - Required Revenue (CGAAP)
Revenue			
Revenue Deficiency			**993,846**
Distribution Revenue	5,055,577	5,066,854	5,066,854
Other Operating Revenue (Net)	364,225	371,410	371,410
Total Revenue	**5,419,801**	**5,438,264**	**6,432,110**
Costs and Expenses			
Administrative & General, Billing & Collecting	2,160,541	2,198,781	2,198,781
Operation & Maintenance	1,108,073	1,118,046	1,118,046
Depreciation & Amortization	1,497,835	1,428,232	1,428,232
Property Taxes	10,290	10,702	10,702
Amortization of deferred balance		0	0
Return on PP&E adj			0
Deemed Interest	591,854	605,202	605,202
Total Costs and Expenses	**5,368,592**	**5,360,963**	**5,360,963**
Utility Income Before Income Taxes	**51,209**	**77,302**	**1,071,147**
Income Taxes:			
Corporate Income Taxes	44,769	64,653	328,022
Total Income Taxes	**44,769**	**64,653**	**328,022**
Utility Net Income	**6,440**	**12,649**	**743,125**
Income Tax Expense Calculation:			
Accounting Income	51,209	77,302	1,071,147
Tax Adjustments to Accounting Income	237,622	298,746	298,746
Taxable Income	**288,831**	**376,048**	**1,369,893**
Income Tax Expense	44,769	64,653	328,022
Tax Rate Refecting No Tax Credits	15.5000%	26.50%	26.50%
Tax Credit	0	35,000	35,000
Actual Return on Rate Base:			
Rate Base	20,124,683	19,933,587	19,933,587
Interest Expense	591,854	605,202	605,202
Net Income	6,440	12,649	743,125
Total Actual Return on Rate Base	**598,294**	**617,851**	**1,348,327**
Actual Return on Rate Base	2.97%	3.10%	6.76%
Required Return on Rate Base:			
Rate Base	20,124,683	19,933,587	19,933,587
Return Rates:			
Return on Debt (Weighted)	4.90%	4.95%	4.95%
Return on Equity	8.01%	9.12%	9.12%
Deemed Interest Expense	591,854	605,202	605,202
Return On Equity	644,795	743,125	743,125
Total Return	**1,236,648**	**1,348,327**	**1,348,327**
Expected Return on Rate Base	6.14%	6.76%	6.76%
Revenue Deficiency After Tax	**638,355**	**730,476**	**0**
Revenue Deficiency Before Tax	**755,449**	**993,846**	**0**

Tax Exhibit		Tax Credit	**2013**
Deemed Utility Income			743,125
Tax Adjustments to Accounting Income			298,746
Taxable Income prior to adjusting revenue to PILs	A		**1,041,872**
Tax Rate - before tax credits	B		26.50%
	A*B		276,096
Total PILs before gross up - tax credit deducted		-35,000	**241,096**
Grossed up PILs			**328,022**

Table 2.5.6 – Revenue Deficiency (MIFRS)

Description	2012 Bridge Actual (MIFRS)	2013 Test Existing Rates (MIFRS)	2013 Test - Required Revenue (MIFRS)
Revenue			
Revenue Deficiency			**392,906**
Distribution Revenue	5,055,577	5,066,854	5,066,854
Other Operating Revenue (Net)	288,796	313,628	313,628
Total Revenue	**5,344,372**	**5,380,482**	**5,773,388**
Costs and Expenses			
Administrative & General, Billing & Collecting	2,160,541	2,198,781	2,198,781
Operation & Maintenance	1,108,073	1,118,046	1,118,046
Depreciation & Amortization	1,225,639	1,010,680	1,010,680
Property Taxes	10,290	10,702	10,702
Amortization of deferred balance		-58,599	-58,599
Return on PP&E adj		-15,517	-15,517
Deemed Interest	591,854	605,202	605,202
Total Costs and Expenses	**5,096,396**	**4,869,295**	**4,869,295**
Utility Income Before Income Taxes	**247,976**	**511,187**	**904,093**
Income Taxes:			
Corporate Income Taxes	27,029	56,848	160,968
Total Income Taxes	**27,029**	**56,848**	**160,968**
Utility Net Income	**220,947**	**454,339**	**743,125**
Income Tax Expense Calculation:			
Accounting Income	247,976	511,187	904,093
Tax Adjustments to Accounting Income	-73,595	-164,592	-164,592
Taxable Income	**174,381**	**346,595**	**739,501**
Income Tax Expense	27,029	56,848	160,968
Tax Rate Refecting No Tax Credits	15.5000%	26.50%	26.50%
Tax Credit	0	35,000	35,000
Actual Return on Rate Base:			
Rate Base	20,241,880	20,370,760	20,370,760
Interest Expense	591,854	605,202	605,202
Net Income	220,947	454,339	743,125
Total Actual Return on Rate Base	**812,800**	**1,059,541**	**1,348,327**
Actual Return on Rate Base	4.02%	5.20%	6.62%
Required Return on Rate Base:			
Rate Base	20,241,880	20,370,760	20,370,760
Return Rates:			
Return on Debt (Weighted)	4.90%	4.95%	4.95%
Return on Equity	8.01%	9.12%	9.12%
Deemed Interest Expense	595,300	605,202	605,202
Return On Equity	648,550	743,125	743,125
Total Return	**1,243,850**	**1,348,327**	**1,348,327**
Expected Return on Rate Base	6.14%	6.62%	6.62%
Revenue Deficiency After Tax	**431,050**	**288,786**	**0**
Revenue Deficiency Before Tax	**510,118**	**392,906**	**0**

Tax Exhibit	Tax Credit	**2013**
Deemed Utility Income		743,125
Tax Adjustments to Accounting Income		(164,592)
Taxable Income prior to adjusting revenue to PILs	A	**578,533**
Tax Rate - before tax credits	B	26.50%
Income tax before tax credits	A*B	153,311
Total PILs before gross up - tax credit deducted	-35,000	**118,311**
Grossed up PILs		**160,968**

GREEN ENERGY PLAN – FUNDING ADDER

LPDL has submitted a basic Green Energy Plan to the OPA and has provided a copy in Appendix C. The OPA provided a Letter of Comment which has been provided in Appendix D. As explained in the submitted Green Energy Plan, LPDL has incurred approximately $240,000 in renewable generation project costs to date, which are tracked in Account 1531: Renewable Generation Connection Capital Deferral Account. These costs are due to expansion/enabling improvement costs incurred to protect and upgrade against LPDL's municipal stations that are connected to two waterpower generation facilities that underwent major upgrades over the past two years to increase their production to approximately 5500 kW combined.

Due to these upgrades, LPDL has been notified by Hydro One that Hydro One will incur costs to remedy protection, controls and communication issues at the Hydro One Muskoka TS due to this increased connected generation. To date, the proposed cost from Hydro One is approximately $1,500,000 but at this time, no charges have been passed on to LPDL. In accordance with the DSC, LPDL's total contribution for expansion costs due to these generation plant upgrades will be capped at $90,000 per MW or approximately $495,000 ($90,000 x 5MW), as per the Green Energy Act.

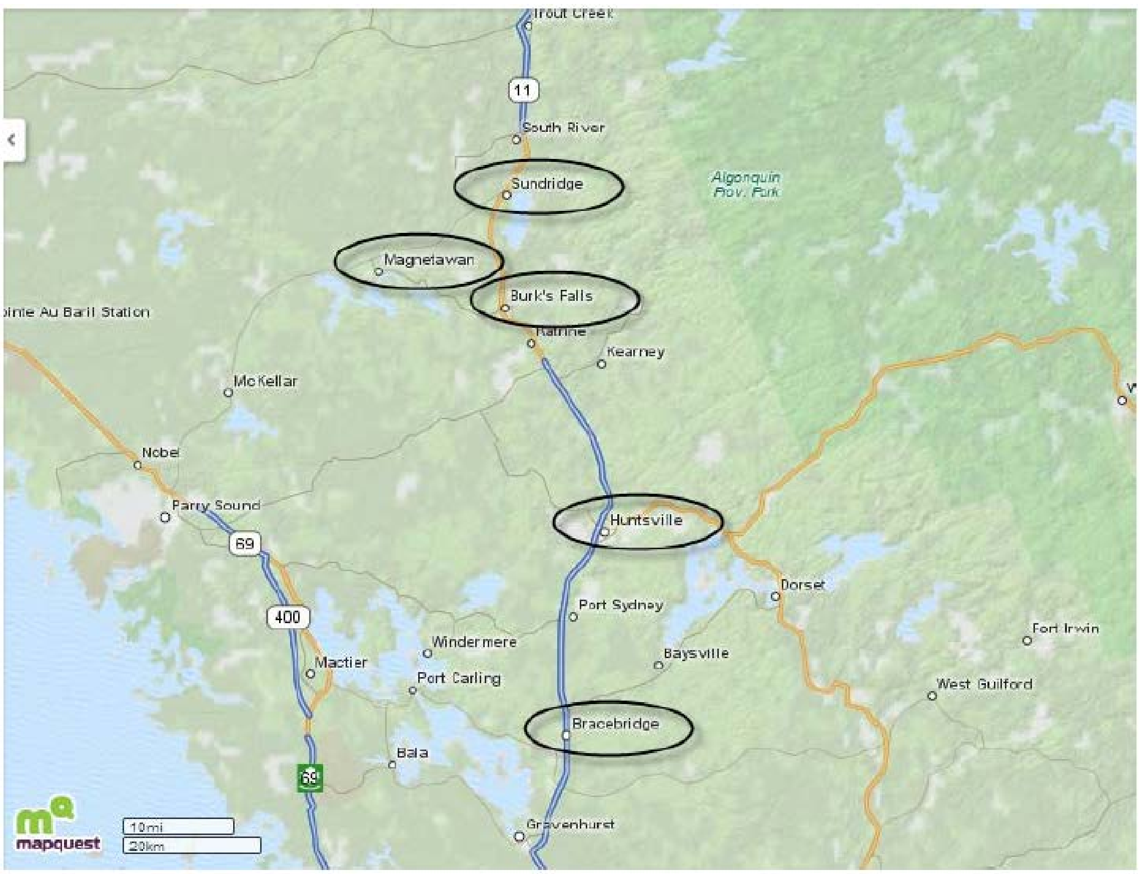
As these additional costs from Hydro One are uncertain as of yet as to the amount and timing, LPDL is not requesting recovery for any renewable generation costs in this Application. Rate recovery for these costs will be addressed in future rate applications.

APPENDIX A

LPDL ASSET MANAGEMENT PLAN

Introduction

Lakeland Power Distribution Ltd. (LPDL) is a Local Distribution Company (LDC), regulated and licensed by the Ontario Energy Board (OEB) that distributes electricity to approximately 9,700 customers across a service area of 144 square kilometers. LPDL was formed in 2000 by the amalgamation of five separate, rural distribution utilities and is completely embedded within Hydro One's system. This non-contiguous service area encompasses: Town of Huntsville, Town of Bracebridge, Municipality of Magnetawan, Village of Burk's Falls and Village of Sundridge (Appendix A). The operations facility for LPDL is located in Bracebridge, which contains the highest concentration of customers and the administration office is located in Huntsville, which is more centrally accessible to all customers.



ASSET MANAGEMENT PLAN: 2013-2016

Due to the amalgamation of five, distinctly separate utilities, LPDL's distribution system consists of widely varying ages of overhead and underground assets, station capacities and system voltages (4.16kV, 12.5kV, 27.6kV and 44kV). A primary focus for LPDL, currently and over the asset management plan period of four years, is the replacement of these aging assets and system voltage conversions. These asset upgrades will assist LPDL in improving the quality, safety and reliability of electricity distribution to their customers and in meeting regulatory performance standards. Another focus of LPDL is to reduce, where possible, the reliance on Hydro One distribution stations. This can be achieved by increasing LPDL owned municipal station and feeder capacities in an effort to minimize the impact of Hydro One outages on LPDL's customers.

Asset Management Plan Overview

The cornerstone of any Asset Management Plan (AMP) is to understand the type of assets, number of assets and condition of the assets owned by the company. The purpose of this AMP is to outline how LPDL will develop, manage and maintain the distribution system equipment in a safe, reliable and cost effective manner. The information systems, currently in place and planned for the future, used to track and analyze operational data will assist LPDL in assessing safety, reliability and business risk challenges. LPDL has established inspection, maintenance and renewal programs to address these challenges, as well as providing reliability data that meet the OEB's Distribution System Code's (DSC) reporting requirements. All of the above are done in an effort to optimize distribution system asset utilization and to meet or exceed customer expectation of the delivery of safe, reliable and affordable electricity.

This AMP covers a four year horizon from 2013 to 2016 and is intended to be reviewed on a periodic basis. The AMP identifies major initiatives and projects to be undertaken that meet customer and stakeholder requirements. Preparation of this AMP is intended to supplement the 2013 cost of service rate application submitted to the OEB for 2013 distribution rate approval.

Asset Management Objectives

The following outlines the key objectives of LPDL's approach to asset management. These objectives aim to maximize the safety, capacity, reliability and security aspects of the distribution system by:

- Maintaining an organized and scheduled inspection and maintenance program to assess LPDL's assets in order to identify and prioritize: assets that require upgrading due to age or failing equipment; equipment that requires replacement due to safety/environmental concerns; and areas that require development due to growth.
- Long term preservation and efficient performance of the distribution system.

- Developing and maintaining a distribution system that meets/exceeds regulated performance and reliability standards.
- Aiding in developing effective annual capital and operating and maintenance budgets that are based on actual system data.
- Informed planning to be proactive in system maintenance and system upgrades to avoid problems and potential crises thus reducing risk to the utility's customers and shareholders.
- Remaining compliant with any new industry standards or reporting requirements that may be prescribed by governmental and/or regulatory bodies.
- Maintaining appropriate software systems and operational processes that accurately track all useful data of the distribution system including age, location, performance and value of all transactions allowing for proper asset valuation, lifecycle management and performance measurement.

In adhering to the OEB's DSC Appendix C requirements, LPDL inspects their complete distribution system over a three year cycle as per the administered maintenance and inspection program. The distribution system is currently split into three inspection areas, based on pole count, to ensure that approximately a third of the system is inspected each year. This inspection covers all major equipment in the inspection area including substation, tree condition, switches, transformers, poles and conductors. One main aspect of this inspection and maintenance program is to ensure the system is safe and reliable to protect the public from physical, electrical and environmental hazards.
Ontario Regulation 22/04 – Electrical Distribution Safety is a key regulation which LPDL adheres to. This regulation requires LDC's to maintain distribution standards, material standards and construction verification programs to safeguard the public from any electrical system hazards. The Electrical Safety Authority (ESA) is responsible for enforcing this regulation by conducting annual audits and regular field inspections of LDC's systems.
LPDL also strives to promote a safe and healthy workplace and distribution system in order to prevent losses to people, assets, and the environment. LPDL conducts monthly health and safety meetings to identify and evaluate the risk of any workplace hazards and review and evaluate feedback on losses and near losses that have occurred to help prevent future losses of this kind. LPDL will continue to follow all regulatory guidelines and requirements to ensure the distribution system has a low impact on the environment.

Asset Management Roles and Responsibilities

ASSET MANAGEMENT PLAN: 2013-2016

LPDL's asset management plan requires a team effort and is the combined responsibility of the Manager of Operations, Lines Supervisor, engineering staff, lines department, GIS/IT support personnel and financial department. Generally these responsibilities include:

- Ensuring schedules for inspection and maintenance are adhered to.
- Reviewing and ensuring the inspection data is complete and thorough in order to be useful.
- Reviewing and analyzing the inspection data to plan for system maintenance and upgrades.
- Analyzing inspection data and trouble call trends to identify and prioritize future areas for capital and operating and maintenance budgets.
- Reviewing and updating the inspection and maintenance program as required, to incorporate changing regulations, standards and system facilities and to enhance the value of the inspection result data.
- Ensure the proposed capital expenditures are financially feasible and support the established budgetary parameters.

Distribution System Maintenance and Inspection Program

A distribution system maintenance and inspection program is a key component to maintaining system reliability and to protect the public and LPDL's employees from physical, electrical and environmental hazards. The purpose of LPDL's inspection and maintenance program is to document the requirements for the maintenance and inspection of all key distribution system assets.

Each distribution system asset has its own program. Within each program is the specific procedure that identifies how the maintenance and inspection of the specific asset will be performed and who is responsible for the delivery of the program. Each program is reviewed annually and is subject to LPDL's continuous improvement process.

LPDL's maintenance and inspection program consists of the following programs:

1) Line Clearing and Tree Trimming Maintenance Program
2) Substation Maintenance Program (includes hydraulic and electronic reclosure maintenance)
3) Distribution Plant Inspection Program
4) Thermography Inspection Program
5) Switch Maintenance Program

In adhering to the OEB's DSC Appendix C requirements, the above inspection and maintenance program spans a three year cycle with approximately one third of LPDL's distribution system being inspected each year. LPDL's system is split into three inspection zones, primarily based on pole count: Bracebridge North Zone, Bracebridge South Zone and Huntsville/Burk's Falls/Sundridge/Magnetawan Zone. The boundary between the Bracebridge North Zone and the Bracebridge South Zone is delineated by the Muskoka River (Appendix B).

1) Line Clearing and Tree Trimming Maintenance Program

The purpose of the line clearing and tree trimming maintenance program is to clear all electrical distribution lines from the encroachment of trees and branches to eliminate, as best as possible, tree contact with the lines. LPDL's service area is heavily forested and has many areas in the five communities with mature trees. This program is a major contributor to improving reliability and reducing system outages and losses.

The areas to be trimmed are defined as zones, with Zones 1 to 6 being located in Bracebridge and Zone 7 covering the rest of the service territory in Huntsville, Burk's Falls, Sundridge and Magnetawan (Appendix C). The line clearing and tree trimming program is organized as a rotating seven year cycle:

- Zone 1 - 2009
- Zone 2 - 2010
- Zone 3 - 2014
- Zone 4 - 2013
- Zone 5 - 2011
- Zone 6 - 2012
- Zone 7 - 2015

This seven year schedule is flexible as the zones may be reprioritized in order to address areas earlier than planned that are experiencing increased trouble calls and/or customer calls. All trees, limbs and branches are trimmed in accordance with LPDL's "Specifications for Tree Trimming" document (Appendix D). In locations where it would be considered inappropriate to trim to the standard clearances, the Contractor will consult with and obtain approval from LPDL for alternate clearances.

The Manager of Operations is responsible for the administration of the line clearing and tree trimming maintenance program with the responsibility of work protection being held by the Lines Supervisor.

2) Substation Maintenance Program

The purpose of the substation maintenance program is to identify any operational or safety issues in a substation and remediate them as quickly as possible to ensure the continuous operation of each substation and to eliminate any danger to the public. This program consists of:

i) monthly inspections
ii) annual oil analysis of all substation power transformers
iii) routine station maintenance (including hydraulic and electronic reclosures)

LPDL's substations that are part of this program are as follows:

Station Name	Address	Installed Capacity (MVA)	# of Transformers	Voltage	# of Reclosures	# of Feeders
Centennial MS	Wellington St, Bracebridge	10MVA	1	44kV/27.6kV	6	3
Douglas MS5	Douglas Dr, Bracebridge	5MVA	1	44kV/27.6kV	6	2
Golden Beach MS	Hwy #118, Bracebridge	10MVA	1	44kV/27.6kV	6	2
MS2 Bracebridge	Wellington St, Bracebridge	7.5MVA	1	44kV/4.16kV	0	4
MS3 Bracebridge	Ecclestone Dr, Bracebridge	5MVA	1	44kV/4.16kV	0	3
MS1 Huntsville	Station St, Huntsville	6MVA	1	44kV/4.16kV	0	5
MS2 Huntsville	West Rd, Huntsville	8MVA	1	44kV/4.16kV	0	4

i) Monthly Substation Inspection:

The purpose of the monthly substation inspection is to identify any deficiencies and to verify that the substation is not going to pose any safety concerns to the public. Each station has a specific "Monthly Substation Inspection" checklist (Appendix E) to be completed and signed off on by the inspector.

The Engineering Technician is responsible for the completion of the substation inspection with the Manager of Operations being responsible for the administration of any noted deficiencies.

ii) Annual Oil Tests:

Conducting annual oil tests on substation transformers have proven to be effective in identifying internal transformer issues before major faults occur, which cause a reduction in reliability and increase costs. Lakeland performs both oil quality and gas-in-oil tests at every substation at least once per year. Additional oil tests are also completed upon recommendations made by the service firm providing the analysis and as required.

The Manager of Operations is responsible for both the administration of the annual oil test program as well as the administration of any noted deficiencies.

iii) Routine Station Maintenance:

In order to ensure the reliability of LPDL's stations, station maintenance activities occur over a seven year interval, with one station being taken off line each year for maintenance. This provides the opportunity to check all electrical connections, inspect the equipment condition, perform tests if necessary, and inspect and clean all insulating devices, switches and protective devices.

The administration of this program is the responsibility of the Manager of Operations with the station maintenance schedule managed by the Engineering Technician and the maintenance work completed by the Lines Department.

3) Distribution System Plant Inspection and Ground Level Maintenance Program

LPDL's distribution system plant inspection and ground level maintenance program is conducted on a 3 year cycle as per the OEB's DSC. As noted earlier, LPDL has split the service area into three zones, Bracebridge North, Bracebridge South and Huntsville/Burk's Falls/Sundridge/Magnetawan, one of which is inspected each year.

This program provides LPDL the opportunity to identify items in the field that require replacement, repair or alteration and the ability to plan the appropriate follow up work to repair it before it causes problems or creates a dangerous hazard. This program involves a site visit to each asset location. For all overhead distribution plant assets, this visit involves inspecting every pole and for underground distribution plant assets, this includes all padmount equipment. The specific work to be completed under this program is detailed below.

i) Visual Inspection:

A visual inspection of each plant asset is completed in adherence with the minimum requirements as specified in the DSC's Appendix C – Minimum Inspection Requirements. Upon each inspection, the condition of LPDL's plant assets are documented in the following inspection forms: "Pole Information Sheet", "Transformer Information Sheet", "Overhead Switch Maintenance Form" and "Pad-Mounted Switch Maintenance Form" (Appendix F).

ii) Wood Pole Integrity Tests:

Wood pole integrity tests are performed on poles where the strength of the pole is determined to be questionable during a visual inspection. LPDL has determined that wood boring, using a ½ inch bit, is the most effective way to establish the condition of the pole at or just below grade, where most of the decay occurs.

iii) Ground Level Repair of Defects:

Through experience, LPDL has found that ground level repairs can be effectively corrected during the inspection process. While on site, the inspector may make any of the following repairs as required:

- Replace guy guard
- Cut unused anchors below grade and replace backfill
- Install molding over exposed down ground
- Drive exposed ground rods to below grade
- Replace ground rod clamp, remake down ground connection and test ground rod resistance
- Bore pole, record, and report findings.

The administration of this program is the responsibility of the Manager of Operations with the correction of the defects being ordered by the Engineering Technician and the correction of the defects being issued and completed by the Lines Supervisor and Lines Department.

4) Thermography Inspection Program

Infrared thermography has proven to be an excellent tool in identifying poor electrical connections and overloaded equipment on the distribution system. The purpose of LPDL's thermography inspection program is to identify any electrical and/or equipment overload issues and remediate them as quickly as possible to ensure continuous operation of the distribution system. This program consists of inspecting each substation and the surrounding switches on an annual basis. Thermography inspections are performed based on the parts of the distribution system. After a thermography scan has been performed by a contractor, the thermography report is forwarded to the Line Supervisor for review of any defects/issues identified.

The administration of this program is the responsibility of the Manager of Operations with the correction of the defects being ordered by the Engineering

Technician and the correction of the defects being issued and completed by the Lines Supervisor and Lines Department.

5) Switch Maintenance Program

The purpose of the switch maintenance program is to ensure the continued reliability of all switching devices in the electrical distribution system. LPDL aims to maintain all switches on a three year rotational basis. This program consists of physically cleaning, lubricating, and inspecting the switch to ensure it operates smoothly. This program applies to three phase gang operated switches only (pole and pad-mounted).

i) Overhead Switches

LPDL's overhead switches are maintained and inspected following the guidelines set out by the manufacturer. For each overhead switch inspection, an "Overhead Switch Maintenance" form is completed (Appendix F).

ii) Pad-Mounted Switches

LPDL's pad-mounted switches are maintained and inspected following the guidelines set out by the manufacturer. For each pad-mounted switch inspection, a "Pad-Mounted Switch Maintenance" form is completed (Appendix F).

The data collected from the above inspections and maintenance activities are filed in the Engineering department. The administration of this program is the responsibility of the Manager of Operations with the correction of the defects being ordered by the Engineering Technician and the correction of the defects being issued and completed by the Lines Supervisor and Lines Department.

Asset Management Information Systems

In order to utilize and track the information gathered from the above inspection programs, visual drive by's, customer reported trouble calls and unplanned maintenance performed, LPDL operates and maintains a number of computer information software systems. Worktech Work Manager is used to organize, issue and track: work to be performed, history of work order and purchase order transactions, customer call details, outage information and detailed asset information. LPDL's Geographic Information System (GIS) is used to track the age, location and current status of each and every distribution system asset in service. Fleet Complete is a truck tracking system which provides real time locations of all trucks, history of hours used and maintenance schedules. Lastly, Worktech Asset Manager is currently being implemented to track the value and useful life of each system asset by location.

1) Worktech Work Manager

Since 2004, LPDL has been using Worktech Work Manager, a comprehensive work management system that provides LPDL with the ability to track and report labour, equipment and material costs for all work performed. An overview of Work Manager includes the following functionalities:

- Work Order Service Management:
  - Track customer call requests (ie name, service address, service request, priority, anticipated work date, employee assigned, job specifics)
  - Schedule work order commitments to employees/departments for each request or job required
  - Track all timesheet entry, equipment allocation, material allocation and external resource purchases by work order with reasons for work performed
  - Easily locate outstanding work orders and apply queries by multiple criteria
  - Establish a work order escalation policy to reassign overdue or pending work orders
  - Track billable versus non-billable work orders with original estimates and actual job costs to effectively invoice customers for work performed
- Purchase Order Management:
  - Requisition of funds for purchase order requests
  - Review and approval platform for purchase orders with account activity, unit price, vendor and cost details
  - Process receiving and invoicing transactions per purchase order
  - Link to work orders, inventory and projects to track all costs related to a job/build
  - System tracking of approval, receipt and dollar value for each purchase to expedite invoice processing
- Job Costing:
  - Track real time costs by job, activity account, project level
  - Record activity unit accomplishments and costs
  - Calculate accurate, detailed job estimates for layouts, builds, customer work, etc. including labour, equipment, materials and external resources

    - Identify areas of operational efficiency and initiate and track success against improvement targets
    - Process time capture, stock usage and equipment usage with all costs valued and transacted to the general ledger
    - Prepare budget forecasts by cost centre and activity
- Equipment and Fleet Management:
    - Collect unlimited qualitative and quantitative data such as specs, attributes, statistics, fuel type, purchase price, original vendor, etc.
    - Establish equipment preventative maintenance plans based on usage data
    - Manage equipment warranties and receive warnings of upcoming expiry values based on time and equipment usage
    - Track operating costs and fluid consumption
    - Perform replacement analysis to determine if equipment should be repaired or replaced to optimize long-term return on investment
    - Store unit prices for equipment usage transactions for job costing
    - Access equipment availability schedules for resource planning
- Inventory Management
    - Record unlimited data for any type of inventory
    - Record minimum levels and reorder quantities and vendors
    - Receive alerts of low inventory levels
    - Perform inventory counts and adjustments
    - Access inventory availability schedules for resource planning
    - Store multiple per unit rates for billable work and estimating purposes
- Performance Reporting
    - Implement and track the distributors success against OEB's performance measures (SAIDI, SAIFI, CAIDI)
    - Generate reports using key performance indicators
    - Obtain operations data on costs, accomplishment, asset inventory and service standards
    - Store performance measure calculations and report layouts for output in multiple subsequent reporting periods

LPDL's engineering and operations department manage and operate the work management system. For every customer request made (ie trouble call, locate request, tree problem, build layout, etc.) or distribution system task required to be performed, a work order is created in this system. Each work order is specific to the service address where the work is to be performed. As well, each work order is attached to a specific service type which identifies the type of work to be performed and the reason for the work.

Outage management statistics are also tracked in Work Manager. Each system outage call is input and tracked including the customer name, location, duration and reason for the outage with space available to document the work performed to fix the outage. System performance and reliability statistics (ie SAIDI/SAIFI/CAIDI) are then produced from this data allowing LPDL to meet regulatory performance statistic reporting requirements and identify trouble areas that require attention.

All materials, external resources and stock inventory purchases are input and tracked in Work Manager. This computerized purchase order system functionality allows for the appropriate approval of all purchase order requisitions, assignment of each purchase to an activity account for efficient financial coding, timely receiving and invoicing capability and attachment of the purchase to a work order for effective job costing.

This computerized work order system allows LPDL to effectively plan, prioritize and allocate the appropriate labour, equipment and material resources to each job or work project. The availability of this work order data, with the querying/reporting tools, also provides the ability to identify areas that show a trend of repeat visits or trouble calls from which high risk areas or aging areas can be identified to be addressed in the capital asset plan. The capturing of all costs (work orders and purchase orders) associated with any capital or maintenance project in Work Manager also allows LPDL the ability to value the true cost of a project or build and thus assist in the planning for future projects of a similar type and scope.

In compliance with the requirements of ESA's Regulation 22/04, Work Manager produces a form for each work order that states no undue hazards exist for the executed job and that the job has been built to a specific standard. Upon completion of each work order, this form is signed off on by operations personnel who performed the work and is filed in accordance to LPDL's Construction Verification program as set out by ESA requirements.

2) LPDL Geographic Information System (GIS)

LPDL implemented a GIS over five years ago and continues to enhance the data collected and maintained in the system. The GIS is based on ESRI technology and has database ties to LPDL's operational data store (ODS) meter database and the work order and asset management systems. The GIS ties together all the pieces of the electric distribution system for improved customer service, better management of assets and outages and increased accuracy of data.

The GIS stores information about a given asset's spatial location, relationship with other assets within the distribution network (ie circuit and voltage) and an asset's physical characteristics, such as age, make, model, serial number, etc. Spatially accurate data for poles, transformers, padmount transformers, switchgear, junction cubicles and meter locations have been collected using global positioning system (GPS) technologies and primary conductor has been modeled around these features. Using this data, the GIS can generate accurate conductor lengths for existing assets and assist in job costing for potential new developments.

LPDL's GIS uses a geometric network to allow circuits to be traced from substation feeders to customer metering points. The geometric network allows for modeling of switching configurations in addition to evaluating consumption at each meter or transformer location for any given fifteen minute interval or total over a day, week, month or year.

Assets can be displayed spatially and symbolized based on numerous characteristics including, but not limited to:

- Physical Characteristics – 3 phase padmount transformer vs. 1 phase polemount transformer
- Electrical Distribution Properties – ie view all assets associated with a specific circuit or voltage
- Age of Asset – unique symbols for age ranges
- Maintenance performed – display assets with work orders coded to a specific job/activity class (ie transformer maintenance)
- Ownership – ownership and joint use properties

The GIS database provides a useful tool for producing graphs and charts identifying system areas that may be of concern because of age, proximity to end of useful life or environmental risk (ie PCB). Future development in the GIS will focus on further utilizing the data made available by smart metering technologies to include peak demand at meter and transformer locations, development of a near real time outage management system and tighter integration with asset management and work order systems. The GIS program at LPDL aims to improve efficiency and reduce costs while enhancing communication and decision-making processes in all aspects of the utility's operations including:

- Smart Grid Initiatives
- Asset Management

- Outage Management
- Regulatory Compliance
- Joint Use

Spatial and contextual data in the GIS are organized into layers, as described in the table below:

GIS Layer	Type	Description
Substation	Point	Location of municipal substations
Feeder	Point	Acts as a "source" in the geometric networks allowing for tracing of each circuit
Primary Meter	Point	Location of primary meter
Pole	Point	Stores information about physical characteristics of each pole, framing standards used and joint use attachments
Service Meter	Point	Stores location and physical characteristics of each meter. Linked to ODS to track consumption at each location and identify which transformer service is supplied from
Repeater	Point	Stores location of each repeater in smart meter network
Collector	Point	Stores location of each collector in smart meter network
Transformer	Point	Stores physical characteristics of each transformer; relates to meters fed from transformer to calculate consumption from each transformer; links to PCB records for each transformer
Surge Arrestor	Point	Stores location of surge arrestor
Junction Cubicle	Point	Stores location and physical properties of each junction cubicle
Reclosure	Point	Stores location of each reclosure
Switch	Point	Stores location and position of each switch (open or closed) for modeling distribution circuits
Switch Gear	Point	Store location and physical characteristics of switch gear
Conduit	Line	Stores length, number of ducts, and size of duct
Primary	Line	Stores physical characteristics of conductor

Conductor		
Secondary Conductor	Line	Stores physical characteristics of conductor
Vaults	Point	Stores physical characteristics of vault
Service Territory	Polygon	Delineates Lakeland's service territory from regions serviced by other utilities
Inspection Zones	Polygon	Delineates boundaries of three inspection zones with the goal of completely inspecting one zone per year on a three year rotation
Tree Trimming Zones	Polygon	Delineates boundaries of seven tree trimming zones with the goal of tree trimming one zone per year on a 7 year rotation
Property Parcels	Polygon	Provides service address and contextual information
Bing Maps	Web Service	Provides base mapping and roads data

3) Worktech Asset Manager

LPDL is currently in the process of implementing an asset management software system. The Worktech Asset Manager system will provide the ability to track the movement, life and value of each asset in our distribution system. An overview of Asset Manager includes the following functionalities:

- Asset Inventory
  - Collect and track asset specific data (ie location, linear reference, joint ownership, materials, statistics)
  - Maintain financial valuation data for financial and management reporting as well as insurance purposes
  - Define relationships between child and parent assets with asset features
  - Apply queries to rapidly locate assets by user defined criteria
- Budget Optimization
  - Predict the future condition of assets based on specific asset deterioration profiles
  - Establish best preventative maintenance practices based on spending objectives and target asset conditions

- Build complex estimates for capital construction projects and analyze the impact of resource allocation fluctuations including equipment, labour, materials and external resources
- Manage major maintenance tasks such as plant overhauls and outages
- Forecast and plan maintenance budgets using job cost history and defined improvement cost profiles

- Condition Assessment
  - Perform thorough asset condition inspections using user defined condition rating formats or industry standards
  - Create multi-year asset repair and maintenance program based on current asset conditions
  - Maintain detailed records of asset elements and components with available links to supporting audio, video, graphic and other documents and systems

In Asset Manager, LPDL is planning to track each asset component (ie pole, transformer, conductor, meter, truck, etc) by identifying each with a unique Feature ID. The Feature ID will be linked to an Asset ID which will be designated as the service street location. This will allow LPDL to retrieve and analyze data for each section of underground or overhead assets in service, as each street serviced by LPDL will be identified as an individual asset.

From the work management system, purchase orders and labour dollars tied to work orders will be linked to the appropriate asset's unique identifier in an effort to capture the total initial cost. On a quarterly basis, the entire asset list along with current assets values will be exported and reconciled with financial data stored in the general ledger. Depreciation calculations will be applied to all assets and the updated values posted in the general ledger will then be reconciled back with the asset manager database. This process will ensure accurate reporting of depreciated asset values, useful life, replacement costs, age and history allowing for improved asset management. This enhanced history detail and valuation by asset functionality will also be a very useful tool in capturing asset purchases, disposal values and depreciation expense by component, compliant with IFRS regulation.

The Asset Manager, Work Manager and GIS systems are/will be integrated with one another in order to provide LPDL with accurate, consistent and timely information and eliminate inconsistencies related to data duplication. Physical properties such as age, serial number, make and model will be stored in the asset management database whereas the location of an asset and it's characteristics and function within the distribution system (such as circuit and voltage) will be stored in the GIS database. These two databases will be linked through each asset's unique identifier. The link between the above three systems will assist the operations department in making effective resource planning and system expenditure decisions based on actual distribution system performance and age data. This also allows for improved system analysis to more effectively plan and operate on a proactive basis rather than a reactive basis.

4) Fleet Complete Truck Tracking System

In 2011, LPDL installed GPS receivers on all service trucks to communicate with a web based Fleet Complete truck tracking software. This program enables LPDL to track each truck's location in real time allowing for quicker response times to trouble calls by identifying and calling in the truck that is closest to the trouble. This system was implemented in an effort to improve LPDL's performance statistics. The software also tracks each truck's hours of usage, PTO hours and maintenance schedules to aid in assessing and optimizing fleet management. Trip speeds by truck are also tracked which provide the ability to identify any safety hazards and to address them.

5) Supervisory Control and Data Acquisition (SCADA) System

LPDL is in the process of reviewing quotes for various SCADA systems which would be compatible with and integrated into a future smart grid system. LPDL is currently investigating smart grid technologies through industry meetings and vendor discussions. Any future upgrades to the distribution system will be planned to be geared towards SCADA ready controls.
The proposed functionalities of a SCADA system would allow LPDL to:

- Improve restoration times by providing information to the line crews on the location of the cause of the outage
- Provide remote access and control of substations and automated switching for faster re-energization
- Collect information on substation performance and loading for analysis of system losses, metering and load issues, etc.
- Improve system reliability
- Provide valuable information for design, troubleshooting and engineering of the distribution system

- Integration with smart meter database to create an outage management system
- Access to instantaneous information on embedded generation in the system
- Provide transfer trip signals to larger embedded generators
- Real time system updates of asset changes performed in the field by engineering technicians.

Currently, LPDL has more than a dozen major system components capable of communication to a SCADA system. Over the past few years, a number of infrastructure upgrades that LPDL has installed, including vacuum reclosures with 651 relays at two of the substations and F35 relays at all of the substations, are SCADA ready controls. Each of the seven LPDL owned substations are connected to the operations centre via a fiber network thus providing the communication accessibility to a future SCADA. It is LPDL's intention to continue to support the smart grid initiative by installing remote operated switches and fault sensing devices on the 27.6kV network to allow for faster restoration of the majority of commercial and higher density residential customers.

Asset Valuation and Condition Assessment

In the fall of 2010, LPDL engaged the services of Suncorp Valuations (Suncorp), a third party asset valuation firm, to perform an independent inventory review and appraisal valuation of LPDL's assets. An inventory and valuation of LPDL's property, plant and equipment (PP&E) was performed to implement a compliant fixed asset system of the PP&E for property management and control as well as financial and regulatory reporting. This detailed asset valuation, on net book value (NBV) as of December 2010, provided a basis for recording, depreciating and reporting on LPDL's assets by component, in accordance with the new International Financial Reporting Standards (IFRS) requirements. In this valuation analysis, Suncorp utilized the 2010 Kinectrics Inc. report titled "Asset Depreciation Study for the Ontario Energy Board" to assist with the determination of the useful lives of assets.
The asset valuation service entailed the following processes:

- Establish PP&E policy for recording and reporting of PP&E with property classifications, capitalization thresholds, depreciation method, useful life guidelines, componentization guidelines and asset attributes
- Conduct a representative visual inspection of LPDL's PP&E asset inventory

- Reconciliation of PP&E inventory to LPDL's historical cost records
- Assign original cost and useful lives to PP&E asset items reconciled above to enable depreciation calculation; as well, assign revised and remaining useful life figures to enable the deprecation calculation on the remaining NBV subsequent to transitioning to IFRS

The PP&E asset classifications that met the capitalization threshold of $5,000 were recorded at the following level:

Asset Class	Level of Inventory Detail
Land	By year of purchase
Land Improvements	By type (ie paving, lighting, fencing)
Buildings and Civil Structures	On a component approach
Substations	Standalone assets recorded individually and integrated systems by logical component
Overhead and Underground Distribution Systems	Standalone assets recorded individually and integrated systems by logical component
Transportation/Rolling Stock	By individual asset
Communication Equipment	By individual asset or system
Office Furniture and Equipment	On a grouped basis by fiscal year
Computer Hardware and Software	As per historical records
Tools and Equipment	As per historical records
Construction in Progress	By location

In order to develop sufficient PP&E information, the following asset attributes, if applicable, were recorded for each asset in the above classifications:

- Asset number (assigned)
- Business unit
- Previous and revised asset class
- Quantity
- Asset description and details (size/capacity, manufacturer, model/type, serial number)
- Asset location
- Depreciation begin date
- Capitalized cost
- Assigned useful life
- Monthly deprecation, 2010 depreciation and accumulated depreciation
- NBV
- Revised normal useful life and revised remaining useful life

The inspection and valuation data resulting from the above study provides LPDL with the ability to better assess system assets by age and remaining useful life to aid in asset management planning. This level of detail by asset component allows for enhanced decision making in planning and prioritizing capital asset spending by identifying the specific type and location of assets ready for upgrade/improvement. LPDL's GIS and work management system were valuable in obtaining age and historical cost figures. The process of conducting this study also provided LPDL with the opportunity to review and improve the level of detail and quality of data in these systems. LPDL is also using the resulting asset values and remaining useful lives in the asset management software system that is currently being implemented.

Overview of Current System Status

LPDL is continuously working towards improving the reliability and sustainability of the distribution system to ensure the customers receive reliable, safe and affordable electricity. Based on the results of the above mentioned inspection and maintenance programs, analysis of system performance statistics and review of the current GIS asset information, a number of areas in LPDL's distribution system have been identified as reaching or nearing the end of their useful life and may be at a higher risk of malfunction or posing a potential hazard. See Appendix G for a graphical presentation of LPDL's assets by age.

LPDL's system assets have been summarized by type and age grouping below:

Assets by Age Grouping						
Asset Type	**< 1972 >40 years**	**1973-1982 >30 years**	**1983-1992 >20 years**	**1993-2002 >10 years**	**2003-2012 0-10 years**	**Total Count**
Poles	**1321**	1096	1074	567	603	4661
Overhead Transformers	**427**	391	431	191	289	1729
Vaults	**12**	88	237	77	107	521
Padmount Transformer	**14**	87	157	87	157	502
Switch Gear	**0**	0	6	0	6	12
Junction Cubicle	**2**	7	11	11	13	44
Overhead-Primary (m)	**118517**	52062	35065	8067	7653	221365
Underground-Primary (m)	**1252**	11736	33565	11634	17667	75854

From the above asset age review, LPDL has identified the following assets that are nearing the end of their useful life and require replacement. These items will thus become priority items in the upcoming capital plans:

- 1321 poles greater than forty years old (represents 28% of poles in service)

- 427 overhead transformers greater than forty years old (represents 25% of overhead transformers in service)
- 14 padmount transformers greater than forty years old (represents 3% of padmount transformers in service)
- 118,517 m of primary overhead conductor greater than forty years old (represents 54% of primary overhead conductor in service)
- 1,252 m of primary underground conductor greater than forty years old (represents 2% of primary underground conductor in service)

LPDL has noticed an increasing trend in system losses over the past few years. In an effort to further address this issue, LPDL is hoping to identify specific service areas that are incurring higher losses. The system attributes contributing to this system loss may include: older transformers with higher impedance ratings, inadequate conductor sizes for the system load, 4.16kV system voltage load which incur higher losses and existing unmetered scattered and streetlight loads that are not metered and thus estimated. The plan is to evaluate the losses by wholesale primary metering point by comparing the volume purchased at each of these points to the actual consumption by customer fed from these points. This analysis will help LPDL identify specific areas to be addressed in the capital plan in order to correct these system losses.

Capital Investment Plan Approval

LPDL has developed a sound process of evaluating, budgeting and approving capital expenditure projects. In the fall of each year, the operations department prepares a detailed capital and operating and maintenance expense budget for review and approval by LPDL's CEO/CFO/COO. The approved projects are included with the complete budget package and presented by the CEO/CFO/COO to the board of directors for approval. For each project proposed in the detailed capital budget, the value, timing, location and reason of the project is included. The identified reasons justifying the budgeted capital expenditures are classified as: aging asset and system reliability, security, customer demand and growth, safety/regulatory and general plant. In planning for the replacement of aging assets that require upgrades in order to improve system reliability and performance, other objectives, such as voltage conversion or relocation, may also be taken into consideration provided the incremental cost for the additional benefit is minimal compared to the initial investment required.
Unplanned capital expenditures that arise throughout the year or planned capital that exceeds the original budgeted amounts, are submitted to the CEO/CFO/COO for approval via the submission of a capital expenditure request (CER) document prepared

by the Manager of Operations. This CER document identifies the description and purpose of the expenditure/increase in expenditure, scope of project, economic justification calculation, cost summary, disposal information and quote details. The CER's approved by the CEO/CFO/COO are then submitted to the board of directors for final approval.

Capital Investment Plan for 2013 to 2016

In supporting LPDL's 2013 cost of service rate application, a four year capital investment plan has been forecasted as part of the AMP. Based on data analyses discussed above, LPDL has identified a number of capital projects to be performed over this four year span. These project details are outlined below including the project year, type of asset, reason/scope of the project and estimated value.

ASSET MANAGEMENT PLAN: 2013-2016

Capital Investment Plan for 2013 to 2016

Proposed Year	Asset Type	Need	Project Scope	Cost Estimate
2013	Computer Software	Security	Software version and integration upgrades between various operating and financial software systems.	$ 10,000
2013	Land Rights	Renewal	Provision for any land easements required.	$ 5,000
2013	Distribution Stations	Aging Asset and System Reliability	Replace Huntsville MS1 Feeder underground cable and upgrade the switch gear as they are approaching the end of their useful life. This is in preparation for the replacement of the transformer, in 2015, with the higher capacity transformer to be decommissioned from Bracebridge MS2.	$ 150,000
2013	Overhead Build	Aging Asset and System Reliability	Replace pole line on Armstrong St in Bracebridge due to age of the pole line. This replacement will also include converting this supply from 4.16kV to 27.6kV thus eliminating load from the 4.16 kV Bracebridge MS2 station.	$ 70,000
2013	Overhead Build	Aging Asset and System Reliability	Replace pole line on Maple St in Bracebridge due to age of the pole line. This replacement will convert this supply from 12.5kV to 27.6kV thus eliminating load from the Hydro One Taylor DS. This will reduce the Hydro One shared distribution charges and increase reliability of our service by eliminating the Hydro One station outages affecting these customers.	$ 174,000
2013	Underground Build	Capacity	Install a third underground feeder from Centennial MS to provide future 27.6kV service to South Bracebridge (Phase 1).	$ 100,000
2013	Underground Build	Aging Asset and System Reliability	Replace underground cable on Curling Rd in Bracebridge as primary cable is over forty years old. This replacement will include new 28kV cable, in duct, from existing 15kV direct buried cable, transformers and provide a loop feed to improve system reliability.	$ 435,000
2013	Underground Build	Aging Asset and System Reliability	Replace 15kV underground cable that is over forty years old, ductwork and vaults on Wilshire Blvd in Bracebridge (first year of three year project) with 28kV cable and transformers. This replacement will convert this supply from 12.5kV to 27.6kV thus eliminating load from the Hydro One Taylor DS. This will reduce the Hydro One shared distribution charges and increase reliability of Lakeland's service by eliminating the Hydro One station outages affecting these customers.	$ 261,000
2013	Underground Build	Aging Asset and Capacity	Replace old 4kV submarine cable at Bracebridge Bay with new 28kV submarine cable in an effort to eliminate all 4.16kV load in Bracebridge. This increase in size of service also accommodates the future 27.6kV feed to South Bracebridge (Phase 2).	$ 200,000
2013	Meters	Customer Demand	Purchase and install new smart meters to meet customer growth.	$ 15,000
2013	Meters	Safety/Regulatory	Replace a range of 2 element meters with 3 element meters as required by Measurement Canada (includes meter and CT/PT replacement). As addressed in the 2011 Measurement Canada audit, the 2 and 2.5 element meters do not meet the current Measurement Canada standards.	$ 85,000

ASSET MANAGEMENT PLAN: 2013-2016

2013	Transportation Equipment	Aging Asset	Purchase a new RBD digger truck to replace the existing digger that is twelve years old and incurring increasing maintenance costs.	$ 300,000
2013	Transportation Equipment	Aging Asset	Purchase a new cargo van and pickup truck to replace Van#23 and Truck#21. The cargo van used by the metering department and the pickup truck used by operations personnel will both be nine years old with very high kilometers and incurring increasing maintenance costs.	$ 95,000
2013	Tools, Shop & Garage Equipmen	General Plant	Provision for replacement of tools and purchase new tool technologies.	$ 10,000
2013	Tools, Shop & Garage Equipmen	General Plant	Replace storage sheds at Bracebridge Operations location due to poor condition of existing structure and to increase storage capacity.	$ 45,000
2013	SCADA System	System Reliability and Smart Grid Compatibility	Purchase and implement SCADA system to track and manage distribution system performance.	$ 100,000
				$ 2,055,000
2014	Land Rights	Renewal	Provision for any land easements required.	$ 5,000
2014	Building & Fixtures	General Plant	Pave the back lot at the Bracebridge Operation's location to improve it's functionality, safety and environmental impact.	$ 100,000
2014	Distribution Stations	System Reliability	Remove the 7.5MVA transformer from Bracebridge MS2 and move it to Huntsville MS1 to replace the current 6MVA 4.16kV transformer with the higher capacity transformer. This upgrade to Huntsville MS1 will also include the replacement of the load break switch. This upgraded station capacity in Huntsville will allow for system redundancy providing the ability to switch the full load from one station to the other if required.	$ 200,000
2014	Distribution Stations	System Reliability and Smart Grid Compatibility	Upgrade Golden Beach MS and Douglas MS5 to automate switching capabilities via the SCADA System. This will include replacing the hydraulic reclosures with vacuum reclosures and controllers on the second set of feeders at each station.	$ 100,000
2014	Overhead Build	Customer Demand and Aging Asset	Replace pole line from Bracebridge Bay submarine cable crossing to EP Lee Dr in Bracebridge in an effort to eliminate all 4.16kV load in Bracebridge. This increase in size of service accommodates the future 27.6kV feed to South Bracebridge (Phase 3).	$ 300,000
2014	Overhead Build	Regulatory	Eliminate Long Term Load Transfers in Bracebridge and Magnetawan by 2014 as required by regulation.	$ 50,000
2014	Overhead Build	Aging Asset and System Reliability	Replace pole line and conductors on Florence St W (between Yonge St and Rice Lane) in Huntsville due to age of pole line which is over forty years old.	$ 150,000

ASSET MANAGEMENT PLAN: 2013-2016

2014	Overhead Build	Aging Asset and System Reliability	Replace 4.16 kV and 12.5kV pole lines on various small side streets in Bracebridge in an effort to convert all to 27.6kV service. This voltage conversion project is an effort to eliminate the need for 4.16kV stations in Bracebridge which allows for the reduction of station maintenance costs and system losses.	$ 100,000
2014	Underground Build	Regulatory	Eliminate Long Term Load Transfers in Sundridge by 2014 as required by regulation.	$ 30,000
2014	Underground Build	System Reliability	Install 28kV underground cable on Brofoco Dr in Bracebridge to create a loop feed which will provide redundancy and improved system reliability.	$ 50,000
2014	Underground Build	Aging Asset and System Reliability	Replace 15kV underground cable that is over forty years old, ductwork and vaults on Wilshire Blvd in Bracebridge (second year of three year project) with 28kV cable. This replacement will convert this supply from 12.5kV to 27.6kV thus eliminating load from the Hydro One Taylor DS. This will reduce the Hydro One shared distribution charges and increase reliability of Lakeland's service by eliminating the Hydro One station outages affecting these customers.	$ 250,000
2014	Underground Build	Aging Asset and System Reliability	Replace 5kV underground cable with 28kV underground cable, with duct, on Herman Ave in Huntsville which is over forty years old.	$ 50,000
2014	Underground Build	Aging Asset and System Reliability	Replace 4.16kV and 12.5kV underground cable on various side streets in Bracebridge in an effort to convert all to 27.6kV service. This voltage conversion project will eliminate the need for 4.16kV stations in Bracebridge, which allows for the reduction of station maintenance costs and system losses. This replacement will also convert these 12.5kV services to 27.6kV thus eliminating load from the Hydro One owned DS's which reduces shared distribution charges and Hydro One station outages affecting these customers.	$ 100,000
2014	Transformers	Aging Asset and System Reliability	Replace transformers for all line rebuild projects above due to voltage conversions and age of the existing transformers. A high number of transformers (single phase, three phase and padmounts) are required for the above builds due to the length of the lines. As well the new transformers will handle higher voltages, 12.5kV to 27.6kV, which previously were only 4.16kV.	$ 250,000
2014	Meters	Safety/Regulatory	Replace a range of 2 element meters with 3 element meters as required by Measurement Canada (includes meter and CT/PT replacement). As addressed in the 2011 Measurement Canada audit, the 2 and 2.5 element meters do not meet the current Measurement Canada standards.	$ 100,000
2014	Transportation Equipment	Aging Asset	Purchase a new truck/vehicle to replace Truck#30. The hybrid Escape used by metering/engineering personnel will be eight years old with high kilometers and incurring increasing maintenance costs.	$ 55,000
2014	Tools	General Plant	Provision for replacement of tools and purchase new tool technologies.	$ 10,000
2014	SCADA System	System Reliability and Smart Grid Compatibility	Purchase enhanced features/modules for SCADA System to increase automation (ie metering, switching) and improve distribution system performance.	$ 100,000
2015	Land Rights	Renewal	Provision for any land easements required.	$ 5,000

ASSET MANAGEMENT PLAN: 2013-2016

2015	Overhead Build	Customer Demand and System Reliability	Replace pole line from EP Lee Dr to Lagoon Lane in Bracebridge to increase the size of service (12.5kV to 27.6kV) in order to accommodate the development of the 27.6kV feed to South Bracebridge (Phase 4). This build will include new poles and conductors. This replacement will also convert these 12.5kV services to 27.6kV thus eliminating load from the Hydro One owned DS's which reduces shared distribution charges and Hydro One station outages affecting these customers.	$ 385,000
2015	Overhead Build	Aging Asset and System Reliability	Replace pole line and conductors on Mary St (from Walpole St to Lorne St) in Huntsville due to age of pole line which is over forty years old.	$ 150,000
2015	Overhead Build	Aging Asset and System Reliability	Replace 4.16kV and 12.5kV pole lines on various small side streets in Bracebridge in an effort to convert all to 27.6kV service. This voltage conversion project will eliminate the need for 4.16kV stations in Bracebridge which allows for the reduction of station maintenance costs and system losses.	$ 100,000
2015	Underground Build	Aging Asset and System Reliability	Replace 15kV underground cable that is over forty years old, ductwork and vaults on Wilshire Blvd in Bracebridge (third year of three year project) with 28kV cable. This replacement will convert this supply from 12.5kV to 27.6kV thus eliminating load from the Hydro One Taylor DS. This will reduce the Hydro One shared distribution charges and increase reliability of Lakeland's service by eliminating the Hydro One station outages affecting these customers.	$ 250,000
2015	Underground Build	Aging Asset and System Reliability	Replace 5kV underground cable with 28kV underground cable, with duct, on Meadowpark Dr in Huntsville which is over forty years old.	$ 50,000
2015	Underground Build	Aging Asset and System Reliability	Replace 4.16kV and 12.5kV underground cable on various side streets in Bracebridge in an effort to convert all to 27.6kV service. This voltage conversion project will eliminate the need for 4.16kV stations in Bracebridge, which allows for the reduction of station maintenance costs and system losses. This replacement will also convert these 12.5kV services to 27.6kV thus eliminating load from the Hydro One owned DS's which reduces shared distribution charges and Hydro One station outages affecting these customers.	$ 100,000
2015	Transformers	Aging Asset and System Reliability	Replace transformers for all line rebuild projects above due to voltage conversions and age of the existing transformers. A high number of transformers (single phase, three phase and padmounts) are required for the above builds due to the length of the lines. As well the new transformers will handle higher voltages, 12.5kV to 27.6kV, which previously were only 4.16kV.	$ 350,000
2015	Meters	Aging Asset and Regulatory	Replace smart meters with expired seal dates as the initial deployment of smart meters began in 2009. Measurement Canada states a six year life span for smart meters at this time. This estimate includes only the meter and installation costs, assuming the network communication technology will remain the same.	$ 100,000
2015	Transportation Equipment	Aging Asset	Purchase a new truck to replace Truck#24. The pickup truck used by operations personnel will be nine years old with high kilometers and incurring increasing maintenance costs.	$ 50,000
2015	Transportation Equipment	Aging Asset	Purchase a new single bucket truck to replace Truck#32. The single bucket truck used by the lines department will be seven years old with high kilometers and incurring increasing maintenance costs.	$ 250,000

ASSET MANAGEMENT PLAN: 2013-2016

2015	Tools	General Plant	Provision for replacement of tools and purchase new tool technologies.	$ 10,000
2015	SCADA System	Smart Grid Compatibility	Purchase enhanced features/modules for SCADA System to increase automation (ie switch automation for load break switches) to improve distribution system performance.	$ 100,000
2016	Land Rights	Renewal	Provision for any land easements required.	$ 5,000
2016	Distribution Stations	System Reliability	Upgrade Douglas MS5 from 5MVA to 10MVA to increase capacity to accommodate the increased 27.6kV load converted over the past few years from 4.16kV and 12.5kV. The decommissioned 5MVA station may be used as a replacement at one of the older 4.16kV stations if required.	$ 600,000
2016	Overhead Build	Customer Demand and System Reliability	Replace pole line from Lagoon Lane to South Industrial Park in Bracebridge to increase the size of service (12.5kV to 27.6kV) in order to accommodate the development of the 27.6kV feed to South Bracebridge (Phase 5). This build will include new poles and conductors with 27.6kV service.	$ 385,000
2016	Overhead Build	Aging Asset and System Reliability	Replace pole lines and conductors on Cliff Ave and Lake Dr in Huntsville due to age of pole lines which are over forty years old.	$ 150,000
2016	Overhead Build	Aging Asset and System Reliability	Replace 4.16kV and 12.5kV pole lines on various small side streets in Bracebridge in an effort to convert all to 27.6kV service. This voltage conversion project will eliminate the need for 4.16kV stations in Bracebridge which allows for the reduction of station maintenance costs and system losses.	$ 100,000
2016	Underground Build	Aging Asset and System Reliability	Replace 15kV underground cable that is over forty years old, ductwork and vaults on Brofoco Dr in Bracebridge with 28kV cable. This replacement will convert this supply from 12.5kV to 27.6kV thus eliminating load from a Hydro One owned DS. This will reduce the Hydro One shared distribution charges and increase reliability by eliminating the Hydro One station outages affecting these customers.	$ 250,000
2016	Underground Build	Aging Asset and System Reliability	Replace 5kV underground cable with 28kV underground cable, with duct, on Princess St in Huntsville which is over forty years old.	$ 50,000
2016	Underground Build	Aging Asset and System Reliability	Replace 4.16kV and 12.5kV underground cable on various side streets in Bracebridge in an effort to convert all to 27.6kV service. This voltage conversion project will eliminate the need for 4.16kV stations in Bracebridge, which allows for the reduction of station maintenance costs and system losses. This replacement will also convert these 12.5kV services to 27.6kV thus eliminating load from the Hydro One owned DS's which reduces shared distribution charges and Hydro One station outages affecting these customers.	$ 100,000
2016	Transformers	Aging Asset and System Reliability	Replace transformers for all line rebuild projects above due to voltage conversions and age of the existing transformers. A high number of transformers (single phase, three phase and padmounts) are required for the above builds due to the length of the lines. As well the new transformers will handle higher voltages, 12.5kV to 27.6kV, which previously were only 4.16kV.	$ 350,000
2016	Meters	Aging Asset and Regulatory	Replace smart meters with expired seal dates as the initial deployment of smart meters began in 2009. Measurement Canada states a six year life span for smart meters at this time. This estimate includes only the meter and installation costs, assuming the network communication technology will remain the same.	$ 400,000

2016	Transportation Equipment	Aging Asset	Purchase a new truck to replace Truck#29. The on-call pickup truck used by the lines department will be eight years old with high kilometers and incurring increasing maintenance costs.	$ 45,000
2016	Transportation Equipment	Aging Asset	Purchase a new truck to replace Truck#26. The pickup truck used by metering/engineering personnel will be ten years old with high kilometers and incurring increasing maintenance costs.	$ 50,000
2016	Tools	General Plant	Provision for replacement of tools and purchase new tool technologies.	$ 10,000

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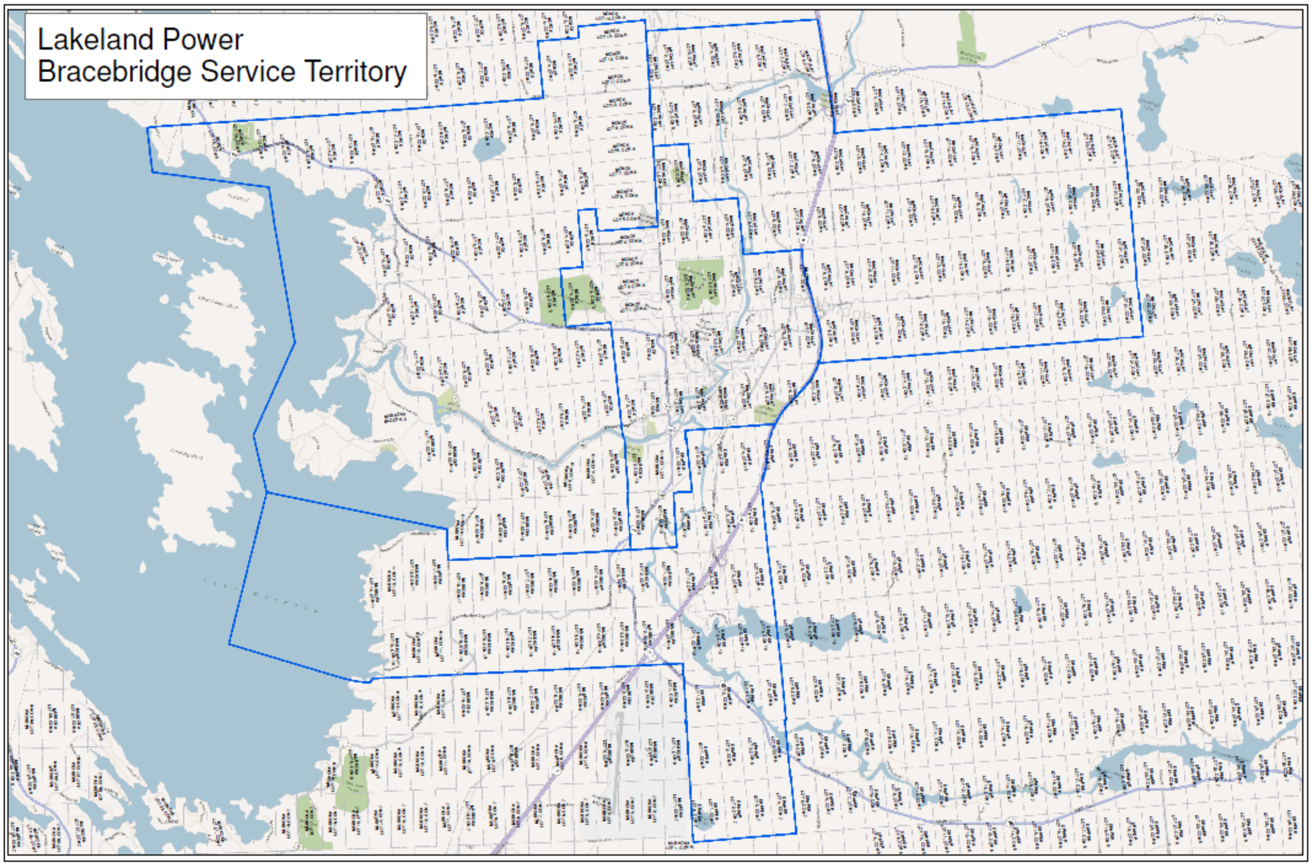
ASSET MANAGEMENT PLAN: 2013-2016

Appendix A - Lakeland's Service Territory Maps



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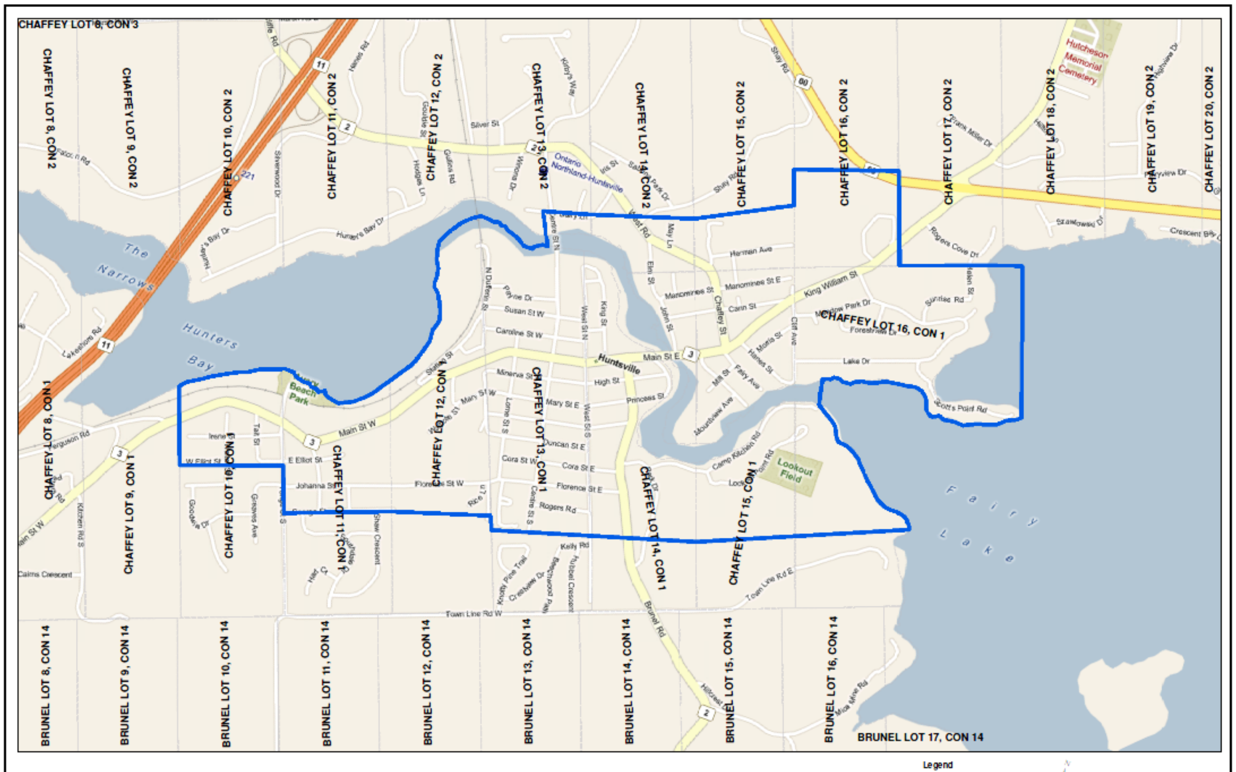
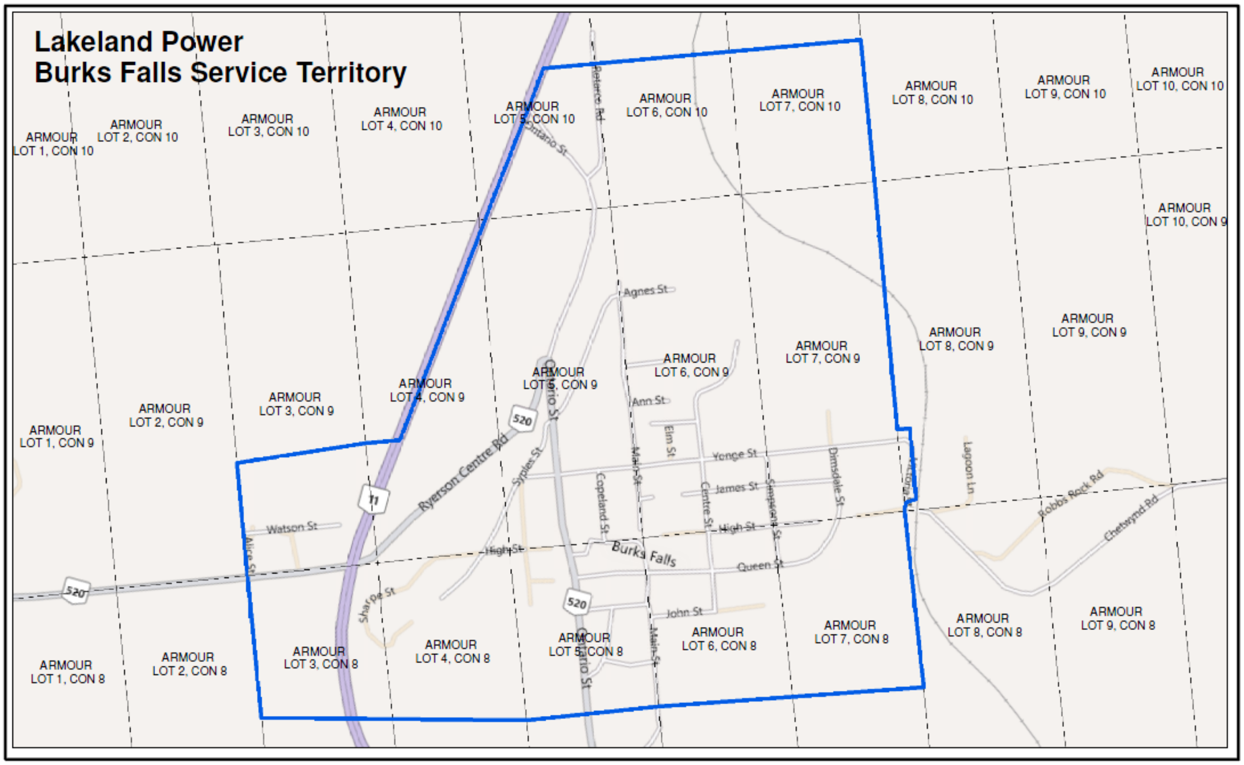
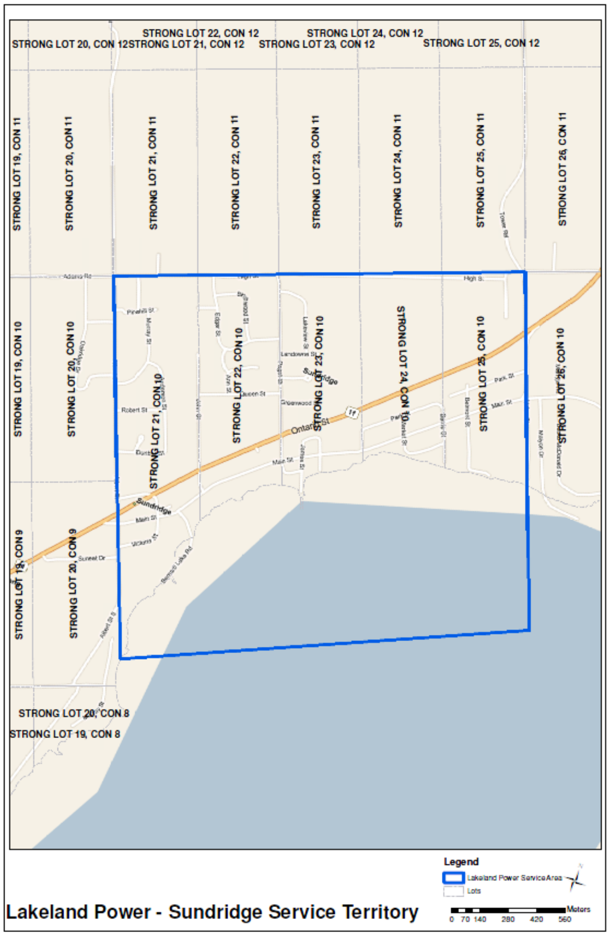


Lakeland Power - Huntsville Service Territory

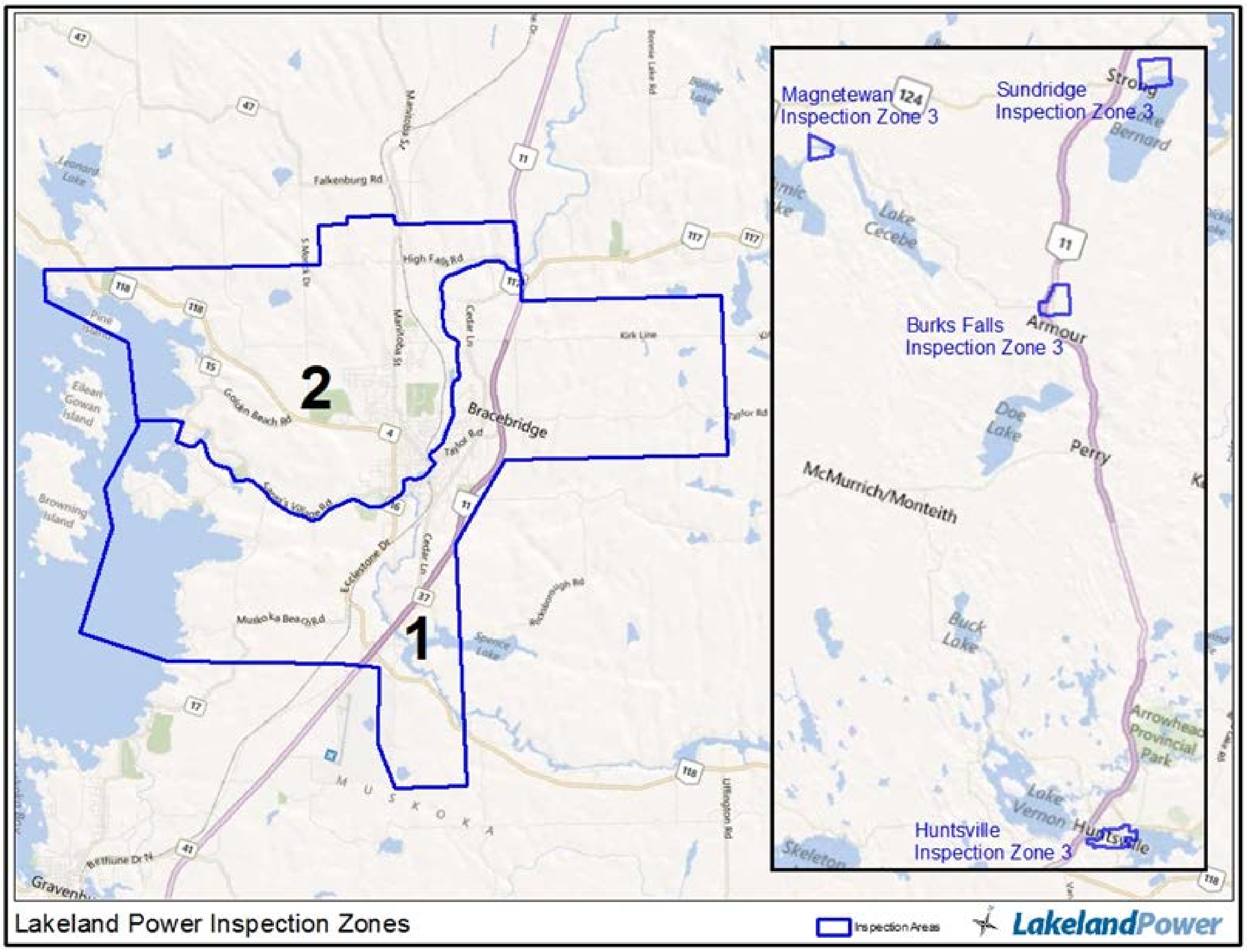
ASSET MANAGEMENT PLAN: 2013-2016



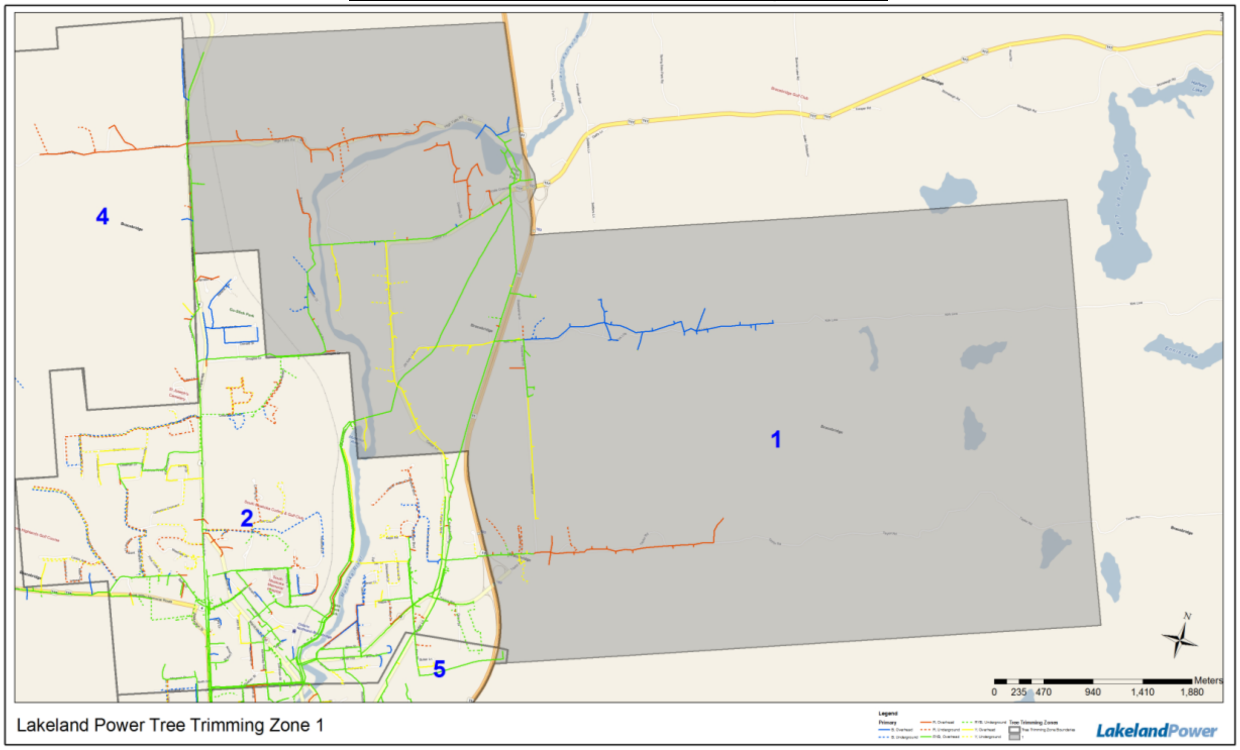
ASSET MANAGEMENT PLAN: 2013-2016



Appendix B – Lakeland Inspection Zones



Appendix C – Tree Trimming Zones



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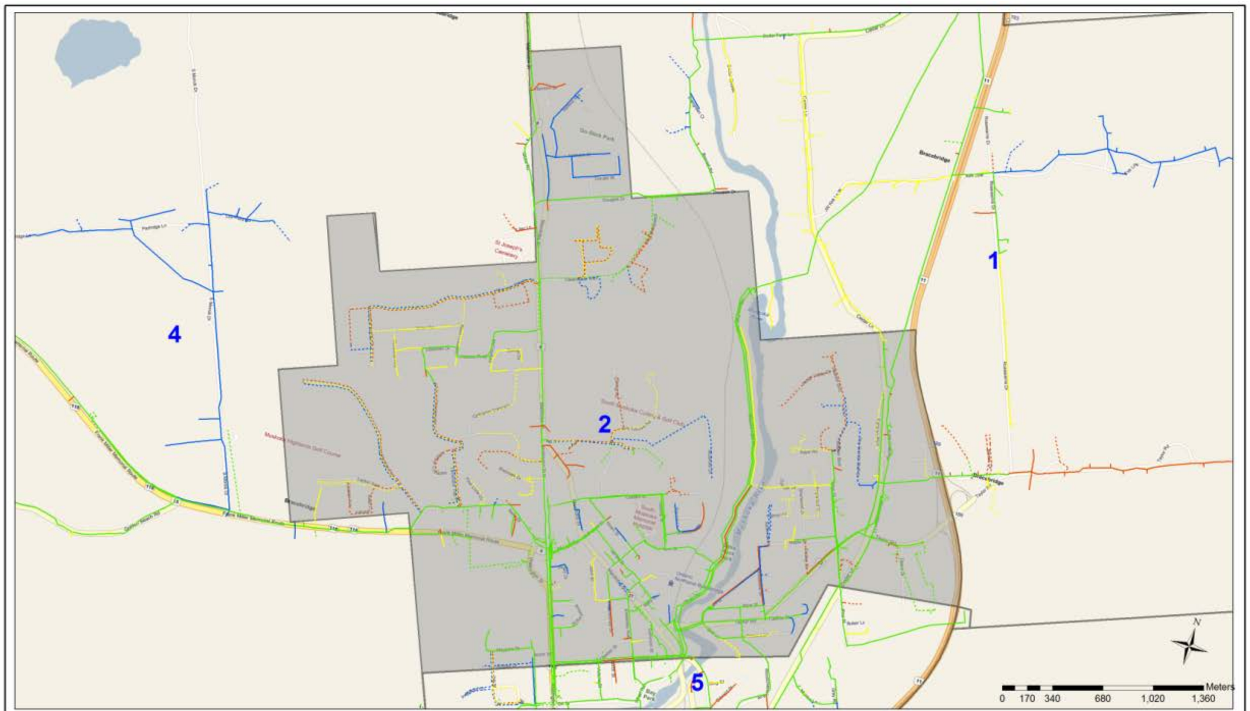
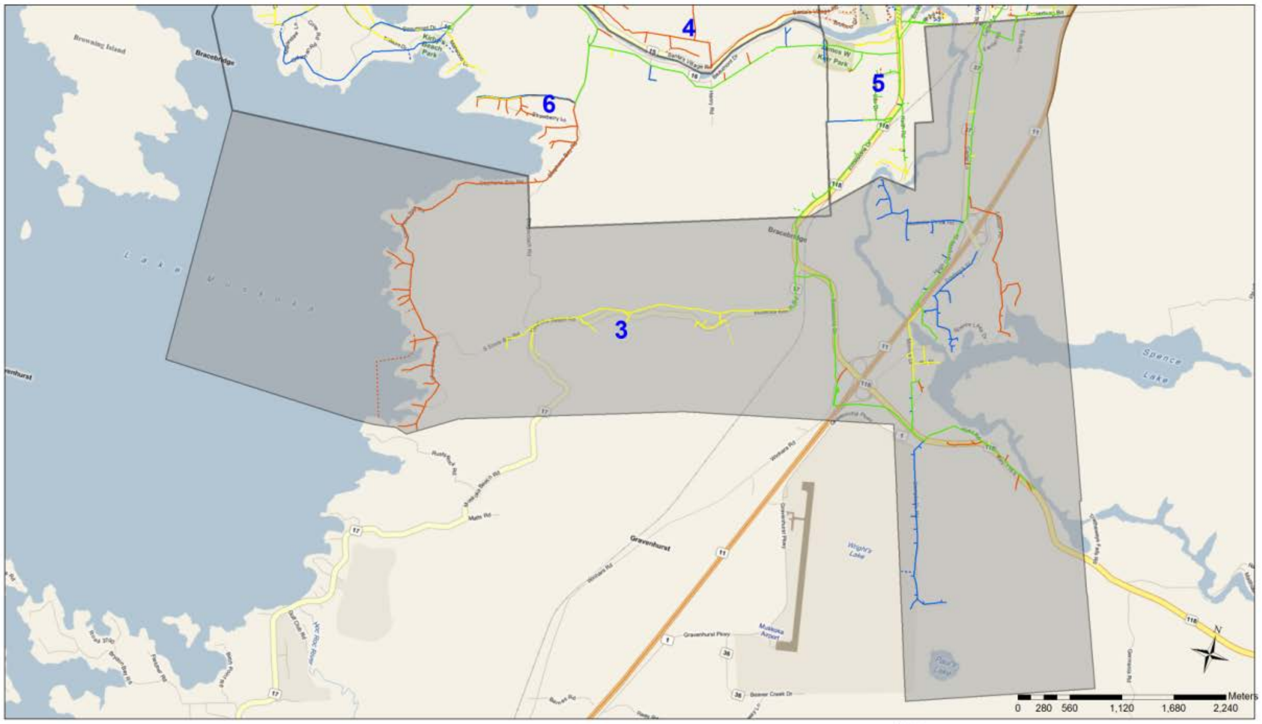


Lakeland Power Tree Trimming Zone 2



Lakeland Power Tree Trimming Zone 3

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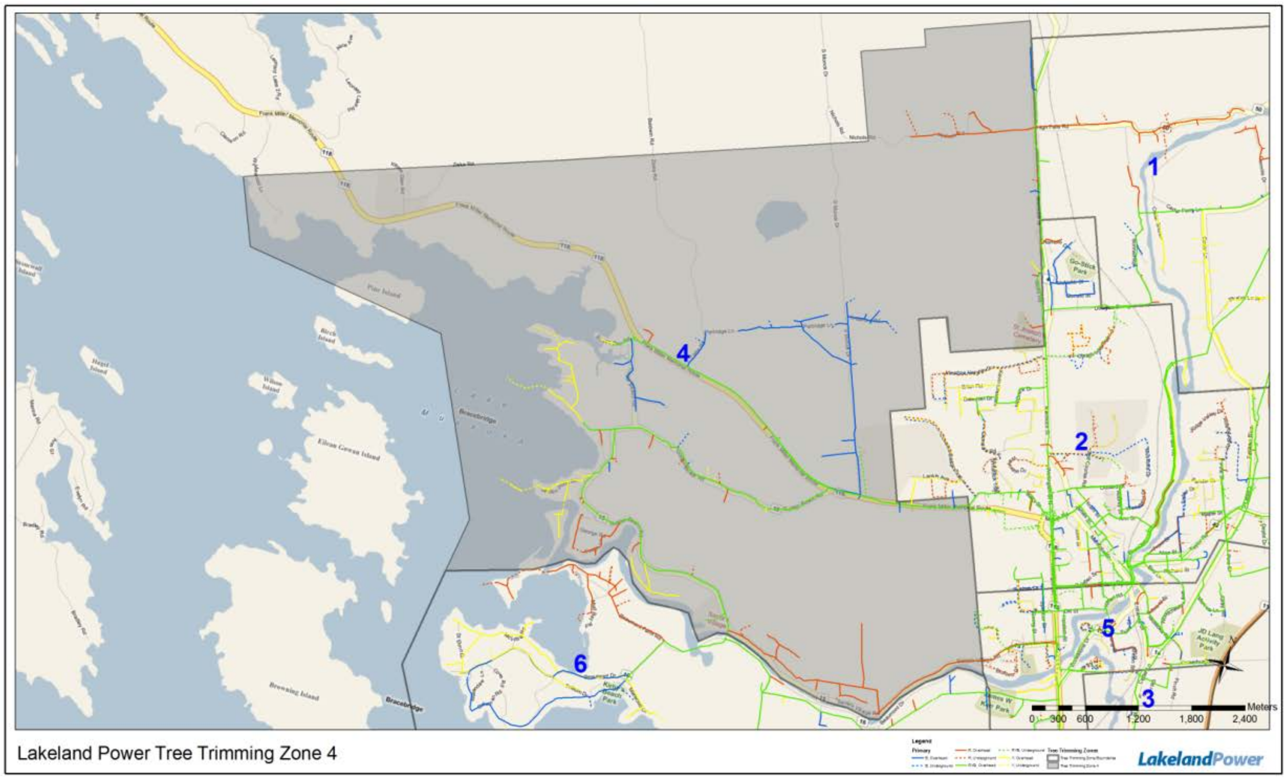

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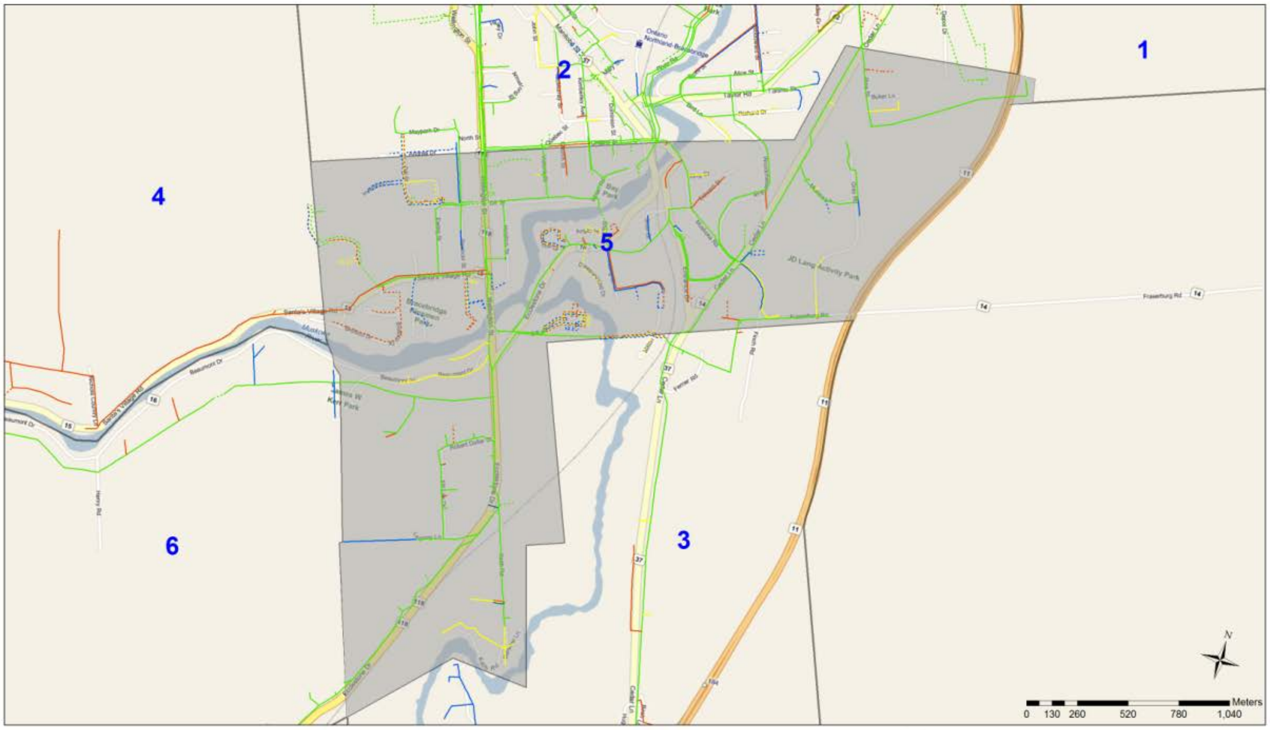
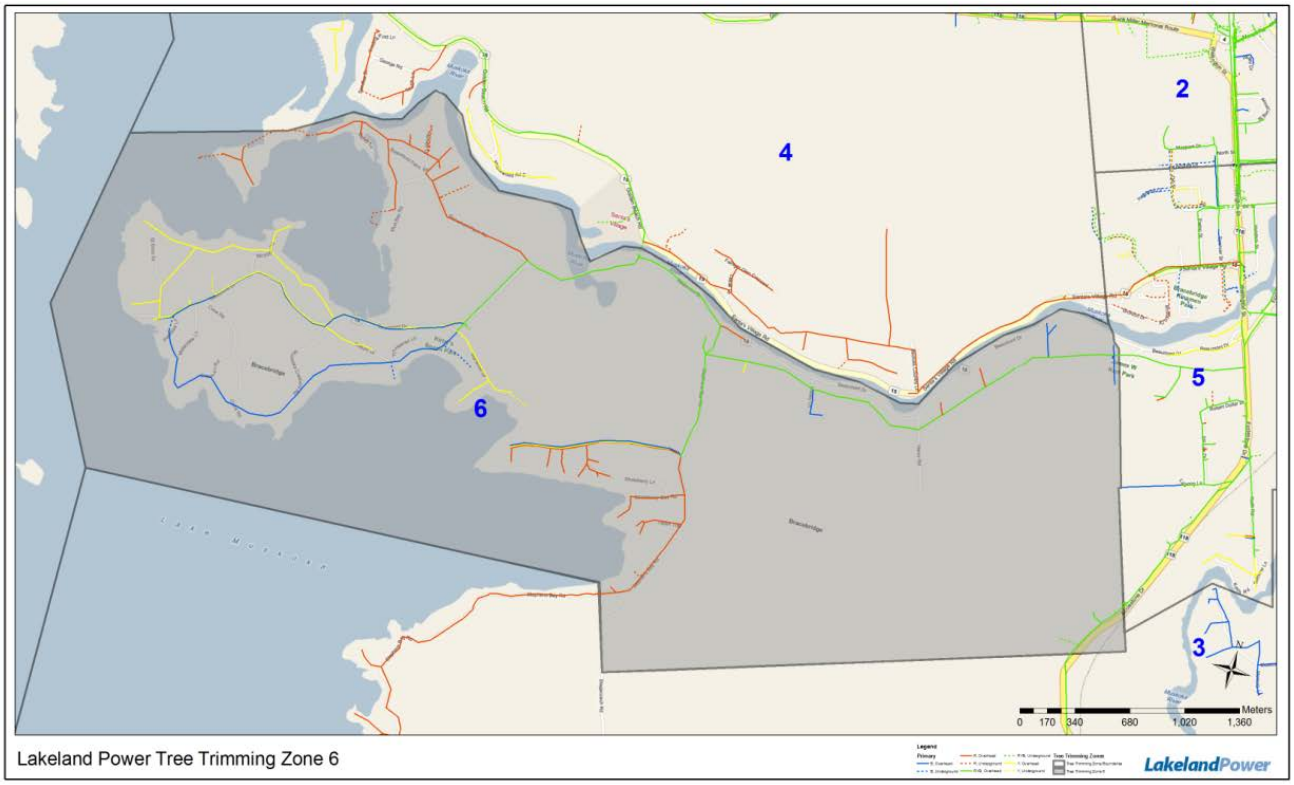


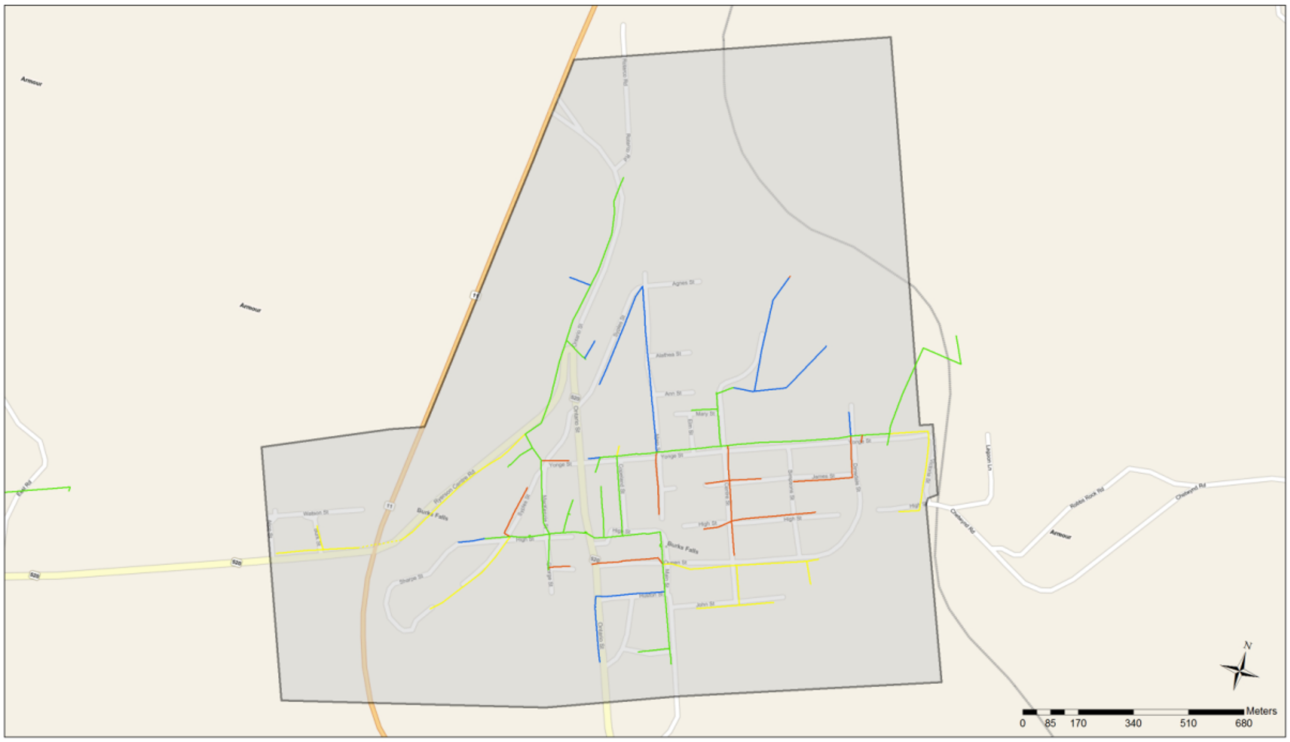
Lakeland Power Tree Trimming Zone 5

ASSET MANAGEMENT PLAN: 2013-2016



Lakeland Power Huntsville Tree Trimming Zone

ASSET MANAGEMENT PLAN: 2013-2016



Lakeland Power Burks Falls Tree Trimming Zone

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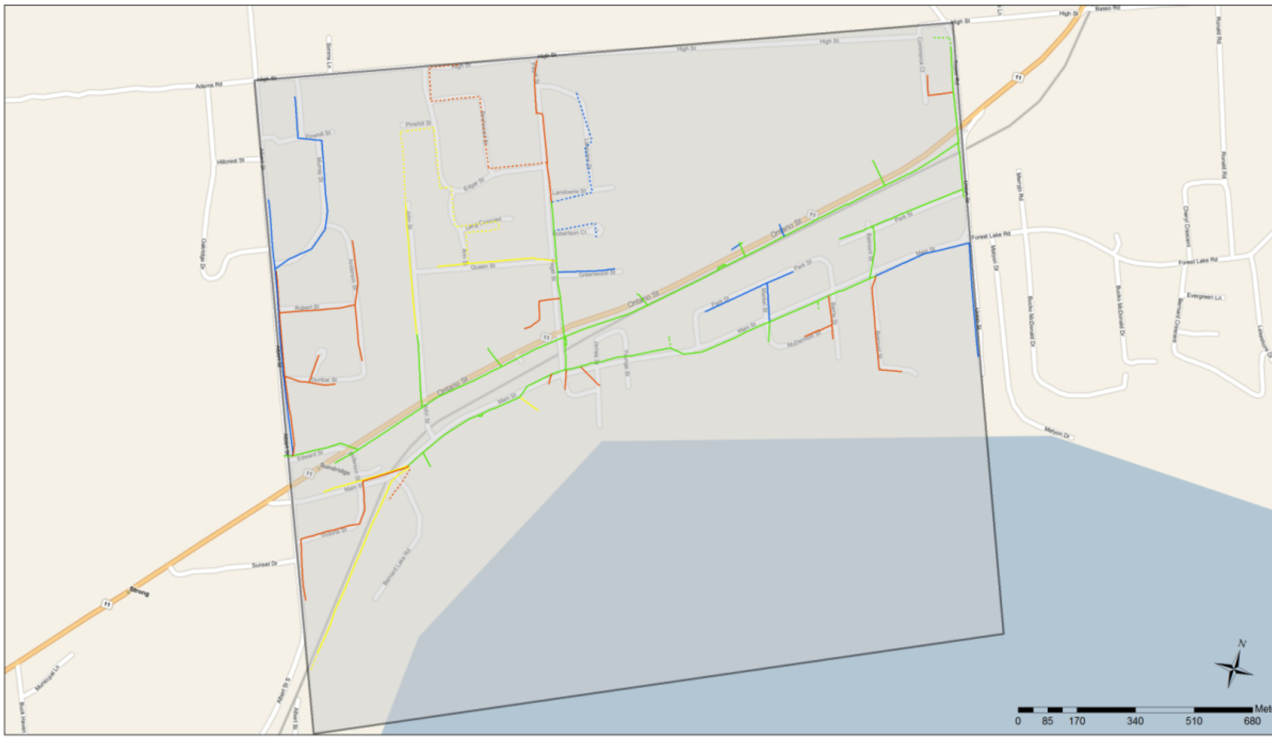
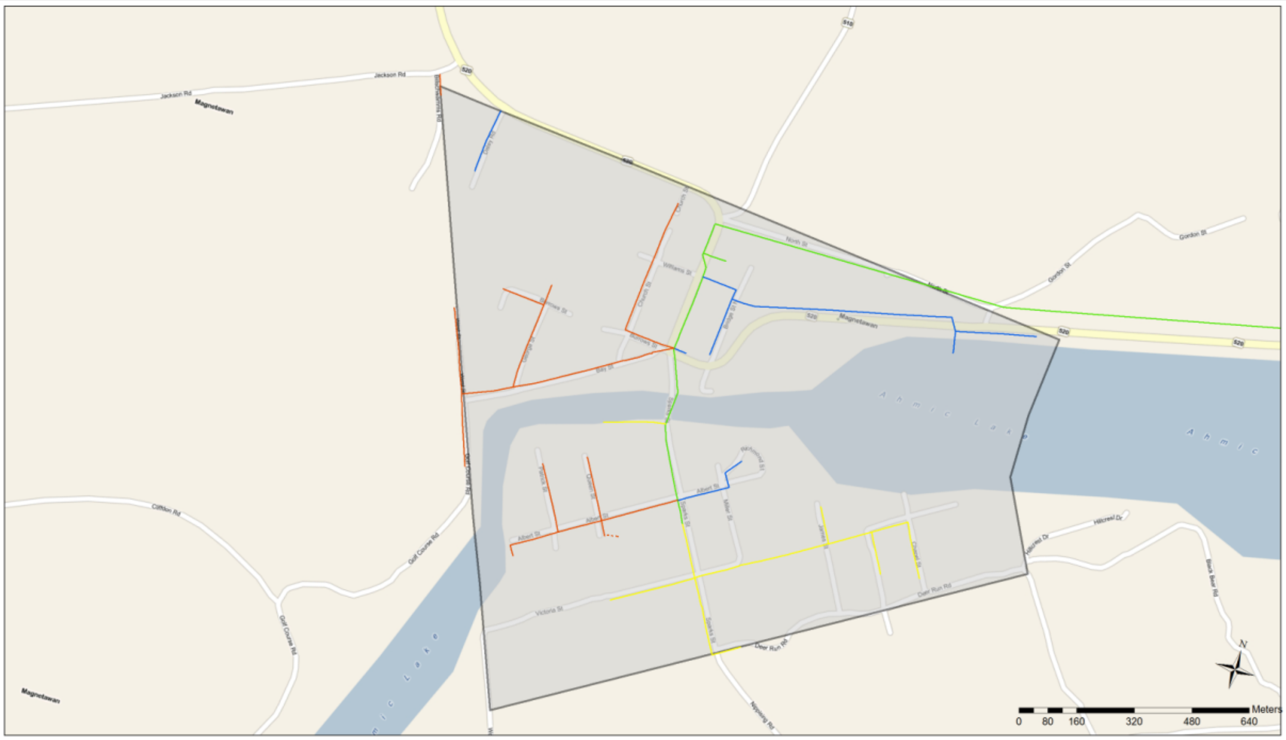


Lakeland Power Sundridge Tree Trimming Zone



Lakeland Power Magnetewan Tree Trimming Zone

Appendix D – Tree Trimming Specifications

1. SCOPE

1.1 This Specification covers the requirements and standard practices for tree trimming and line clearing operations on all overhead transmission, distribution and secondary service lines of Lakeland Power Distribution.

This specification will also cover the trimming of all attachments to Lakeland Power poles consistent with Lakeland's Joint Use Agreements. This will include, but not limited to, Agilis, Bell Aliant, Cogeco, Hydro One and Lakeland Energy.

1.2 This Specification will govern all trimming and line clearing operations authorized by Lakeland unless specifically amended or authorized in writing, to meet special conditions and/or circumstances.

1.3 Any special requirements that differ from those covered in this Specification will be presented at the time of tender.

2. NOTIFICATION

2.1 Any work on trees, either on the public roadways or in private property requires notification to Municipal, Regional or Provincial authorities or private property owners.

Lakeland Power will obtain the necessary permits from Municipal, Regional and/or Provincial authorities.

The Contractor shall formally notify each and every private property owner. This notification shall be given to/delivered to between 7 and 14 calendar days prior to the commencement of work on said property.

Lakeland may assist the Contractor with notification, if required.

3. PROTECTION OF WORK AND PROPERTY

The Contractor shall be responsible for maintaining adequate protection of all his work area from damage and/or injury and restore any property to its original state.

The Contractor shall be responsible to supply, erect and maintain safety items such as guardrails, barriers, night-lights, sidewalk and curb protection, as required by the Towns of Bracebridge, Huntsville, Village of Burk's Falls, Sundridge and Magnetawan, the M.T.O. and the District Municipality of Muskoka.

Lakeland Power will provide the necessary hold off protection to the Contractor for the area being worked that day.

4. **SAFETY**

The Contractor shall be a member of EUSA (Electrical Utilities Safety Association/IHSA) and abide by the Association's rules and regulations regarding tree trimming in the vicinity of energized lines.

The Contractor shall ensure that their employees are knowledgeable of the EUSA/IHSA safety regulations, Occupational Health and Safety Act, Provincial and Federal rules and regulations, and anyone failing to observe them shall be required to leave the work site. All vehicles must have annual inspection certificates and have Manufacture certification in reference to structure, stability and di-electric tests CSA Standard C225-M88 for vehicle mounted aerial devices. Copies of certification must be presented to Lakeland, if awarded the tender. Certificates must be present with vehicles on each and every job site ready to be viewed if inspected by Lakeland, MTO, ESA, Ministry of Labour or other organization of authority.

5. **PERFORMANCE SPECIFICATIONS**

The Contractor shall be required to comply with the following:

5.1 Perform the work in accordance with established and/or approved tree-trimming and arboricultural practices.

5.2 Comply with all by-laws, rules and regulations established by governmental authorities relating to the work.

5.3 Submit a daily/weekly, as agreed upon with Lakeland, progress report showing the area worked, progress made, the degree of trimming and the number of men and vehicles used on the job.

5.4 Communicate daily with the Lakeland Line Supervisor or their delegate, before commencing any work, advising of the following:

5.4.1 Location or area of work
5.4.2 Feeders requiring hold-offs

5.5 Communicate daily with the Lakeland Line Supervisor or their delegate, after each workday, to inform Lakeland that both the work area and employees are clear and surrender and/or release all hold-offs.

5.6 Should a limb fall on any Lakeland overhead plant, or any of Lakeland's Attacher's Plant, advise the Line Supervisor immediately.

5.7 Lakeland Power's Line Supervisor shall have the sole authority on the acceptance and/or refusal of all work performed. Any doubtful situations should be referred to the Customer Area Manager/owner and Lakeland Power's Operations Manager for a decision.

5.8 Lakeland Power shall deal with any disputes with consumers resulting from any planned tree trimming operations on private property. It is the Contractor's responsibility to ensure that the utility is informed of any problems.

6. COMMUNICATIONS EQUIPMENT

The Contractor shall be required to have radio or telephone apparatus allowing direct communication between Lakeland Power and the Work Crews.

7. CLEARANCES TO ENERGIZED CIRCUITS AND APPARATUS

7.1 Under the Terms and Conditions of all Lakeland Power Joint Use Agreements, the Contractor agrees to trim to all attachments.

7.2 All branches and limbs in proximity of the 44KV, 27.6 KV, 12.5KV and 4160V lines will be pruned to within 3.0 metres (10 feet) of the lines.

7.3 All branches and limbs in proximity of Joint Use Attachments including but not limited to Bell, Cable Television, Fibre Optic Cable will be pruned to within 1.5 metres (5 ft.) of these lines. The Contractor shall consult with the Lines Supervisor in those situations (e.g. unsightly appearance) where the required clearances cannot be achieved. Every effort will be made to remove any fast growing species including but not limited to White Pine, Balsam, Aspen, Poplar exceeding 6 ft. in height and standing within 10 ft. of the centre line of any overhead services. These sucker growth and saplings of fast growing species will be removed at ground level.

7.4 Guy wires and strain insulators should never be in contact with heavy limbs.

7.5 Branches and limbs will be pruned to provide a minimum clearance of 1.5 metre (5 ft.) in all directions from pole mounted distribution transformers, drop leads secondary bus and secondary services. In addition, enough space will be cleared to permit a lineman to climb the pole without being obstructed by branches, limbs or climbing vines.

7.6 All dead wood shall be removed regardless of the location of the tree that in falling could strike the conductors or any part of the electrical equipment. Visibly dead trees with a basil diameter of 15 cm. or greater that are outside of Lakeland's specified trimming distances but in danger of falling into the lines should be noted and communicated to Lakeland in writing.

8. PROTECTION OF TREE BARK

Spurs should not be used to climb trees.

9. PRUNING

9.1 Cuts

9.1.1 Saw and pruner cuts shall be flush with the parent limbs of the trunks of trees. Spring and summer cuts should leave approximately 3 cm. away from trunk. In any case, efforts should be made to make trimming cuts perpendicular to the trimmed branch vs. parallel to the tree trunk. All efforts should be made to protect the collar /branch back ridge at the base of the branch.

9.1.2 Limbs should be removed in such a manner as to prevent stripping of the bark.

9.1.3 If in order to satisfy the specified line clearances more than 30% of a tree's canopy has to be removed and is on public property – if basil area is less than 15 cm., tree is to be removed. If basil area is greater than 15 cm., contact Lakeland and is on private property, contact Lakeland and the customer.

9.2 Cut branches

9.2.1 Ropes shall be used for lowering cut branches where necessary, to prevent damage to trees, conductors, fences and other property.

9.2.2 No hangers shall be left on the trees after pruning and no twigs or branches shall be left on the conductors.

9.3 Corrective Pruning

Old stubs remaining from previous line clearing operations in excess of 3 cm. long shall be removed as well as any stubs on the line side of the tree, resulting from storm damage.

9.4 Shaping

When a line passes through a tree, the opening shall be cut back in a slope, away from the line towards the top, so that the notch is a "V" shape. The cutting of slots is not permitted. The cutting of "V" notches shall be kept to a minimum.

Where lines run alongside a tree, the tree should be trimmed to give correct clearance at the lowest utility line and slope away from the upper circuits.

If, in obtaining the desired line clearance, **trees are rendered unsightly due to lack of symmetry, further pruning to restore their appearance shall be carried out**. The extent of such shaping shall be governed by the location of the trees, the nature of their surroundings, etc. Full shaping shall consist of:

9.4.1 The removal of shortening by natural or 'drop-crotch' method, or branches in crown of tree. Sufficient growth must be left on branches that are cut back to keep them alive. When possible, the branch being removed shall be cut in such a way as to preserve the natural appearance of the tree. "Hedge-pruning' or excessive clipping with pole pruners and brush saws shall be avoided.

9.4.2 Removal or shortening of long straggly branches at side of trees.

9.4.3 Removal or shortening of branches at backs of trees, to restore balance which was suffered as a result of limbs being removed to obtain clearance on the line side.

Care must be exercised to avoid an effect similar to girdling, as a result of removing too many adjacent branches.

9.4.4 Removal or shortening of side branches on line side of tree to eliminate or reduce to a minimum a gouged effect.

9.5 **Limbs under Conductors**

Limbs growing up into the conductors from the side of a tree shall be removed at the main trunk. If this appears impractical or inadvisable, the limbs shall be shortened to avoid whipping up into the line.

9.6 **Limbs Parallel with Conductors**

Limbs that are growing out from the side of a tree, parallel with conductors, and could sway or be blown into the conductors, shall be removed wherever practical. Otherwise, they shall be shortened.

9.7 **Trees Below a Line**

Young trees of benefial species growing directly under a line are to be topped and rounded in a pleasing manner. Young trees growing directly under a line of fast grow species as defined in Section 7.2 are to be removed at ground level.

9.8 **Overhanging Limbs**

Limbs directly over the conductors shall be removed if possible; otherwise, they shall be shortened sufficiently to prevent their dropping into the conductors under the additional weight of snow or ice.

9.9 **Dead Limbs**

All dead wood, level with or above the conductors, in trees immediately adjacent to the line, shall be removed. All dead limbs that might be blown into the line from trees located across the road or elsewhere in the near vicinity shall also be removed.

9.10 **Tops of Weak-Wooded Trees to be Lowered**

All tall, weak-wooded trees, towering above the line, shall have their tops lowered as much as practical. The lower the tops, the "drop-crotch" method shall be used so that the tree will not appear to have been chopped off at a definite height.

10. MINIMUM LINE CLEARANCE

10.1 Major Operations

Clearance shall provide for at least seven (7) years growth, except when this would seriously mutilate the tree. A discussion with Lakeland/landowner is required. This should be particularly borne in mind when dealing with fast growing trees such as Manitoba Maple, Willow, etc. All limbs that, by falling, swaying or other means are liable to contact the conductor, shall be removed wherever practical.

10.2 Children Climbing

In establishing clearances, the possibility of children climbing trees and making contact with live apparatus must always be borne in mind. Particular caution shall be exercised regarding trees on or near schoolyards and playground areas.

Where adequate clearance cannot be obtained without mutilating the tree, the Contractor shall inform Lakeland in writing, immediately.

11. DISPOSAL OF WOOD, BRUSH AND DEBRIS

The disposal of brush, wood, and other debris resulting from the Contractor's activities shall be governed by the following:

11.1 The Contractor shall dispose of all brush, wood and other debris at an approved dumping site. Any expense involved in the disposal shall be borne by the Contractor.

11.2 Brush, wood and debris, shall not be left lying overnight along streets, highways, country roads or any main travelled road. Brush left overnight on lightly travelled roads shall be stacked neatly so as not to obstruct traffic and shall be removed the following day. Lawns and grassed areas shall be raked to eliminate small twigs, branches and debris.

11.3 All tree trimming operations performed on trees that are growing (the majority of the trunk lies within) on Town or District road allowances will be cleaned up. All trimming operations performed on privately owned trees will be the cleanup responsibility of the property owner.

12. TREES OF DOUBTFUL STRENGTH

The Contractor shall report in writing all trees of doubtful strength that, in falling, could strike the Corporation's lines. These shall include all trees that are over mature, diseased or showing signs of decay. All oak, beech and basswood trees, regardless of their outward appearance, shall also be reported, since trees of these species are particularly prone to internal decay.

13. INSPECTION

The work done by the Contractor shall be subjected to regular inspections by Lakeland's representatives. It is the Contractor's responsibility to point out any doubtful or difficult situations and/or discuss methods to rectify them with Lakeland's representatives.

Lakeland has sole authority on the acceptance or refusal of work performed.

14. PAYMENT

Payment in full shall be made only upon satisfactory completion of the work covered by the contract. Any deficiencies outstanding, as noted by the Utilities Inspector(s), shall have to be addressed to the satisfaction of Lakeland and no payment shall be made until all issues are resolved.

COMPANY NAME: ____

AUTHORIZED SIGNATURE: ____

PRINT NAME AND POSITION: ____

____

TELEPHONE NUMBER: ____

DATE SIGNED: ____

Appendix E – Substation Inspection Form

LAKELAND POWER
MONTHLY SUBSTATION INSPECTIONS

SUBSTATION ____________________ DATE ____________

Check Items	Inspection	Condition Satisfactory Check (YES OR NO)		Action Required
Station Fence	1. Fencing and Barbed wire in good condition.			
	2. Gate(s) locked & properly adjusted			
	3. Warning signs installed & in good condition.			
	4. Bottom of fence is within 50 mm of the ground.			
	5.Ensure that there no objects, structures or vegetation growth(ie trees) adjacent to the station creating a potential acess or touch voltage hazard.			
	6. Visionally inspect that all grounding and bonding connections are in place and secure.			
Switch Yard	1. Free of debris.			
	2. Is there any Vegetation present.			
	3. Is the gravel coverage accurate and meets standards.			
Structure	1. Visionally inspect that all grounding and bonding connections are in place and secure			
	2. Visionally inspect that all Insulators and Lightning arresters are in good condition no cracks, chips or deterioration.			
Ground Mat(s)	1. Are in place and properly grounded			
	2. Are in good condition			
Switch(es)	1. Nomenclature(s) in place & in good repair			
	2. Switch handle properly locked			
Transformer	1. Visionally inspect that all bushings are in good condition no cracks, chips or deterioration			
	2. Transformer checked for signs of oil leaks			
	3. Transformer oil level OK			
	4. All Temperature/Pressure indicators, gauges are operation and readings recorded			
	5. All fans and fan relay are operational			
	6. Fan control box is corrosion aand rust free			
Breaker Metalclad	1. Cubicle doors secure & Locked			
	2. No unused enclosure openings exist			
	3. Cubicles are clean and free of dust, dirt and debris			
	4. Enclosure(s) are corrosion and rust free			
	5. All heaters are connected and operational			
Cable(s)	1. Visually inspectCables, Terminations and associated equipment on riser pole(s) for signs of deterioration			

COMMENTS:

Operations Manager:(Please initial)	Report Completed By:
ORIGINAL TO FILE	

Appendix F – Visual Inspection Forms
Pole Information Sheet

Lakeland Power Pole Information Sheet

** White Copy Stays with Blue Folder
** Yellow Copy goes to GIS Admin
** Pink Copy Goes to Asset Manager

LakelandPower

Work Order Number	Project Number	Date Visited	Crew Lead

Pole Number	Date Stamped	Class	Height

Information Type
- ☐ New Installation
- ☐ Re-Frame
- ☐ Inspection

LP # Returned to Stock

LP # Scrapped

Ownership
- ☐ Lakeland Power
- ☐ Hydro One
- ☐ Bell
- ☐ Customer Owned
- ☐ Town / District / Township
- ☐ Ministry of Transportation
- ☐ Ontario Power Generation

Pole Type
- ☐ Distribution
- ☐ Transformer
- ☐ Service Pole
- ☐ Stub Pole
- ☐ Streetlight
- ☐ Telco
- ☐ Span Guy

Joint Use Information

	Yes	No	N/A
Lakeland Power	☐	☐	☐
Lakeland Energy	☐	☐	☐
Hydro One	☐	☐	☐
Bell	☐	☐	☐
Cogeco	☐	☐	☐
Eastink	☐	☐	☐
Atria	☐	☐	☐
Agilis Networks	☐	☐	☐
Other	☐	☐	☐

Address / Location

Conductor Information

	Voltage	Circuit	Wire Size	# of Phases
Top Circuit				
Second Circuit				
Third Circuit				
Secondary				

Material
- ☐ Wood
- ☐ Concrete
- ☐ Steel
- ☐ Aluminum

Dip Pole
- ☐ Yes
- ☐ No

Pole Setting
- ☐ Earth
- ☐ Rock Mount
- ☐ Rock Bore
- ☐ Crib
- ☐ Backlot

Transformer Bank

Treatment
- ☐ Pressure Treated
- ☐ Creosote
- ☐ No Treatment

Switch Number

Switch Type
- ☐ Inline
- ☐ Cutout
- ☐ Fused
- ☐ Solid
- ☐ Load Break

Guying Information

Direction		1	2	3	4	5
0	N					
45	NE					
90	E					
135	SE					
180	S					
225	SW					
270	W					
315	NW					

(# / Direction)

Framing Standards

Streetlight Information

Streetlight Head
- ☐ Cobra Head
- ☐ Durastar
- ☐ Decorative
- ☐ Yard
- ☐ Globe

Bulb Type
- ☐ Mercury Vapour
- ☐ HPS
- ☐ Metal Halide
- ☐ Incandescent
- ☐ Flood

Wattage

# of Lights

Meter Number

Comments

Transformer Information Sheet

Transformer Information Sheet

** White Copy Stays with Blue Folder
** Yellow Copy goes to GIS Admin
** Pink Copy Goes to Asset Manager

LakelandPower

Work Order Number	Project Number	Date visited	Crew Lead	Address / Location

☐ Installation ☐ Inspection

Serial Number

Bank Number

☐ Pole Mount ☐ Pad Mount

Year Make	Size (KVA)	Impedance

Mass ☐ LB ☐ KG

Oil Volume ☐ L ☐ G

High Voltage
☐ 2400
☐ 7200
☐ 16000
☐ 2400/16000
☐ 7200/16000
☐ 7.2/14.4/16

Phase Connected
☐ Red
☐ White
☐ Blue

Low Voltage
☐ 120/208
☐ 120/240
☐ 347/600
☐ 600 Delta

Fuse Type
☐ Bayonet
☐ Klink

Fuse Size

Taps
☐ Yes
☐ No

Tap Settings
A ☐ 105
B ☐ 102.5
C ☐ 100
D ☐ 97.5
E ☐ 95

PCB Tester	PCB Test Date	PCB PPM

Remarks

☐ Returned to Stock ☐ Scrapped

Serial Number

Bank Number

☐ Pole Mount ☐ Pad Mount

Year of Make	Size (KVA)	Impedance

Mass ☐ LB ☐ KG

Oil Volume ☐ L ☐ G

High Voltage
☐ 2400
☐ 7200
☐ 16000
☐ 2400/16000
☐ 7200/16000
☐ 7.2/14.4/16

Phase Connected
☐ Red
☐ White
☐ Blue

Low Voltage
☐ 120/208
☐ 120/240
☐ 347/600
☐ 600 Delta

Fuse Type
☐ Bayonet
☐ Klink

Fuse Size

Taps
☐ Yes
☐ No

Tap Setting
A ☐ 105
B ☐ 102.5
C ☐ 100
D ☐ 97.5
E ☐ 95

PCB Tester	PCB Test Date	PCB PPM

Remarks

Overhead Switch Maintenance Form

Lakeland Power
Maintenance and Inspection Program
Overhead Switch Maintenance

Switch Number: ____________
Location: ____

AS FOUND CONDITION

Using the check boxes indicate the condition of the switch when you first arrive. Note - a check indicates you agree with the statement. If you don't agree leave the box unchecked.

- Switch – open and closes freely-- ☐
- Interrupters or arc chutes operate freely-- ☐
- Contacts are clean, aligned, and free from corrosion---------------------------------- ☐
- Moving parts operate freely (switch and operating handle)-------------------------- ☐
- Mounting hardware is tight and free of defects-- ☐
- Insulators are crack, break, and burn free----------------------------------- ---------- ☐
- Electrical contacts and conductors to main line are tight and corrosion free------- ☐

MAINTENANCE PERFORMED

Switch Movement – Not Req'd ☐ Or ______________________________________
____

Mounting Hardware – Not Req'd ☐ Or ______________________________________
____

Switch Components – Not Req'd ☐ Or ______________________________________
____

Interrupters – Not Req'd ☐ Or ______________________________________
____

Comments - ____
____
____

OPTIMIZATION OF MAINTENANCE PROGRAM

Indicate which one of the following statements applies to this particular switch:

☐ A The maintenance was unnecessary; it could have been done later
☐ B The maintenance was performed at the right time; only normal maintenance was req'd
☐ C The maintenance should have been done earlier; major faults were found

Lead Hand: ____________________________ Date Work Completed: ________________

Inspection and Maintenance Procedure

Step 1 – Pre-Check Before Operating Switch

Insulators – check all insulators for cracks, breaks, or burns

Power Conductors – be sure all conductors are routed so they don't interfere with switch operation

Mounting Hardware – check and tighten all thru bolts and mounting hardware. Inspect all pins, rivets, and bolted connections for damaged and worn out parts.

Step 2 – Cycle Switch

Open and close switch several times to clean the contact surfaces and loosen moving parts. Make sure interrupters or arc chutes are operating freely.

Step 3 – Check Switching Sequence

Inspect the switch for proper operating sequence.

Step 4 – Inspect Switch Components

Inspect for eroded fault making contacts
Inspect for alignment and corrosion of "live parts"
Lubricate all contacts with Dow Corning FS-1292 silicone grease or equivalent

Step 5 – Inspect Moving Parts

Inspect all interphase and moving parts for damaged or worn out components
Lubricate as needed all control components with A.B. Chance silicone spray Cat. #C400-1749 or equivalent

Step 6 – Inspect Interrupter or Arc Chutes

Make sure interrupters or arc chutes are operating freely

Notes

Replace any damaged or worn parts as required

Pad-Mounted Switch Maintenance Form

Lakeland Power
Maintenance and Inspection Program
Pad-Mounted Switch Maintenance

Switch Number: ______________
Location: ____

AS FOUND CONDITION

Using the check boxes indicate the condition of the switch when you first arrive. Note - a check indicates you agree with the statement. If you don't agree leave the box unchecked.

Switch(s) –open and closes freely--- ☐
Contacts are clean, aligned, and free from corrosion------------------------------------ ☐
Moving parts operate freely (switch and operating handle)--------------------------- ☐
Insulators are crack, break, and burn free---------------------------------- ---------- ☐
Interior is clean--- ☐
Exterior does not have corroded parts and painting is not required-------------- ☐

MAINTENANCE PERFORMED

Inspect and Clean Interior – Not Req'd ☐ Or ____________________________________

____

Inspect Barriers and Minimum Air Clearances – Not Req'd ☐ Or ______________________

____

Inspect and Exercise Mini Rupter Switches – Not Req'd ☐ Or ______________________

____

Inspect Fuses – Not Req'd ☐ Or ____

____

Inspect Key Interlock and Door Latching Mechanisms – Not Req'd ☐ Or

____

____

Touch up Exterior – Not Req'd ☐ Or ____________________________________

____

Comments - ____

____

____

OPTIMIZATION OF MAINTENANCE PROGRAM

Indicate which one of the following statements applies to this particular switch:

☐ A The maintenance was unnecessary; it could have been done later
☐ B The maintenance was performed at the right time; only normal maintenance was req'd
☐ C The maintenance should have been done earlier; major faults were found

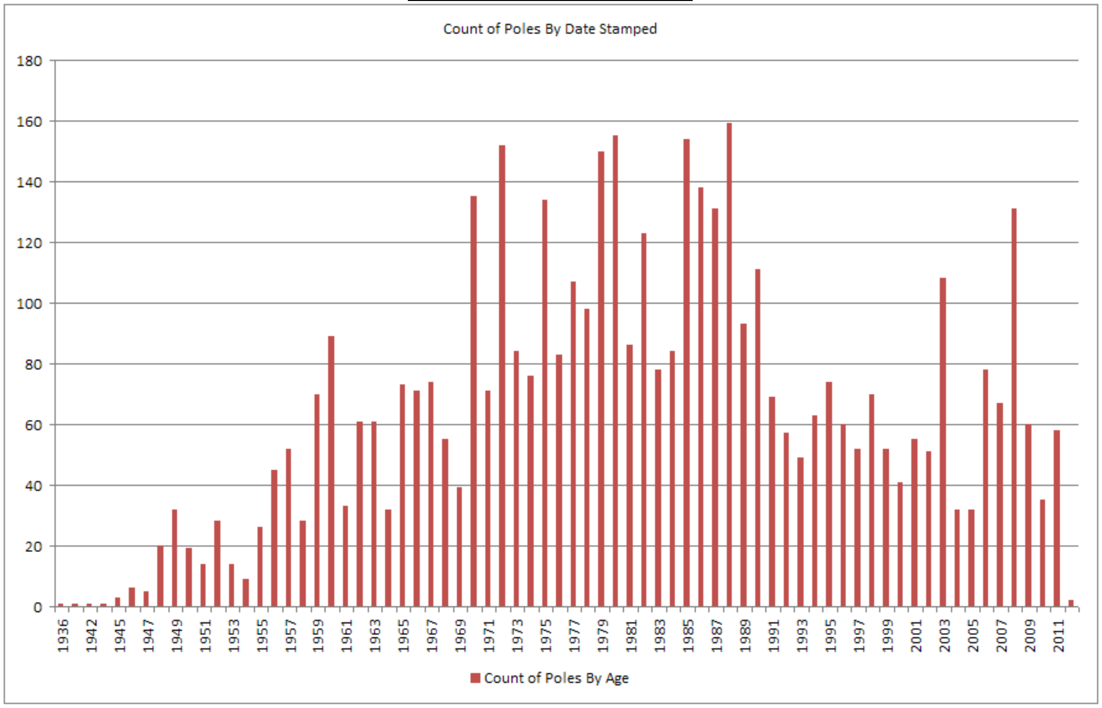
Lead Hand: ______________________________ Date Work Completed: __________________

Inspection and Maintenance Procedure

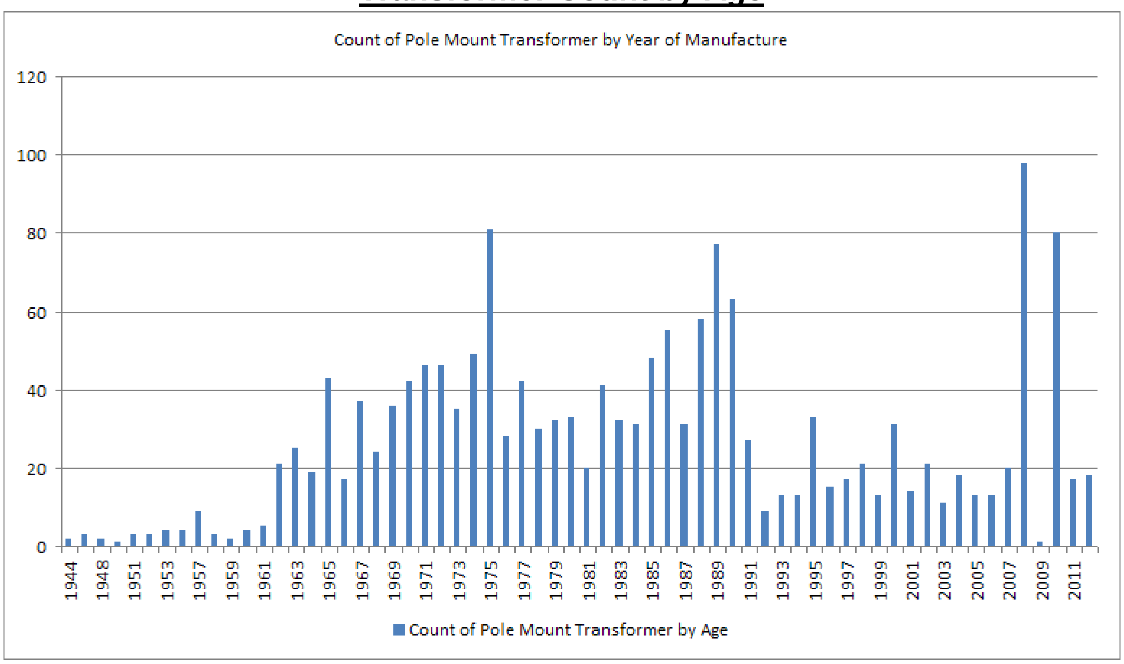
Refer to S&C Manual PMH Pad-Mounted Gear – (Outdoor Distribution (14.4 kv and 25 kv) – Inspection Recommendations – Instruction Sheet 662-590

Appendix G – Graphs: Assets by Age

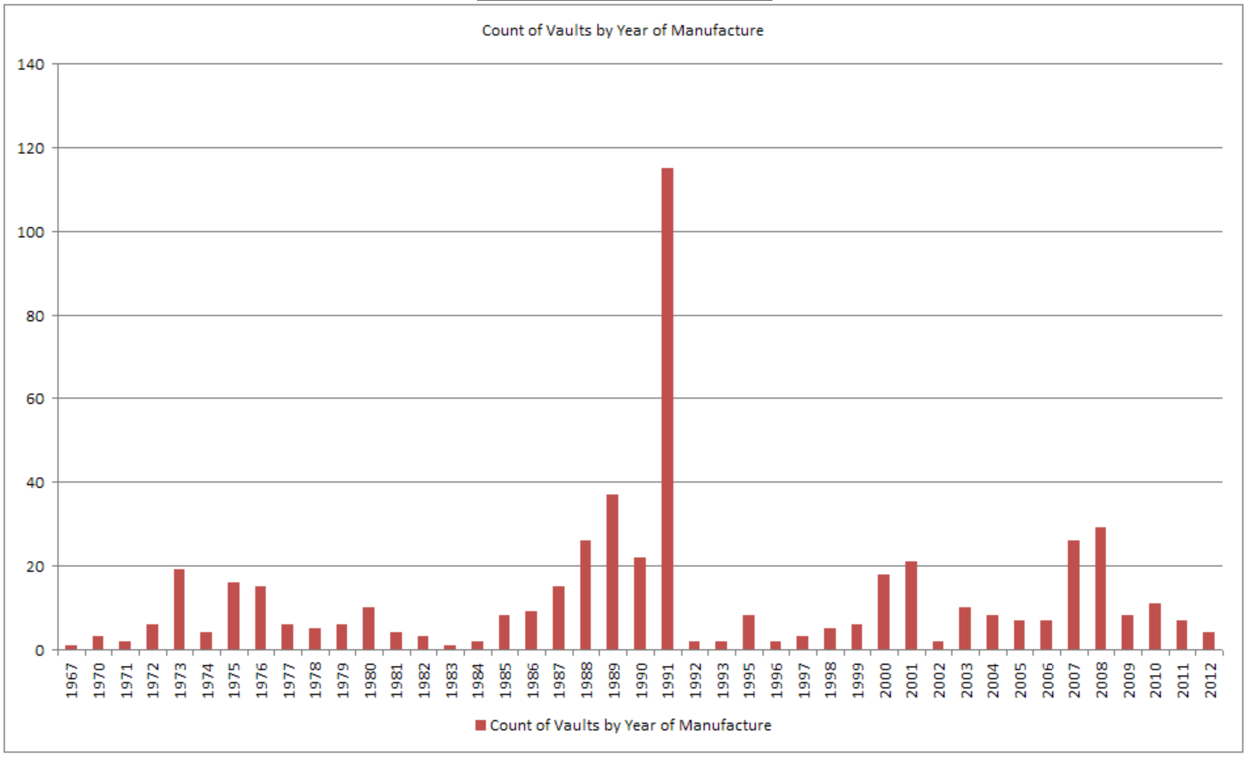
Pole Count by Age



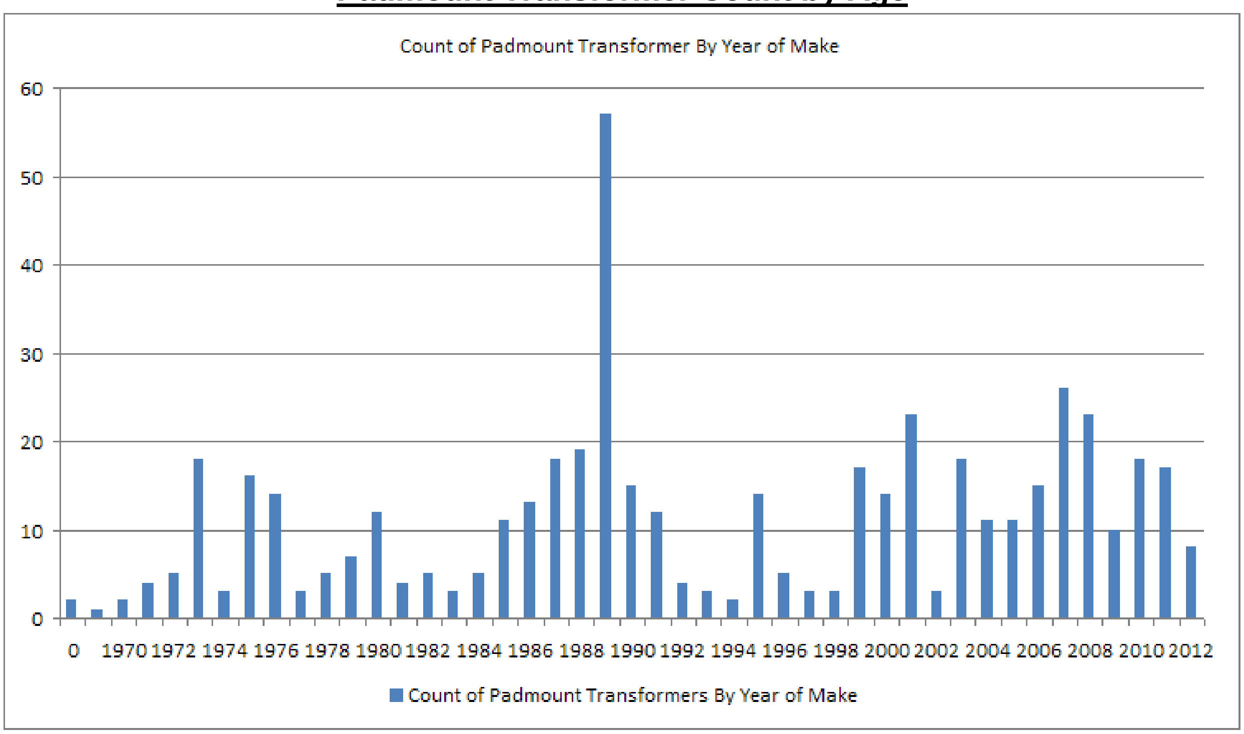
Transformer Count by Age



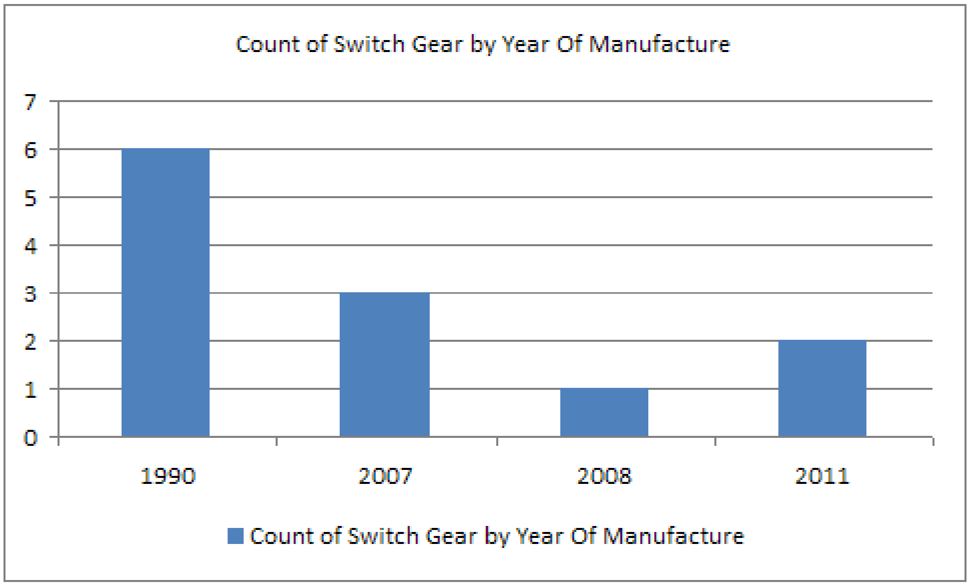
Vault Count by Age



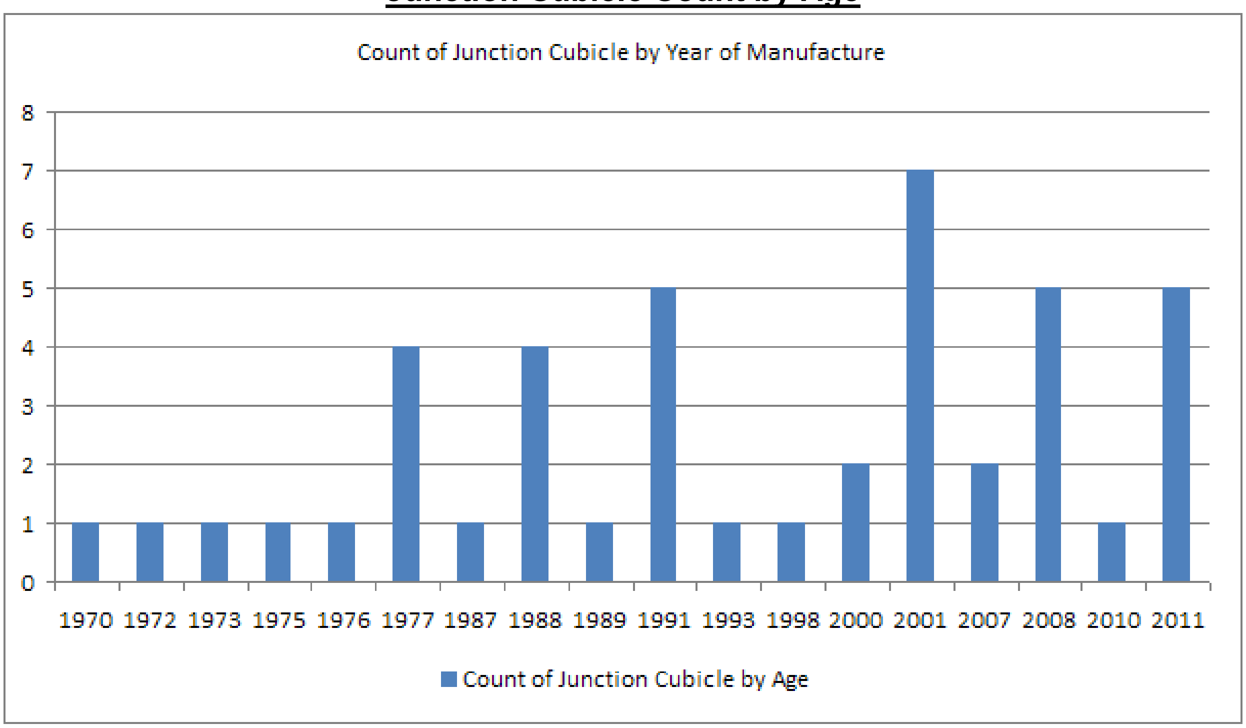
Padmount Transformer Count by Age



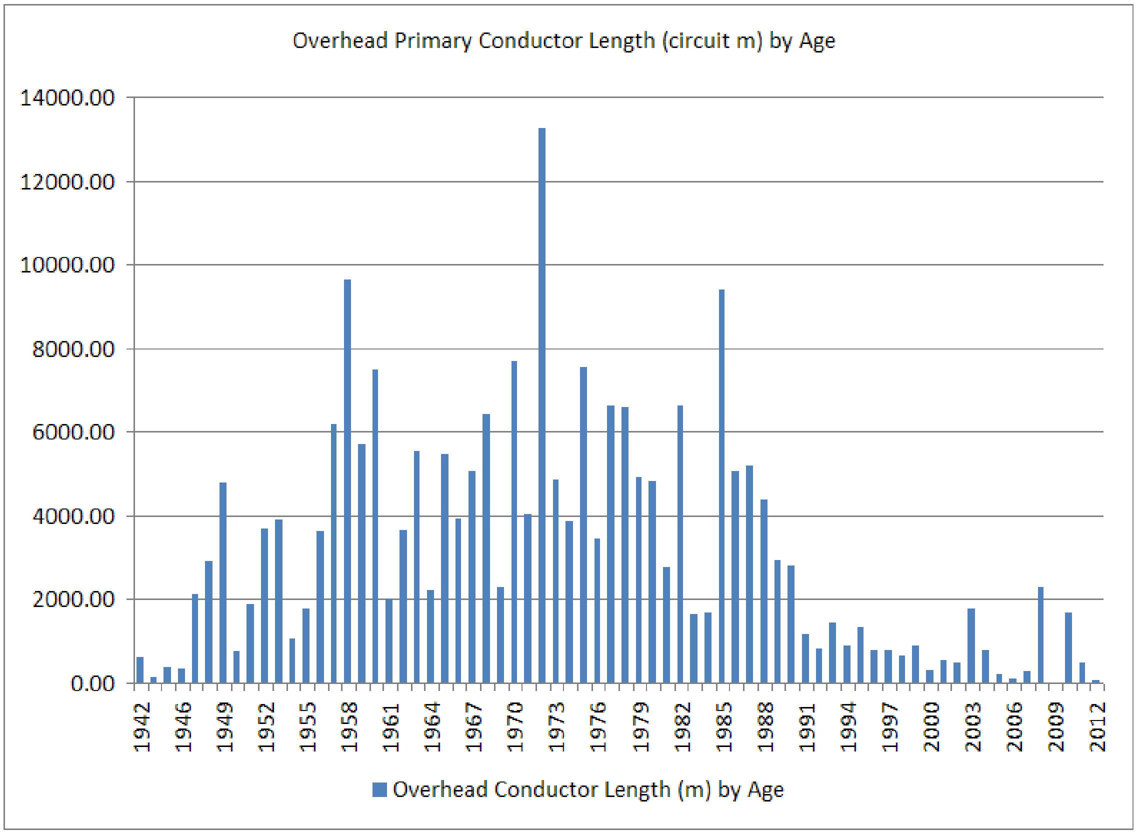
Switch Gear Count by Age



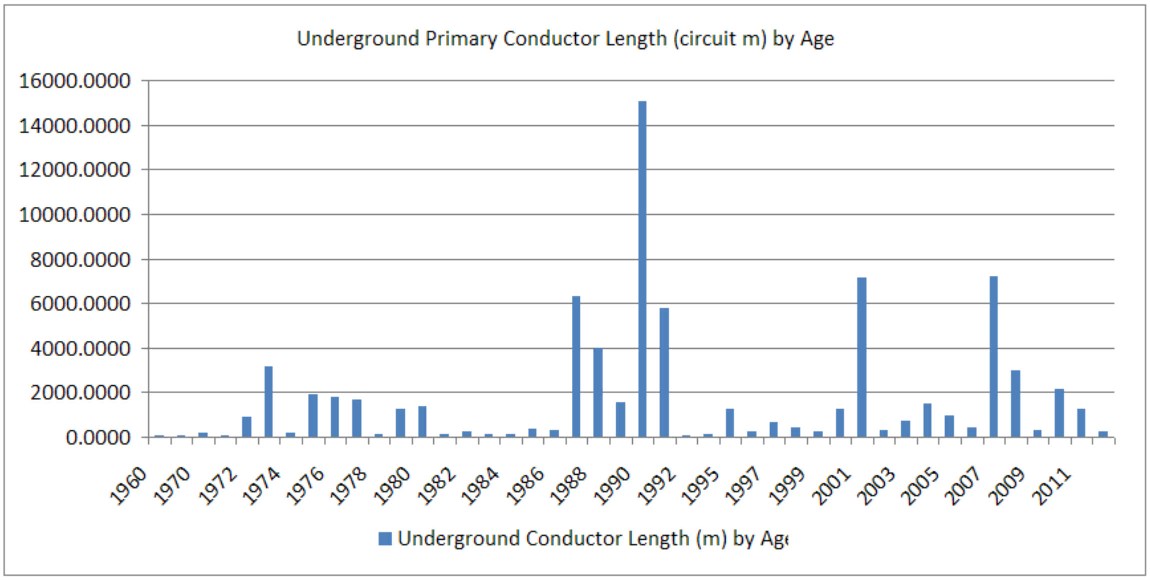
Junction Cubicle Count by Age



Overhead Primary Conductor Length (m) by Age



Underground Primary Conductor Length (m) by Age



APPENDIX B

LPDL COST OF POWER CALCULATION

2012 Cost of Power Calculation:

2012 Load Foreacst	**kWh**	**kW**	**2012 %RPP**
Residential	77,994,771		89.7381%
General Service < 50 kW	42,493,682		89.09%
General Service 50 to 4,999 kW	83,315,486	206,517	0.00%
Street Lighting	1,854,853	5,077	71.43%
Sentinel Lighting	39,762	110	100.00%
Unmetered Scattered Load	118,321		89.47%
TOTAL	**205,816,875**	**211,705**	

Electricity - Commodity RPP	**2012**	**2012 Loss**			
Class per Load Forecast RPP	**Forecasted**	**Factor**		**2012**	
Residential	69,991,026	1.0585	74,085,501	$0.08069	$5,977,959
General Service < 50 kW	37,859,486	1.0585	40,074,266	$0.08069	$3,233,593
General Service 50 to 4,999 kW	0	1.0585	0	$0.08069	$0
Street Lighting	1,324,895	1.0585	1,402,401	$0.08069	$113,160
Sentinel Lighting	39,762	1.0585	42,088	$0.08069	$3,396
Unmetered Scattered Load	105,866	1.0585	112,059	$0.08069	$9,042
TOTAL	**109,321,035**		**115,716,315**		**$9,337,149**

Electricity - Commodity Non-RPP	**2012**	**2012 Loss**			
Class per Load Forecast	**Forecasted**	**Factor**		**2012**	
Residential	8,003,744	1.0585	8,471,963	$0.07877	$667,337
General Service < 50 kW	4,634,196	1.0585	4,905,297	$0.07877	$386,390
General Service 50 to 4,999 kW	83,315,486	1.0585	88,189,442	$0.07877	$6,946,728
Street Lighting	529,958	1.0585	560,960	$0.07877	$44,187
Sentinel Lighting	0	1.0585	0	$0.07877	$0
Unmetered Scattered Load	12,455	1.0585	13,183	$0.07877	$1,038
TOTAL	**96,495,840**		**102,140,846**		**$8,045,680**

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**		**2012**	
Residential		kWh	82,557,465	$0.0051	$421,043
General Service < 50 kW		kW	44,979,563	$0.0047	$211,404
General Service 50 to 4,999 kW		kW	206,517	$1.9996	$412,907
Street Lighting		kWh	5,077	$1.4565	$7,395
Sentinel Lighting		kW	110	$1.4942	$165
Unmetered Scattered Load		kW	125,242	$0.0047	$589
TOTAL					**$1,053,503**

Transmission - Connection		**Volume**			
Class per Load Forecast		**Metric**		**2012**	
Residential		kWh	82,557,465	$0.0040	$330,230
General Service < 50 kW		kW	44,979,563	$0.0037	$166,424
General Service 50 to 4,999 kW		kW	206,517	$1.5659	$323,353
Street Lighting		kWh	5,077	$1.1429	$5,803
Sentinel Lighting		kW	110	$1.1540	$128
Unmetered Scattered Load		kW	125,242	$0.0037	$463
TOTAL					**$826,401**

Wholesale Market Service					
Class per Load Forecast				**2012**	
Residential			82,557,465	$0.0052	$429,299
General Service < 50 kW			44,979,563	$0.0052	$233,894
General Service 50 to 4,999 kW			88,189,442	$0.0052	$458,585
Street Lighting			1,963,362	$0.0052	$10,209
Sentinel Lighting			42,088	$0.0052	$219
Unmetered Scattered Load			125,242	$0.0052	$651
TOTAL			**217,857,162**		**$1,132,857**

Rural Rate Assistance					
Class per Load Forecast				**2012**	
Residential			82,557,465	$0.0011	$90,813
General Service < 50 kW			44,979,563	$0.0011	$49,478
General Service 50 to 4,999 kW			88,189,442	$0.0011	$97,008
Street Lighting			1,963,362	$0.0011	$2,160
Sentinel Lighting			42,088	$0.0011	$46
Unmetered Scattered Load			125,242	$0.0011	$138
TOTAL			**217,857,162**		**$239,643**

Low Voltage		**Volume**			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	77,994,771	$0.0024	$187,187
General Service < 50 kW		kWh	42,493,682	$0.0021	$89,237
General Service 50 to 4,999 kW		kW	206,517	$0.8393	$173,297
Street Lighting		kW	5,077	$0.6488	$3,294
Sentinel Lighting		kW	110	$0.6624	$73
Unmetered Scattered Load		kWh	118,321	$0.0021	$248
TOTAL					**$453,337**

Cost of Power Calculation	**2012**	
4705-Power Purchased	$17,382,830	
4708-Charges-WMS	$1,132,857	
4714-Charges-NW	$1,053,503	
4716-Charges-CN	$826,401	
4730-Rural Rate Assistance	$239,643	
4750-Low Voltage	$677,259	use calculation under 2013 COP Forecast
TOTAL COST OF POWER	**21,312,493**	

2013 Cost of Power Calculation:

2013 Load Foreacst	kWh	kW	2012 %RPP
Residential	77,259,128		89.7381%
General Service < 50 kW	41,707,732		89.09%
General Service 50 to 4,999 kW	82,191,734	203,731	0.00%
Street Lighting	1,839,258	5,035	71.43%
Sentinel Lighting	39,125	109	100.00%
Unmetered Scattered Load	106,109		89.47%
TOTAL	**203,143,087**	**208,875**	

Electricity - Commodity RPP	2013	2013 Loss			
Class per Load Forecast RPP	**Forecasted**	**Factor**		**2013**	
Residential	69,330,875	1.0585	73,386,731	$0.08069	$5,921,575
General Service < 50 kW	37,159,249	1.0585	39,333,065	$0.08069	$3,173,785
General Service 50 to 4,999 kW	0	1.0585	0	$0.08069	$0
Street Lighting	1,313,756	1.0585	1,390,611	$0.08069	$112,208
Sentinel Lighting	39,125	1.0585	41,413	$0.08069	$3,342
Unmetered Scattered Load	94,940	1.0585	100,494	$0.08069	$8,109
TOTAL	**107,937,944**		**114,252,314**		**$9,219,019**

Electricity - Commodity Non-RPP	2013	2013 Loss			
Class per Load Forecast	**Forecasted**	**Factor**		**2013**	
Residential	7,928,254	1.0585	8,392,056	$0.07877	$661,042
General Service < 50 kW	4,548,484	1.0585	4,814,570	$0.07877	$379,244
General Service 50 to 4,999 kW	82,191,734	1.0585	86,999,951	$0.07877	$6,853,077
Street Lighting	525,502	1.0585	556,244	$0.07877	$43,815
Sentinel Lighting	0	1.0585	0	$0.07877	$0
Unmetered Scattered Load	11,169	1.0585	11,823	$0.07877	$931
TOTAL	**95,205,143**		**100,774,644**		**$7,938,110**

Transmission - Network		Volume			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	81,778,787	$0.0051	$417,072
General Service < 50 kW		kW	44,147,635	$0.0047	$207,494
General Service 50 to 4,999 kW		kW	203,731	$1.9996	$407,296
Street Lighting		kWh	5,035	$1.4565	$7,333
Sentinel Lighting		kW	109	$1.4942	$162
Unmetered Scattered Load		kW	112,317	$0.0047	$528
TOTAL					**$1,039,885**

Transmission - Connection		Volume			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	81,778,787	$0.0040	$327,115
General Service < 50 kW		kW	44,147,635	$0.0037	$163,346
General Service 50 to 4,999 kW		kW	203,731	$1.5659	$318,961
Street Lighting		kWh	5,035	$1.1429	$5,754
Sentinel Lighting		kW	109	$1.1540	$125
Unmetered Scattered Load		kW	112,317	$0.0037	$416
TOTAL					**$815,717**

Wholesale Market Service					
Class per Load Forecast				**2013**	
Residential			81,778,787	$0.0052	$425,250
General Service < 50 kW			44,147,635	$0.0052	$229,568
General Service 50 to 4,999 kW			86,999,951	$0.0052	$452,400
Street Lighting			1,946,855	$0.0052	$10,124
Sentinel Lighting			41,413	$0.0052	$215
Unmetered Scattered Load			112,317	$0.0052	$584
TOTAL			**215,026,958**		**$1,118,140**

Rural Rate Assistance					
Class per Load Forecast				**2013**	
Residential			81,778,787	$0.0011	$89,957
General Service < 50 kW			44,147,635	$0.0011	$48,562
General Service 50 to 4,999 kW			86,999,951	$0.0011	$95,700
Street Lighting			1,946,855	$0.0011	$2,142
Sentinel Lighting			41,413	$0.0011	$46
Unmetered Scattered Load			112,317	$0.0011	$124
TOTAL			**215,026,958**		**$236,530**

Low Voltage		Volume			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	77,259,128	$0.0024	$185,422
General Service < 50 kW		kWh	41,707,732	$0.0021	$87,586
General Service 50 to 4,999 kW		kW	203,731	$0.8393	$170,926
Street Lighting		kW	5,035	$0.6488	$3,266
Sentinel Lighting		kW	109	$0.6624	$72
Unmetered Scattered Load		kWh	106,109	$0.0021	$223
TOTAL					**$447,495**

Cost of Power Calculation	**2013**
4705-Power Purchased	$17,157,129
4708-Charges-WMS	$1,118,140
4714-Charges-NW	$1,039,885
4716-Charges-CN	$815,717
4730-Rural Rate Assistance	$236,530
4750-Low Voltage	$677,259
TOTAL COST OF POWER	**21,044,660**

2013 Data for ST/LV Charges							
Number of Monthly Service Charges	14						
Number of Meter Points	14						
Common ST kW	31,470.2						
LVDS kW	12,754.3						
Hydro One Sub Transmission Charges based on				Units	Months	Total	
Service charge		292.56	per month	14	12	$	49,150
Meter Charge		466.14	per meter per m	14	12	$	78,312
Facility charge for connection to Specific ST lines		0.668	per kW	31,470.2	12	$	252,265
Facility charge for connection to low voltage		1.944	per kW	12,754.3	12	$	297,532
Total						**$**	**677,259**

APPENDIX C

<u>LPDL GREEN ENERGY PLAN</u>

1. Introduction

This document outlines the Green Energy Act ("GEA") Plan for Lakeland Power Distribution Ltd ("LPDL"). At this time, LPDL is filing a basic GEA Plan as provided for in the Ontario Energy Board's ("OEB") Filing Requirements document EB-2009-0397. This basic GEA Plan provides information to the OEB and interested stakeholders regarding the readiness of LPDL's system to accommodate the connection of renewable generation and the expansion or reinforcement necessary to accommodate renewable generation. In addition, this report provides information with respect to the general condition of the distribution system.

LPDL distributes electricity to five separate and non-contiguous rural service areas: Town of Bracebridge, Town of Huntsville, Municipality of Magnetawan, Village of Burk's Falls and Village of Sundridge. LPDL's total service area is 144 sq km, with a municipal population of approximately 36,500. The customer base is approximately 9,700 electric customers with a winter peaking load of 41,400 kW. The distribution plant presently consists of a sub-transmission network at 44kV and municipal sub-stations at 27.6KV, 12.5kV and 4.16kV. LPDL's distribution system is fully embedded within Hydro One's system.

All current and proposed renewable generation projects in LPDL's distribution service area are comprised of solar (PV) rooftop installations, solar (PV) non-rooftop installations and waterpower generation plants. To date, the total planned and proposed renewable generation in LPDL's distribution service area is approximately: 704kW for microFIT projects (202 kW connected and 502 kW pending); 620kW for FIT projects (60 kW connected and 560 kW pending); and 8920 kW for waterpower generation (five plants connected).

LPDL is committed to providing reliable service to customers with an infrastructure that meets current and future needs. This GEA Plan is one of the various planning and reporting initiatives undertaken to maintain an effective distribution system. Other planning initiatives include system upgrades, voltage conversions, asset management plan and investigation of smart grid options.

2. Current Assessment of Distribution System

2.1. Distribution System Overview

- LPDL is a rural electric distribution company servicing 5 geographically separate municipalities: Town of Bracebridge, Town of Huntsville, Municipality of Magnetawan, Village of Burk's Falls and Village of Sundridge.
- LPDL's total service area is 144 sq km, with a municipal population of approximately 36,500 and a customer base of approximately 9,700 electric customers with a winter peaking load of 41,400 kW.
- LPDL has a strong residential customer base (town, rural and island customers) mixed with various commercial and industrial loads.
- LPDL has experienced minimal growth over the past number of years. LPDL's five service areas are completely embedded within Hydro One's territory thus limiting room for expansion.
- LPDL's wholesale supply is provided by Hydro One's 44kV sub-transmission at Muskoka TS, which feeds: three 27.6kV municipal stations in Bracebridge and four 4.16kV municipal stations, two of which are located in Bracebridge and two in Huntsville. The remainder of LPDL's customers are serviced by six Hydro One owned 12.5kV distribution stations located in Bracebridge, Burk's Falls and Sundridge.

- LPDL is committed to continuously improving the reliability and sustainability of the distribution system by upgrading poles, insulators, underground and overhead conductors and stations. Since 2005, LPDL has replaced three distribution station transformers: in 2005, a new 27.6kV station was installed; in 2008 a 4.16kV station was replaced with a 27.6kV station; and in 2010, a 4.16kV station was upgraded from 5MVa to 8MVa by installing a new station transformer.
- In 2011, LPDL upgraded hydraulic reclosures to vacuum reclosures at two 27.6kV stations. This created more robust protections to accommodate the upgraded production capacity at two of the waterpower generation plants connected to these stations. In 2012, LPDL plans to upgrade the reclosures at the third 27.6kV station to provide increased protections for future renewable generation connections and improved redundancy.

Table 1 - System Summary Overview	
System Peak (kW - January 2011	41,419.20
Service Area (sq km)	144
Total Customers	9688
GS>50	101
GS<50	1567
Residential	7930
Other (USL, Sentinel, Street L	90
PME's	19
Poles	4661
Distribution Stations	7
Total Primary Lines (km)	297.219
44 kV - OH 3 phase(km)	3.533
27.6kV - OH 3 phase (km)	21.911
27.6kV - OH 1 phase (km)	2.830
27.6kV - UG 3 phase (km)	7.966
27.6kV - UG 1 phase (km)	20.787
12.5kV - OH 3 phase (km)	76.799
12.5kV - OH 1 phase (km)	70.722
12.5kV - UG 3 Phase (km)	3.627
12.5kV - UG 1 Phase (km)	32.766
4.16kV - OH 3 phase (km)	32.715
4.16kV - OH 1 phase (km)	12.855
4.16kV - UG 3 phase (km)	4.465
4.16kV - UG 1 phase (km)	6.243
Total Transformers	2231
OH	1729
UG	502

2.2. Embedded Distribution System

LPDL's entire distribution system is embedded within the Hydro One system. LPDL is fed from two 44kV feeders in Bracebridge (30M3 and 30M7), one 44kV feeder in Huntsville (30M9) and one 44kV feeder serving our northern customers in Sundridge, Burk's Falls and Magnetawan (30M2). Currently, LPDL has waterpower and solar PV generation facilities connected to municipal stations which are fed from Hydro One feeders 30M7, 30M9 and 30M3. LPDL also has waterpower and solar PV generation facilities connected directly to Hydro One distribution stations fed from Hydro One feeders 30M3, 30M7 and 30M2. There are currently no capacity issues that LPDL is aware of, for the distribution system or Hydro One's system to which LPDL is fed from, that may limit the amount of future renewable generation requiring connection.

2.3. Municipal Substations

LPDL operates seven owned municipal stations: three 27.6kV stations in Bracebridge, two 4.16kV stations in Bracebridge and two 4.16kV stations in Huntsville. The remainder of LPDL's service territory, not serviced by the above municipal stations, are serviced by six Hydro One owned 12.5kV distribution stations which are located in Bracebridge, Burk's Falls and Sundridge.

Table 2 - Substation Summary

Station Name	Hydro One Circuit	Transformer Age	Transformer Capacity	Voltage	# of Feeders	Type of Protection
Lakeland Owned:						
Centennial MS	30M7	2008	10MVA	44kV/27.6kV	3	Reclosure
Golden Beach MS	30M7	1991	10MVA	44kV/27.6kV	2	Reclosure
Douglas MS5	30M7	2005	5MVA	44kV/27.6kV	2	Reclosure
MS2 Bracebridge	30M7	1991	8MVA	44kV/4.16kV	3	Breaker
MS3 Bracebridge	30M3	1986	5MVA	44kV/4.16kV	3	Breaker
MS1 Huntsville	30M9	1988	6MVA	44kV/4.16kV	5	Breaker
MS2 Huntsville	30M9	2010	8MVA	44kV/4.16kV	4	Breaker
Hydro One Owned:						
Taylor DS	30M3		6MVA	44kV/12.5kV	3	Reclosure
Beaumaris DS	30M7		6MVA	44kV/12.5kV	3	Reclosure
Golden Beach DS	30M7		6MVA	44kV/12.5kV	2	Reclosure
Muskoka Falls DS	30M7		6MVA	44kV/12.5kV	2	Reclosure
Burk's Falls DS	30M2		10MVA	44kV/12.5kV	1	Reclosure
Sundridge North DS	30M2		6MVA	44kV/12.5kV	1	Reclosure

2.4. Station Metering and Monitoring

LPDL has six substations that have full SCADA ready F35 relays allowing for real time station monitoring. The vacuum reclosures at Centennial MS and Golden Beach MS are connected to a 651 relay which allows for communication with the waterpower generation plants via the RTAC (Real Time Automation Controller). This communication provides transfer trip protection between the distribution system and the generator. LPDL is currently reviewing quotes for a SCADA system which would become a part of the Smart Grid Plan.

2.5. Feeder Capacities to Connect Generation

For each inquiry/application that LPDL receives for a renewable generation project, LPDL logs in to a Hydro One web portal to inquire if there is available connection capacity for that location. The reply received from this Hydro One web inquiry is simply a pass or fail response, stating whether the requested capacity is available or not. If capacity is available, LPDL will proceed with the application and connection process. If capacity is not available, the project capacity and connection requirements will be addressed by LPDL and Hydro One to evaluate what facilities are required to make it feasible. To date, there have been no capacity connection issues or fail responses received for any of the renewable generation projects proposed and/or connected to LPDL's service territory.

Table 3 - Feeder Summary

Station Name	Feeder	Average Load 2011	Available Capacity	Waterpower Connections	FIT Connections	microFIT Connections	Remaining Capacity
Lakeland Owned							
Centennial MS	F1 Feeder	600 kW	5500 kW	2600 kW (=1)	-	-	2900 kW
Centennial MS	F2 Feeder	300 kW	5500 kW	-	-	-	5500 kW
Centennial MS	F3 Feeder	200 kW	2700 kW	-	-	-	2700 kW
Golden Beach MS	F5 Feeder	0 kW	0 kW	-	-	-	0 kW
Golden Beach MS	F6 Feeder	1200 kW	5500 kW	5200 kW (=3)	-	-	300 kW
Douglas MS5	F1 Feeder	1000 kW	2700 kW	-	-	10 kW (=1)	2690 kW
Douglas MS5	F2 Feeder	0 kW	2700 kW	-	-	-	2700 kW
MS2 Bracebridge	F1 Feeder	200 kW	1700 kW	-	-	-	1700 kW
MS2 Bracebridge	F2 Feeder	700 kW	1700 kW	-	-	10 kW (=1)	1690 kW
MS2 Bracebridge	F4 Feeder	200 kW	1700 kW	-	-	-	1700 kW
MS3 Bracebridge	F1 Feeder	200 kW	1700 kW	-	-	-	1700 kW
MS3 Bracebridge	F2 Feeder	200 kW	1700 kW	-	-	10 kW (=1)	1690 kW
MS3 Bracebridge	F3 Feeder	500 kW	1700 kW	-	-	-	1700 kW
MS1 Huntsville	F1 Feeder	600 kW	1700 kW	-	-	-	1700 kW
MS1 Huntsville	F2 Feeder	600 kW	1700 kW	-	-	-	1700 kW
MS1 Huntsville	F3 Feeder	1000 kW	1700 kW	-	-	5 kW (=1)	1695 kW
MS1 Huntsville	F4 Feeder	400 kW	1700 kW	-	-	-	1700 kW
MS1 Huntsville	F5 Feeder	300 kW	1700 kW	-	-	22.2 kW (=3)	1677.8 kW
MS2 Huntsville	F1 Feeder	700 kW	1700 kW	-	-	10 kW (=1)	1690 kW
MS2 Huntsville	F2 Feeder	700 kW	1700 kW	-	-	-	1700 kW
MS2 Huntsville	F3 Feeder	1000 kW	1700 kW	-	-	20 kW (=2)	1680 kW
MS2 Huntsville	F4 Feeder	300 kW	1700 kW	-	-	-	1700 kW
Hydro One Owned:							
Taylor DS (*)	30M3			-	-	27.2 kW (=3)	
Beaumaris DS	30M7			-	-	-	
Golden Beach DS (*)	30M7			-	-	2.4 kW (=1)	
Muskoka Falls DS (*)	30M7			-	60 kW (=1)	15 kW (=2)	
Burk's Falls DS (*)	30M2			1120 kW (=1)	-	20 kW (=2)	
Sundridge North DS (*)	30M2			-	-	50 kW (=5)	

(*) To date, when checked with the Hydro One portal for available capacity on Hydro One substations, Lakeland has received no capacity constraint limitations regarding any proposed FIT or microFIT applications.

2.6. Identification of Expenditures

As of May 31, 2012 LPDL has incurred approximately $240,000 in renewable generation project costs, tracked in 'Account 1531: Renewable Generation Connection Capital Deferral Account'. These capital expenditures are due to expansion/enabling improvement costs incurred to protect and upgrade LPDL's municipal stations that are connected to two waterpower generation facilities that underwent major upgrades. These two waterpower generation plants have been connected to LPDL's service territory since the plants were built in the early 1900's. Both plants were decommissioned for upgrades in October 2010, at which point the combined production was approximately 1200 kW. The generation plants underwent major upgrades from October

2010 to January 2012 to significantly increase their production to approximately 5500 kW combined. Due to this increased generation, LPDL was required to upgrade and protect the two municipal stations that these plants are connected to, including installation of: vacuum reclosures, 651 controls and 44kV voltage transformers at Golden Beach MS; 651 controls at Centennial MS; and replacement of poles and conductors to accommodate the increased capacity from the generation plants. Many of these protection costs/improvements were prescribed by a protection study conducted by Eaton.

LPDL has also been notified by Hydro One that Hydro One will incur costs to remedy protection, controls and communication issues at the Hydro One Muskoka TS due to this increased connected generation. To date, the proposed cost from Hydro One is approximately $1,500,000 but at this time no charges have been passed on to LPDL. Under the DSC, as noted in section 2.4.1 of OEB's Filing Requirements in EB-2009-0397, LPDL's total contribution for expansion costs due to these waterpower generation upgrades will be capped at approximately $495,000 based on the renewable expansion cost cap of $90,000 per MW. Thus, any expenditures over this cap will be passed on and become the responsibility of the generator.

Any future expenditures, if required for expansions/enabling improvements, will be addressed on a case by case basis depending on the size and location of the proposed renewable generation connection. Future growth in LPDL's territory would primarily include microFIT and small FIT connections (<250 kW). LPDL does not foresee any large FIT connections due to the heavily forested and rocky terrain in the service territory.

2.7. Unique Challenges

LPDL's service territory is completely embedded within Hydro One's system and is therefore limited to their system capacity, which to date has not been constrained. Future challenges may become forefront if one of the other existing waterpower generation plants undergo major upgrades but to date, LPDL has not been informed of any.

The majority of connected and proposed renewable generation connections in LPDL's service territory are made up of solar PV microFIT and FIT (<250kW) projects. These projects will typically displace customer load at the host site and are not expected to be net-exporters of energy to the distribution system.

3. Planned Development of the Distribution System to Accommodate Generation Connections

3.1. Existing and Pending Renewable Generation Projects

LPDL's renewable generation connection application process requires the involvement of Hydro One. Each inquiry/application is first reviewed by LPDL's metering staff and distribution departments. As Hydro One is LPDL's host distributor, LPDL also requires approval from Hydro One for available capacity for each connection.

As applications come forth, LPDL continues to meet with interested parties as requested. The total expected new connection over the next 5 years is not deemed to be significant.

As of June 11, 2012, the following renewable generation statistics are available:

MicroFIT Applications: 79 (704 kW)

- MicroFIT Contracts Connected: 23 (201.8 kW)

- MicroFIT Applications with Offers to Connect Issued: 11 (106.28 kW)
- MicroFIT Applications in Progress: 27 (231.14 kW)
- MicroFIT Applications Submitted: 18 (164.78 kW)

FIT Applications: 4 (620 kW)

- FIT Contracts Connected: 1 (60 kW)
- FIT Applications with CIA (via Hydro One) Issued: 1 (175 kW)
- FIT Applications in Progress: 2 (385 kW)

Waterpower Generation Facility Connections: 5 (8920 kW)

- FIT Contracts Connected (Upgrade from HCI Contract): 2 (5500 kW)
- HCI Contracts Connected: 2 (1920 kW)
- RESOP Contracts Connected: 1 (1500 kW)

All FIT applications received must be reviewed and approved by Hydro One through the Connection Impact Assessment (CIA) process.

3.2. Infrastructure Projects and Activities to Accommodate Renewable Generation

LPDL does not foresee any large generation connections over the next five years. Potential projects could be required if any of the existing waterpower generators that are connected to LPDL's service territory undergo any future upgrades or any new generation developments occur, but LPDL is not aware of any at this time. In 2012, LPDL plans to upgrade the reclosures at the third 27.6kV station to provide increased protections for future renewable generation connections and improved redundancy. As mentioned above, LPDL has also been notified by Hydro One that Hydro One will incur costs at the Muskoka TS for protections, controls and communication issues.

3.3. Costs to be Recovered

LPDL is not requesting recovery of the incurred renewable generation costs in our 2013 Cost of Service Rate Application. Rate recovery for these costs will be addressed in future rate applications.

4. Smart Grid Development

LPDL is currently investigating smart grid technologies through industry meetings and vendor discussions. LPDL is in the process of reviewing quotes for various SCADA systems which would be integrated into a smart grid system. Any future upgrades to the distribution system would be geared to smart grid compatibility.

5. Summary

In this GEA Plan, LPDL has illustrated the ability to accommodate existing renewable generation and any potential future green energy projects. Through the plan, the existing capacity has been outlined and at this time LPDL does not foresee any capacity issues to accommodate future green energy initiatives.

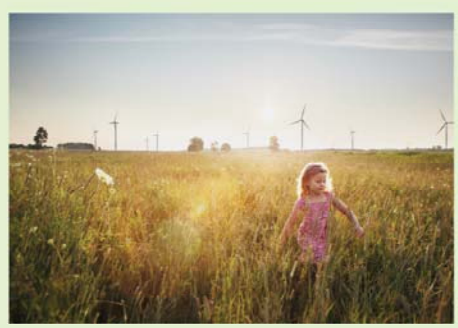
APPENDIX D

LPDL OPA LETTER OF COMMENT

OPA Letter of Comment:

Lakeland Power Distribution Ltd.

Basic Green Energy Act Plan



June 20, 2012

ONTARIO POWER AUTHORITY

Introduction

On March 25, 2010, The Ontario Energy Board ("the OEB") issued its Filing Requirements for Distribution System Plans. As a condition of Licence, Ontario Distributors are required to file a Green Energy Act Plan as part of their cost of service application.

The Filing Requirements distinguish between Basic and Detailed Green Energy Act Plans ("Plan" or "GEA Plan") and outline the specific information and level of detail which must be provided for each type of Plan. Recognizing the importance of coordinated planning in achieving the goals of the *Green Energy and Green Economy Act, 2009* (the "GEA"), distributors must consult with embedded and host distributors, upstream transmitters and the OPA in preparing their Plans. For both Basic and Detailed Plans, distributors are required to submit as part of the Plan, a letter of comment from the OPA.

The OPA will review distributors' Basic Plans to ensure consistency with regard to FIT and microFIT applications received, as well as with integrated Plans for the region or the system as a whole.

Lakeland Power Distribution Ltd. - Basic Green Energy Act Plan

The OPA has reviewed the Basic GEA Plan from Lakeland Power Distribution Ltd. ("Lakeland"), dated June 15, 2012 and has provided its comments below.

OPA FIT/microFIT Applications Received

Lakeland GEA Plan indicates that there are 23 connected microFIT and 1 connected FIT projects in its distribution system, and that 56 microFIT and 3 FIT projects have applied to the FIT/microFIT program to be connected within Lakeland's service territory.

According to OPA's information, as of June 18, 2012, there are 23 connected microFIT projects, totalling 0.2 MW in Lakeland's system. There are also 3 Capacity Allocation Exempt ("CAE") applications, for a total capacity of 0.33 MW, which have received FIT contracts in Lakeland's service area.

In addition, 45 microFIT applications, with 0.4 MW of capacity have applied to connect in Lakeland's service territory. The OPA has also received 3 FIT CAE applications, totalling 0.35 MW of capacity, proposing to connect to Lakeland's distribution system.

Upstream Transmission Constraints

According to the information provided in Lakeland's GEA Plan, Lakeland's distribution system is supplied from feeders originating from Muskoka TS, as well as from several distribution stations owned

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by Hydro One. The OPA confirms that there are no currently known upstream transmission constraints at Muskoka TS or at other nearby transmission supply points.

Further details on capacity at the above mentioned stations may be found in the updated Transmission Availability Table for Small FIT 2012 available on the OPA's FIT website as follows:
http://fit.powerauthority.on.ca/sites/default/files/TAT%20Table%20Final%20-%20April%205%20for%20posting.pdf

Economic Connection Test

The OPA received a directive dated April 5, 2012 from the Minister of Energy with respect to the Feed-in Tariff Program Review. The directive states that "[g]iven the transmission projects planned through the Long Term Energy Plan and changes to the FIT Program, the OPA shall not run the Economic Connection Test ". A link to the full directive is provided on the OPA's website:
http://www.powerauthority.on.ca/sites/default/files/page/FIT-ReviewApril-2012.pdf

Opportunities for Integrated Solutions

The OPA is not aware of any opportunities for integrated solutions among neighbouring LDCs at this time.

Conclusion

The OPA finds that the GEA Plan of Lakeland Power Distribution Ltd. is reasonably consistent with the OPA's information regarding renewable energy generation applications to date.

The OPA appreciates the opportunity to comment on Lakeland's Basic GEA Plan.

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<u>OVERVIEW OF OPERATING REVENUE:</u>

This Exhibit provides the details of LPDL's operating revenue for 2009 Board Approved, 2009 Actual, 2010 Actual, 2011 Actual, the 2012 Bridge Year and the 2013 Test Year. This Exhibit also provides a detailed variance analysis by rate class of the operating revenue components. Distribution revenue excludes revenue from commodity sales.

LPDL is proposing a total Service Revenue Requirement of $5,773,388 for the 2013 Test Year. This amount includes a Base Revenue Requirement of $5,459,760 plus revenue offsets of $313,628 to be recovered through Other Distribution Revenue.

A summary of all operating revenue is presented below in Table 3.1.1 and provides a comparison of total revenues from the 2009 OEB approved year to the 2013 Test Year.

Throughput Revenue

Information related to LPDL's throughput revenue includes details on the weather normalized load forecasting methodology reflecting expected CDM results and a forecast of customers by rate class based on the historical number of customers billed throughout the year.

A detailed variance analysis on the historical throughput revenue is also provided in this Exhibit.

Other Revenue

Other revenues include Standard Service Supply (SSS) Administration Charges, Late Payment Charges, Miscellaneous Service Revenues and Merchandise and Jobbing Revenues.

A detailed variance analysis on other revenue is set out later on this Exhibit.

Table 3.1.1 – Operating Revenue By Rate Class

Operating Revenue by Rate Class	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Residential	$ 2,578,659	$ 2,391,505	$ 2,500,355	$ 2,509,429	$ 2,880,363	$ 3,094,202
GS<50 kW	$ 1,082,654	$ 968,457	$ 1,026,828	$ 1,029,880	$ 1,131,929	$ 1,233,858
GS>50 kW	$ 852,391	$ 855,712	$ 827,995	$ 809,433	$ 830,690	$ 899,897
Sentinel	$ 3,269	$ 2,480	$ 3,945	$ 4,558	$ 4,481	$ 5,840
Street lighting	$ 141,987	$ 103,134	$ 171,002	$ 190,874	$ 199,001	$ 219,846
Unmetered Scattered Load	$ 11,677	$ 10,568	$ 10,150	$ 9,183	$ 9,113	$ 6,117
Throughput Revenue	$ 4,670,637	$ 4,331,857	$ 4,540,275	$ 4,553,357	$ 5,055,577	$ 5,459,761
Throughput revenue as % of Total Revenue	91.5%	91.0%	90.9%	91.4%	94.6%	94.6%
Revenue offsets	$ 435,076	$ 430,701	$ 454,293	$ 428,676	$ 288,796	$ 313,628
Total Revenue	$ 5,105,713	$ 4,762,558	$ 4,994,568	$ 4,982,033	$ 5,344,372	$ 5,773,389

WEATHER NORMALIZED LOAD AND CUSTOMER/CONNECTION FORECAST:

The purpose of this evidence is to present the process used by LPDL to prepare the weather normalized load and customer/connection forecast used to design the proposed 2013 electricity distribution rates.

In summary, LPDL has used the same regression analysis methodology used by a number of distributors in previous cost of service rate applications to determine a prediction model. With regard to the overall process of load forecasting, LPDL submits that conducting a regression analysis on historical electricity purchases to produce an equation that will predict purchases is appropriate. LPDL has the data for the amount of electricity (in kWh) purchased from Hydro One for use by LPDL's customers. With a regression analysis, these purchases can be related to other monthly explanatory variables such as heating degree days and cooling degree days which occur in the same month. The results of the regression analysis produce an equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total level of weather normalized purchases for the Bridge Year and the Test Year which is converted to bill kWh by rate class. A detailed explanation of the process is provided later in this evidence.

During proceedings related to the 2009 and 2010 cost of service applications for a number of other distributors, Intervenors expressed concerns with the load forecasting process that was proposed at the time by those distributors. During the review process of the 2009 cost of service applications, Intervenors suggested the regression analysis should be conducted on an individual rate class basis and the regression analysis would be based on monthly kWh by rate class. LPDL attempted to conduct the regression analysis on an individual rate class basis. LPDL estimated the amount consumed in a month by rate class by shifting the actual monthly billed amount back one month to reflect the actual period of consumption. However, based on the R square and Adjusted R square values shown in Table 3.2.1, LPDL concluded using the equations resulting from the individual rate class regression analysis would not provide individual class based prediction formulas that were in total as good as the prediction equation from the power purchased method. The R square and Adjusted R square values for the power purchased method are 89% and 88%, respectively. In addition, the total 2013 kWh forecast is from the power purchased method is essentially the same as using the individual rate class prediction formulas. The total forecast from the individual rate class prediction formulas was only 0.3% higher which in LPDL's view is immaterial.

Table 3.2.1 – R Square and Adjusted R Square Values for Individual Class Regression Analysis

Class	R Square	Adjusted R Square
Residential	94%	94%
GS<50	79%	79%
GS>50	31%	28%

During the review of 2010 cost of service applications, Board staff and Intervenors expressed concern that the regression analysis assigned coefficients to some variable that were counter intuitive. For example, the customer variable would have a negative coefficient assigned to it which meant as the number of customers increased the energy forecast decreased. 2010 applicants explained that this was related to the recent Conservation and Demand Management ("CDM") savings in the utility but in the view of Board staff and Intervenors this was not a sufficient explanation. Further, the regression analysis indicated that some of the variables used in the load forecasting formula were not statistically significant and should not have been included in the equation. LPDL has attempted to address these concerns in the load forecast used in this Application. Based on the OEB's approval of this methodology in a number of previous cost of service applications, and based on the discussion that follows, LPDL submits that its load forecasting methodology is reasonable for the purposes of this Application.

The following provides the material to support the weather normalized load forecast used by LPDL in this Application.

Table 3.2.2 – Summary of Load and Customer/Connection Forecast

Year	Billed (GWh)	Growth (GWh)	Percent Change	Customer/ Connection Count	Growth	Percent Change (%)
Billed Energy (GWh) and Customer Count / Connections						
2009 Board Approved	225.9			9,302		
2002 Actual	216.0			10,844		
2003 Actual	217.9	2.0	0.9%	10,947	103	0.9%
2004 Actual	220.2	2.3	1.1%	11,010	63	0.6%
2005 Actual	222.7	2.4	1.1%	11,070	60	0.5%
2006 Actual	215.9	(6.8)	(3.1%)	11,113	43	0.4%
2007 Actual	218.6	2.7	1.2%	11,165	52	0.5%
2008 Actual	219.2	0.6	0.3%	11,377	212	1.9%
2009 Actual	210.2	(9.0)	(4.1%)	11,503	126	1.1%
2010 Actual	206.7	(3.5)	(1.7%)	11,597	94	0.8%
2011 Actual	205.9	(0.8)	(0.4%)	11,764	167	1.4%
2012 Bridge	**205.8**	**(0.1)**	**(0.1%)**	**11,873**	**109**	**0.9%**
2013 Test	**203.1**	**(2.7)**	**(1.3%)**	**11,983**	**110**	**0.9%**

The information in the table above provides weather actual data from 2003 to 2011, while 2012 and 2013 are weather normalized. LPDL does not have a process to properly adjust weather actual data to a weather normal basis. However, based on the process outlined in this Exhibit, a process to forecast energy on a weather normalized basis has been developed and used in this Application.

Total Customers and Connections are on a mid-year basis and streetlight, sentinel lights and unmetered loads are measured as connections.

Actual and forecasted billed amounts and numbers of customers are shown in Table 3.2.3 and customer usage is shown in Table 3.2.4, on a rate class basis.

Table 3.2.3 – Billed Energy and Number of Customers/Connections by Rate Class

Year	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL	Total
Billed Energy (GWh)							
2009 Board Approved	87.3	49.4	86.9	2.0	0.0	0.2	225.9
2002 Actual	79.1	47.3	87.4	1.8	0.04	0.3	216.0
2003 Actual	81.3	46.2	88.2	1.9	0.04	0.3	217.9
2004 Actual	81.4	46.9	89.7	1.9	0.04	0.3	220.2
2005 Actual	82.6	47.6	90.3	1.9	0.04	0.3	222.7
2006 Actual	78.2	45.5	90.0	1.9	0.04	0.3	215.9
2007 Actual	79.4	46.1	90.9	1.9	0.04	0.3	218.6
2008 Actual	80.9	45.4	90.7	1.9	0.04	0.2	219.2
2009 Actual	80.6	43.4	84.1	1.9	0.04	0.2	210.2
2010 Actual	79.1	43.0	82.6	1.9	0.04	0.1	206.7
2011 Actual	77.6	42.7	83.6	1.9	0.04	0.1	205.9
2012 Bridge	**78.0**	**42.5**	**83.3**	**1.9**	**0.04**	**0.1**	**205.8**
2013 Test	**77.3**	**41.7**	**82.2**	**1.8**	**0.04**	**0.1**	**203.1**
Number of Customers/Connections							
2009 Board Approved	7,562	1,549	96	7	42	45	9,302
2002 Actual	7,105	1,469	93	2,056	50	71	10,844
2003 Actual	7,212	1,461	97	2,058	49	70	10,947
2004 Actual	7,274	1,465	95	2,058	48	70	11,010
2005 Actual	7,326	1,474	98	2,058	46	68	11,070
2006 Actual	7,374	1,478	92	2,058	45	66	11,113
2007 Actual	7,393	1,509	96	2,058	44	65	11,165
2008 Actual	7,519	1,535	98	2,130	45	50	11,377
2009 Actual	7,637	1,549	100	2,130	44	43	11,503
2010 Actual	7,728	1,553	100	2,130	45	41	11,597
2011 Actual	7,880	1,568	101	2,130	45	40	11,764
2012 Bridge	**7,971**	**1,579**	**102**	**2,138**	**44**	**38**	**11,873**
2013 Test	**8,063**	**1,591**	**103**	**2,147**	**44**	**35**	**11,983**

Table 3.2.4 – Annual Usage per Customer/Connection by Rate Class

Year	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL
Energy Usage per Customer/Connection (kWh per customer/connection)						
2009 Board Approved	11,549	31,909	905,208	285,714	952	4,444
2002 Actual	11,138	32,176	939,716	882	839	4,448
2003 Actual	11,276	31,592	909,529	914	903	4,327
2004 Actual	11,197	31,990	944,244	919	883	4,257
2005 Actual	11,269	32,318	921,308	916	901	4,023
2006 Actual	10,601	30,772	978,631	916	919	4,107
2007 Actual	10,740	30,545	946,995	916	911	3,886
2008 Actual	10,758	29,585	925,978	879	886	4,135
2009 Actual	10,559	28,028	840,552	878	921	3,870
2010 Actual	10,229	27,681	826,079	878	906	3,457
2011 Actual	9,851	27,220	827,689	878	898	3,298
2012 Bridge	**9,785**	**26,905**	**817,377**	**867**	**894**	**3,153**
2013 Test	**9,581**	**26,217**	**798,992**	**857**	**890**	**3,013**
Annual Growth Rate in Usage per Customer/Connection						
2009 Board App. Vs. 2009 Actual	9.4%	13.8%	7.7%	32442.2%	3.5%	14.8%
2002 Actual						
2003 Actual	1.2%	(1.8%)	(3.2%)	3.7%	7.5%	(2.7%)
2004 Actual	(0.7%)	1.3%	3.8%	0.5%	(2.2%)	(1.6%)
2005 Actual	0.6%	1.0%	(2.4%)	(0.3%)	2.1%	(5.5%)
2006 Actual	(5.9%)	(4.8%)	6.2%	0.0%	2.0%	2.1%
2007 Actual	1.3%	(0.7%)	(3.2%)	(0.0%)	(0.8%)	(5.4%)
2008 Actual	0.2%	(3.1%)	(2.2%)	(4.0%)	(2.8%)	6.4%
2009 Actual	(1.8%)	(5.3%)	(9.2%)	(0.1%)	3.9%	(6.4%)
2010 Actual	(3.1%)	(1.2%)	(1.7%)	0.0%	(1.6%)	(10.7%)
2011 Actual	(3.7%)	(1.7%)	0.2%	(0.0%)	(0.9%)	(4.6%)
2012 Bridge	**(0.7%)**	**(1.2%)**	**(1.2%)**	**(1.2%)**	**(0.4%)**	**(4.4%)**
2013 Test	**(2.1%)**	**(2.6%)**	**(2.2%)**	**(1.2%)**	**(0.4%)**	**(4.4%)**

Load Forecast and Methodology

LPDL's weather normalized load forecast is developed in a three-step process. First, a total system weather normalized purchased energy forecast is developed based on a multifactor regression model that incorporates historical load, weather, days in the month, spring/fall seasonal "flag" and CDM activity. Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Next, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load, their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast that has been determined from the regression model. The forecast of customers by rate class is determined using a geometric mean analysis. For those rate classes that use kW for the distribution volumetric billing determinant, an adjustment factor is applied to class energy forecast based on the historical relationship between kW and kWh.

A detailed explanation of the load forecasting process follows.

Purchased KWh Load Forecast

An equation to predict total system purchased energy is developed using a multifactor regression model with the following independent variables: weather (heating and cooling degree days); days in month, spring/fall seasonal "flag" and CDM activity. The regression model uses monthly kWh and monthly values of independent variables from January 2002 to December 2011 to determine a prediction formula with coefficients for each independent variable. This provides 120 monthly data points which represents a reasonable data set for use in a regression analysis. Consistent with the approach used by many other distributors in their cost of service applications, LPDL submits that it is appropriate to review the impact of weather over the period January 2002 to December 2011 and then determine the average weather conditions over this period which would be applied in the prediction formula to determine a weather normalized forecast. However, in accordance with the OEB's Filing Requirements, LPDL has also provided a sensitivity analysis showing the impact on the 2013 forecast of purchases assuming weather normal conditions are based on a 20-year trend of weather data.

Weather impacts on load are apparent in both the winter heating season, and in the summer cooling season. For that reason, both Heating Degree Days (i.e. a measure of coldness in winter) and Cooling Degree Days (i.e. a measure of summer heat) are modeled.

The following outlines the prediction model used by LPDL to predict weather normal purchases for 2012 and 2013:

LPDL's Monthly Predicted kWh Purchases:

= Heating Degree Days * 8,348
+ Cooling Degree Days * 12,771
+ Number of Days in the Month * 500,310
+ Spring Fall Flag * (1,348,468)
+ CDM Activity * (6.4)
+ Intercept of 2,004,347

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix 3-A.

The sources of data for the various data points are:

a) Environment Canada website for monthly heating degree day and cooling degree information. Weather data from Muskoka Airport weather station was used.

b) The calendar provided information related to number of days in the month and the months defined to be spring or fall (i.e. March to May and September to November)

c) The CDM activity variable is an estimated level of monthly activity in CDM. For each year the monthly values grow at constant value over the year. For the years 2006 to 2013, the addition of the monthly CDM activity values shown in Appendix 3-A will equal the Net Energy Savings from the OPA 2006-2010 Final CDM Results for LPDL. These values reflect the net energy savings from 2006 to 2010 programs and how these programs have persistent savings from 2007 to 2013. However, for the years 2011 to 2013, the Net Energy Savings from the OPA 2006-2010 Final CDM Results are adjusted to include preliminary actual results from 2011 programs that contribute to the four year licensed CDM kWh targets of 10,180,000 assigned to LPDL. The 2011 preliminary actual results are based on the fourth quarter 2011 CDM Status Report provided to LPDL by the OPA. The 2011 preliminary actual results have been included in the CDM activity variable since these results have impacted the actual 2011 power purchases. Table 3.2.5 below outlines the adjustments made to the Net Energy Savings from the OPA 2006-2010 Final CDM Results to include the impact of the preliminary actual result from 2011 CDM programs and the persistent impact of the 2011 programs into 2012 and 2013. In addition, the table provides the Net Energy Savings from the OPA 2006-2010 Final CDM Results for the years 2006 to 2013. For 2013, the monthly values for the CDM activity variable will total 2,271,075 kWh which includes 1,776,605 kWh from the OPA final results plus 494,470 kWh reflecting the persistence of 2011 programs into 2013.

Table 3.2.5 – 2011 Preliminary Results and Persistent Impact plus OPA 2010 Final Results and Persistent Impact

Lakeland Power 4 Year 2011 to 2014 kWh target				
10,180,000				
2011	2012	2013	2014	Total
kWh savings from 2011 programs with presistent impact				
494,470	494,470	494,470	494,470	1,977,880
OPA 2010 Final Results - kWh				
2006	2007	2008	2009	
739,673	1,356,235	1,483,198	2,184,545	
2010	2011	2012	2013	
2,098,703	1,863,559	1,804,507	1,776,605	

The impact of 2012 and 2013 CDM programs has not been included in the CDM activity variable since they do not impact the actual purchases used in the regression analysis. A discussion on how the load forecast is adjusted for 2012 and 2013 programs and how LRAM variance account values are determined by rate class is provided later on in this schedule.

The prediction formula has the following statistical results:

Table 3.2.6 – Statistical Results

Statistic	Value
R Square	89%
Adjusted R Square	88%
F Test	180.9
T-stats by Coefficient	
Heating Degree Days	18.6
Cooling Degree Days	2.0
Number of Days in Month	4.8
Spring Fall Flag	(6.1)
CDM Activity	(6.1)
Intercept	0.6

The annual results of the above prediction formula compared to the actual annual purchases from 2003 to 2011 are shown in the chart below. The chart indicates the resulting prediction equation appears to be reasonable.

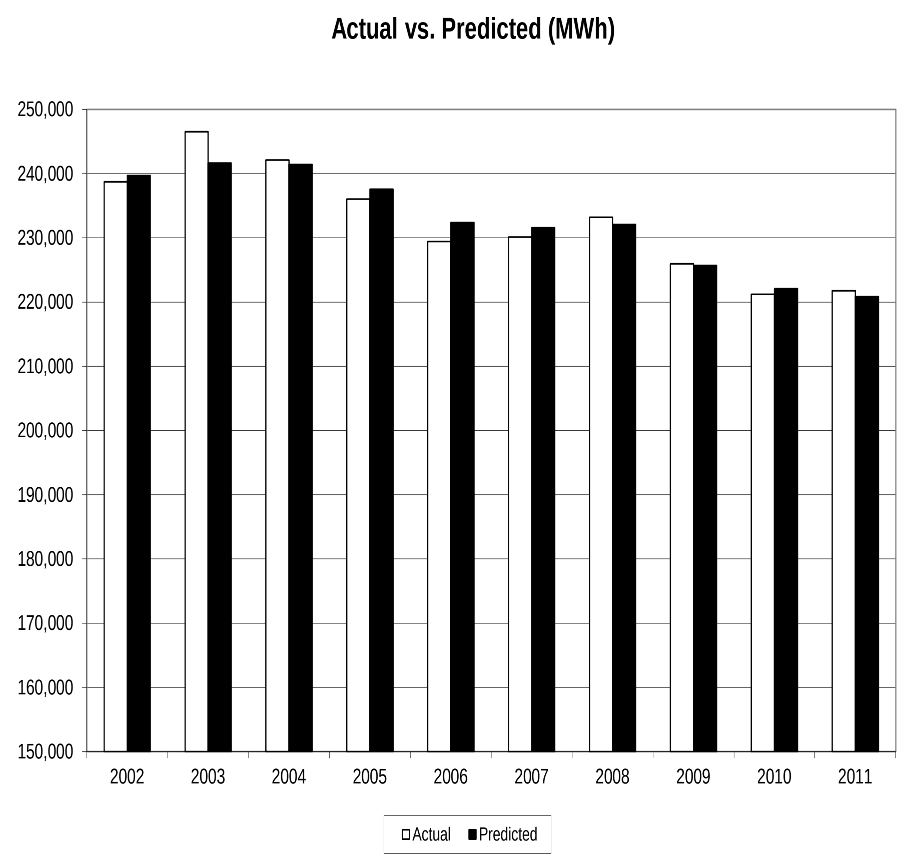

Table 3.2.7 below outlines the data that supports the above chart. In addition, the predicted total system purchases for LPDL are provided for 2012 and 2013. For 2012 and 2013 the system purchases reflect a weather normalized forecast for the full year. In addition, values for 2013 are provided with a 20 year trend assumption for weather normalization.

Table 3.2.7 – Total System Purchases

Year	Actual	Predicted	% Difference
Purchased Energy (GWh)			
2002	238.7	239.7	0.4%
2003	246.5	241.6	(2.0%)
2004	242.1	241.4	(0.3%)
2005	236.0	237.6	0.6%
2006	229.4	232.4	1.3%
2007	230.1	231.6	0.6%
2008	233.2	232.1	(0.5%)
2009	226.0	225.7	(0.1%)
2010	221.2	222.1	0.4%
2011	221.8	220.9	(0.4%)
2012 Weather Normal		**224.8**	
2013 Weather Normal		**224.5**	
2013 Weather Normal - 20 year trend		**222.7**	

The weather normalized amount for 2013 is determined by using 2013 dependent variables in the prediction formula on a monthly basis together with the average monthly heating degree days and cooling degree days that occurred from January 2002 to December 2011 (i.e. ten years). The 2013 weather normalized 20 year trend value reflects the trend in monthly heating degree days and cooling degree days that occurred from January 1992 to December 2011.

The weather normal ten year average has been used in the power purchased forecast in this Application for the purposes of determining a billed kWh load forecast which is used to design rates. The ten year average has been used as this is consistent with the period of time over which the regression analysis was conducted.

Billed KWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by a historical loss factor. This adjustment has been made by LPDL using the average loss factor from 2002 to 2011 of 1.0797. With this average loss factor the total weather normalized billed energy will be 208.2 GWh for 2012 (i.e. 224.8/1.0797) and 207.9 GWh for 2013 (i.e. 224.5/1.0797) before adjustments for 2012 and 2013 CDM programs.

Billed KWh Load Forecast and Customer/Connection Forecast by Rate Class

Since the total weather normalized billed energy amount is known, this amount needs to be distributed by rate class for rate design purposes taking into consideration the customer/connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available as shown in Table 3.2.8.

Table 3.2.8 – Historical Customer/Connection Data

Year	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL	Total
Number of Customers/Connections							
2002	7,105	1,469	93	2,056	50	71	10,844
2003	7,212	1,461	97	2,058	49	70	10,947
2004	7,274	1,465	95	2,058	48	70	11,010
2005	7,326	1,474	98	2,058	46	68	11,070
2006	7,374	1,478	92	2,058	45	66	11,113
2007	7,393	1,509	96	2,058	44	65	11,165
2008	7,519	1,535	98	2,130	45	50	11,377
2009	7,637	1,549	100	2,130	44	43	11,503
2010	7,728	1,553	100	2,130	45	41	11,597
2011	7,880	1,568	101	2,130	45	40	11,764

From the historical customer/connection data the growth rates in customers/ connections can be evaluated. The growth rates are provided in Table 3.2.9 below. The geometric mean growth rate in number of customers is also provided. The geometric mean approach provides the average compounding growth rate from 2002 to 2011.

Table 3.2.9 – Growth Rate in Customer/Connections

Year	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL
Growth Rate in Customers/Connections						
2002						
2003	1.5%	(0.5%)	4.3%	0.1%	(2.0%)	(1.4%)
2004	0.9%	0.3%	(2.1%)	0.0%	(2.0%)	0.0%
2005	0.7%	0.6%	3.2%	0.0%	(4.2%)	(2.9%)
2006	0.7%	0.3%	(6.1%)	0.0%	(2.2%)	(2.9%)
2007	0.3%	2.1%	4.3%	0.0%	(2.2%)	(1.5%)
2008	1.7%	1.7%	2.1%	3.5%	2.3%	(23.1%)
2009	1.6%	0.9%	2.0%	0.0%	(2.2%)	(14.0%)
2010	1.2%	0.3%	0.0%	0.0%	2.3%	(4.7%)
2011	2.0%	1.0%	1.0%	0.0%	0.0%	(2.4%)
Geometric Mean	**1.2%**	**0.7%**	**0.9%**	**0.4%**	**(1.2%)**	**(6.2%)**

The resulting geometric mean was first applied to the 2011 customer/connection numbers to determine the forecast of customer/connections in 2012 and 2013. Table 3.2.10 outlines the forecast of customers and connections by rate class.

Table 3.2.10 –Customer/Connection Forecast

Year	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL	Total
Forecast Number of Customers/Connections							
2012	**7,971**	**1,579**	**102**	**2,138**	**44**	**38**	**11,873**
2013	**8,063**	**1,591**	**103**	**2,147**	**44**	**35**	**11,983**

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. Table 3.2.11 below provides the average annual usage per customer by rate class from 2003 to 2011.

Table 3.2.11 – Historical Annual Usage per Customer

Year	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL
Annual kWh Usage Per Customer/Connection						
2002	11,138	32,176	939,716	882	839	4,448
2003	11,276	31,592	909,529	914	903	4,327
2004	11,197	31,990	944,244	919	883	4,257
2005	11,269	32,318	921,308	916	901	4,023
2006	10,601	30,772	978,631	916	919	4,107
2007	10,740	30,545	946,995	916	911	3,886
2008	10,758	29,585	925,978	879	886	4,135
2009	10,559	28,028	840,552	878	921	3,870
2010	10,229	27,681	826,079	878	906	3,457
2011	9,851	27,220	827,689	878	898	3,298

From the historical usage per customer/connection data the growth rate in usage per customer/connection can be reviewed. That information is provided in the following Table 3.2.12. The geometric mean growth rate has also been shown.

Table 3.2.12 – Growth Rate in Usage per Customer/Connection

Year	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL
Growth Rate in Customer/Connection						
2002						
2003	1.2%	(1.8%)	(3.2%)	3.7%	7.5%	(2.7%)
2004	(0.7%)	1.3%	3.8%	0.5%	(2.2%)	(1.6%)
2005	0.6%	1.0%	(2.4%)	(0.3%)	2.1%	(5.5%)
2006	(5.9%)	(4.8%)	6.2%	0.0%	2.0%	2.1%
2007	1.3%	(0.7%)	(3.2%)	(0.0%)	(0.8%)	(5.4%)
2008	0.2%	(3.1%)	(2.2%)	(4.0%)	(2.8%)	6.4%
2009	(1.8%)	(5.3%)	(9.2%)	(0.1%)	3.9%	(6.4%)
2010	(3.1%)	(1.2%)	(1.7%)	0.0%	(1.6%)	(10.7%)
2011	(3.7%)	(1.7%)	0.2%	(0.0%)	(0.9%)	(4.6%)
Geometric Mean	**(1.4%)**	**(1.8%)**	**(1.4%)**	**(0.0%)**	**0.7%**	**(3.3%)**

For the forecast of usage per customer/connection, the historical geometric mean was applied to the 2011 usage and the resulting usage forecast is as follows in Table 3.2.13:

Table 3.2.13 – Forecast Annual kWh Usage per Customer/Connection

Year	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL
Forecast Annual kWh Usage per Customers/Connection						
2012	9,717	26,719	816,097	878	904	3,190
2013	9,585	26,227	804,668	877	911	3,085

With the preceding information the non-normalized weather billed energy forecast can be determined by applying the forecast numbers of customers/connections from Table 3.2.10 by the forecast of annual usage per customer/connection from Table 3.2.13. The resulting non-normalized weather billed energy forecast is shown in the following Table 3.2.14.

Table 3.2.14 – Non-normalized Weather Billed Energy Forecast (GWh)

Year	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL	Total
NON-normalized Weather Billed Energy Forecast (GWh)							
2012 (Not Normalized)	77.5	42.2	83.2	1.9	0.0	0.1	204.9
2013 (Not Normalized)	77.3	41.7	82.8	1.9	0.0	0.1	203.8

The non-normalized weather billed energy forecast has been determined but this needs to be adjusted in order to be aligned with the total weather normalized billed energy forecast. As previously determined, the total weather normalized billed energy forecast is 208.2 GWh for 2012 and 207.9 GWh for 2013 before adjustments for 2012 and 2013 CDM programs.

The difference between the non-normalized and normalized forecast adjustments is 3.3 GWh in 2012 (i.e. 208.2 – 204.9) and 4.1 GWh in 2013 (i.e. 207.9 – 203.8). The difference is assumed to be associated with moving the forecast from a non-normalized to a weather normal basis and this amount will be assigned to those rate classes that are weather sensitive. Based on the weather normalization work completed by Hydro One for LPDL for the cost allocation study, which has been used to support this Application, it was determined that the weather sensitivity by rate classes is as follows in Table 3.2.15:

Table 3.2.15 – Weather Sensitivity by Rate Class

Residential	GS<50	GS>50	Street Lighting	Sentinels	USL
Weather Sensitivity					
77.5%	77.5%	55.0%	0.0%	0.0%	0.0%

For the GS > 50 kW class the weather sensitivity amount of 55.0% was provided in the weather normalization work completed by Hydro One. For the Residential and General Service < 50 kW classes, it is has been assumed in previous cost of service applications that these two classes are 100% weather sensitive. Intervenors expressed concern with this assumption and have suggested that 100% weather sensitivity is not appropriate. LPDL agrees with this position but also submits that the weather sensitivity for the Residential and GS < 50 kW classes should be higher than the GS > 50 kW class. As a result, LPDL has assumed the weather sensitivity for the Residential and General Service < 50 kW classes to be mid-way between 100% and 55.0%, or 77.5%.

The difference between the non-normalized and normalized forecast of 3.3 GWh in 2012 and 4.1 GWh in 2013 has been assigned on a *pro rata* basis to each rate class based on the above level of weather sensitivity.

In addition a manual adjustment has been made to reflect the impact of 2012 and 2013 CDM programs on the load forecast. This adjustment reflects the “gross” impact of 2012 and 2013 CDM programs on the load forecast. The gross impact includes the net results measured by the OPA plus an estimate of the average net to gross adjustment reflecting gross and net savings information provided in the OPA 2006-2010 Final CDM Results. The net results provide a measurement of the program effectiveness used to achieve the LDC targets. The gross results include the net results plus the estimated impact of customers participating in a program even if an incentive was not provided to participate. In the past this has been termed the level of “free ridership”. In other words, the gross results include the results from those who participated in the program because there was an incentive plus those who participated even if there was not an incentive. In LPDL’s view it is the gross level that impacts the load forecast.

Table 3.2.16 below outlines the average net to gross factor of 73.7% based on information provided in the OPA 2006-2010 Final CDM Results for LPDL.

Table 3.2.16 – Average Net to Gross Percentage

	OPA 2006-2010 Final CDM Results (Gross)	OPA 2006-2010 Final CDM Results (Net)	# Difference	% Difference of Net
2006	826,070	739,673	86,397	11.7%
2007	3,703,140	1,356,235	2,346,905	173.0%
2008	2,533,894	1,483,198	1,050,696	70.8%
2009	3,397,225	2,184,545	1,212,680	55.5%
2010	3,420,526	2,098,703	1,321,823	63.0%
2011	3,189,600	1,863,559	1,326,041	71.2%
2012	3,050,599	1,804,507	1,246,092	69.1%
2013	2,994,600	1,776,605	1,217,995	68.6%
Total	23,115,653	13,307,025	9,808,628	73.7%

As previously discussed the 2011 preliminary actual savings from 2011 CDM programs are known and has been used in the CDM activity variable included in the regression analysis supporting the prediction formula. However, knowing the 2011 results impacts on what savings will be needed from 2012 to 2014 programs in order to achieve the licensed 4 year CDM target. Based on the following Table 3.2.17, the 2011 preliminary actual savings will contribute 19.4% to the four year target. In Table 3.2.17 the 2011 results are consistent with the information provided in Table 3.2.5. The table indicates that assuming persistence, 2012 to 2014 programs will need to achieve 13.4% of the four year target each year in order to achieve the target.

Table 3.2.17 – Schedule to Achieve 4 Year kWh CDM Target

4 Year 2011 to 2014 kWh target					
10,180,000					
	2011	2012	2013	2014	Total
2011 Programs	4.9%	4.9%	4.9%	4.9%	19.4%
2012 Programs		13.4%	13.4%	13.4%	40.3%
2013 Programs			13.4%	13.4%	26.9%
2014 Programs				13.4%	13.4%
	4.9%	18.3%	31.7%	45.1%	100.0%
kWh					
2011 Programs	494,470	494,470	494,470	494,470	1,977,880
2012 Programs		1,367,020	1,367,020	1,367,020	4,101,060
2013 Programs			1,367,020	1,367,020	2,734,040
2014 Programs				1,367,020	1,367,020
	494,470	1,861,490	3,228,510	4,595,530	10,180,000

Table 3.2.17 above suggests that in 2012, the savings from 2012 will be 1,367,020 kWh on a net basis. However on a gross basis this amount would be 1,367,020 times 1.737 (i.e. the net to gross factor determined in Table 3.2.16) or 2,374,652 kWh. In LPDL's view, the 2012 load forecast

should be adjusted by 2,374,652 kWh to reflect CDM savings from 2012 programs. As discussed above in regards to the CDM Activity variable, the persistent savings from 2011 programs in 2012 have been reflected in the prediction formula.

Table 3.2.17 above also suggests that in 2013, the savings from 2012 and 2013 programs will be 1,367,020 kWh times two or 2,734,040 kWh on a net basis. However on a gross basis this amount would be 2,734,040 times 1.737 (i.e. the net to gross factor determined in table 3.2.16) or 4,749,305 kWh. In LPDL's view, the 2013 load forecast should be adjusted by 4,749,305 kWh to reflect CDM savings from 2012 and 2013 programs.

In accordance with the Guidelines for Electricity Distributor Conservation and Demand Management [EB-2012-0003], issued April 26, 2012, it is LPDL's understanding that as part of this application expected CDM savings in 2013 from 2011, 2012 and 2013 programs will need to be established for LRAM variance account purposes. It is also LPDL's understanding that the OPA will measure CDM results attributable to the four year targets on a net basis. Consistent with past practices, it is expected the net level of savings will be used for LRAM calculations. As a result, it is LPDL's view the units used for the 2013 LRAM variance account should also be on a net basis. Based on the net information in Table 3.2.17, LPDL expects to achieve 3,228,510 net kWh savings in 2013 from 2011 to 2013 CDM programs. For LRAM variance account purposes, the following Table 3.2.18 outlines how this expected savings has been allocated by rate class using the 2013 information from Table 3.2.14. The expected kW savings has also been provided for those classes billed distribution charges on a kW basis using the average kW/KWh factors from Table 3.2.21.

Table 3.2.18 – 2013 Expected Savings for LRAM Variance Account

	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL	Total
kWh	1,224,267	660,911	1,311,149	29,829	635	1,721	3,228,510
kW where applicable			3,250	82	1.8		3,333

Table 3.2.19 below outlines how the classes have been adjusted to align the non-normalized forecast with the normalized forecast and reflect the adjustments discussed above.

Table 3.2.19 – Alignment of Non-normal to Weather Normal Forecast

Year	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL	Total
Non-normalized Weather Billed Energy Forecast (GWh)							
2012 Non-Normalized Bridge	77.5	42.2	83.2	1.9	0.04	0.1	204.9
2013 Non-Normalized Test	77.3	41.7	82.8	1.9	0.04	0.1	203.8
Weather Adjustment (GWh)							
2012	1.4	0.8	1.1	0.0	0.00	0.0	3.3
2013	1.8	1.0	1.3	0.0	0.00	0.0	4.1
CDM Adjustment (GWh)							
2012	(0.9)	(0.5)	(1.0)	(0.0)	(0.00)	(0.0)	(2.4)
2013	(1.8)	(1.0)	(1.9)	(0.0)	(0.00)	(0.0)	(4.7)
Weather Normalized Billed Energy Forecast (GWh)							
2012 Normalized Bridge	78.0	42.5	83.3	1.9	0.04	0.1	205.8
2013 Normalized Test	77.3	41.7	82.2	1.8	0.04	0.1	203.1

Billed KW Load Forecast

There are three rate classes that charge volumetric distribution on a per kW basis. These include GS > 50 kW, Street Lighting and Sentinels. As a result, the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. The forecast of kW for these classes is based on a review of the historical ratio of kW to kWh and applying the average ratio to the forecasted kWh to produce the required kW.

Table 3.2.20 below outlines the annual demand units by applicable rate class.

Table 3.2.20 – Historical Annual kW per Applicable Rate Class

Year	GS>50	Street Lighting	Sentinels	Total
Billed Annual kW				
2002	208,333	5,146	116	213,595
2003	219,818	5,152	123	225,093
2004	224,392	5,152	118	229,662
2005	219,273	5,152	115	224,541
2006	228,996	5,153	115	234,265
2007	234,298	5,152	112	239,562
2008	226,242	5,111	111	231,464
2009	208,394	5,075	112	213,581
2010	203,586	5,075	112	208,773
2011	202,662	5,075	113	207,850

The following Table 3.2.21 illustrates the historical ratio of kW/kWh as well as the average ratio for 2002 to 2011.

Table 3.2.21 – Historical kW/kWh Ratio per Applicable Rate Class

Year	GS>50	Street Lighting	Sentinels
Ratio of kW to kWh			
2002	0.2384%	0.2839%	0.2770%
2003	0.2492%	0.2739%	0.2788%
2004	0.2501%	0.2724%	0.2787%
2005	0.2429%	0.2733%	0.2779%
2006	0.2543%	0.2733%	0.2781%
2007	0.2577%	0.2733%	0.2785%
2008	0.2493%	0.2730%	0.2778%
2009	0.2479%	0.2714%	0.2771%
2010	0.2464%	0.2714%	0.2753%
2011	0.2424%	0.2714%	0.2798%
Average 2002 to 2011	**0.2479%**	**0.2737%**	**0.2779%**

The average ratio was applied to the weather normalized billed energy forecast in Table 3.2.19 to provide the forecast of kW by rate class as shown below. The following Table 3.2.22 outlines the forecast of kW for the applicable rate classes.

Table 3.2.22 – kW Forecast by Applicable Rate Class

Year	GS>50	Street Lighting	Sentinels	Total
Predicted Billed kW				
2012 Normalized Bridge	**206,517**	**5,077**	**110**	**211,705**
2013 Normalized Test	**203,731**	**5,035**	**109**	**208,875**

Table 3.2.23 provides a summary of the billing determinants, by rate class that are used to develop the proposed rates.

Table 3.2.23 – Summary of Forecast

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Weather Normalized Bridge	2013 Weather Normalized Test
ACTUAL AND PREDICTED KWH PURCHASES						
Actual kWh Purchases		225,969,773	221,209,083	221,759,892		
Predicted kWh Purchases		225,718,107	222,087,698	220,852,773	224,791,599	224,468,613
% Difference of actual and predicted purchases		(0.1%)	0.4%	(0.4%)		
BILLING DETERMINANTS BY CLASS						
Residential						
Customers	7,562	7,637	7,728	7,880	7,971	8,063
kWh	87,300,000	80,642,283	79,053,122	77,622,641	77,994,771	77,259,128
GS<50						
Customers	1,549	1,549	1,553	1,568	1,579	1,591
kWh	49,500,000	43,415,770	42,988,016	42,681,473	42,493,682	41,707,732
GS>50						
Customers	96	100	100	101	102	103
kWh	86,900,000	84,055,244	82,607,939	83,596,624	83,315,486	82,191,734
kW	207,865	208,394	203,586	202,662	206,517	203,731
Sentinels						
Connections	42	44	45	45	44	44
kWh	40,000	40,502	40,765	40,399	39,762	39,125
kW	115	112	112	113	110	109
Street Lighting						
Connections	7	2,130	2,130	2,130	2,138	2,147
kWh	2,000,000	1,870,097	1,870,098	1,870,092	1,854,853	1,839,258
kW	5,336	5,075	5,075	5,075	5,077	5,035
USL						
Connections	45	43	41	40	38	35
kWh	200,000	166,421	141,736	131,903	118,321	106,109
Total of Above						
Customer/Connections	9,302	11,503	11,597	11,764	11,873	11,983
kWh	225,940,000	210,190,317	206,701,676	205,943,133	205,816,875	203,143,087
kW from applicable classes	213,316	213,581	208,773	207,850	211,705	208,875

MONTHLY DATA USED FOR REGRESSION ANALYSIS:

Appendix 3.2.A

	Purchased	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Spring Fall Flag	CDM Activity	Predicted Purchases
Jan-02	21,908,331	695.8	0	31	0	0	23,322,324
Feb-02	20,148,761	664.9	0	28	0	0	21,563,448
Mar-02	20,969,681	674.7	0	31	1	0	21,797,719
Apr-02	17,766,701	399.4	4.5	30	1	0	19,056,743
May-02	20,825,782	285.9	1.8	31	1	0	18,575,102
Jun-02	18,547,738	65	39.3	30	0	0	18,058,155
Jul-02	17,384,899	19.1	79.2	31	0	0	18,684,868
Aug-02	18,765,385	25.4	46.8	31	0	0	18,323,677
Sep-02	16,411,203	78	31.5	30	1	0	16,718,594
Oct-02	18,258,351	391.4	2.2	31	1	0	19,460,898
Nov-02	22,294,354	561.6	0	30	1	0	20,353,278
Dec-02	25,437,200	753.7	0	31	0	0	23,805,658
Jan-03	25,188,355	990.4	0	31	0	0	25,781,571
Feb-03	25,190,654	857.5	0	28	0	0	23,171,225
Mar-03	21,335,052	705	0	31	1	0	22,050,656
Apr-03	20,656,713	460.9	0	30	1	0	19,512,660
May-03	17,045,418	212.7	0	31	1	0	17,941,059
Jun-03	18,202,719	74.8	15.8	30	0	0	17,839,844
Jul-03	19,482,800	21.9	39	31	0	0	18,194,846
Aug-03	16,908,390	27.4	60.9	31	0	0	18,520,444
Sep-03	16,943,197	113.7	5.6	30	1	0	16,685,839
Oct-03	20,322,953	349.8	0	31	1	0	19,085,535
Nov-03	20,485,648	483.2	0	30	1	0	19,698,815
Dec-03	24,763,703	676.7	0	31	0	0	23,162,882
Jan-04	26,912,980	1041.1	0	31	0	0	26,204,802
Feb-04	23,010,120	746.8	0	29	0	0	22,747,439
Mar-04	21,186,267	592.8	0	31	1	0	21,114,038
Apr-04	20,811,086	395.9	0	30	1	0	18,970,056
May-04	17,703,744	236	5.5	31	1	0	18,205,802
Jun-04	18,630,601	110.4	15.2	30	0	0	18,129,361
Jul-04	18,377,788	21.5	45.2	31	0	0	18,270,687
Aug-04	16,251,149	69.8	28.4	31	0	0	18,459,330
Sep-04	17,555,997	88.4	17.9	30	1	0	16,631,725
Oct-04	17,049,627	310.8	0	31	1	0	18,759,973
Nov-04	18,914,623	485.2	0	30	1	0	19,715,510
Dec-04	25,696,904	801	0	31	0	0	24,200,507
Jan-05	25,525,629	486	0	31	0	0	21,570,966
Feb-05	21,267,840	737.4	0	28	0	0	22,168,660
Mar-05	22,180,291	746.4	0	31	1	0	22,396,252
Apr-05	17,775,417	381.2	0	30	1	0	18,847,344
May-05	17,093,478	252.2	0.4	31	1	0	18,275,903
Jun-05	17,852,363	33.5	76.8	30	0	0	18,274,115
Jul-05	18,659,467	14.8	87.8	31	0	0	18,758,803
Aug-05	18,371,689	13.2	59.8	31	0	0	18,387,858
Sep-05	16,706,530	78	12.6	30	1	0	16,477,222
Oct-05	17,757,743	279.7	6.7	31	1	0	18,585,924
Nov-05	19,413,517	491.1	0	30	1	0	19,764,762
Dec-05	23,443,598	785.6	0	31	0	0	24,071,952

	Purchased	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Spring Fall Flag	CDM Activity	Predicted Purchases
Jan-06	23,178,438	706.5	0	31	0	9,483	23,351,379
Feb-06	21,503,463	751.2	0	28	0	18,966	22,163,327
Mar-06	21,726,896	663.4	0	31	1	28,449	21,522,592
Apr-06	17,617,807	362.7	0	30	1	37,932	18,451,848
May-06	17,278,731	181.7	14	31	1	47,415	17,559,744
Jun-06	17,146,680	58.5	31.3	30	0	56,898	17,540,132
Jul-06	18,619,398	4.9	83.4	31	0	66,381	18,198,107
Aug-06	17,843,517	43.7	39.9	31	0	75,864	17,906,194
Sep-06	16,105,818	163.5	0.7	30	1	85,347	16,496,587
Oct-06	18,481,658	366.1	0	31	1	94,830	18,618,945
Nov-06	19,101,584	441.1	0	30	1	104,313	18,684,451
Dec-06	20,833,616	610	0	31	0	113,796	21,882,897
Jan-07	23,347,852	826.1	0	31	0	113,676	23,687,605
Feb-07	22,500,086	847.5	0	28	0	113,557	22,366,075
Mar-07	21,602,755	653.1	0	31	1	113,438	20,896,495
Apr-07	18,218,527	426.6	0	30	1	113,318	18,506,179
May-07	16,749,718	203.5	9.1	31	1	113,199	17,261,081
Jun-07	17,096,826	62.6	43	30	0	113,079	17,366,738
Jul-07	17,421,792	39.5	43.6	31	0	112,960	17,682,637
Aug-07	17,808,746	26.7	52.3	31	0	112,840	17,687,652
Sep-07	16,166,254	100.1	14.4	30	1	112,721	15,968,336
Oct-07	17,355,793	226.7	1.5	31	1	112,602	17,361,484
Nov-07	19,369,940	555.2	0	30	1	112,482	19,585,012
Dec-07	22,463,316	766.2	0	31	0	112,363	23,195,924
Jan-08	23,032,111	753.1	0	31	0	114,091	23,075,582
Feb-08	22,156,585	815.6	0	29	0	115,820	22,585,709
Mar-08	22,013,050	760.5	0	31	1	117,549	21,766,914
Apr-08	17,842,658	348.6	0	30	1	119,278	17,817,179
May-08	17,029,191	277.3	0	31	1	121,007	17,711,308
Jun-08	16,878,293	48.4	36.4	30	0	122,735	17,102,545
Jul-08	18,183,975	13.9	54.1	31	0	124,464	17,529,918
Aug-08	17,732,167	39.4	26	31	0	126,193	17,372,933
Sep-08	16,860,353	132.7	5.1	30	1	127,922	16,025,099
Oct-08	18,640,281	372.5	0	31	1	129,651	18,451,080
Nov-08	19,886,751	555.9	0	30	1	131,379	19,470,761
Dec-08	22,939,032	782.6	0	31	0	133,108	23,200,986
Jan-09	25,179,016	995.4	0	31	0	140,637	24,929,541
Feb-09	20,744,809	723.7	0	28	0	148,166	21,112,680
Mar-09	20,987,646	652.3	0	31	1	155,695	20,621,267
Apr-09	17,548,619	379.9	0	30	1	163,223	17,799,184
May-09	16,339,291	231	0	31	1	170,752	17,008,667
Jun-09	16,363,954	105.4	19.1	30	0	178,281	17,004,427
Jul-09	17,069,905	38.6	10.3	31	0	185,810	16,786,876
Aug-09	17,698,258	56.9	39.8	31	0	193,339	17,268,539
Sep-09	16,401,389	115.6	2.7	30	1	200,867	15,388,122
Oct-09	18,036,761	341.6	0	31	1	208,396	17,692,695
Nov-09	18,073,124	414.1	0	30	1	215,925	17,749,750
Dec-09	21,527,001	750.2	0	31	0	223,454	22,356,359

	Purchased	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Spring Fall Flag	CDM Activity	Predicted Purchases
Jan-10	23,172,597	839.2	0	31	0	215,983	23,146,789
Feb-10	20,395,977	647.5	0	28	0	208,512	20,093,075
Mar-10	18,966,083	427	0	31	1	201,041	18,452,338
Apr-10	15,876,110	287.3	0	30	1	193,570	16,833,327
May-10	16,780,450	151.6	22.9	31	1	186,099	16,540,784
Jun-10	15,920,655	66.2	12	30	0	178,627	16,584,319
Jul-10	18,247,719	13.1	95.7	31	0	171,156	17,757,779
Aug-10	18,196,813	25.9	61.1	31	0	163,685	17,470,232
Sep-10	16,287,609	143.1	17.5	30	1	156,214	16,090,473
Oct-10	17,018,502	318.6	0	31	1	148,743	17,879,800
Nov-10	18,275,778	398.8	0	30	1	141,272	18,096,459
Dec-10	22,070,790	776.1	0	31	0	133,801	23,142,322
Jan-11	23,225,566	891.9	0	31	0	143,447	24,047,688
Feb-11	20,579,135	650.9	0	28	0	153,094	20,473,646
Mar-11	20,876,532	574.8	0	31	1	162,740	19,929,541
Apr-11	17,445,769	400.5	0	30	1	172,387	17,912,914
May-11	16,194,222	154.9	10.1	31	1	182,033	16,430,700
Jun-11	15,886,340	57.7	13.4	30	0	191,679	16,448,297
Jul-11	17,258,128	2	83	31	0	201,326	17,311,197
Aug-11	18,380,514	15.9	38	31	0	210,972	16,791,230
Sep-11	16,097,698	109.1	17.5	30	1	220,618	15,397,353
Oct-11	16,772,439	290	0	31	1	230,265	17,122,974
Nov-11	18,043,769	432.4	0	30	1	239,911	17,750,079
Dec-11	20,999,780	636	0	31	0	249,557	21,237,154
Jan-12		823	0	31	0	240,638	22,851,111
Feb-12		744	0	29	0	231,719	21,253,963
Mar-12		645	0	31	1	222,799	20,133,869
Apr-12		384	0	30	1	213,880	17,519,731
May-12		219	6	31	1	204,960	16,769,903
Jun-12		68	30	30	0	196,041	16,723,582
Jul-12		19	62	31	0	187,122	17,276,261
Aug-12		34	45	31	0	178,202	17,247,399
Sep-12		112	13	30	1	169,283	15,686,425
Oct-12		325	1	31	1	160,364	17,870,321
Nov-12		482	0	30	1	151,444	18,725,179
Dec-12		734	0	31	0	142,525	22,733,856
Jan-13		823	0	31	0	149,714	23,428,945
Feb-13		744	0	28	0	156,904	21,229,113
Mar-13		645	0	31	1	164,093	20,506,954
Apr-13		384	0.45	30	1	171,283	17,790,443
May-13		219	6.38	31	1	178,472	16,938,241
Jun-13		68	30.23	30	0	185,661	16,789,546
Jul-13		19	62.13	31	0	192,851	17,239,851
Aug-13		34	45.3	31	0	200,040	17,108,615
Sep-13		112	12.55	30	1	207,230	15,445,267
Oct-13		325	1.04	31	1	214,419	17,526,789
Nov-13		482	0	30	1	221,609	18,279,273
Dec-13		734	0	31	0	228,798	22,185,576

OPERATING REVENUE VARIANCE ANALYSIS:

Throughput Revenue and Other Operating Revenue

Table 3.1.1 – Operating Revenue by Rate Class

Operating Revenue by Rate Class	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Residential	$ 2,578,659	$ 2,391,505	$ 2,500,355	$ 2,509,429	$ 2,880,363	$ 3,094,202
GS<50 kW	$ 1,082,654	$ 968,457	$ 1,026,828	$ 1,029,880	$ 1,131,929	$ 1,233,858
GS>50 kW	$ 852,391	$ 855,712	$ 827,995	$ 809,433	$ 830,690	$ 899,897
Sentinel	$ 3,269	$ 2,480	$ 3,945	$ 4,558	$ 4,481	$ 5,840
Street lighting	$ 141,987	$ 103,134	$ 171,002	$ 190,874	$ 199,001	$ 219,846
Unmetered Scattered Load	$ 11,677	$ 10,568	$ 10,150	$ 9,183	$ 9,113	$ 6,117
Throughput Revenue	$ 4,670,637	$ 4,331,857	$ 4,540,275	$ 4,553,357	$ 5,055,577	$ 5,459,761
Throughput revenue as % of Total Revenue	91.5%	91.0%	90.9%	91.4%	94.6%	94.6%
Revenue offsets	$ 435,076	$ 430,701	$ 454,293	$ 428,676	$ 288,796	$ 313,628
Total Revenue	$ 5,105,713	$ 4,762,558	$ 4,994,568	$ 4,982,033	$ 5,344,372	$ 5,773,389

Variance Analysis on Throughput Revenue

A summary of historical and forecast operating revenues is presented in Table 3.1.1. A variance analysis for the other net operating revenue will be provided further in Tab 3 Schedule 2 of this Exhibit.

2009 Board Approved

LPDL's operating revenue in 2009 Board Approved was $5,105,713 . Throughput revenue was $4,670,637 or 91.5% of total revenues. Other net operating revenue accounts for the remaining revenue of $435,076 .

2009 Actual

LPDL's operating revenue in fiscal 2009 was $4,762,558 . Throughput revenue was $4,331,857 or 91.0% of total revenues. Other net operating revenue accounts for the remaining revenue of $430,701 .

Table 3.3.1 – Comparison of 2009 Actual to 2009 Board Approved – Throughput Revenue

Operating Revenue by Rate Class	2009 Board Approved	2009 Actual	Difference $	Difference %
Residential	$ 2,578,659	$ 2,391,505	-$ 187,154	-7.3%
GS<50 kW	$ 1,082,654	$ 968,457	-$ 114,197	-10.5%
GS>50 kW	$ 852,391	$ 855,712	$ 3,321	0.4%
Sentinel	$ 3,269	$ 2,480	-$ 789	-24.1%
Street lighting	$ 141,987	$ 103,134	-$ 38,853	-27.4%
Unmetered Scattered Load	$ 11,677	$ 10,568	-$ 1,109	-9.5%
Total	$ 4,670,637	$ 4,331,857	-$ 338,780	-7.3%

Throughput revenue for 2009 was -7.3% or -$338,780 lower than the amounts approved in the 2009 EDR primarily due to lower kWh usage in the Residential and GS<50 kW classes. The load forecast utilized in the 2009 Cost of Service application did not contain any provision for CDM programs as historical data was not available. The actual results were lower than 2009 Board Approved predominately in Residential and GS<50 kW classes, an indication of the effect of the CDM programs, as these were targeted rate classes. In addition, the 2009 Forecast used historical data that included losses in the billed quantities in error. This would have led to an increase in the kWh consumption of approximately 5% higher than it should have been. This effect was only on the classes that are billed based on kWh, specifically Residential and GS<50 kW.

The timing difference between the 2009 Actual amounts, which are based on the fiscal year of January 1 to December 31, 2009, and the 2009 EDR amounts, which are based on the rate year of June 1, 2009 to April 30, 2010, also contribute to the variance, since the 2009 rates did not come into effect until July 2009.

Table 3.3.2 below compares the 2009 EDR Approved billing quantities to the 2009 Actual quantities.

Table 3.3.2 – Comparison of 2009 Actual Billing Quantities to 2009 Board Approved Quantities

Billing Quantities by Rate Class	2009 Board Approved	2009 Actual	Difference	2009 Board Approved	2009 Actual	2009 Board Approved	2009 Actual	Volumetric Difference
	Customer/Connection			kWh		kW		
Residential	7,562	7,637	75	87,027,546	80,642,283	-	-	- 6,385,263
GS<50 kW	1,549	1,549	-	49,211,450	43,415,770	-	-	- 5,795,680
GS>50 kW	97	100	3	-	-	209,041	208,394	- 647
Sentinel	42	44	2	-	-	115	112	- 3
Street lighting	2,058	2,130	72	-	-	5,336	5,075	- 261
Unmetered Scattered Load	45	43	- 2	249,040	166,421	-	-	- 82,619
Total	11,353	11,503	150	136,488,036	124,224,474	214,492	213,581	

2010 Actual

LPDL's operating revenue in fiscal 2010 was $4,994,568 , as shown in Table 3.1.1 above. Throughput revenue totaled $4,540,275 or 90.9% of total revenues. Other net operating revenue accounts for the remaining revenue of $454,293 .

Table 3.3.3 - Comparison of 2010 Actual to 2009 Actual – Throughput Revenue

Operating Revenue by Rate Class	2009 Actual	2010 Actual	Difference	Difference
Residential	$ 2,391,505	$ 2,500,355	$ 108,851	4.6%
GS<50 kW	$ 968,457	$ 1,026,828	$ 58,371	6.0%
GS>50 kW	$ 855,712	$ 827,995	-$ 27,718	-3.2%
Sentinel	$ 2,480	$ 3,945	$ 1,465	59.1%
Street lighting	$ 103,134	$ 171,002	$ 67,868	65.8%
Unmetered Scattered Load	$ 10,568	$ 10,150	-$ 418	-4.0%
Total	$ 4,331,857	$ 4,540,275	$ 208,419	4.8%

The 2010 throughput revenue was $208,419 or 4.8% higher than the 2009 actual revenue. The increased revenue from Residential, GS<50 kW and Street lighting customer classes was slightly offset by reductions in the GS>50 kW class. Despite usage and load reductions for the Residential and General Service classes, revenue increased for all rate classes due to timing differences between the fiscal and rate year periods, as January 1, 2010 to April 30, 2010 reflected the full impact of the 2009 EDR rate increase with IRM adjustments reflected between May 1, 2010 and December 31, 2010.

Table 3.3.4 – Comparison of 2010 Actual Billing Quantities to 2009 Actual Quantities

Billing Quantities by Rate Class	2009 Actual	2010 Actual	Difference	2009 Actual	2010 Actual	2009 Actual	2010 Actual	Volumetric Difference
	Customer/Connection			kWh		kW		
Residential	7,637	7,728	91	80,642,283	79,053,122	-		- 1,589,161
GS<50 kW	1,549	1,553	4	43,415,770	42,988,016	-		- 427,754
GS>50 kW	100	100	-	-		208,394	203,586	- 4,808
Sentinel	44	45	1	-		112	112	-
Street lighting	2,130	2,130	-	-		5,075	5,075	-
Unmetered Scattered Load	43	41	- 2	166,421	141,736	-		- 24,685
Total	11,503	11,597	94	124,224,474	122,182,874	213,581	208,773	

2011 Actual

LPDL's operating revenue in fiscal 2011 was $4,982,033 , as shown in Table 3.1.1. Throughput revenue totaled $4,553,357 or 91.4% of total revenues. Other net operating revenue accounts for the remaining revenue of $428,676 .

Table 3.3.5 - Comparison of 2011 Actual to 2010 Actual - Throughput Revenue

Operating Revenue by Rate Class	2010 Actual	2011 Actual	Difference	Difference
Residential	$ 2,500,355	$ 2,509,429	$ 9,073	0.4%
GS<50 kW	$ 1,026,828	$ 1,029,880	$ 3,052	0.3%
GS>50 kW	$ 827,995	$ 809,433	-$ 18,562	-2.2%
Sentinel	$ 3,945	$ 4,558	$ 613	15.5%
Street lighting	$ 171,002	$ 190,874	$ 19,872	11.6%
Unmetered Scattered Load	$ 10,150	$ 9,183	-$ 967	-9.5%
Total	$ 4,540,275	$ 4,553,357	$ 13,081	0.3%

Throughput revenue in 2011 was 0.3% or $13,081 higher than in 2010 due to the 2011 IRM rate changes effective May 1, 2011 offset by the slight decline in volume in all classes. The decline was likely a result of the economic recession-like conditions in the area.

Table 3.3.6 - Comparison of 2011 Actual Billing Quantities to 2010 Actual Quantities

Billing Quantities by Rate Class	2010 Actual	2011 Actual	Difference	2010 Actual	2011 Actual	2010 Actual	2011 Actual	Volumetric Difference
	Customer/Connection			kWh		kW		
Residential	7,728	7,880	152	79,053,122	77,622,641	-		- 1,430,481
GS<50 kW	1,553	1,568	15	42,988,016	42,681,473	-		- 306,543
GS>50 kW	100	101	1	-		203,586	202,662	- 924
Sentinel	45	45	-	-		112	113	1
Street lighting	2,130	2,130	-	-		5,075	5,075	-
Unmetered Scattered Load	41	40	- 1	141,736	131,903	-		- 9,833
Total	11,597	11,764	167	122,182,874	120,436,017	208,773	207,850	

2012 Bridge Year

LPDL's operating revenue is forecast to be $5,344,372 in 2012 Bridge Year as shown in Table 3.1.1. Throughput revenue totals $5,055,577 or 94.6% of total revenues. Other net operating revenue accounts for the remaining revenue of $288,796 .

Table 3.3.7 - Comparison of 2012 Bridge to 2011 Actual - Throughput Revenue

Operating Revenue by Rate Class	2011 Actual	2012 Bridge	Difference	Difference
Residential	$ 2,509,429	$ 2,880,363	$ 370,934	14.8%
GS<50 kW	$ 1,029,880	$ 1,131,929	$ 102,049	9.9%
GS>50 kW	$ 809,433	$ 830,690	$ 21,257	2.6%
Sentinel	$ 4,558	$ 4,481	-$ 77	-1.7%
Street lighting	$ 190,874	$ 199,001	$ 8,127	4.3%
Unmetered Scattered Load	$ 9,183	$ 9,113	-$ 70	-0.8%
Total	$ 4,553,357	$ 5,055,577	$ 502,220	11.0%

Total throughput operating revenue is forecast to be 11.0% or $502,220 higher than the 2011 amounts. The Residential class accounts for most of the increase both through volume and customer growth as well as a full year of higher rates than in 2011, which is a blend of 2010 and 2011 rates. Included in the above is the SMIRR (Smart Meter Incremental Revenue Requirement) for 2012, a value of $ 416,106, which accounts for most of the increase in both Residential and GS<50 kW rate classes.

Table 3.3.8 - Comparison of 2012 Forecast Billing Quantities to 2011 Actual Quantities

Billing Quantities by Rate Class	2011 Actual	2012 Bridge	Difference	2011 Actual	2012 Bridge	2011 Actual	2012 Bridge	Volumetric Difference
	Customer/Connection			kWh		kW		
Residential	7,880	7,971	91	77,622,641	77,994,771	-		372,130
GS<50 kW	1,568	1,579	11	42,681,473	42,493,682	-		- 187,791
GS>50 kW	101	102	1	-		202,662	206,517	3,855
Sentinel	45	44	- 1	-		113	110	- 3
Street lighting	2,130	2,138	8	-		5,075	5,077	2
Unmetered Scattered Load	40	38	- 2	131,903	118,321	-		- 13,582
Total	11,764	11,872	108	120,436,017	120,606,774	207,850	211,704	

2013 Test Year

LPDL's 2013 Test Year operating revenue is forecast to be $5,773,389 as shown in Table 3.1.1. Throughput revenue totals $5,459,761 or 94.6% of total revenues. Other operating revenue (net), accounts for the remaining revenue of $313,628 .

Table 3.3.9 - Comparison of 2013 Test Year to 2012 Bridge Year - Throughput Revenue

Operating Revenue by Rate Class	2012 Bridge	2013 Test	Difference	Difference
Residential	$ 2,880,363	$ 3,094,202	$ 213,840	7.4%
GS<50 kW	$ 1,131,929	$ 1,233,858	$ 101,929	9.0%
GS>50 kW	$ 830,690	$ 899,897	$ 69,207	8.3%
Sentinel	$ 4,481	$ 5,840	$ 1,358	30.3%
Street lighting	$ 199,001	$ 219,846	$ 20,845	10.5%
Unmetered Scattered Load	$ 9,113	$ 6,117	-$ 2,995	-32.9%
Total	$ 5,055,577	$ 5,459,761	$ 404,184	8.0%

Total throughput revenue is forecast to be $404,184 or 8.0% higher than the 2012 Bridge year. This variance is due to increased revenue resulting from this rate application.

Table 3.3.10 - Comparison of 2013 Test Year Forecast Billing Quantities to 2012 Bridge Year Forecast Quantities

Billing Quantities by Rate Class	2012 Bridge	2013 Test	Difference	2012 Bridge	2013 Test	2012 Bridge	2013 Test	Volumetric Difference
	Customer/Connection			kWh		kW		
Residential	7,971	8,063	92	77,994,771	77,259,128	-		- 735,643
GS<50 kW	1,579	1,591	12	42,493,682	41,707,732	-		- 785,950
GS>50 kW	102	103	1	-		206,517	203,731	- 2,786
Sentinel	44	44	-	-		110	109	- 1
Street lighting	2,138	2,147	9	-		5,077	5,035	- 42
Unmetered Scattered Load	38	35	- 3	118,321	106,109	-		- 12,212
Total	11,872	11,983	111	120,606,774	119,072,969	211,704	208,875	

TRANSFORMER ALLOWANCE:

LPDL currently provides a Transformer Ownership Allowance Credit of $.60/kW to those customers that own their own transformer facilities. LPDL is proposing to maintain this rate for the 2013 Test Year for eligible customers.

OTHER REVENUE VARIANCE ANALYSIS:

Table 3.3.11 – Breakdown of Other Revenue by USofA Number by Year

USoA #	USoA Description	2009 BA	2009 Actual	2010 Actual	2011 Actual[2]	Bridge Year[3]	Bridge Year[3]	Test Year
						2012	2012	2013
	Reporting Basis					CGAAP	MIFRS	MIFRS
4235	**Specific Service Charges**	$ 86,522	$ 53,211	$ 56,418	$ 54,578	$ 55,000	$ 55,000	$ 55,000
4225	**Late Payment Charges**	$ 122,814	$ 78,645	$ 77,869	$ 78,974	$ 78,000	$ 78,000	$ 78,000
4080	**SSS Admin Charge**	$ 28,000	$ 28,611	$ 29,133	$ 30,099	$ 29,223	$ 29,223	$ 29,521
4210	Rent from Electric Property	$ 110,000	$ 106,523	$ 105,875	$ 104,188	$ 105,000	$ 105,000	$ 105,000
4355	Gain on Disposal		$ 14,274	$ 13,274	$ -	$ 10,000	$ 10,000	$ 15,000
4362	Loss on Retirement		$ -	$ -	$ -	$ -	-$ 75,429	-$ 57,782
4375	Revenues from Non-Utility	$ 15,500	$ 51,159	$ 409,084	$ 256,159	$ 250,000	$ 250,000	$ 250,000
4380	Expenses from Non-Utility		-$ 20,001	-$ 340,950	-$ 207,363	-$ 230,000	-$ 230,000	-$ 230,000
4390	Misc Non-Operating Income	$ 44,500	$ 81,692	$ 81,157	$ 63,853	$ 47,000	$ 47,000	$ 48,880
4405	Interest and Dividend Income	$ 27,740	$ 36,587	$ 22,433	$ 48,188	$ 20,000	$ 20,000	$ 20,000
Specific Service Charges		$ 86,522	$ 53,211	$ 56,418	$ 54,578	$ 55,000	$ 55,000	$ 55,000
Late Payment Charges		$ 122,814	$ 78,645	$ 77,869	$ 78,974	$ 78,000	$ 78,000	$ 78,000
Other Operating Revenues		$ 138,000	$ 135,134	$ 135,008	$ 134,287	$ 134,223	$ 134,223	$ 134,521
Other Income or Deductions		$ 87,740	$ 163,711	$ 184,998	$ 160,837	$ 97,000	$ 21,571	$ 46,098
Total		$ 435,076	$ 430,701	$ 454,293	$ 428,676	$ 364,223	$ 288,794	$ 313,619

Table 3.3.12 – Breakdown of Types of Revenue within Accounts by Year

Account 4210 - Rent from Electric Property

	2009 Bd Approv	2009 Actual	2010 Actual	2011 Actual[2]	2012	2012	2013
Reporting Basis					**CGAAP**	**MIFRS**	**MIFRS**
Joint Use Pole rental	$ 104,000	$ 100,523	$ 99,875	$ 98,188	$ 99,000	$ 99,000	$ 99,000
Rental of storage building	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000
Total	$ 110,000	$ 106,523	$ 105,875	$ 104,188	$ 105,000	$ 105,000	$ 105,000

Account 4355 - Gain on Disposal

	2009 Bd Approv	2009 Actual	2010 Actual	2011 Actual[2]	2012	2012	2013
Reporting Basis					**CGAAP**	**MIFRS**	**MIFRS**
Gain on sale of vehicle		$ 14,274	$ 13,274	$ -	$ 10,000	$ 10,000	$ 15,000
Total	$ -	$ 14,274	$ 13,274	$ -	$ 10,000	$ 10,000	$ 15,000

Account 4362 - Loss from Retirement of Utility and Other Property

	2009 Bd Approv	2009 Actual	2010 Actual	2011 Actual[2]	2012	2012	2013
Reporting Basis					**CGAAP**	**MIFRS**	**MIFRS**
Aging assets replacement		$ -	$ -	$ -	$ -	-$ 20,114	-$ 14,572
PCB transformer replacement		$ -	$ -	$ -	$ -	-$ 14,567	$ -
Removal of non-compliant meters		$ -	$ -	$ -	$ -	-$ 40,748	-$ 43,210
Total	$ -	$ -	$ -	$ -	$ -	-$ 75,429	-$ 57,782

Account 4375 - Revenues from Non-Utility Operations

	2009 Bd Approv	2009 Actual	2010 Actual	2011 Actual[2]	2012	2012	2013
Reporting Basis					**CGAAP**	**MIFRS**	**MIFRS**
CDM Revenues from OPA & Incentives		$ -	$ 346,833	$ 219,371	$ 235,000	$ 235,000	$ 235,000
Streetlight Maintenance	$ 15,500	$ 51,159	$ 38,554	$ 27,070	$ 15,000	$ 15,000	$ 15,000
Staff on loan to CUPE			$ 23,697				
Staff assisting other LDCs	$ -	$ -	$ -	$ 9,718			
Total	$ 15,500	$ 51,159	$ 409,084	$ 256,159	$ 250,000	$ 250,000	$ 250,000

Account 4380 - Expenses from Non-Utility Operations

	2009 Bd Approv	2009 Actual	2010 Actual	2011 Actual[2]	2012	2012	2013
Reporting Basis					**CGAAP**	**MIFRS**	**MIFRS**
CDM Program Expenses		$ -	-$ 291,498	-$ 187,278	-$ 222,000	-$ 222,000	-$ 222,000
Streetlight Maintenance - wages		-$ 20,001	-$ 25,999	-$ 14,389	-$ 8,000	-$ 8,000	-$ 8,000
Staff on loan to CUPE - wages			-$ 23,453				
Staff assisting other LDCs - wages	$ -	$ -	$ -	-$ 5,696			
Total	$ -	-$ 20,001	-$ 340,950	-$ 207,363	-$ 230,000	-$ 230,000	-$ 230,000

Account 4390 - Misc Non-Operating Income

	2009 Bd Approv	2009 Actual	2010 Actual	2011 Actual[2]	2012	2012	2013
Reporting Basis					**CGAAP**	**MIFRS**	**MIFRS**
Charge for interval data access	$ 14,500	$ 15,361	$ 15,361	$ 16,715	$ 17,640	$ 17,640	$ 17,880
Additional charge on MicroFit connection				$ 20,310			
Admin charge on service layouts, new conn	$ 30,000	$ 66,331	$ 65,796	$ 26,828	$ 29,360	$ 29,360	$ 31,000
etc.[1]							
Total	$ 44,500	$ 81,692	$ 81,157	$ 63,853	$ 47,000	$ 47,000	$ 48,880

Account 4405 - Interest and Dividend Income

	2009 Bd Approv	2009 Actual	2010 Actual	2011 Actual[2]	2012	2012	2013
Reporting Basis					**CGAAP**	**MIFRS**	**MIFRS**
Short-term Investment Interest		$ -	$ -	$ -	$ -	$ -	$ -
Bank Deposit Interest	$ 5,000	$ 4,867	$ 1,966	$ 551	$ -	$ -	$ -
Miscellaneous Interest Revenue							
Carrying charges on Reg Assets	$ 22,740	$ 31,720	$ 20,467	$ 47,637	$ 20,000	$ 20,000	$ 20,000
Total	$ 27,740	$ 36,587	$ 22,433	$ 48,188	$ 20,000	$ 20,000	$ 20,000

Table 3.3.13 - 2009 Board Approved Comparison to 2009 Actual – Other Operating Revenue

Operating Revenue by Rate Class	2009 Board Approved	2009 Actual	Difference $	Difference %
Specific Service Charges	$ 86,522	$ 53,211	-$ 33,311	-38.5%
Late Payment Charges	$ 122,814	$ 78,645	-$ 44,169	-36.0%
SSS Admin Charge	$ 28,000	$ 28,611	$ 611	2.2%
Rent from Electric Property	$ 110,000	$ 106,523	-$ 3,477	-3.2%
Gain/Loss on Disposal/Retirement	$ -	$ 14,274	$ 14,274	
Net Revenues from Non-Utility	$ 15,500	$ 31,158	$ 15,658	101.0%
Misc Non-operating income	$ 44,500	$ 81,692	$ 37,192	83.6%
Interest & Dividend Income	$ 27,740	$ 36,587	$ 8,847	31.9%
Total	$ 435,076	$ 430,701	-$ 4,375	-1.0%

Table 3.3.14 - 2010 Actual Comparison to 2009 Actual – Other Operating Revenue

Operating Revenue by Rate Class	2009 Actual	2010 Actual	Difference	Difference
Specific Service Charges	$ 53,211	$ 56,418	$ 3,207	6.0%
Late Payment Charges	$ 78,645	$ 77,869	-$ 776	-1.0%
SSS Admin Charge	$ 28,611	$ 29,133	$ 522	1.8%
Rent from Electric Property	$ 106,523	$ 105,875	-$ 648	-0.6%
Gain/Loss on Disposal/Retirement	$ 14,274	$ 13,274	-$ 1,000	-7.0%
Net Revenues from Non-Utility	$ 31,158	$ 68,134	$ 36,976	118.7%
Misc Non-operating income	$ 81,692	$ 81,157	-$ 535	-0.7%
Interest & Dividend Income	$ 36,587	$ 22,433	-$ 14,154	-38.7%
Total	$ 430,701	$ 454,293	$ 23,592	5.5%

2010 other operating revenue was higher than 2009 by $23,592 predominately due to revenue from CDM activities, specifically incentives from OPA which are part of non-utility revenues.

Table 3.3.15 - 2011 Actual Comparison to 2010 Actual – Other Operating Revenue

Operating Revenue by Rate Class	2010 Actual	2011 Actual	Difference	Difference
Specific Service Charges	$ 56,418	$ 54,578	-$ 1,840	-3.3%
Late Payment Charges	$ 77,869	$ 78,974	$ 1,105	1.4%
SSS Admin Charge	$ 29,133	$ 30,099	$ 966	3.3%
Rent from Electric Property	$ 105,875	$ 104,188	-$ 1,687	-1.6%
Gain/Loss on Disposal/Retirement	$ 13,274	$ -	-$ 13,274	-100.0%
Net Revenues from Non-Utility	$ 68,134	$ 48,796	-$ 19,338	-28.4%
Misc Non-operating income	$ 81,157	$ 63,853	-$ 17,304	-21.3%
Interest & Dividend Income	$ 22,433	$ 48,188	$ 25,755	114.8%
Total	$ 454,293	$ 428,676	-$ 25,617	-5.6%

In 2010 there was a disposal of a truck that resulted in a gain on disposal of $13,274 that 2011 did not have.

Table 3.3.16 - 2012 Bridge Year Comparison to 2011 Actual – Other Operating Revenue

Operating Revenue by Rate Class	2011 Actual	2012 Bridge (CGAAP)	Difference	Difference
Specific Service Charges	$ 54,578	$ 55,000	$ 422	0.8%
Late Payment Charges	$ 78,974	$ 78,000	-$ 974	-1.2%
SSS Admin Charge	$ 30,099	$ 29,223	-$ 876	-2.9%
Rent from Electric Property	$ 104,188	$ 105,000	$ 812	0.8%
Gain/Loss on Disposal/Retirement	$ -	$ 10,000	$ 10,000	
Net Revenues from Non-Utility	$ 48,796	$ 20,000	-$ 28,796	-59.0%
Misc Non-operating income	$ 63,853	$ 47,000	-$ 16,853	-26.4%
Interest & Dividend Income	$ 48,188	$ 20,000	-$ 28,188	-58.5%
Total	$ 428,676	$ 364,223	-$ 64,453	-15.0%

2012 other operating revenue is lower than 2011 on a CGAAP basis by -$64,453 . Non-utility revenue consisting predominately of incentives for CDM program administration is currently lower with the new 2011-2014 programs.

Table 3.3.17 - 2013 Test Year Comparison to 2012 Bridge Year – Other Operating Revenue

Operating Revenue by Rate Class	2012 Bridge (MIFRS)	2013 Test (MIFRS)	Difference	Difference
Specific Service Charges	$ 55,000	$ 55,000	$ -	0.0%
Late Payment Charges	$ 78,000	$ 78,000	$ -	0.0%
SSS Admin Charge	$ 29,223	$ 29,521	$ 298	1.0%
Rent from Electric Property	$ 105,000	$ 105,000	$ -	0.0%
Gain/Loss on Disposal/Retirement	-$ 65,429	-$ 42,782	$ 22,647	-34.6%
Net Revenues from Non-Utility	$ 20,000	$ 20,000	$ -	0.0%
Misc Non-operating income	$ 47,000	$ 48,880	$ 1,880	4.0%
Interest & Dividend Income	$ 20,000	$ 20,000	$ -	0.0%
Total	$ 288,794	$ 313,619	$ 24,825	8.6%

2012 other operating revenue on a MIFRS basis is lower than 2012 on a CGAAP basis due to the identification of disposed assets throughout the year. Previously LPDL utilized pooled asset accounting and as such did not identify specific assets or their specific disposal. With the implementation of IFRS, LPDL is now able to identify specific assets and there current value in order to dispose of them correctly in the financial records. 2012 contains a loss on retirement of

-$75,429 and 2013 contains a loss on retirement of -$57,782 . The specific items are identified in Exhibit 2 in the discussion on capital projects.

OVERVIEW:

MANAGER'S SUMMARY OF OPERATING COSTS:

The operating costs presented in this Exhibit represent the annual expenditures required to sustain LPDL's distribution operations. LPDL follows the OEB's Accounting Procedures Handbook (the "APH") in distinguishing work performed between operations and maintenance. Historically LPDL has followed the Canadian Generally Accepted Accounting Principles (CGAAP) in preparation of its financial statements. As stated through this application, LPDL will be converting to International Financial Reporting Standards (IFRS) in 2013 and has prepared this application under modified IFRS (MIFRS). For clarity and ease of comparison to historical data, this Exhibit presents all information as 2012 Bridge Year in both CGAAP and MIFRS, then 2013 Test Year under MIFRS. At the end of this Exhibit, under Tab 4, the 2012 Bridge and 2013 Test years will be presented under MIFRS with full explanation of changes from CGAAP. Under MIFRS, there is no impact on OM&A however, there are changes due to useful live extensions giving rise to changes in depreciation and tax calculations.

LPDL has not included any one-time or non-regulatory expenses in the 2012 Bridge Year and 2013 Test Year. LPDL's audited financial statements for the years 2009, 2010 and 2011 included charitable contributions as well as a contra account for Smart Meter costs (5695). For costs related to the cost of service application, LPDL has handled this one-time cost by taking ¼ each year until the next rebasing year.

In order to provide a useful comparison to historical data these non-regulatory/one-time expenses have been removed from OM&A as illustrated in Table 4.1.1.

Table 4.1.1 - OM&A Reconciliation to Audited Financial Statements

	Last Rebasing Year (Approved)	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual[2]
OM&A on Financial Statements	$ 2,846,013	$ 2,872,034	$ 2,973,873	$ 2,830,741
5681 - Special Purpose Charge Expense	$ -	$ -	$ -	$ -
6205 - Donations (not including LEAP)	$ -	$ -	$ -	$ 2,913
5695 OM&A Contra Account for Smart Meter OM&A costs	$ -	-$ 95,447	-$ 166,182	-$ 71,609
5330 - Collection charges (included in Other Income)	$ -	$ 30,030	$ 33,965	$ 14,970
4380 - Expenses of Non-utility Operations (included in Operation)	$ -	$ 17,435	$ -	$ -
Total	**$ 2,846,013**	**$ 2,920,016**	**$ 3,106,090**	**$ 2,884,467**

A summary of LPDL's operating costs for 2009 Board Approved, 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year (CGAAP and MIFRS are the same) and the 2013 Test Year (MIFRS) is provided in Table 4.1.2 below. LPDL does not currently and has not in the past capitalized overheads. Consequently, no changes to LPDL's OM&A expenses would result from the transition from CGAAP to MIFRS.

Table 4.1.2 – Summary of OM&A Expenses

	Last Rebasing Year (2009 BA)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Operations	$ 223,674	$ 196,371	$ 164,974	$ 156,712	$ 207,888	$ 197,000
Maintenance	$ 927,043	$ 832,493	$ 764,547	$ 808,995	$ 900,185	$ 921,046
Billing and Collecting	$ 655,137	$ 644,517	$ 798,870	$ 650,758	$ 783,034	$ 798,025
Community Relations	$ 11,255	$ 25,980	$ 32,988	$ 20,952	$ 21,000	$ 21,000
Administrative and General	$ 1,028,905	$ 1,220,654	$ 1,344,710	$ 1,247,050	$ 1,356,507	$ 1,379,756
Total	**$ 2,846,013**	**$ 2,920,016**	**$ 3,106,089**	**$ 2,884,467**	**$ 3,268,614**	**$ 3,316,827**
%Change (year over year)			6.4%	-7.1%	13.3%	1.5%

LPDL is proposing recovery of 2013 Test Year OM&A costs, excluding amortization, property taxes, PILs and Interest totaling $3,316,827 . This is a 10% increase over 2011 actuals when the cost of Smart Meters ($126 K) is excluded since the cost of smart meters has already been approved in EB-2011-0413 (15% when Smart Meter cost included), and 12% over 2009 Board Approved values without Smart Meter costs.

A summary of the Recoverable OM&A variances, as required by the Filing Requirements, is provided in Tables 4.1.3 and 4.1.4**.** As noted above, no changes to the OM&A expenses are made on the transition from CGAAP to MIFRS.

Table 4.1.3 - Summary of Recoverable OM&A Expenses 2009 Board Approved to 2013 Test Year

	Last Rebasing Year (2009 BA)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS
Operations	$ 223,674	$ 196,371	$ 164,974	$ 156,712	$ 207,888	$ 197,000
Maintenance	$ 927,043	$ 832,493	$ 764,547	$ 808,995	$ 900,185	$ 921,046
SubTotal	**$ 1,150,717**	**$ 1,028,865**	**$ 929,521**	**$ 965,707**	**$ 1,108,073**	**$ 1,118,046**
%Change (year over year)			-9.7%	3.9%	14.7%	0.9%
%Change (Test Year vs Last Rebasing Year - Actual)						8.7%
Billing and Collecting	$ 655,137	$ 644,517	$ 798,870	$ 650,758	$ 783,034	$ 798,025
Community Relations	$ 11,255	$ 25,980	$ 32,988	$ 20,952	$ 21,000	$ 21,000
Administrative and General	$ 1,028,905	$ 1,220,654	$ 1,344,710	$ 1,247,050	$ 1,356,507	$ 1,379,756
SubTotal	**$ 1,695,296**	**$ 1,891,151**	**$ 2,176,568**	**$ 1,918,760**	**$ 2,160,541**	**$ 2,198,781**
%Change (year over year)			15.1%	-11.8%	12.6%	1.8%
%Change (Test Year vs Last Rebasing Year - Actual)						16.3%
Total	**$ 2,846,013**	**$ 2,920,016**	**$ 3,106,089**	**$ 2,884,467**	**$ 3,268,614**	**$ 3,316,827**
%Change (year over year)			6.4%	-7.1%	13.3%	1.5%

Table 4.1.4 - Summary of OM&A Expense Variances 2009 Board Approved to 2013 Test Year

	Last Rebasing Year (2009 BA)	Last Rebasing Year (2009 Actuals)	Variance 2009 BA – 2009 Actuals	2010 Actuals	Variance 2010 Actuals vs. 2009 Actuals	2011 Actuals	Variance 2011 Actuals vs. 2010 Actuals	2012 Bridge Year	Variance 2012 Bridge vs. 2011 Actuals	2013 Test Year	Variance 2013 Test vs. 2012 Bridge
Operations	$ 223,674	$ 196,371	$ 27,303	$ 164,974	-$ 31,398	$ 156,712	-$ 8,262	$ 207,888	$ 51,176	$ 197,000	-$ 10,888
Maintenance	$ 927,043	$ 832,493	$ 94,550	$ 764,547	-$ 67,946	$ 808,995	$ 44,447	$ 900,185	$ 91,190	$ 921,046	$ 20,861
Billing and Collecting	$ 655,137	$ 644,517	$ 10,620	$ 798,870	$ 154,354	$ 650,758	-$ 148,112	$ 783,034	$ 132,276	$ 798,025	$ 14,991
Community Relations	$ 11,255	$ 25,980	-$ 14,725	$ 32,988	$ 7,008	$ 20,952	-$ 12,036	$ 21,000	$ 48	$ 21,000	$ -
Administrative and General	$ 1,028,905	$ 1,220,654	-$ 191,750	$ 1,344,710	$ 124,056	$ 1,247,050	-$ 97,660	$ 1,356,507	$ 109,457	$ 1,379,756	$ 23,249
Total OM&A Expenses	$ 2,846,013	$ 2,920,016	-$ 74,003	$ 3,106,089	$ 186,074	$ 2,884,467	-$ 221,623	$ 3,268,614	$ 384,147	$ 3,316,827	$ 48,213
Variance from previous year				$ 186,074		-$ 221,623		$ 384,147		$ 48,213	
Percent change (year over year)				6%		-7%		13%		1%	
Percent Change: Test year vs. Most Current Actual						14.99%					
Simple average of % variance for all years						13.59%					4%
Compound Annual Growth Rate for all years											3.9%
Compound Growth Rate (2011 Actuals vs. 2009 Actuals)						-1.22%					

Table 4.1.5 below sets out the OM&A cost per customer and Full Time equivalent employees.

Table 4.1.5 – OM&A Per Customer and FTE

	Last Rebasing Year (2009 Board-Approved)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
Number of Customers	9,215	9,286	9,381	9,549	9,653	9,757
Total Recoverable OM&A from Appendix 2-I	$ 2,846,013	$ 2,920,016	$ 3,106,089	$ 2,884,467	$ 3,268,614	$ 3,316,827
OM&A cost per customer	$ 308.85	$ 314.45	$ 331.10	$ 302.07	$ 338.63	$ 339.94
Number of FTEEs	18.6	16.6	16.7	15.6	17.9	17.9
Customers/FTEEs	494.13	559.40	561.42	611.72	539.25	545.09
OM&A Cost per FTEE	152,609.54	175,904.56	185,889.81	184,783.25	182,604.13	185,297.60

The number of customers for the years 2009, 2010 and 2011 include the average number of residential, GS<50 and GS>50 customers in each year. The number of customers for the years 2012 and 2013 include the residential, GS<50 and GS>50 customers as found in LPDL's Load Forecast as set out in Exhibit 3.

The number of FTEEs includes both full time and part time employees. The part time employee calculation is based on the actual number of hours worked during the year vs. the number of hours a full time employee worked in each year.

Detailed information with respect to OM&A costs and drivers, arranged by USofA account, is provided in Exhibit 4, Tab 2, Schedule 2. Detailed information with respect to OM&A variances, arranged by USofA account, is provided in Exhibit 4, Tab 2, Schedule 3.

The variance used to determine the OM&A accounts requiring analysis as prescribed by the Filing Requirements, is $50,000 for a distributor with a distribution revenue requirement of less than or equal to $10 million. As LPDL's distribution revenue requirement is less than $10 million, details of variances over $50,000 will be provided.

OM&A COSTS

OM&A costs in this Exhibit represent LPDL'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. OM&A costs also include, providing services to customers connected to LPDL's distribution system, and meeting the requirements of the OEB's Standard Supply Service Code and Retail Settlement Code.

The proposed OM&A cost expenditures for the 2013 Test Year are the result of a business planning and work prioritization process that ensures that the most appropriate, cost effective solutions are put in place.

OM&A Budgeting Process

The operating budget is prepared annually by management and is reviewed and approved by the Board of Directors. The budget is prepared before the start of each fiscal year, and provides a plan against which actual results are evaluated. Once approved, the budget is only revised if a material change in plan is required. In such cases, the revised budget is approved by the Board of Directors.

The operating budget is a component of the overall budget process described in Exhibit 1, Tab 2, Schedule 2.

Operating Work Plans

Each Department Manager provides input for the preparation of the departmental budget. The following directives are provided to each manager:

- All department budgets are built using previous year actual, current year forecast and current year budget as the base;

- Significant variances in spending from prior years must be explained;
- Review the head count of the department for accuracy and outline any changes;
- Accounting prepares a total labour budget by department using union contract as well as projected wage and benefit costs. Overtime and account distribution are based on previous years actual plus any identified changes for the future year.

Income Tax, Large Corporation Tax and Ontario Capital Taxes

LPDL is subject to the payment of PILs under Section 93 of the *Electricity Act, 1998*, as amended. The Applicant does not pay Section 89 proxy taxes, and is exempt from the payment of income and capital taxes under the *Income Tax Act (Canada)* and the Ontario *Corporations Tax Act*. Please refer to Exhibit 4, Tab 3, Schedule 1 and Appendix C for further tax calculations and Appendix D for a copy of the 2011 Federal and Ontario tax returns.

LPDL has not included any one-time costs in the operating budget, with the exception of legal and consulting costs related to regulatory matters (cost of service rate application). The estimated costs for completing this application have been divided over four years. Table 4.1.6 provides these details as well as other regulatory expenses.

Regulatory Costs

Regulatory costs as indicated in the variance analysis are presented in Table 4.1.6(a). Regulatory costs for the 2013 rate application (amounting to $200,000), include LPDL's consulting costs and legal costs as well as anticipated Board and Intervenor expenses which are shown on Table 4.1.6(b). These costs have been spread over a four year period beginning with the 2013 OM&A budget (25% of actual 2013 expenses relating to the 2013 cost of service application are included in OM&A for 2013). The costs that have been included are indicated below:

Table 4.1.6(a) - Regulatory Costs

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2009 Board Approved)	Most Current Actuals Year 2011	2012 Bridge Year	Annual % Change	2013 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 26,234	$ 29,635	$ 31,012	4.65%	$ 32,252	4.00%
2	OEB Section 30 Costs (Applicant-originated)									
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going	$ 1,500	$ 1,293	$ 1,300	0.54%	$ 1,300	0.00%
4	Expert Witness costs for regulatory matters									
5	Legal/Consultant/Intervenor costs for regulatory matters (COS)	5655		On-Time	$ 25,000		$ 20,000		$ 50,000	150.00%
6	Consultants' costs for regulatory matters (IRM)	5655		On-Going	$ 5,000	$ 3,354	$ 15,000	347.23%	$ 15,000	0.00%
7	Operating expenses associated with staff resources allocated to regulatory matters	5665 (5655 in 2009 COS)		On-Going	$ 9,000	$ 23,416	$ 57,500	145.56%	$ 57,383	-0.20%
8	Operating expenses associated with other resources allocated to regulatory matters [1]	5655		On-Going	$ 6,000	$ 2,065	$ 6,011	191.09%	$ 5,000	-16.82%
9	Other regulatory agency fees or assessments	5655		On-Going	$ 800	$ 800	$ 800	0.00%	$ 800	0.00%
10	Any other costs for regulatory matters (please define)									
11	Intervenor costs	5655		On-Going	$ 11,133	$ 600	$ 2,973	395.50%	$ 1,500	-49.55%
12	Sub-total - Ongoing Costs [3]		$ -		$ 59,667	$ 61,163	$ 114,596	87.36%	$ 113,235	-1.19%
13	Sub-total - One-time Costs [4]		$ -		$ 25,000	$ -	$ 20,000		$ 50,000	150.00%
14	Total		$ -		$ 84,667	$ 61,163	$ 134,596	120.06%	$ 163,235	21.28%

Table 4.1.6(b) - Regulatory Costs – One-Time

		Historical Year(s)	2012 Bridge Year	2013 Test Year	Total Costs	Cost/4 yrs
5	Legal/Consultant/Intervenor costs for regulatory matters (COS)			$ 50,000	$ 200,000	$ 50,000

Low Income Assistance Program (LEAP)

LPDL has included $6,900 of expense for the Low Income Assistance Program (LEAP) under Donations (USofA #6205). This amount is based on 0.12% of the 2013 Test Year Revenue

Requirement, rounded. Based on a service revenue requirement of $5,773,388 LPDL's LEAP commitment would be $6,928 .

Charitable Contributions

LPDL has not included charitable donations, other than LEAP funding, in OM&A expenses for the 2013 Test Year.

Green Energy Act

Exhibit 2 of this application provides LPDL's plan for capital spending under the Green Energy Act. LPDL has not included any operating expenses related to the Green Energy Act in this application. LPDL does intend to record any incremental operating expenses related to the Green Energy Act in the proscribed deferral account and to seek recovery on a historical/actual basis when incurred.

Inflation in 2012 Bridge and 2013 Test Years

The 2012 Bridge Year forecast is based on budgeted expenses for the year. Each account was reviewed from a zero-based budget position with known expenses and known increases added. In the 2013 Test Year expenses have been budgeted based on existing prices and increases if known. A range of inflation rate changes from 1.5% to 2% has been applied to some accounts where increases are not known. Wages in both years show a 3% increase to match with the existing union contract in place.

DEPARTMENTAL AND CORPORATE OM&A ACTIVITIES:

OPERATIONS & MAINTENANCE

The expenses for this department include all costs relating to the operation (5000-5096) and maintenance (5105-5195) of LPDL's distribution system. This includes direct labour costs (labour, burden & benefits) and non-capital material spending to support both scheduled and reactive maintenance events. LPDL's maintenance strategy is, to the extent possible, to minimize reactive and emergency-type work through an effective planned maintenance program, including predictive and preventative actions.

LPDL's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. LPDL's Asset Management plan completed in 2010/2011 is a tool used by operations to ensure maintenance is completed where required. This effort is coordinated with LPDL's capital project work so that where maintenance programs have identified matters which require capital investments, LPDL may adjust its capital spending priorities to address those matters.

Predictive Maintenance

Predictive maintenance activities involve the testing of elements of the distribution system. These activities include infrared thermography testing, transformer oil analysis, planned visual inspections and pole testing. These evaluation tools are all administered using a grid system or regions, with appropriate frequency levels. Any identified deficiencies found are prioritized and addressed within a suitable time frame. LPDL adheres to ESA Regulation 22/04 in regards to maintenance schedules and frequency of inspections.

Preventative Maintenance

Preventative maintenance activities include inspection, servicing and repair of network components. This includes overhead and pad-mounted load break switch maintenance and cleaning/inspection of underground vaults. Also included are regular inspection and repair of substation components and ancillary equipment. The work is performed using a combination of time and condition based methodologies. LPDL adheres to ESA Regulation 22/04 in regards to maintenance schedules and frequency of inspections.

Emergency Maintenance

This item includes unexpected system repairs to the electrical system that must be addressed immediately. The costs include those related to repairs caused by storm damage, emergency tree trimming and on-call premiums. LPDL constantly evaluates its maintenance data to adjust predictive and preventative actions. The ultimate objective is to reduce this emergency maintenance. An answering service company has been contracted to contact "on call" lineperson and supervisory staff in the event of service problems outside of normal business hours.

Service Work

The majority of costs related to this work pertain to service upgrades requested by customers, and requests to provide safety coverage for work (overhead line cover ups). This includes service disconnections and reconnections by LPDL for all service classes; assisting pre-approved contractors; the making of final connections after Electrical Safety Authority ("ESA") inspection for service upgrades; and changes of service locations.

Network Control Operations (5085)

LPDL is in the process of implementing a Supervisory Control and Data Acquisition ("SCADA") system. LPDL's plan is to upgrade the SCADA to a windows based environment in 2013, the costs of which form part of the capital plan more particularly described in Exhibit 2. This, in conjunction with the data from the GIS system, form the asset management plan for the next 1-5 years.

Metering

The metering department is responsible for the installation, testing, and commissioning of new and existing simple and complex metering installations. Testing of complex metering installations ensures the accuracy of the installation and verifies meter multipliers for billing purposes.

Revenue Protection is another key activity performed by Metering, by proactively investigating potential diversion and theft of power.

Substation Services

Substation services activities address the maintenance of all equipment at LPDL's 6 substations. This includes both labour costs and non-capital material spending to support both scheduled and emergency maintenance events. As with the maintenance activities, substation maintenance strategy focuses on minimizing, to the extent possible, emergency-type work by improving the effectiveness of LPDL's planned maintenance program (including predictive and preventative actions) for its substations.

Tree Trimming Program (5135)

LPDL utilizes a 7-year tree trimming program for its service area. LPDL's service area is one of the most heavily forested areas of the province and outages due to falling trees are high. A concerted program is in place to improve system reliability through a regular tree trimming schedule and strict limits of distances from lines, as described in more detail in Exhibit 2.

Engineering Expenses

Engineering delivers design and drafting services for capital projects and provides distribution system asset information to other departments within LPDL. In addition, engineering has implemented and continues to maintain the GIS system, AutoCAD, and system mapping.

Garage/Transportation Fleet

This area maintains and controls 13 fleet vehicles. Its objectives include, keeping maintenance schedules to ensure vehicle reliability and safety and the minimization of vehicle down time. Vehicle costs are allocated to operations, maintenance, capital and Third Party receivable accounts based on number of hours used. A standard "cost per hour" is set for all vehicles within the fleet (one rate for passenger vehicles and pickup and another rate for large bucket trucks).

Labour Burden/Safety and Health

The cost of all employee benefits and payroll taxes such as EI, CPP, EHT, WSIB, and group insurances are collected for the year. Directly attributable costs are allocated to all departments, capital and Third Party receivable amounts based on direct labour. An overhead rate for payroll burdens is set at the beginning of each year based on the previous year's actual costs adjusted for known anomalies and this is trued up at year end, again based on direct labour.

CUSTOMER SERVICE

The Customer Service group is responsible for the customer care activities for the approximately 10,000 customers in LPDL's service area. These activities include meter reading, billing, call centre, collections, and other back office functions. LPDL aspires to achieve customer service excellence in its processes and customer programs. The costs associated with the Customer Service department are reported in accounts 5305 to 5340.

Meter Reading

Prior to May 2011, meter reading services were contracted out to a non-affiliated third party under a service contract agreement. The transition to electronic meter reading in conjunction with TOU billing was completed in July 2011.

Billing

LPDL performs monthly billing and issues approximately 116,000 electricity invoices annually to customers. An annual billing schedule is created based on the meter reading schedule to ensure timely billing of services, monthly. The billing functions include the VEE processes (verification, estimation and edit); Electronic Billing Transactions (EBT) and retailer settlement functions for 1078 retailer accounts; account adjustments; processing meter changes; and other various account related field service orders and mailing services. LPDL offers customers a number of billing and payment options including walk-in counter service, an equal payment plan and a preauthorized payment plan.

Collections

Collections involve a combination of activities, including the collection of overdue active accounts, security deposits and final bills for service termination. In an effort to minimize credit losses, LPDL enforces a prudent credit policy in accordance with the Distribution System Code. Active overdue accounts are collected by in-house staff through notices, letters and direct telephone contact. Final bill collections are turned over to a collection agency after collection methods are exhausted.

Community Relations

LPDL is committed to providing consumer information and responses, in a timely and proactive manner, on electricity distribution and related issues. LPDL maintains a presence in the communities it serves, where staff is available to answer customer questions in a friendly environment.

Since LDCs are the “face-to-the-customer” for the electricity industry, LPDL has an important role to play in educating the public about electricity safety and energy conservation. LPDL continues to participate with the OPA in administering programs directed at Energy Conservation. LPDL is very active in the community promoting conservation initiatives and attending a number of community events each year.

ADMINISTRATIVE AND GENERAL EXPENSES

Administrative and general expenses include expenses incurred in connection with the general administration of the utility's operations. Within LPDL, the following functional areas are considered to be part of general administration and, as such, all expenses incurred within these functional areas are accounted for as administrative and general expenses:

- Executive Management;
- Management, Accounting, Finance, Human Resources;
- Board of Directors.

Executive Salaries and Expenses: 5605

This account includes expenses for Executive Management which includes remuneration and related expenses for LPDL's Board of Directors. Consistent with Section 2.7.4 of the current filing requirements which states that… "where there are three or fewer employees in any category, the applicant should aggregate this category with the category to which it is most closely related. This higher level of aggregation should be continued, if required, to ensure that no category contains three or fewer employees." LPDL has shown the expenses attributable to Board of Directors only in this account. LPDL Executive Management expenses form part of the Management Fee within account 5665.

Office Supplies & Expenses: 5620

Office Supplies & Expenses include, but are not limited to, software licensing/maintenance for accounting and payroll systems, telephone and internet connectivity, liability insurance, fees for office machines (photocopier/postage), bank service fees, and office supplies.

Outside Service Employed: 5630

Outside Services Employed include, but are not limited to, consulting and professional fees of accountants and auditors, actuaries, legal services, public relations counsel and tax consultants.

Regulatory Expenses: 5655

Regulatory Expenses include those expenses incurred in connection with Decisions and Orders on Cost Awards for hearings, proceedings, technical sessions, and other matters before the OEB or other regulatory bodies, including annual assessment fees paid to a regulatory body. Annual fees assessed by the OEB are included in this expenditure category.

Miscellaneous General Expense: 5665

Included in this account is a Management Fee from LPDL's parent company for Management Salaries and Expense comprised of: senior management, accounting and human resources. The accounting and finance departments are responsible for the preparation of statutory, management and Board of Directors financial reporting in accordance with CGAAP/IFRS; all daily accounting functions including accounts payable, accounts receivable, and general accounting; treasury functions including cash management, risk management, accounting systems and internal control processes; preparation of budgets and forecasts; and supporting tax compliance. The department is also responsible for all regulatory reporting and compliance with applicable codes and legislation governing LPDL, including development and preparation of rate filings, performance reporting, and compliance.

Membership dues, and other miscellaneous costs are included in this account. LPDL is a member of the Electricity Distributors Association and the Cornerstone Hydro Electric Concepts (CHEC) Group. CHEC has a membership of 12 small LDCs, who have worked together on common issues which have been mutually beneficial to the members. These include Conditions of Service, Economic Evaluation process, Smart Meter procurement, RFP for Collection Agency services and Audit services, CDM programs, IESO and settlement issues, joint training sessions and International Financial Reporting Standards.

In addition, the cost of Health, Safety & Environment and Training is included in this department. Costs include Health & Safety program supplies as well labour costs associated with safety meetings. It also includes all training programs for all staff and covers items such as bucket truck certification, chainsaw safety, and apprenticeship courses. LPDL is committed to maximizing productivity and reducing risk of injury by initiating safety and health measures that focus on preventative actions. The commitment to safety and health is significant, and involves documenting unsafe behaviors; monitoring conformance to established standards and policies; determining the effectiveness of safety training and monitoring the resolution of safety recommendations/audits; commitment to continuous improvement in training; and identifying and correcting root causes for system deficiencies.

Maintenance of General Plant: 5675

Expenses under Maintenance of General Plant include all costs of operating the operations center and office building. These include items such as: building utility costs, maintenance & repairs to the office building, lawn care & snow removal. In addition, this account includes the expenses related to IT support and service for the computer network including on-site trouble shooting, server maintenance/operation, and system reliability. This service is performed by an affiliate company and will be discussed further in Exhibit 4, Tab 2, Schedule 5.

Electrical Safety Authority (“ESA”): 5680

Expenses under Electrical Safety Authority (“ESA”) fees include all annual charges from the ESA as well as annual audit expenses.

OM&A DETAILED COSTS TABLES:

Tables 4.2.1, 4.2.2, 4.2.3, 4.2.4 and 4.2.5 provide details of OM&A per USofA number for the years 2009 to 2011 Actual under CGAAP and forecasts for 2012 Bridge Year under CGAAP and MIFRS and 2013 Test Year under MIFRS.

Table 4.2.1 - Detailed Account by Account Operation Expenses

Account	Description	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual[2]	Bridge Year 2012[3] CGAAP	Bridge Year 2012[3] MIFRS	Test Year 2013 MIFRS
Reporting Basis		CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
Operations								
5005	Operation Supervision and Engineering	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5010	Load Dispatching	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5012	Station Buildings and Fixtures Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5014	Transformer Station Equipment - Operation Labour	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5015	Transformer Station Equipment - Operation Supplies and Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5016	Distribution Station Equipment - Operation Labour	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ -	$ 7,270	$ 1,475	$ 7,932	$ 8,000	$ 8,000	$ 8,300
5030	Overhead Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5035	Overhead Distribution Transformers - Operation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5040	Underground Distribution Lines and Feeders - Operation Labour	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5045	Underground Distribution Lines and Feeders - Operation Supplies and Exper	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5050	Underground Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5055	Underground Distribution Transformers - Operation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5060	Street Lighting and Signal System Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5065	Meter Expense	$ 27,379	$ 47,214	$ 19,417	$ 37,102	$ 41,188	$ 41,188	$ 35,000
5070	Customer Premises - Operation Labour	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5075	Customer Premises - Operation Materials and Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5085	Miscellaneous Distribution Expenses	$ 154,795	$ 113,427	$ 115,430	$ 106,696	$ 130,000	$ 130,000	$ 125,000
5090	Underground Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ 41,500	$ 28,461	$ 28,652	$ 4,982	$ 28,700	$ 28,700	$ 28,700
5096	Other Rent	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total - Operations		$ 223,674	$ 196,371	$ 164,974	$ 156,712	$ 207,888	$ 207,888	$ 197,000

Table 4.2.2 - Detailed Account by Account Maintenance Expenses

Account Description	Last Rebasing Year (Approved)	2009 Actual	2010 Actual	2011 Actual[2]	Bridge Year 2012[3] CGAAP	Bridge Year 2012[3] MIFRS	Test Year 2013 MIFRS
Maintenance							
5105 Maintenance Supervision and Engineering	$ 275,391	$ 219,574	$ 200,863	$ 198,402	$ 285,685	$ 285,685	$ 294,256
5110 Maintenance of Buildings and Fixtures - Distribution Stations	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5112 Maintenance of Transformer Station Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5114 Maintenance of Distribution Station Equipment	$ 39,654	$ 46,963	$ 39,247	$ 37,268	$ 41,000	$ 41,000	$ 41,500
5120 Maintenance of Poles, Towers and Fixtures	$ -	$ -	$ 770	$ 1,679	$ -	$ -	$ -
5125 Maintenance of Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5130 Maintenance of Overhead Services	$ 334,412	$ 279,427	$ 252,881	$ 293,403	$ 285,000	$ 285,000	$ 293,550
5135 Overhead Distribution Lines and Feeders - Right of Way	$ 130,000	$ 153,662	$ 120,291	$ 141,006	$ 140,000	$ 140,000	$ 140,000
5145 Maintenance of Underground Conduit	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5150 Maintenance of Underground Conductors and Devices	$ 2,100	$ 3,408	$ 3,195	$ 37,348	$ 41,000	$ 41,000	$ 41,820
5155 Maintenance of Underground Services	$ 84,852	$ 46,946	$ 52,621	$ 47,326	$ 43,500	$ 43,500	$ 44,500
5160 Maintenance of Line Transformers	$ 51,100	$ 73,684	$ 85,557	$ 26,730	$ 38,000	$ 38,000	$ 38,380
5165 Maintenance of Street Lighting and Signal Systems	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5170 Sentinel Lights - Labour	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5172 Sentinel Lights - Materials and Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5175 Maintenance of Meters	$ 9,534	$ 8,829	$ 9,122	$ 25,832	$ 26,000	$ 26,000	$ 27,040
5178 Customer Installations Expenses - Leased Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5195 Maintenance of Other Installations on Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total - Maintenance	$ 927,043	$ 832,493	$ 764,547	$ 808,995	$ 900,185	$ 900,185	$ 921,046

Table 4.2.3 - Detailed Account by Account Billing & Collecting Expenses

Account Description	Last Rebasing Year (Approved)	2009 Actual	2010 Actual	2011 Actual[2]	Bridge Year 2012[3] CGAAP	Bridge Year 2012[3] MIFRS	Test Year 2013 MIFRS
Billing and Collecting							
5305 Supervision	$ 106,396	$ 152,617	$ 164,531	$ 77,665	$ 86,000	$ 86,000	$ 88,580
5310 Meter Reading Expense	$ 127,069	$ 116,926	$ 172,863	$ 94,589	$ 114,000	$ 114,000	$ 116,394
5315 Customer Billing	$ 240,256	$ 277,298	$ 309,906	$ 321,488	$ 400,000	$ 400,000	$ 406,000
5320 Collecting	$ 77,001	$ 75,808	$ 81,879	$ 70,227	$ 72,685	$ 72,685	$ 74,502
5325 Collecting - Cash Over and Short	$ -	$ 1	$ 9	$ -	$ -	$ -	$ -
5330 Collection Charges	$ -	-$ 30,030	-$ 33,965	-$ 14,970	-$ 17,700	-$ 17,700	-$ 18,000
5335 Bad Debt Expense	$ 35,000	$ 15,121	$ 36,733	$ 27,837	$ 32,500	$ 32,500	$ 35,000
5340 Miscellaneous Customer Accounts Expenses	$ 69,414	$ 36,776	$ 66,914	$ 73,922	$ 95,549	$ 95,549	$ 95,549
Total - Billing and Collecting	$ 655,137	$ 644,517	$ 798,870	$ 650,758	$ 783,034	$ 783,034	$ 798,025

Table 4.2.4 - Detailed Account by Account Community Relations Expenses

Account Description	Last Rebasing Year (Approved)	2009 Actual	2010 Actual	2011 Actual[2]	Bridge Year 2012[3] CGAAP	Bridge Year 2012[3] MIFRS	Test Year 2013 MIFRS
Community Relations							
5405 Supervision	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5410 Community Relations - Sundry	$ 11,255	$ 25,529	$ 32,988	$ 20,952	$ 21,000	$ 21,000	$ 21,000
5415 Energy Conservation	$ -	$ 451	$ -	$ -	$ -	$ -	$ -
5420 Community Safety Program	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5425 Miscellaneous Customer Service and Informational Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5505 Supervision	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5510 Demonstrating and Selling Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5515 Advertising Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5520 Miscellaneous Sales Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total - Community Relations	$ 11,255	$ 25,980	$ 32,988	$ 20,952	$ 21,000	$ 21,000	$ 21,000

Table 4.2.5 - Detailed Account by Account General & Administrative Expenses

Account Description	Last Rebasing Year (Approved)	2009 Actual	2010 Actual	2011 Actual[2]	Bridge Year 2012[3] CGAAP	Bridge Year 2012[3] MIFRS	Test Year 2013 MIFRS
Administrative and General Expenses							
5605 Executive Salaries and Expenses	$ -	$ 5,521	$ 5,098	$ 5,329	$ 7,000	$ 7,000	$ 7,280
5610 Management Salaries and Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5615 General Administrative Salaries and Expenses	$ -	$ -	$ 502	$ 841	$ -	$ -	$ -
5620 Office Supplies and Expenses	$ 94,496	$ 81,159	$ 97,280	$ 98,956	$ 100,500	$ 100,500	$ 104,520
5625 Administrative Expense Transferred - Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5630 Outside Services Employed	$ 42,000	$ 46,131	$ 47,107	$ 38,399	$ 38,225	$ 38,225	$ 39,754
5635 Property Insurance	$ 24,787	$ 41,719	$ 43,721	$ 42,412	$ 43,825	$ 43,825	$ 45,578
5640 Injuries and Damages	$ 3,000	$ -	$ 2,544	$ 2,450	$ -	$ -	$ -
5645 OMERS Pensions and Benefits	$ 3,000	$ 25,550	$ 7,353	$ 1,045	$ 1,300	$ 1,300	$ 1,352
5646 Employee Pensions and OPEB	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5647 Employee Sick Leave	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5650 Franchise Requirements	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5655 Regulatory Expenses	$ 84,667	$ 70,345	$ 34,918	$ 36,048	$ 83,530	$ 83,530	$ 105,852
5660 General Advertising Expenses	$ 7,219	$ -	$ -	$ -	$ -	$ -	$ -
5665 Miscellaneous General Expenses	$ 671,837	$ 821,693	$ 894,228	$ 796,263	$ 840,000	$ 840,000	$ 823,100
5670 Rent	$ -	$ -	$ -	$ 236	$ -	$ -	$ -
5672 Lease Payment Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5675 Maintenance of General Plant	$ 73,469	$ 121,465	$ 199,583	$ 206,112	$ 223,000	$ 223,000	$ 231,920
5680 Electrical Safety Authority Fees	$ 24,429	$ 7,072	$ 12,377	$ 12,834	$ 13,000	$ 13,000	$ 13,500
5681 Special Purpose Charge Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5685 Independent Electricity System Operator Fees and Penalties	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5695 OM&A Contra Account	$ -	-$ 95,447	-$ 166,182	-$ 71,609	$ -	$ -	$ -
6205 Donations	$ -	$ -	$ -	$ 2,913	$ 6,033	$ 6,033	$ 5,000
6205 Donations, Sub-account LEAP Funding	$ -	$ -	$ -	$ 6,127	$ 6,127	$ 6,127	$ 6,900
Total - Administrative and General Expenses	$ 1,028,905	$ 1,125,207	$ 1,178,528	$ 1,178,354	$ 1,362,540	$ 1,362,540	$ 1,384,756

VARIANCE ANALYSIS ON OM&A COSTS:

LPDL has provided a detailed OM&A expense analysis covering the periods from LPDL's last cost of service application. An analysis of expense changes by cost driver is provided in Table 4.2.6 with explanations below.

Table 4.2.6 - Cost Driver Table

Appendix 2-J
OM&A Cost Driver Table

OM&A	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	MIFRS	CGAAP
Opening Balance	$ 2,846,013	$ 2,920,016	$ 3,106,089	$ 2,884,466	$ 3,268,614
Wages/benefits/headcount increases	$ 5,885	-$ 29,462	-$ 81,404	$ 161,250	$ 43,224
Management Fee	$ 94,308	$ 46,756	-$ 53,367	$ 45,054	-$ 14,808
Training/H&S meetings/membership	$ -	$ 25,780	-$ 2,187	-$ 1,317	-$ 2,093
IT support	$ 40,783	$ 43,280	$ 16,850	-$ 2,250	$ -
Building maintenance	-$ 6,124	$ 34,838	-$ 10,321	$ 200	$ 203
GIS & Misc Operating Expenses	-$ 41,368	$ 2,003	-$ 8,733	$ 23,304	-$ 5,000
Tree trimming	$ 23,662	-$ 33,370	$ 20,714	-$ 1,006	$ -
Transformer maintenance	$ -	$ 11,873	-$ 58,827	$ 11,270	$ 380
Overhead & Underground maintenance	$ -	$ -	$ 64,675	$ -	$ -
Billing & Collecting	-$ 8,485	$ 148,184	-$ 143,410	$ 149,312	$ 6,300
Regulatory costs	-$ 14,322	-$ 35,427	$ 1,130	$ 47,482	$ 22,322
Misc	-$ 20,336	-$ 28,381	$ 33,257	-$ 49,152	-$ 2,316
Closing Balance	$ 2,920,016	$ 3,106,089	$ 2,884,466	$ 3,268,614	$ 3,316,827
	-$ 0	-$ 0	$ 0	$ 0	$ 0

Notes:

Wages/Benefits/Headcount

For the past three years, LPDL has struggled to maintain a Lines Supervisor in the complement due to lower than market wages, lack of experience, location and offers from neighbouring utilities. In the 2012 Bridge Year, there is a cost associated with filling this position at market value based on Mearie/EDA survey for similar sized utilities. In addition, due to the current age of the line staff complement, LPDL will be undertaking the hiring of another lineperson/meter technician to be trained to full competency by the time retirements occur. LPDL currently has 3 linestaff that are eligible to retire now or within the next two years. The third vacancy to be filled is for a Regulatory/Financial Analyst. The filing requirements and compliance requirements have become more onerous and complex in the past three years and are unable to be processed using current staff efficiently and in completeness. This includes assistance for rate application filings, RRR filings, regulatory asset reconcilations and 1598 submissions. The final component is the wage increases within the time frame. Union staff are under a collective agreement until June 30, 2013 which allows a 3% increase year over year. The same increase has been implemented for all other staff.

Year over year changes in compensation and benefits are detailed under "Employee Compensation and Benefits" in Exhibit 4, Tab 2, Schedule 4. This includes details of employee compliment, base wages, overtime and benefits by employee category.

Management Fee

The management fee included in Account 5665, represents the Corporate cost allocation from LPDL's parent company, Lakeland Holding Ltd. The services offered are Executive and Management services, Human Resources, Finance, accounting/payroll systems and communication, general office machines, audit and legal services, training, and building rent. The costs of all of these services are shared amongst the Lakeland group of companies including Bracebridge Generation Ltd and Lakeland Energy Ltd. The allocators used for sharing the costs are predominately based on timesheets as well as number of employees and square footage occupied. The cost of these services has increased over the years due to salary increases of 3% per year as well as the time spent on LPDL business especially in the regulatory area regarding filings as well as rate applications. Rate applications up until this point have been handled in house with outside assistance in order to save costs. Much of the time needed to complete the rate application was handled with extraneous overtime which has not been included in the costs in prior years ($42 K in 2009 application, not included in actual costs).

Due to IFRS conversion, a new position was staffed for a Financial Analyst/Asset Management Co-ordinator, to be shared with all companies. This position is responsible for the fixed asset register as well as monitoring additions and disposals on a financial basis in conjunction with the physical implementation. This was a result of the conversion to IFRS, the requirement for componentization of assets and true assessment of remaining useful lives as well as disposals of individual assets rather than pooled assets. In addition, IFRS conversion has created the obligation for two sets of books, one for IFRS, the other for MIFRS (Modified IFRS). In order to co-ordinate and maintain this effectively, a new accounting software package was implemented in 2009 and is also shared with all companies. The ability to share resources effectively reduces the costs to LPDL by approximately 40%.

Year over year changes in the Management Fee from LPDL's parent company are detailed under "Shared Services and Corporate Cost Allocation" in Exhibit 4, Tab 2, Schedule 5. This includes details of expenses and allocation methodology.

<u>Training/H&S Meetings/Memberships</u>

In 2010, LPDL underwent a concerted effort to train all employees in Joint Health and Safety, $37 K, (variance 2010 $26K)as safety is one of the foundations of LPDL's mission statement. At the completion, all 17 employees were fully certified and a Joint Health & Safety committee was developed with monthly meetings and site inspections. This will be provided for all new employees with a refresher for all employees every three years.

<u>IT Support</u>

Prior to 2009, LPDL utilized the services of a remote IT support operator located 3 hours away with minimal contact as most trouble shooting was done by staff on their own. With the advent of Smart Meters, web presentment, IFRS and increasing customer information security, it was becoming evident that backup systems were not in place, servers were old and unreliable, and internal staff did not have the expertise. As part of a detailed Risk Assessment, the Board of Directors required LPDL to address IT gaps and security for the betterment of customers, confidentiality, financial data, and shareholders. An affiliate company provided IT support services, server hosting and on-site support for a number of companies. A quoting process was implemented and the affiliate (Lakeland Energy) was chosen to provide the service for the next 5 years. In 2010, the company information infrastructure grew to include servers for Smart Meter data as well as a new accounting platform in order to run dual ledgers with IFRS, full GIS system for asset management program, updated work order and fixed asset manager system and enhancements to billing system to allow for online access and web presentment (variance 2009 $41K, 2010 $43K, 2011 $17K). Lakeland Energy has and continues to allow LPDL to have up-to-date IT systems.

Building Maintenance

Building maintenance costs include the cost of utilities, cleaning, outside building maintenance, water & sewer costs and snowplowing. 2010 had additional costs to fix plumbing at Operations building, repair driveway, install shelves for storage and have an environmental disposal company on site for a contained oil clean-up for a total of $42 K. 2011 saw a large increase in the cost of utilities (electricity as well as natural gas and water/sewer) as well as a repair on garage doors (variance 2010 $35K, 2011 ($10)K).

GIS & Misc Operating Expenses

In the 2009 COS application it was expected that the asset management program along with the full GIS mapping of LPDL's distribution system would be up and running in 2009. It was delayed until 2010/2011 to align with the change in useful lives for IFRS as well as smart meters being fully implemented. The cost variances are due to the annual license and maintenance on the GIS system and new SCADA system implemented in 2012 as well as updates from the GIS service provider (variance 2009 ($41)K). As outlined in the Asset Management plan in Exhibit 2, the GIS and SCADA systems will allow operations staff better visibility of asset conditions and readily available data to assist with improving customer reliability. 2012 includes Smart Meter operational expenses for troubleshooting and repair of $22 K.

Tree Trimming

In 2009, LPDL embarked on a 7-year tree trimming plan. Year one of the plan (2009) involved the most densely forested areas and the areas creating the highest reliability issues. More than the planned trimming was done leading to a variance of $24 K. The following year a smaller area was completed as the contractor was late in starting in the year so there was a catch up in 2011 (variance ($33 K) for 2010, $21 K for 2011). 2012 saw the start of a new contractor utilizing a three year contract, in order to keep rates at a consistent level for an extended period of time.

Transformer Maintenance

LPDL is in the process of completing all change outs of PCB transformers. This project will be completed in 2012. In 2011, there was a focus on installing new transformers (capital) and placing the old ones in storage until testing could be completed ($59 K). Testing and disposal were completed in 2012 giving rise to a variance of $11 K. Good corporate governance suggested that this process be completed as soon as possible in order to eliminate public hazard.

Overhead and Underground Maintenance

The summer and early fall of 2011 saw a number of severe storms that caused damage to overhead lines as well as a lightning strike to underground line causing a power outage $65 K. Repairs were made quickly that day with a plan to improve and upgrade the area in the capital budget for 2012.

Billing and Collecting

Table 4.2.7 - Billing and Collecting Cost Breakdown

Item	Variance 2009 A to 2009 BA	Variance 2010 to 2009	Variance 2011 to 2010	Variance 2012 to 2011	Variance 2013 to 2012
Smart Meters	$ 74,062	$ 78,507	-$ 87,314	$ 104,320	$ 1,600
Bad Debt	-$ 19,879	$ 21,612	-$ 8,896	$ 4,663	$ 2,500
Olameter Meter Reading		$ 8,268	-$ 83,336	-$ 16,808	$ -
Postage		$ 7,015	$ 8,766	$ 5,938	$ 1,125
Bill Print & Stuff		$ 3,236	$ 2,217	$ 4,711	$ 480
Software Updates		$ 3,343	-$ 850	$ 27,591	$ 895
Retailer/interval reads	-$ 32,638	$ 30,138	$ 7,008	$ 21,627	$ -
Collection charges	-$ 30,030	-$ 3,935	$ 18,995	-$ 2,730	-$ 300
Sub-total	**-$ 8,485**	**$ 148,184**	**-$ 143,410**	**$ 149,312**	**$ 6,300**
Wage changes	-$ 2,135	$ 6,170	-$ 4,702	-$ 17,036	$ 8,691

1. Smart Meters

Smart meter costs in 2009 through to 2011 were posted to the correct expense accounts then offset in Account 5695. After filing EB-2011-0413, Smart Meters costs were approved for rate recovery in 2012. Actual Smart Meter costs for 2012 are $104 K in Billing and Collecting and $22 K in O&M giving rise to a total cost of $126 K in 2012.

2. Bad Debt Write-Offs

As part of its Allowance for Doubtful Accounts calculation, LPDL writes off bad debts for uncollectable accounts in the preceding year. Each year, all final customer accounts that are older than 365 days and have had no collection activity in the past year, are written off as well as any bankrupt accounts. In addition, each quarter LPDL reviews all outstanding accounts for the current quarter and calculates a provision on what, if any, accounts may not be collectable and adjusts the Allowance for Doubtful Accounts balance accordingly to match this provision. Therefore, Bad Debt Expense is a function of actual write offs and the above-noted adjustment to the Allowance for Doubtful Accounts. Table 4.2.8 below sets out the year end balances for Bad Debt Expense and the Allowance for Doubtful Accounts in the years 2009 to 2011, along with the Bridge Year (2012) and Test Year (2013) forecasts.

Table 4.2.8 - Bad Debt Expense and Allowance For Doubtful Accounts

Account	Description	2009	2010	2011	2012 Bridge	2013 Test
Reporting Basis						
Bad Debt Expenses						
5335	Bad Debt Write-Offs	$ 62,234	$ 31,900	$ 24,584	$ 30,000	$ 32,500
5335	Bad Debt Recovery	-$ 8,471	-$ 2,553	-$ 2,406	-$ 2,067	-$ 1,000
5335	Bad Debt Recovery via Credit Risk Insurance	-$ 29,020	-$ 9,330	-$ 917	-$ 1,433	-$ 2,500
5335	Adjustment to Allowance for Doubtful Accounts Provi	-$ 9,622	$ 16,716	$ 6,576	$ 6,000	$ 6,000
Total - Bad Debt Expenses		$ 15,121	$ 36,733	$ 27,837	$ 32,500	$ 35,000
	Year over Year change		$ 21,612	-$ 8,896	$ 4,663	$ 2,500
1130	Allowance for Doubtful Accounts	-$ 24,131	-$ 40,849	-$ 47,425	-$ 53,425	-$ 59,425

In 2009, LPDL's Bad Debt Expense was $15,121 due to actual write offs of $62,234 which were offset by the recovery of bad debts of $37,491 recovered mainly through LPDL's credit risk insurance coverage for commercial and industrial accounts and a decrease in the Allowance for Doubtful Accounts of $9,622 (to $24,131).

In 2010, LPDL's Bad Debt Expense increased to $36,733 over 2009, represented by an increase in the Allowance for Doubtful Accounts of $16,716 (to $40,849) and actual write offs of $31,900 offset by the recovery of bad debts in 2010 of $11,883 mainly through LPDL's credit risk insurance coverage.

In 2011, LPDL's Bad Debt Expense decreased to $27,837 over 2010, represented by an increase in the Allowance for Doubtful Accounts of $6,576 (to $47,425) and actual write offs of $24,584 offset by the recovery of bad debts in 2011 of $3,323. LPDL has prudently purchased Credit Risk insurance for Commercial and Industrial customers. Over the first three years of the program, the amounts received back from the insurer were higher than the premiums paid, resulting in a positive cash impact on the utility.

Bad Debt Expense is forecasted at $30,000 in 2012 and $32,500 in 2013

3. Olameter Manual Meter Reading

Prior to Spring 2011, LPDL contracted with a non-affiliated Third Party who provided manual meter reading services on a monthly basis. The introduction of smart meter technology gave LPDL the ability to read meters electronically and consequently, the contract with the Third Party was terminated. There were no cost savings in 2010 as LPDL's smart meter communication network was not fully functional until early 2011 and the monthly manual meter reads for usage and system validation for were still required. However, the savings in manual meter reading expenses for 2011 over 2010 was significant with a savings of $83,336.

4. Retailer Hub/EBT fees/Interval Reads

Retailer/Interval reads are charges from Utilismart to read interval meters and calculate settlement information. In 2010 the costs started to increase for the change out of non-interval GS>50 kW meters to Smart Synch meters which could be read electronically, all of which were fully online by 2012. 2010 also saw the start of meter reading charges and settlement for MicroFit and Fit customers, the costs of which are in Account 5340. In 2009 and 2011, there was an increase in the Retailer transaction fees for both the hub as well as EBT fees. In 2011, the supplier of this service, Systrends was replaced with SPI which provided LPDL with lower costs on a longer term contract.

5. Collection Charges

In 2009 Board Approved, the collection charges in 5330 where included in the revenue offsets for purposes of the rate application. The actual charges were booked to Account 5330 giving rise to a credit of $30K in the comparison to 2009 Actual.

The balance of the difference in Billing and Collecting costs is attributable to wage changes and headcount changes which are discussed in the first cost driver.

Regulatory Costs

Changes in all regulatory costs are detailed in Exhibit 4, Tab 1, Schedule 1. In the 2009 Cost of Service application, LPDL had included $25 K for Legal/Consulting fees while the actual fees for 2009 were $10 K as most of the work and preparation were done in house and an oral hearing did not take place. 2010 was lower than 2009 as 2010 was an IRM year which is a significantly shorter and less labour intensive process. 2012 climbs again to cover costs related to the preparation of the 2013 Cost of Service rate application. The overall cost is expected to be in the neighbourhood of $200 K and has been split by ¼ per year or $50 K. 2013 includes the costs related to an IRM application in addition to the $50 K spread from the 2013 COS application.

Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2009 Board Approved)	Most Current Actuals Year 2011	2012 Bridge Year	Annual % Change	2013 Test Year
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)
1	OEB Annual Assessment	5655		On-Going	$ 26,234	$ 29,635	$ 31,012	4.65%	$ 32,252
2	OEB Section 30 Costs (Applicant-originated)								
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going	$ 1,500	$ 1,293	$ 1,300	0.54%	$ 1,300
4	Expert Witness costs for regulatory matters								
5	Legal/Consultant/Intervenor costs for regulatory matters (COS)	5655		On-Time	$ 25,000		$ 20,000		$ 50,000
6	Consultants' costs for regulatory matters (IRM)	5655		On-Going	$ 5,000	$ 3,354	$ 15,000	347.23%	$ 15,000
7	Operating expenses associated with staff resources allocated to regulatory matters	5665 (5655 in 2009 COS)		On-Going	$ 9,000	$ 23,416	$ 57,500	145.56%	$ 57,383
8	Operating expenses associated with other resources allocated to regulatory matters [1]	5655		On-Going	$ 6,000	$ 2,065	$ 6,011	191.09%	$ 5,000
9	Other regulatory agency fees or assessments	5655		On-Going	$ 800	$ 800	$ 800	0.00%	$ 800
10	Any other costs for regulatory matters (please define)								
11	Intervenor costs	5655		On-Going	$ 11,133	$ 600	$ 2,973	395.50%	$ 1,500
12	Sub-total - Ongoing Costs [3]		$ -		$ 59,667	$ 61,163	$ 114,596	87.36%	$ 113,235
13	Sub-total - One-time Costs [4]		$ -		$ 25,000	$ -	$ 20,000		$ 50,000
14	Total		$ -		$ 84,667	$ 61,163	$ 134,596	120.06%	$ 163,235

All Other Expenses

Changes in all other expenses represent various year over year changes as described in the account by account variance analysis below.

Variance Analysis by Account

Consistent with the Ontario Energy Board Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 28, 2012, LPDL has provided variance analyses for the 2013 Test Year vs. 2009 Actual (last rebase year) and between the 2013 Test Year and 2011 Actual (Most Current Actual). LPDL has reviewed the variance of each USoA account and provided explanations for variances exceeding a materiality threshold of $50,000. The variances are indicated in the following tables (Table 4.2.9 to Table 4.2.13) and an explanation of each variance is presented in the following section.

Table 4.2.9 - Operations Expenses – Account Variances

2013 Test Year vs. 2009 COS and 2013 Test Year vs. 2011 Actual

Account	Description	Last Board-approved Rebasing Year (2009 Year)	Most Current Actuals Year 2011	Test Year 2013	Test Year Versus Last Rebasing		Test Year Versus Most Current Actuals	
Reporting Basis		CGAAP	CGAAP	MIFRS				
Operations								
5005	Operation Supervision and Engineering	$ -	$ -	$ -	$ -		$ -	
5010	Load Dispatching	$ -	$ -	$ -	$ -		$ -	
5012	Station Buildings and Fixtures Expense	$ -	$ -	$ -	$ -		$ -	
5014	Transformer Station Equipment - Operation Labour	$ -	$ -	$ -	$ -		$ -	
5015	Transformer Station Equipment - Operation Supplies and Expenses	$ -	$ -	$ -	$ -		$ -	
5016	Distribution Station Equipment - Operation Labour	$ -	$ -	$ -	$ -		$ -	
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ -	$ -	$ -	$ -		$ -	
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ -	$ -	$ -	$ -		$ -	
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ -	$ 7,932	$ 8,300	$ 8,300		$ 368	4.64%
5030	Overhead Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -		$ -	
5035	Overhead Distribution Transformers - Operation	$ -	$ -	$ -	$ -		$ -	
5040	Underground Distribution Lines and Feeders - Operation Labour	$ -	$ -	$ -	$ -		$ -	
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expens	$ -	$ -	$ -	$ -		$ -	
5050	Underground Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -		$ -	
5055	Underground Distribution Transformers - Operation	$ -	$ -	$ -	$ -		$ -	
5060	Street Lighting and Signal System Expense	$ -	$ -	$ -	$ -		$ -	
5065	Meter Expense	$ 27,379	$ 37,102	$ 35,000	$ 7,621	27.83%	-$ 2,102	-5.66%
5070	Customer Premises - Operation Labour	$ -	$ -	$ -	$ -		$ -	
5075	Customer Premises - Operation Materials and Expenses	$ -	$ -	$ -	$ -		$ -	
5085	Miscellaneous Distribution Expenses	$ 154,795	$ 106,696	$ 125,000	-$ 29,795	-19.25%	$ 18,304	17.15%
5090	Underground Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -		$ -	
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ 41,500	$ 4,982	$ 28,700	-$ 12,800	-30.84%	$ 23,718	476.03%
5096	Other Rent	$ -	$ -	$ -	$ -		$ -	
Total - Operations		$ 223,674	$ 156,712	$ 197,000	-$ 26,674	-11.93%	$ 40,288	25.71%

Table 4.2.10 - Maintenance Expenses – Account Variances

2013 Test Year vs. 2009 COS and 2013 Test Year vs. 2011 Actual

Account	Description	Last Board-approved Rebasing Year (2009)	Most Current Actuals Year 2011	Test Year	Test Year Versus Last: Variance ($)	Test Year Versus Last: Percentage Change (%)	Test Year Versus Most: Variance ($)	Test Year Versus Most: Percentage Change (%)
5105	Maintenance Supervision and Engineering	$ 275,391	$ 198,402	$ 294,256	$ 18,865	6.85%	$ 95,854	48.31%
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$ -	$ -	$ -	$ -		$ -	
5112	Maintenance of Transformer Station Equipment	$ -	$ -	$ -	$ -		$ -	
5114	Maintenance of Distribution Station Equipment	$ 39,654	$ 37,268	$ 41,500	$ 1,846	4.65%	$ 4,232	11.36%
5120	Maintenance of Poles, Towers and Fixtures	$ -	$ 1,679	$ -	$ -		-$ 1,679	-100.00%
5125	Maintenance of Overhead Conductors and Devices	$ -	$ -	$ -	$ -		$ -	
5130	Maintenance of Overhead Services	$ 334,412	$ 293,403	$ 293,550	-$ 40,862	-12.22%	$ 147	0.05%
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 130,000	$ 141,006	$ 140,000	$ 10,000	7.69%	-$ 1,006	-0.71%
5145	Maintenance of Underground Conduit	$ -	$ -	$ -	$ -		$ -	
5150	Maintenance of Underground Conductors and Devices	$ 2,100	$ 37,348	$ 41,820	$ 39,720	1891.43%	$ 4,472	11.97%
5155	Maintenance of Underground Services	$ 84,852	$ 47,326	$ 44,500	-$ 40,352	-47.56%	-$ 2,826	-5.97%
5160	Maintenance of Line Transformers	$ 51,100	$ 26,730	$ 38,380	-$ 12,720	-24.89%	$ 11,650	43.58%
5165	Maintenance of Street Lighting and Signal Systems	$ -	$ -	$ -	$ -		$ -	
5170	Sentinel Lights - Labour	$ -	$ -	$ -	$ -		$ -	
5172	Sentinel Lights - Materials and Expenses	$ -	$ -	$ -	$ -		$ -	
5175	Maintenance of Meters	$ 9,534	$ 25,832	$ 27,040	$ 17,506	183.62%	$ 1,208	4.68%
5178	Customer Installations Expenses - Leased Property	$ -	$ -	$ -	$ -		$ -	
5195	Maintenance of Other Installations on Customer Premises	$ -	$ -	$ -	$ -		$ -	
Total - Maintenance		$ 927,043	$ 808,995	$ 921,046	-$ 5,997	-0.65%	$ 112,051	13.85%

Table 4.2.11 - Billing and Collecting Expenses – Account Variances

2013 Test Year vs. 2009 COS and 2013 Test Year vs. 2011 Actual

Account	Description	Last Board-approved Rebasing Year (2009)	Most Current Actuals Year 2011	Test Year	Test Year Versus Last: Variance ($)	Test Year Versus Last: Percentage Change (%)	Test Year Versus Most: Variance ($)	Test Year Versus Most: Percentage Change (%)
5305	Supervision	$ 106,396	$ 77,665	$ 88,580	-$ 17,816	-16.75%	$ 10,915	14.05%
5310	Meter Reading Expense	$ 127,069	$ 94,589	$ 116,394	-$ 10,675	-8.40%	$ 21,805	23.05%
5315	Customer Billing	$ 240,256	$ 321,488	$ 406,000	$ 165,744	68.99%	$ 84,512	26.29%
5320	Collecting	$ 77,001	$ 70,227	$ 74,502	-$ 2,499	-3.24%	$ 4,275	6.09%
5325	Collecting - Cash Over and Short	$ -	$ -	$ -	$ -		$ -	
5330	Collection Charges	$ -	-$ 14,970	-$ 18,000	-$ 18,000		-$ 3,030	20.24%
5335	Bad Debt Expense	$ 35,000	$ 27,837	$ 35,000	$ -	0.00%	$ 7,163	25.73%
5340	Miscellaneous Customer Accounts Expenses	$ 69,414	$ 73,922	$ 95,549	$ 26,135	37.65%	$ 21,628	29.26%
Total - Billing and Collecting		$ 655,137	$ 650,758	$ 798,025	$ 142,888	21.81%	$ 147,267	22.63%

Table 4.2.12 - Community Relations Expenses – Account Variances

2013 Test Year vs. 2009 COS and 2013 Test Year vs. 2011 Actual

Account	Description	Last Board-approved Rebasing Year (2009)	Most Current Actuals Year 2011	Test Year	Test Year Versus Last Variance ($)	Test Year Versus Last Percentage Change (%)	Test Year Versus Most Variance ($)	Test Year Versus Most Percentage Change (%)
5405	Supervision	$ -	$ -	$ -	$ -		$ -	
5410	Community Relations - Sundry	$ 11,255	$ 20,952	$ 21,000	$ 9,745	86.59%	$ 48	0.23%
5415	Energy Conservation	$ -	$ -	$ -	$ -		$ -	
5420	Community Safety Program	$ -	$ -	$ -	$ -		$ -	
5425	Miscellaneous Customer Service and Informational Expenses	$ -	$ -	$ -	$ -		$ -	
5505	Supervision	$ -	$ -	$ -	$ -		$ -	
5510	Demonstrating and Selling Expense	$ -	$ -	$ -	$ -		$ -	
5515	Advertising Expenses	$ -	$ -	$ -	$ -		$ -	
5520	Miscellaneous Sales Expense	$ -	$ -	$ -	$ -		$ -	
Total - Community Relations		$ 11,255	$ 20,952	$ 21,000	$ 9,745	86.59%	$ 48	0.23%

Table 4.2.13 - Administrative and General Expenses – Account Variances

2013 Test Year vs. 2009 COS and 2013 Test Year vs. 2011 Actual

Account	Description	Last Board-approved Rebasing Year (2009)	Most Current Actuals Year 2011	Test Year	Test Year Versus Last Variance ($)	Test Year Versus Last Percentage Change (%)	Test Year Versus Most Variance ($)	Test Year Versus Most Percentage Change (%)
5605	Executive Salaries and Expenses	$ -	$ 5,329	$ 7,280	$ 7,280		$ 1,951	36.62%
5610	Management Salaries and Expenses	$ -	$ -	$ -	$ -		$ -	
5615	General Administrative Salaries and Expenses	$ -	$ 841	$ -	$ -		-$ 841	-100.00%
5620	Office Supplies and Expenses	$ 94,496	$ 98,956	$ 104,520	$ 10,024	10.61%	$ 5,564	5.62%
5625	Administrative Expense Transferred - Credit	$ -	$ -	$ -	$ -		$ -	
5630	Outside Services Employed	$ 42,000	$ 38,399	$ 39,754	-$ 2,246	-5.35%	$ 1,355	3.53%
5635	Property Insurance	$ 24,787	$ 42,412	$ 45,578	$ 20,791	83.88%	$ 3,166	7.46%
5640	Injuries and Damages	$ 3,000	$ 2,450	$ -	-$ 3,000	-100.00%	-$ 2,450	-100.00%
5645	OMERS Pensions and Benefits	$ 3,000	$ 1,045	$ 1,352	-$ 1,648	-54.93%	$ 307	29.44%
5646	Employee Pensions and OPEB	$ -	$ -	$ -	$ -		$ -	
5647	Employee Sick Leave	$ -	$ -	$ -	$ -		$ -	
5650	Franchise Requirements	$ -	$ -	$ -	$ -		$ -	
5655	Regulatory Expenses	$ 84,667	$ 36,048	$ 105,852	$ 21,185	25.02%	$ 69,804	193.64%
5660	General Advertising Expenses	$ 7,219	$ -	$ -	-$ 7,219	-100.00%	$ -	
5665	Miscellaneous General Expenses	$ 671,837	$ 796,263	$ 823,100	$ 151,263	22.51%	$ 26,837	3.37%
5670	Rent	$ -	$ 236	$ -	$ -		-$ 236	-100.00%
5672	Lease Payment Charge	$ -	$ -	$ -	$ -		$ -	
5675	Maintenance of General Plant	$ 73,469	$ 206,112	$ 231,920	$ 158,451	215.67%	$ 25,808	12.52%
5680	Electrical Safety Authority Fees	$ 24,429	$ 12,834	$ 13,500	-$ 10,929	-44.74%	$ 666	5.19%
5681	Special Purpose Charge Expense	$ -	$ -	$ -	$ -		$ -	
5685	Independent Electricity System Operator Fees and Penalties	$ -	$ -	$ -	$ -		$ -	
5695	OM&A Contra Account	$ -	-$ 71,609	$ -	$ -		$ 71,609	-100.00%
6205	Donations	$ -	$ 2,913	$ 5,000	$ 5,000		$ 2,087	71.64%
6205	Donations, Sub-account LEAP Funding	$ -	$ 6,127	$ 6,900	$ 6,900		$ 773	12.62%
Total - Administrative and General Expenses		$ 1,028,905	$ 1,178,354	$ 1,384,756	$ 355,851	34.59%	$ 206,402	17.52%
Adjustments for non-recoverable items								
5681	Special Purpose Charge Expense	$ -	$ -	$ -	$ -		$ -	
6205	Donations[1]	$ -	$ 2,913	$ 5,000	$ 5,000		$ 2,087	71.64%
5695	OM&A Contra Account	$ -	-$ 71,609	$ -	$ -		$ 71,609	-100.00%
					$ -		$ -	
					$ -		$ -	
Total Recoverable OM&A		$ 2,846,013	$ 2,884,467	$ 3,316,827	$ 470,814	16.54%	$ 432,360	14.99%
Less: Smart Meter costs				(127,000)				
Total				$3,189,827	$343,814	12%	$305,360	10%

2013 TEST YEAR vs. 2009 Board Approved COST OF SERVICE FILING:

TABLE 4.2.9 - OPERATIONS

There are no expense variances greater than $50,000 when comparing the 2013 Test Year with the 2009 COS expenses.

TABLE 4.2.10 - MAINTENANCE

There are no expense variances greater than $50,000 when comparing the 2013 Test Year with the 2009 COS expenses.

TABLE 4.2.11 - BILLING AND COLLECTING

#5315 – Customer Billing Expense $165,744

Customer Billing Expenses have increased due to the implementation of the smart meter infrastructure, an increase of $50 K. This is broken down below. Salary and benefit increases account for $45 K (time allocated here for Smart Meter data processing out of meter reading, $20 K), postage increase of $23 K (rate and volume), increase cost for bill print & stuff with additional bill inserts for TOU and OCEB, $11 K and software licensing/support/maintenance for the CIS system as well as web hosting and bill presentment has increased by $37 K.

Smart Meters - N-Dimension – Security Audit - $17 K

With the mass deployment of AMI systems, security of the AMI network is critical to prevent utilities from becoming susceptible to new levels of potential security breaches and to ensure customer privacy and acceptance of the network. LPDL, along with approximately 20 other Elster LDCs have contracted with N-Dimension to perform this security audit on behalf of the group, thereby reducing the individual LDC cost significantly.

Smart Meters - Sync Operator - $25 K

LPDL has contracted with Util-Assist Inc to provide Sync Operator services as an integral part of the billing process. In 2011, a contract Sync Operator was required who provides expertise to LPDL billing staff in regard the smart metering infrastructure. The Sync Operator's duties include support and training to LPDL staff for daily validation of overall performance of our AMI network, identification and resolution of exceptions within the network, running of daily performance reports and delivery to LPDL for review, following up on outstanding issues with the network, monitoring the data sync between CIS, head end system, MDMR and the ODS, monitoring and resolving BQR exceptions from MDMR and CIS and developing configuration and testing of the MDMR interface and ODS rules engine.

TABLE 4.2.12 - COMMUNITY RELATIONS

There are no expense variances greater than $50,000 when comparing the 2013 Test Year with the 2009 COS expenses.

TABLE 4.2.13 - ADMINISTRATIVE AND GENERAL EXPENSES

#5665 – Miscellaneous General Expenses $151,263

Account Description	2009 COS	2011	2013 Test	Variance 2013 to 2009	Variance 2013 to 2011
Reporting Basis					
Miscellaneous General Expenses					
5665 Management Fee	$ 557,277	$ 644,973	$ 675,221	$ 117,944	$ 30,248
5665 Other Training/Conferences/Seminars/Meetings	$ 37,285	$ 38,346	$ 46,979	$ 9,694	$ 8,633
5665 Apprentice training	$ 20,000	$ 32,031	$ 20,000	$ -	-$ 12,031
5665 Supervisory training	$ 10,000	$ 12,275	$ 15,000	$ 5,000	$ 2,725
5665 Contractor Training		$ 5,927	$ -	$ -	-$ 5,927
5665 H&S Meetings/Operations Daily meetings	$ 10,000	$ 12,700	$ 15,000	$ 5,000	$ 2,300
5665 Legal Fees		$ 2,270		$ -	-$ 2,270
5665 Line of Credit standby fees		$ 1,930	$ 5,400	$ 5,400	$ 3,470
5665 EDA Membership	$ 12,275	$ 15,250	$ 15,500	$ 3,225	$ 250
5665 CHEC Membership	$ 25,000	$ 30,561	$ 30,000	$ 5,000	-$ 561
Total - Misc General Expenses	$ 671,837	$ 796,263	$ 823,100	$ 151,263	$ 26,837

Miscellaneous General Expenses has increased specifically in the Management Fee from Lakeland Holding for Corporate allocation. This is discussed in Exhibit 4, Tab 2, Schedule 5. The joint effort of the CHEC group of LDCs is an estimated benefit to LPDL of approximately $80 K in costs annually.

#5675 – Maintenance General Plant $158,451

Account	Description	2009 COS	2011	2013 Test	Variance 2013 to 2009	Variance 2013 to 2011
Miscellaneous General Plant						
5675	IT Support	$ 15,000	$ 134,248	$ 148,000	$ 133,000	$ 13,752
5675	Cleaning	$ 15,000	$ 16,913	$ 20,000	$ 5,000	$ 3,088
5675	Outside & building mtce/snowplowing/lawn cutting	$ 9,000	$ 9,495	$ 14,000	$ 5,000	$ 4,505
5675	Utilities	$ 34,469	$ 45,457	$ 49,920	$ 15,451	$ 4,463
Total - Miscellaneous General Plant		**$ 73,469**	**$ 206,112**	**$ 231,920**	**$ 158,451**	**$ 25,808**

Miscellaneous General Plant expenses includes the IT support for all the systems that LPDL uses. The 2009 level of service was remote support with most issues being handled by individuals users. Board of Directors considered IT support a high risk and required that better service was provided for customers, security, confidentiality, and support. Current level of service being provided by Lakeland Energy Ltd. is the following:

- On site support
- Smart meters – VPN connections, troubleshooting and support of gatekeepers, virtual PC with secure VPN access
- Manage security and access for all systems
- Managed network switches
- Management of CCTV system over fiber network
- Support of all electronic equipment including PCs, laptops, servers, printers
- Support for all servers and systems related to
    - AS2 file transfer and tunnels for SM Communications
    - Backup Elster EA_MS Server for SM data collection & reporting

- Customer web portal – eCare
- Worktech – work order/purchasing/asset manager program
- Great Plains – financial/payroll system
- File Nexus – file storage
- IT server (windows update, anit-virus,backup domain controller)
- Harris billing/CIS system

2013 TEST YEAR vs. 2011 ACTUAL:

TABLE 4.2.9 - OPERATIONS

There are no expense variances greater than $50,000 when comparing the 2013 Test Year with the 2011 Actual expenses.

TABLE 4.2.10 - MAINTENANCE

<u>#5105 – Maintenance Supervision and Engineering</u> $95,854

LPDL has had a difficult time filling the position of Lines Supervisor in the past. In 2011, LPDL was without a Lines Supervisor for the year despite advertising a number of times. Salary level, location and experience have been the issues. The Lines supervisor that was in place left to work for another utility at a significantly higher salary in 2010. Since that time, one of the linesman filled in partially as did the Operations manager and Chief Operating Officer. The position will be filled in 2012, returning this to its full complement in 2013.

TABLE 4.2.11 - BILLING AND COLLECTING

<u>#5315 – Customer Billing Expense</u> $84,512

Customer billing expenses for 2013 have changed significantly from previous years and are not directly comparable to past expenses. From 2009 through to 2010, LPDL employed a third party contractor to read all meters and supply data for billing purposes. In 2011, electronic meter reading expenses as well as billing under Smart Meters were recorded in a variance account under the Smart Meter Infrastructure. This moved the expenses from meter reading to billing as now the emphasis was on correcting and verifying data along with the systems to transfer data between our systems and the MDMR. Consequently, the increase in 2013 over 2011 expenses is a result of the smart meter reading and billing expenses. This constituted the majority of the expense in this account, with the balance of the expense being attributed to internal staff time for data editing and verification as their time has been reallocated from meter reading to billing. In 2013, LPDL has forecasted expenses based on electronic meter reading of its smart meters.

TABLE 4.2.12 - COMMUNITY RELATIONS

There are no expense variances greater than $50,000 when comparing the 2013 Test Year with the 2011 Actual expenses.

TABLE 4.2.13 - ADMINISTRATIVE AND GENERAL EXPENSES

#5655 – Regulatory Expenses $69,804

Account	Description	2009 COS	2011	2013 Test	Variance 2013 to 2009	Variance 2013 to 2011
Regulatory						
5665	OEB Annual Assessment	$ 26,234	$ 29,635	$ 32,252	$ 6,018	$ 2,617
5665	OEB Section 30 costs (OEB-initiated)	$ 1,500	$ 1,293	$ 1,300	-$ 200	$ 7
5665	Legal/Consultant/Intervenor for COS	$ 35,000	$ -	$ 50,000	$ 15,000	$ 50,000
5665	Consultant for IRM	$ 5,000	$ 1,655	$ 15,000	$ 10,000	$ 13,345
5665	Intervenor costs for IRM	$ 1,133	$ 600	$ 1,500	$ 367	$ 900
5665	Staff resources for Regulatory matters	$ 9,000	$ -	$ -	-$ 9,000	$ -
5665	Operating expenses for Regulatory matters	$ 6,000	$ 2,065	$ 5,000	-$ 1,000	$ 2,935
5665	Other regulatory agency fees or assessments	$ 800	$ 800	$ 800	$ -	$ -
Total - Regulatory Costs in 5655		$ 84,667	$ 36,048	$ 105,852	$ 21,185	$ 69,804
5655	Staff resources for Regulatory matters(in Mgmt Fee)	$ -	$ 23,416	$ 57,383	$ 57,383	$ 33,967
Total - Regulatory Costs		$ 84,667	$ 59,464	$ 163,235	$ 78,568	$ 103,771

Regulatory Expenses include those expenses incurred in connection with Decisions and Orders on Cost Awards for hearings, proceedings, technical sessions, and other matters before the OEB or other regulatory bodies, including annual assessment fees paid to a regulatory body. Annual fees assessed by the OEB are included in this expenditure category. In 2009 Cost of Service filing, Regulatory Expenses totaled $84,667 vs. the 2013 projected expense of $105,852. The increase in cost is due to the increase in COS and IRM Applications of $25,000, annual OEB Assessment increases of $6,018, Section 30 cost decreases of $200, and other regulatory decreases of $9,633. In 2009 COS, staff resources were allocated to Account 5655 however, on an actual basis, they are part of the Management Fee ($57,383 in 2013). As indicated in Exhibit 4, Tab 1, Schedule 1 and shown under Table 4.1.6 Regulatory costs for the 2013 Cost of Service Application include LPDL's consulting and legal costs as well as anticipated Board and Intervenor expenses. These costs have been spread over a four year period beginning with the 2013 OM&A budget (25% of actual 2013 expenses relating to the 2013 Cost of Service Application are included in OM&A for 2013).

#5695 – OM&A Contra Account

– excluded from total OM&A as one-time

EMPLOYEE COMPENSATION:

Compensation/Performance System

Union

LPDL's unionized staff is represented by (CUPE) Union. The current collective agreement expires June 30, 2013 and LPDL will be entering formal negotiations prior to that date. The current agreement, which was entered into July 2009, includes annual wage increases of 3% over the next four years. LPDL recognizes that this increase may, on the surface be considered excessive given the current economic climate. However, LPDL would point out in order to achieve a balance between our neighbouring LDCs and industry averages, a 3% increase was negotiated. For example, one neighbouring LDC wage rates for line crew are $2 per hour more than LPDL. This would have resulted in a 6% increase. All staff who have voluntarily resigned in the past have taken positions with higher wages at other LDCs.

Management

The management compensation plan consists of salaries and benefits. Each position within the company is reviewed annually by senior management. Each employee's position within their respective range is reviewed based on performance and an inflationary adjustment. Changes to senior management compensation, if any, are approved by the CEO. LPDL does not offer incentive or bonus compensation.

Benefits

A comprehensive and competitive benefits package exists which includes medical insurance, life insurance and vacation. The plans are designed to address the health and welfare needs of the employee population, with similar plans for both union and management employees. LPDL does not provide post-retirement benefits to its employees.

All full time staff participate in the OMERS pension plan.

Employee Compensation and Benefits

The employee complement, compensation and benefit information is provided in Table 4.2.14 below. LPDL has aggregated the executive and management together in the management category.

Table 4.2.14 - Employee Compensation and Benefits

	Last Rebasing Year (2009 Board-Approved)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Reporting Basis						
Number of Employees (FTEs including Part-Time)[1]						
Executive						
Management	3.0	3.5	3.7	2.8	3.0	3.0
Non-Union	5.6	3.6	4.0	3.9	4.9	4.9
Union	10.0	9.5	9.0	9.0	10.0	10.0
Total	18.6	16.6	16.7	15.6	17.9	17.9
Number of Part-Time Employees						
Executive						
Management						
Non-Union	4.5	1.0	1.0	1.0	1.0	1.0
Union						
Total	5	1	1	1	1	1
Total Salary and Wages						
Executive						
Management	$ 221,487	$ 258,671	$ 273,580	$ 211,529	$ 247,077	$ 254,489
Non-Union	$ 244,823	$ 158,865	$ 183,391	$ 183,632	$ 270,681	$ 278,802
Union	$ 679,698	$ 653,108	$ 615,649	$ 630,282	$ 725,826	$ 747,601
Total	$ 1,146,008	$ 1,070,644	$ 1,072,620	$ 1,025,444	$ 1,243,585	$ 1,280,892
Current Benefits						
Executive						
Management	$ 48,507	$ 64,668	$ 69,422	$ 55,216	$ 69,182	$ 73,802
Non-Union	$ 45,836	$ 39,716	$ 46,571	$ 46,828	$ 75,791	$ 80,853
Union	$ 148,850	$ 156,310	$ 149,634	$ 159,224	$ 197,706	$ 210,676
Total	$ 243,193	$ 260,694	$ 265,627	$ 261,268	$ 342,679	$ 365,330
Accrued Pension and Post-Retirement Benefits						
Executive						
Management						
Non-Union						
Union						
Total	$ -	$ -	$ -	$ -	$ -	$ -
Total Benefits (Current + Accrued)						
Executive	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ 48,507	$ 64,668	$ 69,422	$ 55,216	$ 69,182	$ 73,802
Non-Union	$ 45,836	$ 39,716	$ 46,571	$ 46,828	$ 75,791	$ 80,853
Union	$ 148,850	$ 156,310	$ 149,634	$ 159,224	$ 197,706	$ 210,676
Total	$ 243,193	$ 260,694	$ 265,627	$ 261,268	$ 342,679	$ 365,330
Total Compensation (Salary, Wages, & Benefits)						
Executive	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ 269,994	$ 323,339	$ 343,002	$ 266,745	$ 316,258	$ 328,291
Non-Union	$ 290,659	$ 198,582	$ 229,962	$ 230,460	$ 346,472	$ 359,654
Union	$ 828,548	$ 809,418	$ 765,282	$ 789,506	$ 923,533	$ 958,277
Total	$ 1,389,201	$ 1,331,338	$ 1,338,246	$ 1,286,712	$ 1,586,263	$ 1,646,222
Compensation - Average Yearly Base Wages						
Executive						
Management	$ 73,830	$ 73,906	$ 72,968	$ 76,641	$ 82,359	$ 84,830
Non-Union	$ 43,339	$ 44,129	$ 46,311	$ 47,697	$ 55,241	$ 56,898
Union	$ 61,592	$ 61,414	$ 63,651	$ 65,335	$ 68,333	$ 70,383
Total						
Compensation - Average Yearly Overtime						
Executive						
Management	$ -	$ -	$ -	$ -	$ -	$ -
Non-Union	$ 566	$ -	$ -	$ -	$ -	$ -
Union	$ -	$ 7,334	$ 4,754	$ 4,696	$ 4,250	$ 4,378
Total						
Compensation - Average Yearly Incentive Pay						
Executive						
Management	$ -	$ -	$ -	$ -	$ -	$ -
Non-Union	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ -	$ -	$ -	$ -	$ -	$ -
Total						
Compensation - Average Yearly Benefits						
Executive						
Management	$ 16,169	$ 18,477	$ 18,516	$ 20,006	$ 23,061	$ 24,601
Non-Union	$ 11,459	$ 11,032	$ 11,760	$ 12,163	$ 15,468	$ 16,501
Union	$ 14,885	$ 16,454	$ 16,626	$ 17,692	$ 19,771	$ 21,068
Total						
Total Compensation	$ 1,389,201	$ 1,331,338	$ 1,338,246	$ 1,286,712	$ 1,586,263	$ 1,646,222
Total Compensation	$ 1,389,201	$ 1,331,338	$ 1,338,246	$ 1,286,712	$ 1,586,263	$ 1,646,222
Total Compensation Capitalized (CGAAP)	$ 299,723	$ 235,975	$ 272,346	$ 302,215	$ 440,516	
Total Compensation Charged to OM&A (CGAAP)	$ 1,089,478.00	$ 1,095,363.19	$ 1,065,901	$ 984,496.87	$ 1,145,746.99	
Total Compensation Capitalized (MIFRS)				$ 302,215	$ 440,516	$ 457,251
Total Compensation Charged to OM&A (MIFRS)				$ 984,496.87	$ 1,145,746.99	$ 1,188,971.44

Table 4.2.14 provides details of LPDL's compensation and benefits for three employee categories – Management, Non-Union and Union.

The salaries and wage amounts include all salaries and wages paid inclusive of vacations, stat holidays, floater days, sick leave, bereavement leave and other miscellaneous paid leave which may be considered as benefits, however, for the purposes of this analysis they are considered salaries/wages.

The benefit amounts include LPDL's costs to provide extended health care, dental, long-term disability and life insurance, along with statutory benefits (EI, CPP, EHT) and OMERS for all employees.

Regulatory, financial reporting and technical operations requirements have changed the way LPDL does business. The staffing levels changed to provide regulatory and financial reporting requirements, and required additional technical and managerial expertise. Additional support is required as a result of the Asset Management plan and the incorporation of policy and procedure requirements for safety and other regulatory requirements. LPDL participates in market surveys in order to pay competitive salaries to its management and non-union staff and assist in retaining talented employees. LPDL recognizes the costs in retaining head hunters and the time and resources involved in training new staff. Consequently, LPDL needs to retain staff at market rates. LPDL continues to monitor and review its salary structure with its Board of Directors on a yearly basis. All management positions are reviewed and adjustments are made by the CEO where deemed appropriate. Salaries are expected to increase by 3% in 2013 which would include performance plus cost of living increases.

LPDL is undergoing substantial increases in its fixed assets due to the enhancement and/or replacement of system infrastructure and system enhancements. All management positions play an important role in the design and implementation of these replacements/enhancements.

Change in Employee Compensation & Benefits

2010 Actual vs. 2009 Actual

Management:

Change in FTE: +.25

Dollar impact –	Headcount	$17,446
	Wage increase	2,217

In 2009, the Lines Supervisor left the company and the position was filled in the last half of the year ($23 K). Wages decreased in 2010 due to the change in Billing Supervisor from a long term employee to a new employee with limited experience ($3 K) and salary increases for remaining staff. Management inflationary increase in 2010 was 3%.

Non-Union:

Change in FTE: +.36

Dollar impact –	Headcount	$20,906
	Wage increase	7,854

In 2010, the part time employee was given more hours in order handle to more of the day-to-day collection calls. Non-union inflationary increase in 2010 was 3%.

Union:

Change in FTE: -.5

Dollar impact –	Headcount	$40,139
	Wage increase	21,253
	Overtime	(26,886)

The decrease in FTE of .5 in 2010 was due to the departure of one linesperson. Wage increase was as per union contract, 3%. Contract labour was utilized when possible, reducing overtime and the addition of full time employees, keeping the organization lean.

<u>2011 Actual vs. 2010 Actual</u>

Management:

Change in FTE: -1.0

Dollar impact –	Headcount	$(95,613)
	Wage increase	13,771
	Benefit increase	4,112

2011 saw LPDL without a Lines Supervisor and this position remained vacant until 2012. A line crew position assisted in the interim along with the Operations Manager and COO. Wage increase was 3%. The benefit increase was partially due to the change in wages in addition to the increase in the rates for OMERS contribution and Employment Insurance.

Non-Union:

Change in FTE: -0.1

Dollar impact –	Headcount	$(6,584)
	Wage increase	5,487
	Benefit increase	1,550

Hours for part time staff was reduced creating the headcount decrease. Wage increase was 3%. The benefit increase was partially due to the change in wages in addition to the increase in the rates for OMERS contribution and Employment Insurance.

Union:

Change in FTE: 0

Dollar impact –	Headcount	$0
	Wage increase	15,153
	Benefit increase	9,591

Wage increase was 3% as per union contract. The benefit increase was partially due to the change in wages in addition to the increase in the rates for OMERS contribution and Employment Insurance.

2012 Bridge vs. 2011 Actual

Management:

Change in FTE: +.25

Dollar impact –	Headcount	$ 25,301
	Wage increase	15,781
	Benefit increase	9,164

A new Lines Supervisor is to be hired in late 2012. Wage increase was 3%. The benefit increase was partially due to the change in wages in addition to the large increase in the rates for OMERS contribution, CPP and Employment Insurance.

Non-Union:

Change in FTE: +1.05

Dollar impact –	Headcount	$74,244
	Wage increase	29,046
	Benefit increase	16,192

LPDL added a staff person to manage the change and implementation of the Asset Management program and the conversion to IFRS and increased hours for part time staff. Wage increase was 3% plus an increase to one staff for taking on additional responsibilities around Smart Meter data management. The benefit increase was partially due to the change in wages in addition to the large increase in the rates for OMERS contribution, CPP and Employment Insurance.

Union:

Change in FTE: +1.0

Dollar impact –	Headcount	$88,103
	Wage increase	26,978
	Benefit increase	9,591

A new linesman will be hired for succession planning as there are currently 3 staff who are close to retirement within the next 1-3 years. Wage increase was 3% as per union contract. The benefit increase was partially due to the change in wages in addition to the large increase in the rates for OMERS contribution, CPP and Employment Insurance.

<u>2013 Test vs. 2012 Bridge</u>

Management:

Change in FTE: 0

Dollar impact –	Headcount	$ 0
	Wage increase	7,412
	Benefit increase	4,620

Wage increase was 3%. The benefit increase was partially due to the change in wages in addition to the large increase in the rates for OMERS contribution, CPP and Employment Insurance as well as health & dental benefits.

Non-Union:

Change in FTE: 0

Dollar impact –	Headcount	$0
	Wage increase	8,120
	Benefit increase	5,062

Wage increase was 3%. The benefit increase was partially due to the change in wages in addition to the large increase in the rates for OMERS contribution, CPP and Employment Insurance as well as health & dental benefits

Union:

Change in FTE: 0

Dollar impact –	Headcount	$0
	Wage increase	20,500
	Benefit increase	12,970

Wage increase was 3% as per union contract. The benefit increase was partially due to the change in wages in addition to the large increase in the rates for OMERS contribution, CPP and Employment Insurance as well as health & dental benefits

Change in Benefits

In 2011, OMERS released a 3-year plan indicating approximately 1% per year increase in OMERS premiums beginning in 2011, to be matched by employers. In September 2011 OMERS announced that pension contribution rates were to include the 1% per year increase as outlined in the 3-year plan. The total change in premiums increased from 10% to 13%.

Contribution rates for normal retirement age 65 members

- On earnings up to CPP earnings limit*: 2011 is 7.4%; **2012 is 8.3%**
- On earnings over CPP earnings limit*: 2011 is 10.7%; **2012 is 12.8%**

*CPP earnings limit (Year's Maximum Pensionable Earnings or YMPE) in 2011 is $48,300; the limit in 2012 will be higher. OMERS members pay a lower rate of contributions on earnings up to the YMPE because OMERS and the CPP are designed to work together to provide pension benefits.

Contribution Rates for 2013

Beginning with the first, *full* pay period in 2013, the rates paid by active members (and matched by their employers) will be as follows.

Normal retirement age 65 members

- On earnings up to CPP earnings limit - 9.0%
- On earnings over CPP earnings limit - 14.6%
- On earnings over CPP earnings limit - 15.9%

CHARGES TO/FROM AFFILIATES FOR SERVICES PROVIDED:

Introduction

LPDL purchases the following services from its affiliates, Lakeland Holding Ltd. and Lakeland Energy Ltd. The cost allocators described below set out the current methodologies used to allocate costs to the corporate group of companies.

A summary of LPDL's 2009 Board Approved, 2010 Actual, 2011 Actual and 2012 Bridge Year and 2013 Test Year shared services costs is presented in Table 4.2.15.

Table 4.2.15 – Shared Services and Corporate Cost Allocation – 2009 through 2013

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2009 Board Approved

Shared Services

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service
From	To			$	$
Lakeland Energy	Lakeland Power	Fibre optic connect	Market based	$ 10,343	
Lakeland Energy	Lakeland Power	IT Support	Market based		
Lakeland Energy	Lakeland Power	GIS services	Market based	$ 50,000	
Lakeland Power	Lakeland Energy	Streetlight Mtce	Cost plus margin		

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methdology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Lakeland Holding	Lakeland Power	Executive services	Cost - timesheets	62%	$ 127,188
Lakeland Holding	Lakeland Power	Management servi	Cost - timesheets	62%	$ 219,299
Lakeland Holding	Lakeland Power	Human resources	Cost - timesheets	62%	$ 66,125
Lakeland Holding	Lakeland Power	Financial services	Cost - timesheets	62%	$ 46,665
Lakeland Holding	Lakeland Power	Telephone/Internet	Cost - number of employees	74%	$ 24,000
Lakeland Holding	Lakeland Power	Insurance	Cost - asset base	60%	$ 10,500
Lakeland Holding	Lakeland Power	Audit fees	Cost - revenue percentage	65%	$ 3,500
Lakeland Holding	Lakeland Power	Legal services	Cost - direct disbursement	100%	$ 5,000
Lakeland Holding	Lakeland Power	Training services	Cost - number of employees	74%	$ 6,000
Lakeland Holding	Lakeland Power	Building rent	Cost - sq. footage	81%	$ 49,000

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2010

Shared Services

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service
From	To			$	$
Lakeland Energy	Lakeland Power	Fibre optic connect	Cost plus	$ 13,860	$ 11,745
Lakeland Energy	Lakeland Power	IT Support	Cost plus	$ 117,399	$ 102,150
Lakeland Energy	Lakeland Power	GIS services	Cost plus	$ 48,628	$ 44,250
Lakeland Power	Lakeland Energy	Streetlight Mtce	Market based	$ 33,112	$ 27,500

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methdology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Lakeland Holding	Lakeland Power	Executive services	Cost - timesheets	45%	$ 208,379
Lakeland Holding	Lakeland Power	Board of Directors	Cost	40%	$ 10,450
Lakeland Holding	Lakeland Power	Management servic	Cost - timesheets	69%	$ 87,083
Lakeland Holding	Lakeland Power	Human resources	Cost - timesheets	39%	$ 39,295
Lakeland Holding	Lakeland Power	Financial services	Cost - timesheets	60%	$ 138,993
Lakeland Holding	Lakeland Power	Telephone/Internet	Cost - number of er	68%	$ 32,831
Lakeland Holding	Lakeland Power	Insurance	Cost - asset base	51%	$ 8,736
Lakeland Holding	Lakeland Power	Audit fees	Cost - revenue perc	59%	$ 11,707
Lakeland Holding	Lakeland Power	Legal services	Cost - direct disburs	100%	$ -
Lakeland Holding	Lakeland Power	Training services	Cost - number of er	68%	$ 36,110
Lakeland Holding	Lakeland Power	Building rent	Cost - sq. footage	81%	$ 94,327
Lakeland Holding	Lakeland Power	Accounting softwar	Cost - number of er	68%	$ 30,430

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2011

Shared Services

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service
From	To			$	$
Lakeland Energy	Lakeland Power	Fibre optic connection	Cost plus	$ 13,860	$ 12,095
Lakeland Energy	Lakeland Power	IT Support	Cost plus	$ 134,248	$ 116,990
Lakeland Energy	Lakeland Power	GIS services	Cost plus	$ 33,260	$ 30,250
Lakeland Power	Lakeland Energy	Streetlight Mtce	Market based	$ 27,070	$ 22,500

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methdology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Lakeland Holding	Lakeland Power	Executive services	Cost - timesheets	51%	$ 251,672
Lakeland Holding	Lakeland Power	Board of Directors	Cost	40%	$ 10,450
Lakeland Holding	Lakeland Power	Management services	Cost - timesheets	77%	$ 77,789
Lakeland Holding	Lakeland Power	Human resources	Cost - timesheets	35%	$ 31,412
Lakeland Holding	Lakeland Power	Financial services	Cost - timesheets	59%	$ 109,969
Lakeland Holding	Lakeland Power	Telephone/Internet/IT support/Off	Cost - number of employees	62%	$ 19,706
Lakeland Holding	Lakeland Power	Insurance	Cost - asset base	36%	$ -
Lakeland Holding	Lakeland Power	Audit fees	Cost - revenue percentage	59%	$ 19,362
Lakeland Holding	Lakeland Power	Legal services	Cost - direct disbursement	100%	$ -
Lakeland Holding	Lakeland Power	Training services	Cost - number of employees	62%	$ 3,216
Lakeland Holding	Lakeland Power	Building rent	Cost - sq. footage	81%	$ 85,618
Lakeland Holding	Lakeland Power	Accounting software	Cost - number of employees	62%	$ 35,780

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2012

Shared Services

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service
From	To			$	$
Lakeland Energy	Lakeland Power	Fibre optic connect	Cost plus	$ 16,000	$ 14,000
Lakeland Energy	Lakeland Power	IT Support	Cost plus	$ 148,000	$ 135,000
Lakeland Energy	Lakeland Power	GIS services	Cost plus	$ 70,400	$ 67,000

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methdology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Lakeland Holding	Lakeland Power	Executive services	Cost - timesheets	51%	$ 250,088
Lakeland Holding	Lakeland Power	Board of Directors	Cost	40%	$ 12,450
Lakeland Holding	Lakeland Power	Management servic	Cost - timesheets	70%	$ 75,000
Lakeland Holding	Lakeland Power	Human resources	Cost - timesheets	35%	$ 34,100
Lakeland Holding	Lakeland Power	Financial services	Cost - timesheets	60%	$ 106,350
Lakeland Holding	Lakeland Power	Telephone/Internet	Cost - number of er	63%	$ 29,450
Lakeland Holding	Lakeland Power	Insurance	Cost - asset base	36%	$ -
Lakeland Holding	Lakeland Power	Audit fees/IFRS co	Cost - revenue perc	59%	$ 44,250
Lakeland Holding	Lakeland Power	Legal services	Cost - direct disbur	100%	$ -
Lakeland Holding	Lakeland Power	Training services	Cost - number of er	62%	$ 8,060
Lakeland Holding	Lakeland Power	Building rent	Cost - sq. footage	81%	$ 94,500
Lakeland Holding	Lakeland Power	Accounting softwar	Cost - number of er	62%	$ 35,780

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2013

Shared Services

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service
From	To			$	$
Lakeland Energy	Lakeland Power	Fibre optic connection	Cost plus	$ 16,000	$ 14,000
Lakeland Energy	Lakeland Power	IT Support	Cost plus	$ 148,000	$ 135,000
Lakeland Energy	Lakeland Power	GIS services	Cost plus	$ 70,400	$ 67,000

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methdology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Lakeland Holding	Lakeland Power	Executive services	Cost - timesheets	51%	$ 260,000
Lakeland Holding	Lakeland Power	Board of Directors	Cost	40%	$ 12,450
Lakeland Holding	Lakeland Power	Management services	Cost - timesheets	70%	$ 77,250
Lakeland Holding	Lakeland Power	Human resources	Cost - timesheets	35%	$ 35,000
Lakeland Holding	Lakeland Power	Financial services	Cost - timesheets	60%	$ 109,541
Lakeland Holding	Lakeland Power	Telephone/Internet/IT su	Cost - number of employees	62%	$ 25,000
Lakeland Holding	Lakeland Power	Insurance	Cost - asset base	36%	$ -
Lakeland Holding	Lakeland Power	Audit fees/IFRS conversi	Cost - revenue percentage	59%	$ 17,700
Lakeland Holding	Lakeland Power	Legal services	Cost - direct disbursement	100%	$ -
Lakeland Holding	Lakeland Power	Training services	Cost - number of employees	62%	$ 8,000
Lakeland Holding	Lakeland Power	Building rent	Cost - sq. footage	81%	$ 94,500
Lakeland Holding	Lakeland Power	Accounting software	Cost - number of employees	62%	$ 35,780

Shared Services:

Table 4.2.16 – Shared Services

Account	Description	2009 COS	2011	2013 Test	Variance 2013 to 2009	Variance 2013 to 2011
Shared Services						
5620	Fibre Optic connection	$ 10,343	$ 13,860	$ 16,000	$ 5,657	$ 2,140
5675	IT Support	$ -	$ 134,248	$ 148,000	$ 148,000	$ 13,752
5085	GIS services	$ 50,000	$ 33,260	$ 70,400	$ 20,400	$ 37,140

LPDL receives Shared Services from an affiliate company, Lakeland Energy Ltd. The services are providing fibre optic communication between Bracebridge and Huntsville offices as well as to distribution stations. IT support is also provided as per the description in Exhibit 4, Tab 2, Schedule 3 under Account 5675. The GIS services have increased in recent years with the advent of the Asset Management plan referenced in Exhibit 2 and the full GIS mapping of the distribution system to better identify LPDL assets. Lakeland Energy Ltd. also provides these services to other utilities as well as districts and municipalities. The rates charged are based on cost plus small mark up for overheads as opposed to market based pricing.

Corporate Cost Allocation:

Description of cost allocators to corporate group of companies:

Type of Service	**Executive Services**
Cost Allocators	Percentage of time allocated or specific distribution
Explanation	Includes salaries, benefits and expenses for CEO and Board of Directors
Type of Service	**Senior Management Services**
Cost Allocators	Percentage of time allocated
Explanation	Includes salaries, benefits and expenses for CFO, COO, and Administration assistant. Also includes time spent preparing regulatory filings including rate applications.
Type of Service	**Human Resources** To provide various human resources services including recruitment, collective bargaining and health and safety services
Cost Allocators	Percentage of time allocated
Type of Service	**General Financial Services** To provide accounts payables processing, miscellaneous accounts receivables processing, cheques administration, banking administration, purchasing administration. Also includes time spent preparing regulatory filings including rate applications.
Cost Allocators	Percentage of time allocated
Type of Service	**Office supplies/Photocopying/Postage/Courier/Telephone/internet services** To provide and maintain telephone services and ISP charge for internet at administration office
Cost Allocators	Number of employees
Type of Service	**Insurance** To provide insurance for assets, Director's and vehicle insurance
Cost Allocators	Net asset base

Type of Service	**Audit fees** Third party audit fees for consolidated company
Cost Allocators	Revenue percentage
Type of Service	**Legal Services** To provide internal legal counsel and related legal services; e.g. corporate contract drafting, easement registrations
Cost Allocators	Direct disbursement
Type of Service	**Training** To provide training for all employees on general areas, teamwork, harassment, first aid, and JH&SC certification.
Cost Allocators	Number of employees
Type of Service	**Building Rent** To provide and maintain physical office and operations space
Cost Allocators	200-395 Centre St N, Huntsville - based on actual square footage

Table 4.2.17 – Variance Analysis

2013 Test Year vs. 2009 Board approved and 2013 Test Year vs. 2011 Actual

$ - $ 0 $ -

Account	Description	2009 COS	2011	2013 Test	Variance 2013 to 2009	Variance 2013 to 2011
Corporate Cost Allocation						
5665	Executive Services	$ 127,188	$ 251,672	$ 260,000	$ 132,812	$ 8,328
5665	Board of Directors	$ -	$ 10,450	$ 12,450	$ 12,450	$ 2,000
5665	Management Services	$ 219,299	$ 77,789	$ 77,250	-$ 142,049	-$ 539
5665	Human Resources	$ 66,125	$ 31,412	$ 35,000	-$ 31,125	$ 3,588
5665	Financial Services	$ 46,665	$ 109,969	$ 109,541	$ 62,876	-$ 428
5665	Office Supplies/Telephone/Internet	$ 24,000	$ 19,706	$ 25,000	$ 1,000	$ 5,294
5665	Insurance	$ 10,500	$ -	$ -	-$ 10,500	$ -
5665	Audit Fees	$ 3,500	$ 19,362	$ 17,700	$ 14,200	-$ 1,662
5665	Legal services	$ 5,000	$ -	$ -	-$ 5,000	$ -
5665	Training services	$ 6,000	$ 3,216	$ 8,000	$ 2,000	$ 4,784
5665	Building rent	$ 49,000	$ 85,618	$ 94,500	$ 45,500	$ 8,882
5665	Accounting software	$ -	$ 35,780	$ 35,780	$ 35,780	$ -

Executive services, Board of Directors and Management services were realigned in the actual years versus 2009 Cost of Service filing. When combining the three, the variance is $3,213. Financial services increased in 2013 over 2009 due to the conversion to IFRS, the implementation of the fixed asset database and the 2013 Cost of Service rate application. Building rent increased as the administration offices were moved to a new location in order to house the staff, accommodate file storage, meeting area and premises that met building code and wheelchair accessible. The accounting software charge is the fee for the use of Great Plains software for finance, AR, AP, and payroll that was implemented in order to convert to dual ledgers with the implementation of IFRS(Financial) and MIFRS (Regulatory). There are minimal changes to the charges for 2013, and the variance is predominately to cover salary increases.

PURCHASE OF PRODUCTS AND SERVICES FROM NON-AFFILIATES:

LPDL purchases many services and products from third parties. Tables 4.2.18, 4.2.19 and 4.2.20 disclose the expenditures by vendor where the annual amount exceeded $50,000 per year, for the years 2009, 2010 and 2011, respectively. These tables contain the historical Non-Affiliate Supplier information including Vendor, total amount of goods or services purchased and the procurement method used.

A copy of LPDL's purchasing policy has been provided in Appendix B. LPDL has followed this policy in the past and will continue to do so.

Table 4.2.18 - 2009 Non-Affiliate Suppliers

Vendor Name	Total Inv Paid	Product or Service	Procurement Method
HYDRO ONE NETWORKS INC	$ 14,981,855.22	Electricity Purchases	Market Rate
ELSTER ELECTRICITY METER	$ 1,336,321.95	Meter Purchases	RFP (Smart Meters)
ONTARIO ELECTRIC FIN CORP	$ 1,270,393.25	Debt Retirement Remittances	Statutory
BLACK & MCDONALD LTD	$ 432,900.88	Distribution Station Equipment Purchases	Quote
RECEIVER GENERAL-GST	$ 426,406.05	GST Remittances	Statutory
TILTRAN SERVICES INC.	$ 401,926.88	Distribution Station Contract Work	Quote
RECEIVER GENERAL CANADA	$ 313,172.24	Source Deductions	Statutory
OLAMETER INC	$ 196,151.82	Meter Reading & Smart Meter Installation Contractor	Contract/RFP (Smart Meters)
ONTARIO ELECTRIC FIN CORP	$ 190,940.00	PILS Remittances	Statutory
STANDARD LIFE	$ 176,819.38	Benefit Provider	Market Rate
H D SUPPLY UTILITIES	$ 157,317.63	Pole Line Materials/Wire/Stock Supplies	Quote
TERRY EXELL	$ 154,077.10	Linesman Contractor	Quote
O.M.E.R.S.	$ 138,585.02	Pension	Market Rate
DAVEY TREE EXPERT CO.	$ 130,830.01	Tree Trimming Contractor	RFP
MOLONEY ELECTRIC	$ 128,071.94	Transformers	Quote
HARRIS COMPUTER SYSTEMS	$ 118,089.09	CIS Software Maintenance	Contract
ENERSPECTRUM GROUP	$ 95,201.06	CDM Program Management	RFP
ALTEC INDUSTRIES LTD	$ 94,262.26	Large Truck Maintenance and Purchases	Quote
UTILISMART CORPORATION	$ 71,552.25	Retail Settlement Provider Services	RFP
HYDRO ONE	$ 71,237.98	Load Transfer and Joint Use Settlement	Market Rate
BOWMAN FUELS LTD.	$ 58,214.23	Fuel Purchases	Market Rate
CANADA POST CORPORATION	$ 56,405.96	Postage	Market Rate

Table 4.2.19 - 2010 Non-Affiliate Suppliers

Vendor Name	Total Inv Paid	Product or Service	Procurement Method
HYDRO ONE NETWORKS INC	$ 14,032,408.61	Electricity Purchases	Market Rate
ONTARIO ELECTRIC FIN CORP	$ 1,140,808.43	Debt Retirement Remittances	Statutory
RECEIVER GENERAL-GST	$ 524,882.36	GST Remittances	Statutory
RECEIVER GENERAL CANADA	$ 285,460.01	Source Deductions	Statutory
ONTARIO ELECTRIC FIN CORP	$ 229,200.00	PILS Remittances	Statutory
SOUTHWEST POWER CORP	$ 153,596.57	Pole Line Construction Contractor	Quote
LAKEPORT POWER LTD	$ 149,215.98	Transformers	Quote
STANDARD LIFE ASSURANCE COMPAN	$ 134,770.55	Benefit Provider	Market Rate
H D SUPPLY UTILITIES	$ 134,468.37	Pole Line Materials/Wire/Stock Supplies	Quote
O.M.E.R.S.	$ 128,683.36	Pension	Market Rate
MOLONEY ELECTRIC	$ 125,605.15	Transformers	Quote
CLEARBROOK BUILDING CORPORATIO	$ 117,409.34	Subdivision Development Economic Evaluation Settlement	Contract
OLAMETER INC	$ 96,986.57	Meter Reading	Contract
MINISTER OF FINANCE 1	$ 85,594.00	OEB Special Purpose Charge for Recovery	Regulatory
BURMAN ENERGY	$ 84,087.27	CDM Program Management	RFP
TERRY EXELL	$ 74,962.13	Linesman Contractor	Quote
ELSTER ELECTRICITY METER	$ 68,123.24	Meter Purchases	RFP (Smart Meters)
UTILISMART CORPORATION	$ 66,816.80	Retail Settlement Provider Services	RFP
EPTCON LTD.	$ 64,632.28	Distribution Station Contract Work	Quote
P. MEDLEY & SONS LTD	$ 56,142.63	Excavation/Trenching Contractor	Quote
HYDRO ONE	$ 53,438.14	Load Transfer and Joint Use Settlement	Market Rate
TILTRAN SERVICES INC	$ 53,209.81	Distribution Station Contract Work	Quote

Table 4.2.20 - 2011 Non-Affiliate Suppliers

Vendor Name	Total Inv Paid	Product or Service	Procurement Method
HYDRO ONE NETWORKS INC	$ 15,066,552.97	Electricity Purchases	Market Rate
ONTARIO ELECTRIC FIN CORP - DRC	$ 1,174,215.88	Debt Retirement Remittances	Statutory
GREYSTONE PROJECT MANAGEMENT INC	$ 1,002,326.48	Construction Contractor (Building Upgrades)	Quote
RECEIVER GENERAL-GST	$ 742,984.55	GST Remittances	Statutory
SOUTHWEST POWER CORP	$ 368,569.89	Pole Line Construction Contractor	Quote
RECEIVER GENERAL CANADA - OTTAWA TAX CENTRE	$ 260,065.14	Source Deductions	Statutory
H D SUPPLY UTILITIES	$ 206,728.20	Pole Line Materials/Wire/Stock Supplies	Quote
ONTARIO ELECTRIC FIN CORP - CORP TAX BRANCH-HY	$ 164,304.00	PILS Remittances	Statutory
STANDARD LIFE ASSURANCE COMPANY	$ 139,211.04	Benefit Provider	Market Rate
O.M.E.R.S.	$ 137,324.12	Pension	Market Rate
ONTARIO LINE CLEARING	$ 96,112.15	Tree Trimming Contractor	RFP
BOWMAN FUELS LTD	$ 73,245.94	Fuel Purchases	Market Rate
UTILISMART CORPORATION	$ 68,524.33	Retail Settlement Provider Services	RFP
POI BUSINESS INTERIORS	$ 66,459.64	Furniture Purchases (Building Upgrades)	Quote
STEVE DUBEAU	$ 66,391.75	Linesman Contractor	Quote
ABB INC	$ 64,226.94	Transformers	Quote
LAKEPORT POWER LTD	$ 60,268.55	Transformers	Quote
LARRY HARRIS	$ 59,897.08	Linesman Contractor	Quote
BURMAN ENERGY	$ 58,463.56	CDM Program Management	RFP
CANADA POST CORPORATION	$ 52,539.55	Postage	Market Rate
TOWN OF BRACEBRIDGE	$ 51,856.38	Property Taxes and Building Permits	Market Rate

DEPRECIATION, AMORTIZATION AND DEPLETION:

Amortization on capital assets is calculated as follows:

- LPDL uses the pooling of assets for all fixed assets with the exception of Computer Equipment/Software, Automotive Equipment and Furniture & Equipment. Amortization is calculated on a straight line basis over the estimated remaining useful life of the assets at the end of the previous year plus 50% of the current year capital additions.
- LPDL's amortization policy has been to take a half-year's amortization on capital additions during the current year. As per OEB guidelines, LDCs are required to use the half-year rule when accounting for amortization expense.
- Depreciation rates are in line with rates set out in the APH. These rates are reflected in the tables that follow.
- Table 4.2.21 below provides a summary of amortization expense for the years 2009 to 2011 Actual, 2012 Bridge Year (CGAAP and MIFRS) and 2013 Test Year (MIFRS).

Table 4.2.21: – Summary of Amortization Expense for 2009 to 2013 – CGAAP (MIFRS)

CCA Class	OEB	Description	2009 Actual	2010 Actual	2011 Actual	2012 Bridge (CGAAP)	2012 Bridge (MIFRS)	2013 Test (MIFRS)
12	1611	Computer Software (Formally known as Account 1925)	$ 18,387	$ 19,732	$ 26,053	$ 39,718	$ 112,845	$ 22,720
12	1611	Computer Software (Formally known as Account 1925) - Smart Meters				$ 40,472	$ 70,826	$ 70,826
CEC	1612	Land Rights (Formally known as Account 1906)					$ -	$ -
N/A	1805	Land					$ -	$ -
47	1808	Buildings	$ 19,173	$ 19,987	$ 40,601	$ 60,402	$ 76,374	$ 76,374
13	1810	Leasehold Improvements					$ -	$ -
47	1815	Transformer Station Equipment >50 kV					$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 98,710	$ 133,516	$ 145,034	$ 148,093	$ 73,037	$ 76,224
47	1825	Storage Battery Equipment					$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 265,869	$ 274,363	$ 285,308	$ 296,538	$ 206,375	$ 210,027
47	1835	Overhead Conductors & Devices	$ 116,389	$ 123,215	$ 132,729	$ 141,365	$ 152,605	$ 154,749
47	1840	Underground Conduit	$ 132,822	$ 136,063	$ 139,529	$ 142,741	$ 46,275	$ 49,303
47	1845	Underground Conductors & Devices	$ 59,149	$ 65,216	$ 72,422	$ 80,013	$ 66,323	$ 72,902
47	1850	Line Transformers	$ 245,938	$ 266,750	$ 286,204	$ 299,840	$ 192,015	$ 198,595
47	1855	Services (Overhead & Underground)	$ 15,553	$ 17,909	$ 20,924	$ 23,953	$ 13,222	$ 15,292
47	1860	Meters	$ 51,728	$ 6,712	$ 9,906	$ 14,379	$ 18,355	$ 22,533
47	1860	Meters (Stranded Meters)					$ -	$ -
47	1860	Meters (Smart Meters)				$ 107,995	$ 110,584	$ 109,720
N/A	1905	Land					$ -	$ -
47	1908	Buildings & Fixtures	$ 5,969	$ 6,141	$ 6,141	$ 6,141	$ 5,651	$ 5,651
13	1910	Leasehold Improvements					$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 13,596	$ 11,871	$ 10,964	$ 14,758	$ 21,647	$ 22,647
8	1915	Office Furniture & Equipment (5 years)					$ -	$ -
10	1920	Computer Equipment - Hardware					$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 18,763	$ 11,656	$ 3,441		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 13,343	$ 15,483	$ 16,358	$ 14,598	$ 28,088	$ 2,000
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07) - Smart Meters				$ 9,233	$ 10,772	$ 10,772
10	1930	Transportation Equipment	$ 128,464	$ 121,384	$ 124,321	$ 116,436	$ 77,415	$ 101,869
8	1935	Stores Equipment	$ 820	$ 820	$ 820	$ 820	$ 697	$ 697
8	1940	Tools, Shop & Garage Equipment	$ 14,524	$ 16,123	$ 16,247	$ 17,211	$ 22,778	$ 28,028
8	1945	Measurement & Testing Equipment					$ -	$ -
8	1950	Power Operated Equipment					$ -	$ -
8	1955	Communications Equipment	$ 18,914	$ 14,545	$ 14,302	$ 13,447	$ 13,944	$ 13,944
8	1955	Communication Equipment (Smart Meters)				$ 82,117	$ 33,813	$ 33,813
8	1960	Miscellaneous Equipment					$ -	$ -
47	1975	Load Management Controls Utility Premises					$ -	$ -
47	1980	System Supervisor Equipment				$ 3,333	$ 2,500	$ 7,500
47	1985	Miscellaneous Fixed Assets					$ -	$ -
47	1995	Contributions & Grants	-$ 157,546	-$ 175,689	-$ 193,397	-$ 199,886	-$ 193,638	-$ 193,638
							$ -	$ -
							0	0
		Total	**$ 1,080,565**	**$ 1,085,797**	**$ 1,157,907**	**$ 1,473,717**	**$ 1,162,500**	**$ 1,112,547**

		Less: Fully Allocated Depreciation						
		Transportation	$ 128,464	$ 120,293	$ 124,321	$ 116,436	$ 77,415	$ 101,869
		Stranded Meters in 1555				-$ 140,553	-$ 140,553	
		Deferred PP&E						$ 58,599
		Total on Financial Statements	**$ 952,101**	**$ 965,504**	**$ 1,033,586**	**$ 1,497,834**	**$ 1,225,638**	**$ 952,080**

The year-over-year fluctuations in amortization expense (as seen above) are natural based on capital additions, disposal of assets, and assets becoming fully depreciated. The increase for 2012 over 2011 is mainly due to the inclusion of Smart Meters in 2012's rate base.

LPDL has provided detailed amortization expense calculations using the OEB's methodology. There are no differences between this methodology and LPDL's Audited Financial Statement amortization amounts.

Depreciation rates are in line with rates as set out in the APH. These rates are reflected in Tables 4.2.22 to 4.2.27 below for the years 2011, 2012 (CGAAP and MIFRS) and 2013 (MIFRS).

Table 4.2.22 – Amortization Expense for 2011

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2011 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2011 Depreciation Expense (h) = (e) / (f)
1611	Computer Software (Formally known as Account 1925)	$ 202,604.00	$ 94,024.28	$ 108,579.72	$ 66,105.00	$ 141,632.22	5.00	20.00%	$ 28,326.44
1611	Computer Software (Formally known as Account 1925) - Smart Meters	$ -			$ -		5.00		
1612	Land Rights (Formally known as Account 1906)	$ 493,354.00	$ 14,146.51	$ 479,207.49	$ 22,650.00	$ 490,532.49	-		$ -
1805	Land	$ -		$ -	$ -	$ -			$ -
1808	Buildings	$ 652,936.00		$ 652,936.00	$ 1,188,048.00	$ 1,246,960.00	30.00	3.33%	$ 41,565.33
1810	Leasehold Improvements	$ -		$ -	$ -	$ -			$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -	$ -			$ -
1820	Distribution Station Equipment <50 kV	$ 3,174,761.00		$ 3,174,761.00	$ 47,952.00	$ 3,198,737.00	25.00	4.00%	$ 127,949.48
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -			$ -
1830	Poles, Towers & Fixtures	$ 5,556,075.00		$ 5,556,075.00	$ 336,718.00	$ 5,724,434.00	25.00	4.00%	$ 228,977.36
1835	Overhead Conductors & Devices	$ 3,120,640.00		$ 3,120,640.00	$ 257,034.00	$ 3,249,157.00	25.00	4.00%	$ 129,966.28
1840	Underground Conduit	$ 3,036,781.00		$ 3,036,781.00	$ 73,853.00	$ 3,073,707.50	25.00	4.00%	$ 122,948.30
1845	Underground Conductors & Devices	$ 1,699,482.00		$ 1,699,482.00	$ 169,062.00	$ 1,784,013.00	25.00	4.00%	$ 71,360.52
1850	Line Transformers	$ 5,520,518.00		$ 5,520,518.00	$ 393,057.00	$ 5,717,046.50	25.00	4.00%	$ 228,681.86
1855	Services (Overhead & Underground)	$ 484,651.00		$ 484,651.00	$ 76,951.00	$ 523,126.50	25.00	4.00%	$ 20,925.06
1860	Meters	$ 193,262.26		$ 193,262.26	$ 73,679.00	$ 230,101.76	25.00	4.00%	$ 9,204.07
1860	Meters (Stranded Meters)	$ 1,006,848.74		$ 1,006,848.74	$ -	$ 1,006,848.74	25.00	4.00%	$ 40,273.95
1860	Meters (Smart Meters)	$ -			$ -		15.00	6.67%	
1905	Land	$ 278,455.00		$ 278,455.00	$ -	$ 278,455.00			$ -
1908	Buildings & Fixtures	$ 174,386.00		$ 174,386.00	$ -	$ 174,386.00	30.00	3.33%	$ 5,812.87
1910	Leasehold Improvements	$ -		$ -	$ -	$ -			$ -
1915	Office Furniture & Equipment (10 years)	$ 166,164.00	$ 89,458.99	$ 76,705.01	$ 65,879.00	$ 109,644.51	10.00	10.00%	$ 10,964.45
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -			$ -
1920	Computer Equipment - Hardware	$ 175,958.69	$ 175,958.69	$ -	$ -	$ -	5.00	20.00%	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 105,476.57	$ 71,061.70	$ 34,414.87	$ -	$ 34,414.87	5.00	20.00%	$ 6,882.97
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 78,865.86		$ 78,865.86	$ 5,839.00	$ 81,785.36	5.00	20.00%	$ 16,357.07
1920	Computer Equip.-Hardware(Post Mar. 19/07) - Smart Meters	$ -			$ -		5.00	20.00%	
1930	Transportation Equipment	$ 1,175,512.00	$ 260,344.40	$ 915,167.60	$ -	$ 915,167.60	7.35	13.61%	$ 124,512.60
1935	Stores Equipment	$ 10,960.00	$ 2,761.53	$ 8,198.47	$ -	$ 8,198.47	10.00	10.00%	$ 819.85
1940	Tools, Shop & Garage Equipment	$ 238,014.00	$ 82,408.25	$ 155,605.75	$ 13,734.00	$ 162,472.75	10.00	10.00%	$ 16,247.28
1945	Measurement & Testing Equipment	$ -		$ -	$ -	$ -			$ -
1950	Power Operated Equipment	$ -		$ -	$ -	$ -			$ -
1955	Communications Equipment	$ 188,721.00	$ 45,697.51	$ 143,023.49	$ -	$ 143,023.49	10.00	10.00%	$ 14,302.35
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -			$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -			$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -			$ -
1980	System Supervisor Equipment	$ -		$ -	$ -	$ -			$ -
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -			$ -
1995	Contributions & Grants	-$ 4,672,795.00		-$ 4,672,795.00	-$ 324,443.00	-$ 4,835,016.50	25.00	4.00%	-$ 193,400.66
etc.				$ -	$ -	$ -			$ -
				$ -		$ -			$ -
	Total	$ 23,061,631.12	$ 835,861.86	$ 22,225,769.26	$ 2,466,118.00	$ 23,458,828.26			$ 1,052,677.43

Table 4.2.23 – Variance Analysis on 2011 Depreciation Calculation

Account	Description	2011 Depreciation Expense (h) = (e) / (f)	2011 Depreciation Expense per Appendix 2-B Fixed Assets, Column K	Variance ² (m) = (h) - (l)	Reason For variance
1611	Computer Software (Formally known as Account 1925)	$ 28,326.44	$ 26,053.00	$ 2,273.44	$ 2,273.01
1611	Computer Software (Formally known as Account 1925) - Smart Meters		$ -		
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	
1805	Land	$ -	$ -	$ -	
1808	Buildings	$ 41,565.33	$ 40,601.00	$ 964.33	$ 963.84
1810	Leasehold Improvements	$ -	$ -	$ -	
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	
1820	Distribution Station Equipment <50 kV	$ 127,949.48	$ 145,034.00	-$ 17,084.52	-$ 17,085.18
1825	Storage Battery Equipment	$ -	$ -	$ -	
1830	Poles, Towers & Fixtures	$ 228,977.36	$ 285,308.00	-$ 56,330.64	-$ 56,331.13
1835	Overhead Conductors & Devices	$ 129,966.28	$ 132,729.00	-$ 2,762.72	-$ 2,765.32
1840	Underground Conduit	$ 122,948.30	$ 139,529.00	-$ 16,580.70	-$ 16,580.39
1845	Underground Conductors & Devices	$ 71,360.52	$ 72,422.00	-$ 1,061.48	-$ 1,062.36
1850	Line Transformers	$ 228,681.86	$ 286,204.00	-$ 57,522.14	-$ 57,523.21
1855	Services (Overhead & Underground)	$ 20,925.06	$ 20,924.00	$ 1.06	
1860	Meters	$ 9,204.07	$ 9,906.00	-$ 701.93	-$ 701.93
1860	Meters (Stranded Meters)	$ 40,273.95	$ -	$ 40,273.95	$ 46,850.95
1860	Meters (Smart Meters)		$ -		
1905	Land	$ -	$ -	$ -	
1908	Buildings & Fixtures	$ 5,812.87	$ 6,141.00	-$ 328.13	-$ 274.62
1910	Leasehold Improvements	$ -	$ -	$ -	
1915	Office Furniture & Equipment (10 years)	$ 10,964.45	$ 10,964.00	$ 0.45	
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	
1920	Computer Equipment - Hardware	$ -	$ -	$ -	
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 6,882.97	$ 3,441.00	$ 3,441.97	$ 3,441.50
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 16,357.07	$ 16,358.00	-$ 0.93	
1920	Computer Equip.-Hardware(Post Mar. 19/07) - Smart Meters		$ -		
1930	Transportation Equipment	$ 124,512.60	$ 124,321.00	$ 191.60	
1935	Stores Equipment	$ 819.85	$ 820.00	-$ 0.15	
1940	Tools, Shop & Garage Equipment	$ 16,247.28	$ 16,247.00	$ 0.27	
1945	Measurement & Testing Equipment	$ -	$ -	$ -	
1950	Power Operated Equipment	$ -	$ -	$ -	
1955	Communications Equipment	$ 14,302.35	$ 14,302.00	$ 0.35	
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	
1960	Miscellaneous Equipment	$ -	$ -	$ -	
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	
1980	System Supervisor Equipment	$ -	$ -	$ -	
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	
1995	Contributions & Grants	-$ 193,400.66	-$ 193,397.00	-$ 3.66	
etc.		$ -		$ -	
		$ -		$ -	
	Total	$ 1,052,677.43	$ 1,157,907.00	-$ 105,229.57	-$ 105,229.57

Table 4.2.24 – Amortization Expense for 2012 (CGAAP)

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2012	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	2012 Depreciation Expense
		(a)	(b)	(c)	(d)	[illegible]	(f)	(g) = 1 / (f)	(h) = (e) / (f)
1611	Computer Software (Formally known as Account 1925)	$ 268,709.00	$116,754.31	$ 151,954.69	$ 108,600.00	$ 206,254.69	5.00	20.00%	$ 41,250.94
1611	Computer Software (Formally known as Account 1925) - Smart Meters	$ 202,361.40		$ 202,361.40	$ -	$ 202,361.40	5.00	20.00%	$ 40,472.28
1612	Land Rights (Formally known as Account 1906)	$ 516,004.00		$ 516,004.00	$ 5,000.00	$ 518,504.00	-	0.00%	$ -
1805	Land	$ -		$ -	$ -	$ -	-	0.00%	$ -
1808	Buildings	$ 1,840,984.00		$ 1,840,984.00	$ -	$ 1,840,984.00	30.00	3.33%	$ 61,366.13
1810	Leasehold Improvements	$ -		$ -	$ -	$ -	-	0.00%	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -	$ -	-	0.00%	$ -
1820	Distribution Station Equipment <50 kV	$ 3,222,713.00		$ 3,222,713.00	$ 105,000.00	$ 3,275,213.00	25.00	4.00%	$ 131,008.52
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -	-	0.00%	$ -
1830	Poles, Towers & Fixtures	$ 5,892,793.00		$ 5,892,793.00	$ 224,750.00	$ 6,005,168.00	25.00	4.00%	$ 240,206.72
1835	Overhead Conductors & Devices	$ 3,377,674.00		$ 3,377,674.00	$ 174,750.00	$ 3,465,049.00	25.00	4.00%	$ 138,601.96
1840	Underground Conduit	$ 3,110,634.00		$ 3,110,634.00	$ 86,750.00	$ 3,154,009.00	25.00	4.00%	$ 126,160.36
1845	Underground Conductors & Devices	$ 1,868,544.00		$ 1,868,544.00	$ 210,500.00	$ 1,973,794.00	25.00	4.00%	$ 78,951.76
1850	Line Transformers	$ 5,913,575.00		$ 5,913,575.00	$ 288,750.00	$ 6,057,950.00	25.00	4.00%	$ 242,318.00
1855	Services (Overhead & Underground)	$ 561,602.00		$ 561,602.00	$ 74,500.00	$ 598,852.00	25.00	4.00%	$ 23,954.08
1860	Meters	$ 266,941.26		$ 266,941.26	$ 90,000.00	$ 311,941.26	22.81	4.38%	$ 13,677.43
1860	Meters (Stranded Meters)	$ -		$ -	$ -	$ -		0.00%	$ -
1860	Meters (Smart Meters)	$ 1,619,923.32		$ 1,619,923.32	$ -	$ 1,619,923.32	15.00	6.67%	$ 107,994.89
1905	Land	$ 278,455.00		$ 278,455.00	$ -	$ 278,455.00	-	0.00%	$ -
1908	Buildings & Fixtures	$ 174,386.00		$ 174,386.00	$ -	$ 174,386.00	30.00	3.33%	$ 5,812.87
1910	Leasehold Improvements	$ -		$ -	$ -	$ -	-	0.00%	$ -
1915	Office Furniture & Equipment (10 years)	$ 232,043.00	$ 89,458.99	$ 142,584.01	$ 10,000.00	$ 147,584.01	10.00	10.00%	$ 14,758.40
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -	-	0.00%	$ -
1920	Computer Equipment - Hardware	$ 175,958.69	$175,958.69	$ -	$ -	$ -	5.00	20.00%	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 105,476.57	$105,476.57	$ -	$ -	$ -	5.00	20.00%	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 84,704.86		$ 84,704.86	$ 10,000.00	$ 89,704.86	5.00	20.00%	$ 17,940.97
1920	Computer Equip.-Hardware(Post Mar. 19/07) - Smart Meters	$ 46,163.99		$ 46,163.99	$ -	$ 46,163.99	5.00	20.00%	$ 9,232.80
1930	Transportation Equipment	$ 1,175,512.00	$298,101.87	$ 877,410.13	$ 115,000.00	$ 934,910.13	8.00	12.50%	$ 116,863.77
1935	Stores Equipment	$ 10,960.00	$ 2,761.53	$ 8,198.47	$ -	$ 8,198.47	10.00	10.00%	$ 819.85
1940	Tools, Shop & Garage Equipment	$ 251,748.00	$109,647.42	$ 142,100.58	$ 60,000.00	$ 172,100.58	10.00	10.00%	$ 17,210.06
1945	Measurement & Testing Equipment	$ -		$ -	$ -	$ -	-	0.00%	$ -
1950	Power Operated Equipment	$ -		$ -	$ -	$ -	-	0.00%	$ -
1955	Communications Equipment	$ 188,721.00	$ 54,246.64	$ 134,474.36	$ -	$ 134,474.36	10.00	10.00%	$ 13,447.44
1955	Communication Equipment (Smart Meters)	$ 410,583.25		$ 410,583.25	$ -	$ 410,583.25	5.00	20.00%	$ 82,116.65
1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -	-	0.00%	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -	-	0.00%	$ -
1980	System Supervisor Equipment	$ -		$ -	$ 100,000.00	$ 50,000.00	15.00	6.67%	$ 3,333.33
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -	-	0.00%	$ -
1995	Contributions & Grants	-$ 4,997,238.00		-$ 4,997,238.00	$ -	-$ 4,997,238.00	25.00	4.00%	-$ 199,889.52
etc.				$ -		$ -		0.00%	$ -
				$ -		$ -		0.00%	$ -
	Total	$ 26,799,932.34	$952,406.02	$ 25,847,526.32	$ 1,663,600.00	$ 26,679,326.32			$ 1,327,609.68

Table 4.2.25 – Variance Analysis on 2012 Depreciation Calculation

Account	Description	2012 Depreciation Expense (h) = (e) / (f)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance 2 (m) = (h) - (l)	Reason For variance
1611	Computer Software (Formally known as Account 1925)	$ 41,250.94	$ 39,718.30	$ 1,532.64	$ 1,532.25
1611	Computer Software (Formally known as Account 1925) - Smart Meters	$ 40,472.28	$ 40,472.28	$ -	
1612	Land Rights (Formally known as Account 1906)	$ -		$ -	
1805	Land	$ -		$ -	
1808	Buildings	$ 61,366.13	$ 60,402.00	$ 964.13	$ 963.84
1810	Leasehold Improvements	$ -		$ -	
1815	Transformer Station Equipment >50 kV	$ -		$ -	
1820	Distribution Station Equipment <50 kV	$ 131,008.52	$ 148,093.00	-$ 17,084.48	-$ 17,085.18
1825	Storage Battery Equipment	$ -		$ -	
1830	Poles, Towers & Fixtures	$ 240,206.72	$ 296,537.75	-$ 56,331.03	-$ 56,331.13
1835	Overhead Conductors & Devices	$ 138,601.96	$ 141,364.64	-$ 2,762.68	-$ 2,765.32
1840	Underground Conduit	$ 126,160.36	$ 142,740.73	-$ 16,580.37	-$ 16,580.39
1845	Underground Conductors & Devices	$ 78,951.76	$ 80,012.82	-$ 1,061.06	-$ 1,062.36
1850	Line Transformers	$ 242,318.00	$ 299,840.01	-$ 57,522.01	-$ 57,523.21
1855	Services (Overhead & Underground)	$ 23,954.08	$ 23,953.19	$ 0.89	
1860	Meters	$ 13,677.43	$ 14,379.37	-$ 701.94	-$ 701.93
1860	Meters (Stranded Meters)	$ -		$ -	
1860	Meters (Smart Meters)	$ 107,994.89	$ 107,994.89	-$ 0.00	
1905	Land	$ -		$ -	
1908	Buildings & Fixtures	$ 5,812.87	$ 6,141.46	-$ 328.59	-$ 274.62
1910	Leasehold Improvements	$ -		$ -	
1915	Office Furniture & Equipment (10 years)	$ 14,758.40	$ 14,758.40	$ 0.00	
1915	Office Furniture & Equipment (5 years)	$ -		$ -	
1920	Computer Equipment - Hardware	$ -		$ -	
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 17,940.97	$ 14,598.00	$ 3,342.97	$ 3,342.82
1920	Computer Equip.-Hardware(Post Mar. 19/07) - Smart Meters	$ 9,232.80	$ 9,232.80	-$ 0.00	
1930	Transportation Equipment	$ 116,863.77	$ 116,436.23	$ 427.54	
1935	Stores Equipment	$ 819.85	$ 819.89	-$ 0.04	
1940	Tools, Shop & Garage Equipment	$ 17,210.06	$ 17,210.52	-$ 0.46	
1945	Measurement & Testing Equipment	$ -		$ -	
1950	Power Operated Equipment	$ -		$ -	
1955	Communications Equipment	$ 13,447.44	$ 13,447.41	$ 0.03	
1955	Communication Equipment (Smart Meters)	$ 82,116.65	$ 82,116.65	$ -	
1960	Miscellaneous Equipment	$ -		$ -	
1975	Load Management Controls Utility Premises	$ -		$ -	
1980	System Supervisor Equipment	$ 3,333.33	$ 3,333.33	$ 0.00	
1985	Miscellaneous Fixed Assets	$ -		$ -	
1995	Contributions & Grants	-$ 199,889.52	-$ 199,886.27	-$ 3.25	
etc.		$ -		$ -	
		$ -	$ -	$ -	
	Total	$ 1,327,609.68	$ 1,473,717.40	-$ 146,107.72	

Table 4.2.26 – Amortization Expense for 2012 (MIFRS)

Account	Description	Opening NBV as at Jan 1, 2012 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2012 Depreciation Expense (k) = (j) + (h)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (k) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 101,985.00	$ 108,600.00	1.00	5.00	20.00%	$ 101,985.00	$ 10,860.00	$ 112,845.00	$ 112,845.00	$ -
1611	Computer Software (Formally known as Account 1925) - Smart Meters	$ 141,652.98	$ -	2.00	5.00	20.00%	$ 70,826.49	$ -	$ 70,826.49	$ 70,826.49	$ -
1612	Land Rights (Formally known as Account 1906)	$ 500,857.00	$ 5,000.00			0.00%	$ -	$ -	$ -	$ -	$ -
1805	Land	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ 1,664,950.00	$ -	21.80	50.00	2.00%	$ 76,373.85	$ -	$ 76,373.85	$ 76,373.85	$ -
1810	Leasehold Improvements	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 2,332,467.00	$ 105,000.00	32.52	40.00	2.50%	$ 71,724.08	$ 1,312.50	$ 73,036.58	$ 73,036.58	$ -
1825	Storage Battery Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 3,027,588.00	$ 224,750.00	14.85	45.00	2.22%	$ 203,877.98	$ 2,497.22	$ 206,375.20	$ 206,375.20	$ -
1835	Overhead Conductors & Devices	$ 2,342,799.00	$ 174,750.00	15.50	60.00	1.67%	$ 151,148.32	$ 1,456.25	$ 152,604.57	$ 152,604.57	$ -
1840	Underground Conduit	$ 1,620,530.00	$ 86,750.00	35.86	40.00	2.50%	$ 45,190.46	$ 1,084.38	$ 46,274.84	$ 46,274.84	$ -
1845	Underground Conductors & Devices	$ 1,343,671.00	$ 210,500.00	21.00	45.00	2.22%	$ 63,984.33	$ 2,338.89	$ 66,323.22	$ 66,323.22	$ -
1850	Line Transformers	$ 3,647,540.00	$ 288,750.00	19.36	40.00	2.50%	$ 188,405.99	$ 3,609.38	$ 192,015.37	$ 192,015.37	$ -
1855	Services (Overhead & Underground)	$ 439,514.00	$ 74,500.00	35.46	45.00	2.22%	$ 12,394.64	$ 827.78	$ 13,222.42	$ 13,222.42	$ -
1860	Meters	$ 207,286.94	$ 90,000.00	13.50	15.00	6.67%	$ 15,354.59	$ 3,000.00	$ 18,354.59	$ 18,354.59	$ -
1860	Meters (Stranded Meters)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -
1860	Meters (Smart Meters)	$ 1,492,879.58	$ -	13.50	15.00	6.67%	$ 110,583.67	$ -	$ 110,583.67	$ 110,583.67	$ -
1905	Land	$ 278,455.00	$ -			0.00%	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 123,184.00	$ -	21.80	50.00	2.00%	$ 5,650.64	$ -	$ 5,650.64	$ 5,650.64	$ -
1910	Leasehold Improvements	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 105,944.00	$ 10,000.00	5.01	10.00	10.00%	$ 21,146.51	$ 500.00	$ 21,646.51	$ 21,646.51	$ -
1915	Office Furniture & Equipment (5 years)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	-$ 0.31	$ -	-	5.00	20.00%	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 0.20	$ -	-	-	0.00%	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 27,087.86	$ 10,000.00	1.00	5.00	20.00%	$ 27,087.86	$ 1,000.00	$ 28,087.86	$ 28,087.86	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07) - Smart Meters	$ 32,314.79	$ -	3.00	5.00	20.00%	$ 10,771.60	$ -	$ 10,771.60	$ 10,771.60	$ -
1930	Transportation Equipment	$ 410,640.00	$ 115,000.00	5.73	10.00	10.00%	$ 71,664.92	$ 5,750.00	$ 77,414.92	$ 77,414.92	$ -
1935	Stores Equipment	$ 2,376.00	$ -	3.41	10.00	10.00%	$ 696.77	$ -	$ 696.77	$ 696.77	$ -
1940	Tools, Shop & Garage Equipment	$ 78,319.00	$ 60,000.00	3.96	10.00	10.00%	$ 19,777.53	$ 3,000.00	$ 22,777.53	$ 22,777.53	$ -
1945	Measurement & Testing Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -
1950	Power Operated Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment	$ 59,960.00	$ -	4.30	10.00	10.00%	$ 13,944.19	$ -	$ 13,944.19	$ 13,944.19	$ -
1955	Communication Equipment (Smart Meters)	$ 287,408.27	$ -	8.50	10.00	10.00%	$ 33,812.74	$ -	$ 33,812.74	$ 33,812.74	$ -
1960	Miscellaneous Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -	$ 100,000.00	20.00	20.00	5.00%	$ -	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ -
1985	Miscellaneous Fixed Assets	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	-$ 3,923,109.00	$ -	20.26	42.50	2.35%	-$ 193,638.15	$ -	-$ 193,638.15	-$ 193,638.15	$ -
etc.						0.00%	$ -	$ -	$ -		$ -
						0.00%	$ -	$ -	$ -		$ -
	Total	$ 16,346,300.31	$ 1,663,600.00				$ 1,122,764.01	$ 39,736.39	$ 1,162,500.40	$ 1,162,500.40	$ -

Notes:

LPDL has averaged the number of years useful lives under the "New Year's Additions Only" column under account #1820.

Table 4.2.27 – Amortization Expense for 2013 Test Year - MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2013 Depreciation Expense [1] (h)=2012 Full Year Depreciation + ((d)*0.5)/(f)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 10,000.00	5.00	20.00%	$ 22,720.00	$ 22,720.00	$ -
1611	Computer Software (Formally known as Account 1925) - Smart Meters	$ -	5.00	20.00%	$ 70,826.49	$ 70,826.49	$ -
1612	Land Rights (Formally known as Account 1906)	$ 5,000.00	-	0.00%	$ -	$ -	$ -
1805	Land	$ -	-	0.00%	$ -	$ -	$ -
1808	Buildings	$ -	50.00	2.00%	$ 76,373.85	$ 76,373.85	$ -
1810	Leasehold Improvements	$ -	-	0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -	-	0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 150,000.00	40.00	2.50%	$ 76,224.08	$ 76,224.08	$ -
1825	Storage Battery Equipment	$ -	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 147,400.00	45.00	2.22%	$ 210,027.31	$ 210,027.31	$ -
1835	Overhead Conductors & Devices	$ 123,000.00	60.00	1.67%	$ 154,749.49	$ 154,749.49	$ -
1840	Underground Conduit	$ 155,500.00	40.00	2.50%	$ 49,302.96	$ 49,302.96	$ -
1845	Underground Conductors & Devices	$ 404,500.00	45.00	2.22%	$ 72,902.16	$ 72,902.16	$ -
1850	Line Transformers	$ 297,800.00	40.00	2.50%	$ 198,594.80	$ 198,594.80	$ -
1855	Services (Overhead & Underground)	$ 111,800.00	45.00	2.22%	$ 15,292.42	$ 15,292.42	$ -
1860	Meters	$ 84,500.00	15.00	6.67%	$ 22,532.85	$ 22,532.85	$ -
1860	Meters (Stranded Meters)	$ -	-	0.00%	$ -	$ -	$ -
1860	Meters (Smart Meters)	$ 15,500.00	15.00	6.67%	$ 109,720.34	$ 109,720.34	$ -
1905	Land	$ -	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ -	50.00	2.00%	$ 5,650.64	$ 5,650.64	$ -
1910	Leasehold Improvements	$ -	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 10,000.00	10.00	10.00%	$ 22,646.51	$ 22,646.51	$ -
1915	Office Furniture & Equipment (5 years)	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ -	5.00	20.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	5.00	20.00%	$ 2,000.00	$ 2,000.00	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07) - Smart Meters	$ -	5.00	20.00%	$ 10,771.60	$ 10,771.60	$ -
1930	Transportation Equipment	$ 395,000.00	7.68	13.03%	$ 101,868.70	$ 101,868.70	$ -
1935	Stores Equipment	$ -	10.00	10.00%	$ 696.77	$ 696.77	$ -
1940	Tools, Shop & Garage Equipment	$ 45,000.00	10.00	10.00%	$ 28,027.53	$ 28,027.53	$ -
1945	Measurement & Testing Equipment	$ -	-	0.00%	$ -	$ -	$ -
1950	Power Operated Equipment	$ -	-	0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ -	10.00	10.00%	$ 13,944.19	$ 13,944.19	$ -
1955	Communication Equipment (Smart Meters)	$ -	10.00	10.00%	$ 33,812.74	$ 33,812.74	$ -
1960	Miscellaneous Equipment	$ -	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 100,000.00	20.00	5.00%	$ 7,500.00	$ 7,500.00	$ -
1985	Miscellaneous Fixed Assets	$ -	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	$ -	42.50	2.35%	-$ 193,638.15	-$ 193,638.15	$ -
etc.		$ -	-	0.00%	$ -	$ -	$ -
				0.00%	$ -	$ -	$ -
	Total	$ 2,055,000.00			$ 1,112,547.27	$ 1,112,547.27	$ -

INCOME TAX, LARGE CORPORATION TAX

TAX CALCULATIONS:

Table 4.3.1 below provides a summary of 2009 Approved, the 2009, 2010, 2011 Actual, and the 2012 Bridge Year (CGAAP and MIFRS) and 2013 Test Year (MIFRS) income tax estimate using rates prescribed by the OEB in LPDL's 2011 IRM rate decision and order. A copy of LPDL's 2011 annual federal and provincial tax return has been provided as Appendix D to this exhibit. In accordance with the June 2012 filing requirements the Board's PILs model has also been completed and submitted and is consistent with the PILs included in the 2013 revenue requirement (Appendix C).

Table 4.3.1 – Summary of Income & Capital Taxes 2009 to 2013

Description	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge (CGAAP)	2012 Bridge (MIFRS)	2013 Test (MIFRS)
Income Taxes		225,460	203,178	176,592	44,769	27,029	160,968
Large Corporation Tax		0	0	0	0	0	0
Ontario Capital Tax		11,515	3,807	0	0	0	0
Total Taxes	0	236,975	206,985	176,592	44,769	27,029	160,968

Detailed calculations of LPDL's PILs are provided in the 2013 Test Year Income Tax PILs Workform V2 filed with this Application (Appendix C).

LPDL's detailed tax calculations used the most recent tax rates as provided in Table 4.3.2. No Capital Tax is paid effective July, 2010.

1 **Table 4.3.2: Schedule of Corporate Tax Rates 2012 and 2013**

Corporate Tax Rates for Tax Year:	2012 Bridge	2013 Test
Federal Income Tax	15.00%	15.00%
Ontario Income Tax	11.25%	11.50%
Combined Income Tax	26.25%	26.50%
Small Business Threshold	500,000	500,000
Federal Small Business Rate	11.00%	11.00%
Ontario Small Business Rate	4.50%	4.50%
Combined Small Business Rate	15.50%	15.50%
Small Business Credit	$33,750	$35,000

CAPITAL COST ALLOWANCE:

LPDL is providing Capital Cost Allowance continuity schedules and the Cumulative Eligible Capital Continuity schedules for the 2012 Bridge Year (MIFRS) (Tables 4.3.3 & 4.3.4) and the 2013 Test Year (MIFRS) (Tables 4.3.5 & 4.3.6) as follows:

Table 4.3.3 – 2012 CCA / UCC Continuity Schedule

Class	Class Description	UCC Regulated Historic Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA	UCC End of Bridge Year
1	Distribution System - post 1987	$ 10,126,185		-$ 81,085	$ 10,045,100	$ -	$ 10,045,100	4%	$ 401,804	$ 9,643,296
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election				$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988				$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 187,971	$ 70,000		$ 257,971	$ 35,000	$ 222,971	20%	$ 44,594	$ 213,377
10	Computer Hardware/ Vehicles	$ 279,345	$ 115,000	-$ 76,332	$ 318,013	$ 19,334	$ 298,679	30%	$ 89,604	$ 228,409
10.1	Certain Automobiles				$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 33,053	$ 108,600		$ 141,653	$ 54,300	$ 87,353	100%	$ 87,353	$ 54,300
13 1	Lease # 1				$ -	$ -	$ -		$ -	$ -
13 2	Lease #2				$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3				$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4				$ -	$ -	$ -		$ -	$ -
14	Franchise				$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				$ -	$ -	$ -	8%	$ -	$ -
42	Fibre Optic Cable	$ 54,116			$ 54,116	$ -	$ 54,116	12%	$ 6,494	$ 47,622
43.1	Certain Energy-Efficient Electrical Generating Equipment				$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment				$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 1,342			$ 1,342	$ -	$ 1,342	45%	$ 604	$ 738
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 6,040,436	$ 1,355,000	-$ 45,276	$ 7,350,160	$ 654,862	$ 6,695,298	8%	$ 535,624	$ 6,814,536
50	Data Network Infrastructure Equipment - post Mar 2007	$ 6,816	$ 10,000		$ 16,816	$ 5,000	$ 11,816	55%	$ 6,499	$ 10,317
52	Computer Hardware and system software				$ -	$ -	$ -	100%	$ -	$ -
95	CWIP				$ -	$ -	$ -		$ -	$ -
1	Valuation bump	$ 1,229,021			$ 1,229,021	$ -	$ 1,229,021	4%	$ 49,161	$ 1,179,860
6	Portable office	$ 43,599			$ 43,599	$ -	$ 43,599	10%	$ 4,360	$ 39,239
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 18,001,884	$ 1,658,600	-$ 202,693	$ 19,457,791	$ 768,496	$ 18,689,295		$ 1,226,096	$ 18,231,695

Table 4.3.4 – 2012 CEC Continuity Schedule

Cumulative Eligible Capital				**0**
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**0**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**0**
Current Year Deduction		**0**	**x 7% =**	**0**
Cumulative Eligible Capital - Closing Balance				**0**

Table 4.3.5 – 2013 CCA / UCC Continuity Schedule

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 9,643,296		-40,180	$ 9,603,116	$ -	$ 9,603,116	4%	$ 384,125	$ 9,218,991
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ -			$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 213,377	45,000		$ 258,377	$ 22,500	$ 235,877	20%	$ 47,175	$ 211,201
10	Computer Hardware/ Vehicles	$ 228,409	395,000	-190,067	$ 433,342	$ 102,467	$ 330,876	30%	$ 99,263	$ 334,080
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 54,300	10,000		$ 64,300	$ 5,000	$ 59,300	100%	$ 59,300	$ 5,000
13 1	Lease # 1	$ -			$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than B	$ -			$ -	$ -	$ -	8%	$ -	$ -
42	Fibre Optic Cable	$ 47,622			$ 47,622	$ -	$ 47,622	12%	$ 5,715	$ 41,907
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 738			$ 738	$ -	$ 738	45%	$ 332	$ 406
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -			$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 6,814,536	1,590,000	-51,852	$ 8,352,684	$ 769,074	$ 7,583,610	8%	$ 606,689	$ 7,745,995
50	Data Network Infrastructure Equipment - post Mar 2007	$ 10,317	10,000		$ 20,317	$ 5,000	$ 15,317	55%	$ 8,424	$ 11,893
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ -			$ -	$ -	$ -	0%	$ -	$ -
1	Valuation bump	$ 1,179,860			$ 1,179,860	$ -	$ 1,179,860	4%	$ 47,194	$ 1,132,666
6	Portable office	$ 39,239			$ 39,239	$ -	$ 39,239	10%	$ 3,924	$ 35,315
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 18,231,695	$ 2,050,000	-$ 282,099	$ 19,999,596	$ 904,041	$ 19,095,555		$ 1,262,141	$ 18,737,455

Table 4.3.6 - 2013 CEC Continuity Schedule

Cumulative Eligible Capital				**0**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**0**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**0**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")		**0**	**x 7% =**	**0**
Cumulative Eligible Capital - Closing Balance				**0**

MIFRS CONVERSION

<u>MIFRS – IMPACT ON OM&A</u>

Conversion to Modified International Financial Reporting Standards (MIFRS)

International Accounting Standard 16 (IAS 16) – Property, Plant and Equipment (PP&E), states the cost of an item of PP&E includes any costs that are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. IAS 16 does not define the term "directly attributable". The specific facts and circumstances surrounding the nature of the costs and the activity associated with it must be considered to determine if it is directly attributable to an item of PP&E. Where Canadian GAAP allowed for the capitalization of general and administrative overhead, MIFRS does not.

In order to allocate costs between operating expenses and capital expenses, LPDL utilizes payroll and vehicle maintenance burdens.

In reviewing each of these burdens LPDL has identified there are no changes to be made for capitalization under MIFRS.

MIFRS – IMPACT ON DEPRECIATION

IAS 16 requires each part of an item of PP&E with a cost that is significant in relation to the total cost of the time to be depreciated separately. In addition IAS 16 requires that entities perform a review of assets' useful lives, depreciation methods and residual values on an annual basis.

The Board commissioned a depreciation study to assist electricity distributors in their transition to IFRS. In the Report of the Board, Transition to International Financial Reporting Standards, (EB-2009-0408) the Board stated:

> "While utilities remain solely responsible for complying with financial reporting requirements, the Board notes that a generic depreciation study could assist utilities with IFRS compliance in addition to providing considerable regulatory benefits. The study should provide a good starting point for the determination of service lives for distribution assets that may be both acceptable to the Board and useful for financial reporting purposes. Distributors will remain responsible for review and updates of the service lives for their particular assets for financial reporting and regulatory requirements."

LPDL has reviewed the useful life of its assets with the aid of the Asset Depreciation Study by Kinetrics (Kinetrics Report). Table 2.5.1 included in Exhibit 2, Tab 5, Schedule 1 contains the useful lives by Uniform System of Account, compared to the current useful lives used under CGAAP. Overall, the useful lives have been extended causing depreciation to be reduced in the 2013 Test year by $463,340 , from $1,575,887 under CGAAP to $1,112,547 under MIFRS.

As discussed previously, LPDL retained Suncorp Valuations and Grant Thornton, LLP to provide assistance in the transition of financial records from CGAAP to IFRS which included the assignment of useful lives to the asset base.

The new levels of componentization and the corresponding useful lives will be applied beginning January 1, 2013.

MIFRS – IMPACT ON TAXES

TAX CALCULATIONS:

Tax calculations under MIFRS are provided in Exhibit 4, Tab 3, Schedule 1. As indicated above depreciation under CGAAP for the year 2013 would have been $1,575,887 . This would have resulted in increased PILS under CGAAP as the amount would have been added onto regulatory income vs the depreciation for MIFRS of $1,112,547 .

A P P E N D I X   A

AFFILIATE SERVICES AGREEMENT

THIS SERVICES AGREEMENT is made this 1st day of August, 2008

BETWEEN:

Lakeland Power Distribution Ltd., a corporation incorporated pursuant to the laws of the Province of Ontario and licensed by the Ontario Energy Board (hereinafter referred to as "LLP")

PARTY OF THE FIRST PART;

- and -

Lakeland Holding Ltd.
(hereinafter referred to as "Holding")

PARTY OF THE SECOND PART.

From time to time, LLP and Holding shall be individually referred to in this Agreement as a "Party" and collectively as "Parties".

WHEREAS:

A. Holding is a company who is to contract services out to LLP;

B. This Agreement acknowledges the regulatory oversight of the Ontario Energy Board of LLP and this Agreement must be governed by the following objectives:

a) protecting ratepayers from harm that may arise as a result of dealings between LLP and Holding;

b) preventing LLP from cross-subsidizing Holding activities;

c) protecting the confidentiality of information collected by LLP in the course of provision of LLP services;

d) ensuring there is no preferential access to LLP services;

e) preventing LLP from acting in a manner that provides an unfair business advantage to Holding*;* and

f) preventing customer confusion that may arise from the relationship between a LLP and Holding.

NOW THEREFORE in consideration of the mutual covenants, agreements, terms and conditions herein and other good and valuable consideration, the receipt and sufficiency of which is hereby irrevocably acknowledged, the parties agree as follows:

1. Definitions

(a) All terms that are defined in the Distribution System Code and the Retail Settlement Code which appear herein without definition shall have the meanings respectively ascribed thereto in the Distribution System Code and the Retail Settlement Code.

(b) Throughout this Agreement, unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

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

"Agreement" means this Services Agreement and attached Schedules

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

"Formal Notice" means the written notices required or permitted to be given in Sections 3, 5.2, 7.1 and 7.5 hereof.

"Open Access" is the date that Section 26(1) of the Electricity Act, 1998 is proclaimed in force; and

"Representative" means (i) a person controlling or controlled by or under common control of a party and each of the respective directors, officers, employees and independent contractors of the party and such party's Representative, and (ii) any consultants, agents or legal, financial or professional advisors of a party.

2. Term

The term of this Agreement shall commence on the date first written above and shall remain in full force and effect for no longer than 5 years or until one party gives 10 days notice to cancel this agreement, whichever comes first.

For greater certainty, the Parties acknowledge and agree that:

(i) this Agreement does not abrogate, amend or modify in any way whatsoever any agreement, written or otherwise, that LLP may have with other customers.

3. Services

(i) Holding is contracted to provide President & CEO services for strategic direction and management to ensure that LLP's corporate goals are achieved.

(ii) Holding is contracted to provide Chief Financial Officer and Chief Operations Officer services for strategic direction and management to ensure that LLP's corporate goals are achieved.

(iii) Holding is contracted to supply the following services to LLP;

a. Services of Administration Assistant
b. Human resources/Payroll services
c. General Financial services including Accounts payable processing, miscellaneous accounts receivable processing, cheque administration, banking administration, and purchasing administration,
d. Office expenses, Telephone and internet services,
e. Insurance, audit, legal services, building rent
f. IT Support,
g. Training,
h. Office supplies/machines.

(iv) LLP shall not endorse or support marketing activities of Holding.

(v) Holding shall not use LLP's name, logo or other distinguishing characteristics in a manner which would mislead consumers as to the distinction between LLP and Holding.

(vi) LLP shall take reasonable steps to ensure that Holding does not imply in its marketing material favoured treatment or preferential access to LLP's system or services. If the LLP becomes aware of inappropriate marketing activity by Holding, it shall:

(a) immediately take reasonable steps to notify affected customers of the violation;
(b) take necessary steps to ensure Holding is aware of the concern; and
(c) inform the Ontario Holding Board in writing of such activity and the remedial measures that were undertaken by LLP.

(vii) LLP shall apply all Rate Orders and rate schedules to Holding in the same manner as would be applied to similarly situated non-affiliated parties.

(viii) Requests by Holding or its customers for access to a LLP's transmission or distribution network or for LLP services shall be processed and provided by LLP in the same manner as would be processed or provided for similarly situated non-affiliated parties.

4. Fees and Invoicing

Holding will issue regular invoices to LLP which are payable at the due date. Late payments are subject to a late payment charge as may be set out on the invoice, and which charges shall not exceed 1.5% per month, from the date of the due invoice.

6. Payables & Receivables

(i) Holding will invoice LLP for the provision of services at cost, based on the allocation methodology outlined in Appendix A.

7. Payment Conditions

Holding will accept bill payments made by LLP through the following payment method:

- Cheque to Lakeland Holding Ltd.;

8. Dispute Resolution

In the event of any dispute or claim respecting this Agreement, the parties agree to first use good faith efforts to resolve the dispute without resorting to the Courts. The parties agree to attempt a resolution by direct contact between the most senior people in each organization, prior to resorting to litigation.

In all matters related to this Agreement, on which the documents are silent or ambiguous, the parties adopt the following hierarchy of approaches to resolve any conflict between them: a) common sense, b) commercial reasonableness, c) conventional trade practices, and d) Ontario Energy Board Codes.

9. General

9.1 Force Majeure: LLP shall not be liable for, nor shall Holding be entitled to cancel its contract, because of any outage or downtime resulting from any failure of performance or equipment due to causes beyond Energy’s control, including but not limited to: acts of God, fire, flood or other catastrophes; acts or omissions of third parties; any law, order, regulation, direction, action, or request of the any government, or of any department, agency commission, bureau, corporation or other instrumentality of any one or more of federal, provincial, or local governments; national emergencies; insurrections; riots; wars; unavailability of rights-of-way or materials; or strikes, lock-outs, work stoppages, or other labor difficulties.

9.2 Consideration: This Agreement is made for valuable consideration the receipt and sufficiency of which each party acknowledges by the signing of this Agreement.

9.3 Amendments: The terms of this Agreement shall only be amended by a document in writing signed or acknowledged by authourized representatives of both parties.

9.4 Assignment: Holding shall not assign this Agreement without the prior written consent of the LLP.

9.5 Non Waiver: No waiver of any term of this Agreement or of any breach or default shall be valid unless in writing and signed by the party giving the waiver. LLP will not be liable to Holding or other Third Party for any indirect , incidental, special or consequential damages, expenses or costs whatsoever, under any circumstances. LLP would not enter this Agreement unless Holding agreed to limit LLP's liability in this way. Energy acknowledges that the limitation of LLP's liability in this way is fair and reasonable under the circumstances of this Agreement.

10. Indemnity

Holding shall indemnify and save LLP harmless from all liability or damages arising from any and all claims by any third party, or LLP's failure to comply with terms of this Agreement. This indemnity shall survive termination of this Agreement.

11. Liability

Notwithstanding the foregoing, neither Party shall be liable under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential or incidental damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in statute, contract, tort or otherwise.

12. Entire Agreement.

This Agreement, together with the schedules attached hereto, constitutes the entire agreement between the Parties and supersedes all prior oral or written representations and agreements of any kind whatsoever with respect to the matters dealt with herein.

13. Incorporation of Schedules

Set out below are the schedules and appendices that form a part of, and that are hereby incorporated by reference into, this Agreement:

Appendix "A"	-	Allocation Methodology(EXAMPLE – REVISED ANNUALLY)
Schedule "A":	-	LLP Contact Information
Schedule "B"	-	Holding Contact Information
Attachment "C"	-	Confidentiality Agreement
Attachment "D"	-	Amended Affiliate Relationships Code For Electricity Distributors and Transmitters (2008)

14. Applicable Law.

This Agreement shall be construed and enforced in accordance with, and the rights of the Parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein, and the courts of Ontario shall have exclusive jurisdiction to determine all disputes arising out of this Agreement.

(i) LLP ensures accounting and financial separation from Holding and shall maintain separate financial records and books of accounts.

(ii) LLP ensures that at least one-third of its Board of Directors is independent from Holding.

(iii) This Agreement may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same agreement.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper officers, as of the day and year first written above.

Lakeland Holding Ltd.

____
Name: Chris Litschko
Title: President and Chief Executive Officer
I have authority to bind the Corporation

Lakeland Power Distribution Ltd.

____
Name: Holly Chantler
Title: General Manager
I have authority to bind the Corporation

Description of cost allocators to corporate group of companies:

Type of Service	**Executive Services**
Cost Allocators	Percentage of time allocated or specific distribution
Explanation	Includes salaries, benefits and expenses for CEO and Board of Directors
Type of Service	**Senior Management Services**
Cost Allocators	Percentage of time allocated
Explanation	Includes salaries, benefits and expenses for CFO, COO, and Administration assistant
Type of Service	**Human Resources** To provide various human resources services including recruitment, collective bargaining and health and safety services
Cost Allocators	Percentage of time allocated
Type of Service	**General Financial Services** To provide accounts payables processing, miscellaneous accounts receivables processing, cheques administration, banking administration, purchasing administration
Cost Allocators	Percentage of time allocated
Type of Service	**Telephone/internet services** To provide and maintain telephone services and ISP charge for internet.
Cost Allocators	Number of employees
Type of Service	**Insurance** To provide insurance for assets, Director's and vehicle insurance
Cost Allocators	Net asset base
Type of Service	**IT Support** To provide and maintain standard information systems, network services and support.
Cost Allocators	Number of employees
Type of Service	**Audit fees** Third party audit fees for consolidated company
Cost Allocators	Revenue percentage

Type of Service	**Legal Services**
	To provide internal legal counsel and related legal services; e.g. corporate contract drafting, easement registrations
Cost Allocators	Direct disbursement
Type of Service	**Training**
	To provide training for all employees on general areas, teamwork, harassment, health & safety.
Cost Allocators	Number of employees
Type of Service	**Office supplies/Photocopying/Postage/Courier**
	General office expenses incurred in day to day operations
Cost Allocators	Percentage of time allocated
Type of Service	**Building Rent**
	To provide and maintain physical office and operations space
Cost Allocators	5-45 Cairns Cres, Huntsville - based on actual square footage

TYPE OF SERVICE	**COST ALLOCATORS**	**COST ALLOCATION PERCENTAGES [%]**		
		Power	**Energy**	**Generation**
Executive & Director services	% of time spent	62.3	18.7	19
Management services	% of time spent	62.3	18.7	19
Human Resources	% of time spent	62.3	18.7	19
General Financial Services	% of time spent	62.3	18.7	19
Telephone services	# of employees	74	11	15
Insurance	Assets	60	4	36
IT support	# of employees	74	11	15
Audit fees	% of revenue	65.4	9	25.6
Legal services	Direct charge	1	1	1
Training services	# of employees	74	11	15
Office Supplies	# of employees	74	11	15
Building rent	Sq.ft. in Huntsville office	81	11	8

Schedule "A" – Lakeland Power Contact Information

Corporate Name: Lakeland Power Distribution Ltd.

1.0 Designated Contact for Contractual Matters and Formal Notice:

Name:	Holly Chantler
Title:	General Manager
Mailing Address:	5-45 Cairns Crescent
City:	Huntsville
Province:	ON
Postal Code:	P1H 2M2
Email Address:	hchantler@lakelandpower.on.ca
Phone:	705-789-5442
Fax:	705-789-3110

2.0 Designated Billing Contact:

Name:	Debbie Eccles
Title:	Accounting Associate
Mailing Address:	5-45 Cairns Crescent
City:	Huntsville
Province:	ON
Postal Code:	P1H 2M2
Email Address:	deccles@lakelandpower.on.ca
Phone:	705-789-5442
Fax:	705-789-3110

Schedule "B" – Lakeland Holding Contact Information

Corporate Name: Lakeland Holding Ltd.

1.0 Designated Contact for Contractual Matters and Formal Notice:

Name:	Chris Litschko
Title:	President & CEO
Mailing Address:	5-45 Cairns Cres
City:	Huntsville
Province:	ON
Postal Code:	P1H 2M2
Email	cjlitschko@lakelandholding.com
Phone:	705-789-5442
Fax:	705-789-3110

2.0 Designated Billing Contact:

Name:	_Janis Jenkins_
Title:	_Payroll & Benefits Administrator
Mailing Address:	_5-45 Cairns Cres
City:	_Huntsville
Province:	_ON_
Postal Code:	_P1H 2M2
Phone:	705-789-5442
Fax:	705-789-3110

CONFIDENTIALITY AGREEMENT

This Confidentiality Agreement (the "Agreement"), dated as of August 1st, 2008, is entered into by and between Lakeland Power Distribution Ltd. ("LLP") and Lakeland Holding Ltd. ("Holding") (each, a "Party", and collectively, the "Parties").

BACKGROUND:

A. Parties have entered into agreements related to the mapping services by Holding.

B. LLP will provide to Holding, data file information.

C. As a condition of such information being provided, the Parties covenant and agree to the terms and conditions herein contained.

NOW THEREFORE, for good and valuable consideration, the receipt and sufficiency of which is acknowledged, the Parties agree as follows:

1. Information. Subject to Section 6 of this Agreement, "Information" refers to all information relating to a Party or the Project that is provided by one Party (or its Representatives) (the "providing Party") to the other (the "receiving Party") which, irrespective of whether it is labelled "confidential", is confidential, a trade secret or otherwise proprietary to a Party including, without limitation, information with regard to current or projected assets, business strategies or projected financial information.

2. Provision of Information. The providing Party will supply at its discretion certain information to the receiving Party under reserve and condition that the stipulations herein contained shall be applied to that confidential information so disclosed. For more certainty, the present does not oblige either party to disclose to the other any details or information of any particular nature.

3. Ownership and Treatment of Information. All Information shall remain, at all times, the exclusive property of the providing Party. Except as expressly set out in this Section 3, neither the receiving Party nor any of its Representatives has any license or other right to use or disclose any Information received by it for any purpose whatsoever. The receiving Party may use the Information only in connection with this Project. Accordingly and specifically, the receiving Party will not use any Information either in its own business or to provide any consulting or other services to any other company or other entity. Before providing any Information to any of its Representatives, the receiving Party will first inform such Representative of the confidential nature of the Confidential Information and of the Party's obligations under this Agreement. The receiving Party will use the same means to protect the confidentiality of the Information that the receiving Party uses to protect its own confidential and proprietary information, and in any event the receiving Party will use not less than reasonable means.

4. Representatives. Each of the Parties may transmit the Information to its directors, officers, shareholders, employees and consultants (including, but not limited to, legal and financial advisors) ("Representatives") provided such Representatives (i) need to know the Information for the purpose of the Project and (ii) will preserve the confidentiality of the Information in accordance with the terms and provisions of this Agreement. Each Party shall remain liable for any breach of this Agreement by its Representatives.

5. Copies and Use of Information. Unless otherwise agreed to herein, neither Party shall, unless authorized by the other Party to do so, (i) copy, reproduce, distribute or disclose to any person, firm, entity, or corporation any of the Information, or any facts related thereto; (ii) permit any third party to have access to such Information; or (iii) use such Information for any purpose other than for the purpose of pursuing the activities as contemplated herein.

6. Required Disclosure. In the event that either Party or any of its Representatives, who has received Information from the other Party, is requested in any legal proceeding or regulatory process to disclose any Information, the receiving Party will and will cause its Representatives to give the providing Party prompt notice of such request so that the providing Party may seek an appropriate protective order or other remedy. If, in the absence of a protective order, the receiving Party is nonetheless advised in writing by internal or external counsel that disclosure of the Information is required (after exhausting any appeal requested by the providing Party at the providing Party's expense), the receiving Party may disclose only such Information as is required by law without liability hereunder. In any event, each Party agrees to use best efforts to ensure that all information is accorded confidential treatment.

7. Exclusions from Information. "Information" shall not include any information that the receiving Party can clearly demonstrate:

(a) was or becomes generally known to the public through no fault or action by the receiving Party or any of its Representatives;

(b) was readily and lawfully available to the receiving Party on a non-confidential basis prior to the disclosure hereunder to the receiving Party;

(c) was or becomes known to receiving Party on a non-confidential basis from a source other than the providing Party, so long as the source was not subject to any confidentiality obligation that the receiving Party was aware of; or

(d) as shown by written record, was independently developed by the receiving Party without reference to the Information.

8. Destruction of Information. At any time, at the providing Party's request, the receiving Party will deliver promptly to the providing Party all, or a specified portion of, the Information, together with all copies, extracts or other reproductions in whole or in part of such Information, provided however that the receiving Party's counsel may retain one copy subject to the condition that it keep the information confidential in accordance with the terms and conditions of this Agreement. In addition, at any time, at the providing Party's request, the receiving Party will destroy, promptly and irrevocably:

(a) all such copies, extracts or other reproductions of Information, or a specified portion of Information, which cannot, because of the device on which such Information is stored, be removed from the possession of the receiving Party by delivery to the providing Party; and

(b) all analyses, compilations, studies, documents, memoranda, notes and other writings and information whatsoever (regardless of the form, medium or device on or in which such Information is written, recorded, stored or reproduced) prepared by the receiving Party or its Representatives and which is based on any of the Information.

Following such delivery and destruction, the receiving Party will promptly provide the providing Party with written confirmation of completion. In any event, the receiving Party will complete all such actions within ten (10) business days of receipt of the providing Party's initial request.

9. No Obligation. This Agreement does not obligate either Party to enter into any further agreements.

10. No Representations or Warranties. Neither Party makes any representation or warranty as to the accuracy or completeness of any of the Information and neither Party will have any liability to the other Party or any of its Representatives in respect of the use of the Information by the other Party or any of its Representatives.

11. Headings, etc. The division of this Agreement into sections and the insertion of headings are for convenience of reference only and are not to affect the construction or interpretation of this Agreement. Words importing the singular include the plural and vice versa. The term "including" means "including without limitation", and the term "includes" and "included" have similar meanings.

12. Severability. The Parties agree that if any provision of this Agreement is found to be unenforceable or unconstitutional, the remaining provisions shall remain in full force and effect.

13. Remedies. Each Party acknowledges that the other Party may not have an adequate remedy at law for money damages if each Party fails to fulfill any of its obligations under this Agreement. Accordingly, providing Party will be entitled to any injunction, specific performance or other remedy in law or equity (without being required to post a bond or other security), in respect of any breach or threatened breach of this Agreement. Receiving Party will indemnify providing Party from all damages, liabilities, costs and losses (including legal fees and expenses) suffered or incurred by providing Party and arising in respect of a breach or threatened breach of any term of this Agreement by receiving Party or any of its Representatives (even after any Representative ceases to be a Representative of receiving Party).

14. Amendments. Any amendment to this Agreement must be in writing and approved by Parties.

15. Governing Law. This Agreement shall be governed by the laws of Ontario and the laws of Canada applicable therein. The Parties irrevocably submit to the non-exclusive jurisdiction of the courts of Ontario.

16. Successors and Assigns. This Agreement shall be binding on all successors and permitted assigns of each of the Parties and shall inure to the benefit of the respective successors and permitted assigns of each Party. Nothing in this Agreement shall be deemed to create rights in or benefits for any third parties; however, no assignment, sale, or encumbrance of either Party's position with regard to this Agreement shall be made without the prior written approval of the other Party.

17. Nature of Relationship. This Agreement is not intended to create, and shall not be construed to create a relationship of partnership or joint venture between the Parties. This Agreement shall not constitute either Party as the legal representative or agent of the other, nor shall either Party have the right or authority to assume, create or incur any liability or obligation, express or implied, against, in the name of or on the behalf of the other Party.

18. Failure to Exercise Rights or Remedies. No failure to exercise and no delay in exercising, any right or remedy under this Agreement will be deemed to be a waiver of that right or remedy. No waiver of any breach of any term of this Agreement will be deemed to be a waiver of any subsequent breach of that term.

19. Notices. All notices with regard to this Agreement should be forwarded, if intended for Lakeland Power Distribution Ltd to:

Lakeland Power Distribution Ltd
Attention: Holly Chantler
5-45 Cairns Crescent
Huntsville, Ontario
P1H 2M2

Telephone: 888-282-7711
Fax: (705) 789-3110

If intended for Lakeland Holding Ltd, to:

Lakeland Holding Ltd.

Attention: Chris Litschko
President & CEO
5-45 Cairns Crescent
Huntsville, Ontario
P1H 2M2

Telephone: 888-282-7711
Fax: (705) 789-3110

18. Counterpart. This Agreement may be signed in counterpart, each of which when taken together shall constitute one and the same instrument.

19. Term of Agreement. The parties agree that the terms and conditions imposing an obligation to keep information confidential shall apply for five (5) years from the date the Parties agree to enter into this project, or decide that they shall not jointly pursue a Project, whichever is earlier.

20. Entire Agreement. This Agreement contains the entire agreement of the parties hereto with respect to its subject matter.

The parties have duly executed this Agreement.

Lakeland Power Distribution Ltd.

By:

Name:

Title:

I have authority to bind the Corporation.

Lakeland Holding Ltd.

By:

Name:

Title:

I have authority to bind the Corporation

IT Services Agreement

This Agreement made as of November 10, 2009

Between:

Lakeland Energy Ltd. (the consultant)

- and -

Lakeland Power Distribution Ltd. (the customer)

The customer specified acknowledges that the terms and conditions of this service agreement have been made available to the customer and has been reviewed by the customer prior to the customer submitting the order requesting the performance of services by Lakeland Energy. The customer further acknowledges that the submission of the order constitutes acceptance of this agreement and will bind the customer to all of the terms and conditions hereof.
In consideration of the mutual promises and covenants made herein, the parties agree as follows:

1: **Services:**
Lakeland Energy shall, during the term (in section 3) provide the following services to the customer. These services will be provided during normal business hours being 7:30 am and 4:00 pm, Monday through Friday.

The following is a list of duties Lakeland Energy will provide Lakeland Power:

a) On-site support and or remote support for users as required
b) Data backup review
c) Disaster recovery management, monitoring and review
d) Diagnosis of any problems until resolved (software or hardware)
e) Repair any connection difficulties
f) Manage and assign required VPN access to consultants and internal
g) Update software and firmware
h) Installation of all 3rd party software

i) Consult on IT related matters

2. **Software:**
Lakeland Energy will support all software as per the list attached (**Appendix D**). Lakeland Energy will assist but is not solely responsible for the support of Harris, Great Plains and, Worktech.

3. **Term:**
This agreement shall commence on January 1st, 2010 and shall remain in effect until December 31, 2014. This contract can be extended provided that the parties agree in writing.

4. **Hardware:**
Lakeland Energy will provide servers, replacement desktops and laptops as required based on age and, performance. The purchase of desktops and laptops will be charged extra upon consultation with the customer.

5. **Compensation: IT SUPPORT and CONNECTIVITY**
Lakeland Power shall pay Lakeland Energy (the consultant) the sum of:

YEAR 2010
IT SUPPORT $116,736.00
- Complete remote virtual server hosting and back up.
- Desk top support
- All server hardware
- All windows server operating systems
- All network switches, routers and firewalls
- Remote access VPN systems
- VMware virtual infrastructure
- Redundant servers, MAS and ODS
- VLAN to servers.
- Full UPS DC battery backup for 3 days of continuous run-time.
- Management of all cellular, telephony, IT hardware
- BES server

CONNECTIVITY $13,860.00
- ALL fiber optic connectivity including VLANS and internet to all offices and substations

YEAR 2011
IT SUPPORT $132,000.00
CONNECTIVITY $13,860.00
- Services as 2010 plus
- Smart meters, increase in servers and data

- Increase in user count

YEAR 2012
IT SUPPORT $132,000.00
CONNECTIVITY $13,860.00
- Services as 2011

YEAR 2013
IT SUPPORT $148,000.00
CONNECTIVITY $16,000.00
- Services as 2012 plus
- Rental of NEC PBX solution and handsets
- All phone lines including long distance

YEAR 2014
IT SUPPORT $148,000.00
CONNECTIVITY $16,000.00
- Same as 2013

The Consultant shall submit monthly invoices to Lakeland Power for its compensation due at the end of each month (within 30 days).

6. **Confidential Information:**
For the purposes of this Agreement, the term "Confidential Information" means all information disclosed to, or acquired by, the Consultant, its employees or agents in connection with, and during the term of this Agreement which relates to Lakeland Power's past, present and future research, developments, systems, operations and business activities, including, without limiting the generality of the foregoing:

1- All items and documents prepared for, or submitted to Lakeland Power in connection with this agreement.
2- All information specifically designated by Lakeland Power as confidential.

But shall not included any information which was known to the Consultant, its employees or agents prior to the date hereof, or which was publicly disclosed otherwise than by breach of this Agreement.

Lakeland Energy acknowledges that pursuant to the performance of its obligations under this Agreement, it may require Confidential Information. The Consultant covenants and agrees, during the Term and following any termination of this Agreement, to hold and maintain all Confidential Information in trust and confidence for Lakeland Power and not to use Confidential

Information other than for the benefit of Lakeland Power. Except as authorized in writing by Lakeland Power, the Consultant covenants and agrees not to disclose any Confidential Information, by publication or otherwise, to any person other

than those persons whose services are contemplated for the purposes of carrying out this Agreement, provided that such persons agree in writing to be bound by, and comply with the provisions of this paragraph. The Consultant shall obtain similar covenants and agreement to those contained in this paragraph for the benefit of Lakeland Power from each of its employees or agents who are or may be exposed to Confidential Information.

7. **Customer Satisfaction Guarantee**
Lakeland Energy offers a 30 Day Money Back Guarantee to all new customers. The purpose of this guarantee is to allow customers to experience Lakeland Energy's Services and determine to their satisfaction that these Services meet or exceed industry standards for performance and reliability. If the Customer is not satisfied that Lakeland Energy has met industry standards for performance and reliability during the first 30 days of the Initial Term of this Agreement, the Customer may submit a "Money Back Guarantee" request form. To request this form, the Customer may send an email to support@lakelandenergy.com. Upon receipt of the request form within the specified guarantee period, Lakeland Energy will terminate the Services to the Customer and will refund the fees paid by the Customer. This refund will not include any setup fees or hourly support fees paid to Lakeland Energy.

8. **Temporary Service Suspension**
The Customer agrees that from time to time, it may be necessary for Lakeland Energy to temporarily suspend Services for technical reasons or to maintain the PEER 1 network, the hardware or any other facilities, the timing of which will be determined by Lakeland Energy. Lakeland Energy will provide the Customer with reasonable advance notice of the temporary suspension of Services.

9. **Emergency Service Suspension**
Lakeland Energy may at any time and from time to time suspend Services without penalty or liability for any claim by the Customer where necessary, acting reasonably, to prevent the improper or unlawful use of Lakeland Energy's services or equipment by the Customer or any other person. Lakeland Energy will provide the Customer with notice following such an emergency suspension to advise of the reasons for the suspension.

10. **Limitation of Liability**
CUSTOMER AGREES THAT NEITHER LAKELAND ENERGY NOR ANY OF ITS MEMBERS, SHAREHOLDERS, DIRECTORS, OFFICERS, EMPLOYEES OR

REPRESENTATIVES OF LAKELAND ENERGY WILL AT ANY TIME BE HELD LIABLE FOR ANY LOSS OF BUSINESS OR INJURIES OR LOSSES TO PERSONS OR PROPERTY FROM WILLFUL, ACCIDENTAL OR MISTAKEN SUSPENSION OR DELETION OF CUSTOMER INFORMATION OR DATA.

The Customer acknowledges and agrees that in no event will Lakeland Energy or any of its members, shareholders, directors, officers, employees or representatives be liable for any special, indirect, consequential, punitive or exemplary damages, or economic damages (including but not limited to damages for loss of profits or revenues, loss of

data, or loss of use) in connection with this Agreement, even if Lakeland Energy has been advised of the possibility of such damages.

If, despite the foregoing limitations, Lakeland Energy or any Lakeland Energy Indemnity should become liable to the Customer in connection with this Agreement for any reason, then in no event will the aggregate liability of Lakeland Energy or any of the Lakeland Energy Indemnities exceed the amount payable by the Customer to Lakeland Energy for one month of Services under this Agreement.

11. **Indemnity**

The Customer will indemnify and save harmless Lakeland Energy from and against all damages, losses, liabilities, fines, costs and expenses (including actual legal fees and costs), incurred by or awarded, asserted or claimed against Lakeland Energy in connection with this Agreement which are attributable, in whole or in part, to any negligent or willful activities or omissions of the Customer or any breaches by the Customer of its obligations under this Agreement.

12. **Customer Acknowledgement**

The Customer acknowledges that it accepts all risk of any unauthorized or illegal use of the Lakeland Energy network or any inter-connected network by third parties. Lakeland Energy provides no warranties, makes no representations, and accepts no liability for the unauthorized or illegal access or interference with the Customer's server and or network.

13. **Electronic Commerce**

The Customer is solely responsible for all aspects of its online activities, including the operation of any store or e-business. This includes, but is not limited to: a) the accuracy of statements and materials related to products and/or services offered online; b) the accuracy of accounting or billing; c) the accurate calculation and application of shipping and sales tax; d) the processing of orders, inquiries and complaints; and e) the maintaining of the confidentiality of client credit card numbers and personal information.

14. **IP Addresses**

Lakeland Energy assigns IP (Internet Protocol) addresses to the Customer for its use. The Customer has no right to use IP addresses not assigned to it, to move IPs between different servers or accounts or to use IP addresses in any manner not permitted by Lakeland Energy.

Lakeland Energy maintains control of all IP addresses that are assigned to the Customer and reserves the right to change or remove them at its sole and absolute discretion. Lakeland Energy acknowledges that IP address changes are rare and typically made only at the request of ARIN. Also, the allocation of IP addresses

is restricted by the policies of ARIN. These policies dictate that name-based hosting must be used whenever possible. Lakeland Energy reserves the right to periodically review IP address usage and revoke authorization to use those IP addresses not being utilized or where name-based hosting could be used.

15. **Acceptable Use Policy**

The Customer shall at all times comply with the terms and conditions of the current Lakeland Holding acceptable usage policy.

16. **Severability and Waiver**

If any provision of this Agreement is held invalid or unenforceable for any reason by a court of competent jurisdiction, the offending provision will be severed but the remaining provisions will continue in full force without being impaired or invalidated in any way. The waiver by either party of a breach of any provision of this Agreement will not operate or be interpreted as a waiver of any other or subsequent breach.

17. **Relationship of Parties**

No agency, partnership, joint venture, or employment relationship is created by this Agreement and neither party has the power to bind the other party.
We recognize that there is a relationship between the two parties but this agreement will be handled as if Lakeland Energy was a 3rd party vendor.

______________________________________ ________________________

Customer Acceptance – Please Print Name and Title Date

____

Customer Acceptance - Signature

______________________________________ ________________________

Vince Kulchycki – Chief Operation Officer Date

____

Signature

A P P E N D I X B

LPDL PURCHASING POLICY

Procedure Number:	**205-CEER**	**Revision Number: 2007-02**
Title:	**Capital & Expenditure Expense Requests (CEER)**	
Issued by:	Finance	**Approved by:**
Date:	Last Revised June 2011	**Page: 1 of 5 pages**

Note: All amounts are in CDN funds

1.0 PURPOSE AND APPLICABILITY

To prescribe the approval procedure for authorizing major capital items and expenditures for repairs, tooling, inventory items, etc, legal fees, environmental costs, outside consultants and services, and leases. This policy applies to Lakeland Holding Ltd. and its subsidiaries "(The Company)".

2.0 POLICY STATEMENT

It is the policy of the Company that all capital and expense expenditures greater than the approved annually approved budget amount or anything greater than $50,000 not in the approved budget must be brought to the Board for approval. Leases for equipment must be supported by a lease versus purchase analysis. All other expenses to be approved based on the criteria and levels set out below. Upon approving annually the budget, the Board may require certain capital and expense items still be brought forward with additional justification. These requests will be made at the time of the annual budget approval.

3.0 PROCEDURE AND RESPONSIBILITY

It is the joint responsibility of both the Chief Executive Officer and of the Chief Financial Officer to insure that proper approvals for all transactions are received. For ALL transactions exceeding $50,000 an expense request form (Exhibit A) must be submitted for approval with appropriate attachments explaining: 1) Reason for the proposed expenditure; 2) Financial or business analysis resulting from proposed expenditure; and 3) quotation comparison

Supplemental requests are to be prepared for each project as soon as it becomes evident that the cost of the project is likely to exceed the approved amount by more than 10%. The word "Supplement" is to be typed on the Expense Request form to distinguish it from a regular Expense Request. Approval will be in the same manner as the original Expense Request.

VERBAL PURCHASE ORDERS/REQUISITIONS ARE ALLOWED UNDER SPECIAL CIRCUMSTANCES

4.0 APPROVAL PROCEDURE & LEVELS

All requests for purchase shall be set up in the purchasing system as requisitions. Requisitions shall be approved by Chief Operating Officer, validated for appropriateness of expenditure and checked for account coding accuracy. Requisitions exceeding the level of the COO and CFO shall be approved by the CEO before becoming a purchase order. All invoices shall be approved by the CFO with approved purchase orders.

Authority Limits

Supervisors	Approval of purchase orders not to exceed $1,000
Managers	Approval of purchase orders not to exceed $2,500
COO/CFO	Approval of purchase orders not to exceed $5,000
President & CEO	Approval of purchase orders over $5,000
Board of Directors	Approval of Capital expenditure and Expense projects in excess of $50,000 not in the approved budget or as otherwise requested during the annual budget approval.

Note: the next level supervisor may decrease or cancel the approval amount of their direct report at their discretion.

Purchase of miscellaneous items under a value of $500 do not require a purchase order but do require approval and account coding by COO, CFO, or CEO.

Rental of equipment does not require a purchase order at the time of issue but does require a work order to be associated. The work order shall contain the account coding and the invoice shall be approved at the time it is received. Work order number must be recorded on third party documentation. Consideration should be given to the cost of renting equipment against purchasing depending on future requirements

5.0 APPROVAL REQUIREMENT

The capital and expense approval/tracking procedure is broken down as follows:

1. Submission of annual capital and expense plan
2. Approval for individual capital or expense expenditure requests over $50,000 not in the approved budget or as outlined in Approval Procedure and Levels in Section 2.0 above
3. Monthly tracking of the capital and expense plan implementation
4. Evaluation of actual benefits derived from expenditures

1. <u>Annual Capital and Expense Plan</u>

The plans consists of:

A. A list of planned expenditures prioritized.

B. A planned implementation schedule indicating the following:

a) Date funds may be requested (subject to vendor and customer confirmation)
b) Planned delivery date
c) Start-up period
d) Anticipated post audit date (usually 6 months after the end of the start-up period)

C. For each capital and expense project, a concise narrative explaining the rationale/benefits for each of the four spending categories. Why are funds being requested and what are the anticipated financial benefits?

2. <u>Individual Capital and Expense Expenditure Requests</u>

The approved capital and expense budgets form the basis for individual capital requests throughout the budget year. The following chart shows the limits of authority.

All Management & Executive	All approved annual budget items unless requested by the Board
Board of Directors	All CEERs over $50 K not in the approved budget or any items expressly stated by the Board during annual budget approval

6.0 GENERAL INFORMATION

a) CEER's requiring Board of Directors approval should be received at the Huntsville office seven days prior to the Board meeting.

b) A separate CEER is required for each project having a distinct purpose. Some major projects could involve multiple capital and expense requests that are dependent upon each other to generate the overall benefits. Such projects should be submitted as a single request even though the total funds will be approved in stages as they are needed. Under no circumstances are CEERs to be subdivided to circumvent the approval authorization levels.

c) All data should be submitted in CDN funds (indicate exchange rate applied to other currencies)

d) Overruns: Expenditures which will likely exceed the approved appropriation by 10% or more require a supplemental Expenditure Request to cover the project's overrun. The financial justification should be revised at the time of the supplemental request.

e) Authorization: Approval provides authorization for the operations unit to purchase only items included in the CEER. If a project is under spent, purchase of additional items is not permitted.

f) Disposals: When the Capital Request replaces an existing asset, a Disposal Request should be attached in accordance with Corporate Policy.

g) For 100% recoverable work / items, Exhibit A and F are the only pages required to be filled out. This will assist Finance with cash flow planning.

A. <u>Preparation</u>

All CEER's should be prepared in accordance with the following instructions and should contain all of the necessary exhibits. Each CEER package should have tabs distinguishing the various exhibits as follows:

a) Capital and Expense Expenditure Request
b) Reason for Proposed Expenditure
c) Economic Justification
d) Capital and Expense Expenditure Detail
e) Related Detail
f) Disposal of Fixed Assets
g) Quotation Comparison

a) Capital and Expense Expenditure Request Form (Exhibit A): Summary of Capital and Expense Expenditure Request detail which is self-explanatory. *Note:* that this cover page shows the scheduled implementation dates, request date, delivery date, start-up period, and post audit date.

b) Reason for Proposed Expenditure (Exhibit B): This section should contain a concise discussion of the business purpose and anticipated benefits of the proposed expenditure, and why this action is preferred over other alternative actions. Capital and Expense Expenditure Detail (Exhibit D)

Listing of the individual items comprising the l project.

c) Related Expense Detail (Exhibit E): Listing of the individual expenses that will be incurred to complete the project.

d) Quotation Comparison (Exhibit G): The general rule is to have three quotes for every project. The quotes should be summarized in this section with a brief statement explaining how the final selection was made. Any time three quotes cannot be obtained, an explanation is required. The details of the individual quotes must be maintained at the business unit and available for audit.

e) Disposal of Fixed Assets (Exhibit F): The exhibit is self-explanatory and is required when the capital request is for replacement of an existing asset with a net book value in excess of $25,000.

f) Economic Justification (Exhibit C): Expenditures should be justified on the combined basis of economic value added (E.V.A.), the after-tax internal rate of return, and the payback period. Exhibit C is provided as a guideline which should be modified as appropriate. (If there are no incremental sales, eliminate that section. If a shorter or longer time period is more appropriate, change the form, etc.)

The individual savings shown on Exhibit C should be fully explained in supporting work papers and should represent true/measurable cash savings. Do not show combined or netted numbers.

The benefits of the program should be well supported and be measurable.

Most of these projects are either cost/risk avoidance or are simply necessary to maintain existing business. Explain them as such. Providing some data on down-time, machine accuracy, and repair costs would be in order. The business discussion should fully explain the consequences of delaying replacement expenditures.

3. <u>Monthly Tracking of the Capital Plan Implementation</u>

Exhibit H is required to be submitted with the Monthly Performance Reports. This report tracks planned spending as compared to actual spending.

7.0 RESPONSIBILITY OF ACCOUNTS PAYABLE

1. Examine purchase order for the appropriate electronic signature(s) of approval.
2. Review receiving documents for matching to invoiced amounts.
3. Code expenses to the correct account classification as per purchase order.
4. Enter the Expense Report into computer system and subsequently control the cheque printing, matching, signing, and delivery of the cheque.
5. Invoices received in the Accounts Payable department which are not in accordance with this policy will return to the appropriate individual for the required adjustment and/or approval.

8.0 SUMMARY

Supervisors	Approval of purchase orders not to exceed $1,000
Managers	Approval of purchase orders not to exceed $2,500
COO/CFO	Approval of purchase orders not to exceed $5,000
President & CEO	Approval of purchase orders over $5,000
Board of Directors	Approval of Capital expenditure and Expense projects in excess of $50,000 not in the approved budget or otherwise stated during the annual budget approval.

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Purchase of miscellaneous items under a value of $500 do not require a purchase order but do require approval and account coding by COO, CFO, or CEO.

The approved capital and expense budgets form the basis for individual requests throughout the budget year. The following chart shows the limits of authority.

All Management & Executive	All approved annual budget items unless requested by the Board
Board of Directors	All CEERs over $50 K not in the approved budget or any items expressly stated by the Board during annual budget approval

For internal use requiring CEO but not Board approval.

Management & Executive	All CEERs over $50 K in the approved budget All CEERs over $25 K not in the approved budget

APPENDIX C

PIILS WORKFORM V2

v 2.0

Income Tax/PILs Workform for 2013 Filers

Utility Name	Lakeland Power Distribution Ltd.
Assigned EB Number	EB-2012-0145
Name and Title	Margaret Maw, Chief Financial Officer
Phone Number	705-789-5442
Email Address	mmaw@lakelandholding.com
Date	August 31,2012
Last COS Re-based Year	**2009**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Income Tax/PILs Workform for 2013 Filers

Income Tax/PILs Workform for 2013 Filers

Rate Base			**$**	**20,370,760**	

Return on Ratebase

Deemed ShortTerm Debt %	4.00%	T	$	814,830	*W = S * T*
Deemed Long Term Debt %	56.00%	U	$	11,407,626	*X = S * U*
Deemed Equity %	40.00%	V	$	8,148,304	*Y = S * V*
Short Term Interest Rate	2.08%	Z	$	16,948	*AC = W * Z*
Long Term Interest	5.16%	AA	$	588,253	*AD = X * AA*
Return on Equity (Regulatory Income)	9.12%	AB	**$**	**743,125**	*AE = Y * AB*
Return on Rate Base			**$**	**1,348,327**	*AF = AC + AD + AE*

Questions that must be answered

	Historic	Bridge	Test Year
1. Does the applicant have any Investment Tax Credits (ITC)?	No	No	No
2. Does the applicant have any SRED Expenditures?	No	No	No
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No	Yes	Yes
4. Does the applicant have any Capital Leases?	No	No	No
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No	No	No
6. Since 1999, has the applicant acquired another regulated applicant's assets?	No	No	No
7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.*	No	No	No
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No

Income Tax/PILs Workform for 2013 Filers

Tax Rates Federal & Provincial As of June 20, 2012	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Federal income tax				
General corporate rate	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%
Rate reduction	-11.50%	-13.00%	-13.00%	-13.00%
	16.50%	15.00%	15.00%	15.00%
Ontario income tax	11.75%	11.50%	11.50%	11.50%
Combined federal and Ontario	28.25%	26.50%	26.50%	26.50%
Federal & Ontario Small Business				
Federal small business threshold	500,000	500,000	500,000	500,000
Ontario Small Business Threshold	500,000	500,000	500,000	500,000
Federal small business rate	11.00%	11.00%	11.00%	11.00%
Ontario small business rate	4.50%	4.50%	4.50%	4.50%

Income Tax/PILs Workform for 2013 Filers

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historic per tax returns	Less: Non-Distribution Portion	UCC Regulated Historic Year
1	Distribution System - post 1987	10,126,185		10,126,185
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election			0
2	Distribution System - pre 1988			0
8	General Office/Stores Equip	187,971		187,971
10	Computer Hardware/ Vehicles	279,345		279,345
10.1	Certain Automobiles			0
12	Computer Software	33,053		33,053
13_1	Lease # 1			0
13_2	Lease #2			0
13_3	Lease # 3			0
13_4	Lease # 4			0
14	Franchise			0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs			0
42	Fibre Optic Cable	54,116		54,116
43.1	Certain Energy-Efficient Electrical Generating Equipment			0
43.2	Certain Clean Energy Generation Equipment			0
45	Computers & Systems Software acq'd post Mar 22/04	1,342		1,342
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			0
47	Distribution System - post February 2005	6,040,436		6,040,436
50	Data Network Infrastructure Equipment - post Mar 2007	6,816		6,816
52	Computer Hardware and system software			0
95	CWIP			0
1	Valuation bump	1,229,021		1,229,021
6	Portable office	43,599		43,599
				0
				0
				0
				0
				0
				0
				0
				0
	SUB-TOTAL - UCC	18,001,884	0	18,001,884

Schedule 10 CEC - Historical Year

Cumulative Eligible Capital

Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**0**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**0**
Current Year Deduction		**0**	**x 7% =**	**0**
Cumulative Eligible Capital - Closing Balance				**0**

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital Gains Reserves ss.40(1)			0
Tax Reserves Not Deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)			0
Reserve for goods and services not delivered ss. 20(1)(m)			0
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & Share Issue Expenses ss. 20(1)(e)			0
Other tax reserves			0
			0
			0
			0
			0
			0
Total	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)			
General Reserve for Inventory Obsolescence (non-specific)			0
General reserve for bad debts			0
Accrued Employee Future Benefits:			0
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost			0
- Other Post-Employment Benefits			0
Provision for Environmental Costs			0
Restructuring Costs			0
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other			0
			0
			0
Total	**0**	**0**	**0**

Income Tax/PILs Workform for 2013 Filers

Schedule 7-1 Loss Carry Forward - Historic

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic			0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic			0

Income Tax/PILs Workform for 2013 Filers

Adjusted Taxable Income - Historic Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	A	827,016		827,016
Additions:				
Interest and penalties on taxes	103	19		19
Amortization of tangible assets	104	1,105,776		1,105,776
Amortization of intangible assets	106			0
Recapture of capital cost allowance from Schedule 8	107			0
Gain on sale of eligible capital property from Schedule 10	108			0
Income or loss for tax purposes- joint ventures or partnerships	109			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111			0
Charitable donations	112			0
Taxable Capital Gains	113			0
Political Donations	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118			0
Capitalized interest	119			0
Non-deductible club dues and fees	120			0
Non-deductible meals and entertainment expense	121	7,836		7,836
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements- balance at end of year	126			0
Soft costs on construction and renovation of buildings	127			0
Book loss on joint ventures or partnerships	205			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other Additions				
Interest Expensed on Capital Leases	290			0
Realized Income from Deferred Credit Accounts	291			0
Pensions	292			0
Non-deductible penalties	293			0
	294			0
	295			0
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))		324,443		324,443
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received				0
				0

				0
				0
				0
				0
				0
				0
				0
				0
				0
Total Additions		**1,438,074**	**0**	**1,438,074**
Deductions:				
Gain on disposal of assets per financial statements	401			0
Dividends not taxable under section 83	402			0
Capital cost allowance from Schedule 8	403	1,152,314		1,152,314
Terminal loss from Schedule 8	404			0
Cumulative eligible capital deduction from Schedule 10	405			0
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411			0
Tax reserves claimed in current year	413			0
Reserves from financial statements - balance at beginning of year	414			0
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390			0
Capital Lease Payments	391			0
Non-taxable imputed interest income on deferral and variance accounts	392			0
	393			0
	394			0
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received		324,443		324,443
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)				0
				0
				0
				0
				0
				0
				0
				0
Total Deductions		**1,476,757**	**0**	**1,476,757**
Net Income for Tax Purposes		**788,333**	**0**	**788,333**
Charitable donations from Schedule 2	311			0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320			0
Non-capital losses of preceding taxation years from Schedule 4	331			0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332			0
Limited partnership losses of preceding taxation years from Schedule 4	335			0
TAXABLE INCOME		**788,333**	**0**	**788,333**

Income Tax/PILs Workform for 2013 Filers

PILs Tax Provision - Historic Year

Note: Input the actual information from the tax returns for the historic year.

						Wires Only	
Regulatory Taxable Income						$ 788,333	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.75%	**B**	$ 92,613	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**				
	Rate reduction (negative)	-7.25%	**E**	-$ 36,240	**F = D * E**		
Ontario Income tax						$ 56,373	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			7.15%	**K = J / A**		
	Federal tax rate			16.50%	**L**		
	Combined tax rate					23.65%	**M = K + L**
Total Income Taxes						**$ 186,448**	**N = A * M**
Investment Tax Credits							**O**
Miscellaneous Tax Credits							**P**
Total Tax Credits						**$ -**	**Q = O + P**
Corporate PILs/Income Tax Provision for Historic Year						**$ 186,448**	**R = N - Q**

Schedule 8 CCA - Bridge Year

Class	Class Description	UCC Regulated Historic Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA	UCC End of Bridge Year
1	Distribution System - post 1987	$ 10,126,185		-$ 81,085	$ 10,045,100	$ -	$ 10,045,100	4%	$ 401,804	$ 9,643,296
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election				$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988				$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 187,971	$ 70,000		$ 257,971	$ 35,000	$ 222,971	20%	$ 44,594	$ 213,377
10	Computer Hardware/ Vehicles	$ 279,345	$ 115,000	-$ 76,332	$ 318,013	$ 19,334	$ 298,679	30%	$ 89,604	$ 228,409
10.1	Certain Automobiles				$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 33,053	$ 108,600		$ 141,653	$ 54,300	$ 87,353	100%	$ 87,353	$ 54,300
13 1	Lease # 1				$ -	$ -	$ -		$ -	$ -
13 2	Lease #2				$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3				$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4				$ -	$ -	$ -		$ -	$ -
14	Franchise				$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				$ -	$ -	$ -	8%	$ -	$ -
42	Fibre Optic Cable	$ 54,116			$ 54,116	$ -	$ 54,116	12%	$ 6,494	$ 47,622
43.1	Certain Energy-Efficient Electrical Generating Equipment				$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment				$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 1,342			$ 1,342	$ -	$ 1,342	45%	$ 604	$ 738
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 6,040,436	$ 1,355,000	-$ 45,276	$ 7,350,160	$ 654,862	$ 6,695,298	8%	$ 535,624	$ 6,814,536
50	Data Network Infrastructure Equipment - post Mar 2007	$ 6,816	$ 10,000		$ 16,816	$ 5,000	$ 11,816	55%	$ 6,499	$ 10,317
52	Computer Hardware and system software				$ -	$ -	$ -	100%	$ -	$ -
95	CWIP				$ -	$ -	$ -		$ -	$ -
1	Valuation bump	$ 1,229,021			$ 1,229,021	$ -	$ 1,229,021	4%	$ 49,161	$ 1,179,860
6	Portable office	$ 43,599			$ 43,599	$ -	$ 43,599	10%	$ 4,360	$ 39,239
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 18,001,884	$ 1,658,600	-$ 202,693	$ 19,457,791	$ 768,496	$ 18,689,295		$ 1,226,096	$ 18,231,695

Income Tax/PILs Workform for 2013 Filers

Schedule 10 CEC - Bridge Year

Cumulative Eligible Capital				**0**
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**0**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**0**
Current Year Deduction		**0**	**x 7% =**	**0**
Cumulative Eligible Capital - Closing Balance				**0**

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

Description	Historic Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Bridge Year Adjustments: Additions	Bridge Year Adjustments: Disposals	Balance for Bridge Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	0		0			0	0	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Income Tax/PILs Workform for 2013 Filers

Corporation Loss Continuity and Application

Schedule 7-1 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction	**Total**
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Net Capital Loss Carry Forward Deduction	**Total**
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Income Tax/PILs Workform for 2013 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Total for Regulated Utility
Income before PILs/Taxes	**A**	915,000

Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets	104	978,830
Amortization of intangible assets	106	183,671
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves deducted in prior year	125	0
Reserves from financial statements- balance at end of year	126	0
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	

Adjusted Taxable Income - Bridge Year

Other Additions		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		
Total Additions		**1,162,501**
Deductions:		
Gain on disposal of assets per financial statements	401	10,000
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	1,226,096
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10	405	0
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves claimed in current year	413	0
Reserves from financial statements - balance at beginning of year	414	0
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		

Adjusted Taxable Income - Bridge Year

Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Total Deductions		**1,236,096**
Net Income for Tax Purposes		**841,405**
Charitable donations from Schedule 2	311	
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	
Non-capital losses of preceding taxation years from Schedule 4	331	
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
TAXABLE INCOME		**841,405**

Income Tax/PILs
Workform for 2013 Filers

PILS Tax Provision - Bridge Year

							Wires Only	
Regulatory Taxable Income							$ 841,405	**A**
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$	96,762	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**					
	Rate reduction	-7.00%	**E**	-$	35,000	**F = D * E**		
Ontario Income tax							$ 61,762	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			7.34%		**K = J / A**		
	Federal tax rate			15.00%		**L**		
	Combined tax rate						22.34%	**M = K + L**
Total Income Taxes							**$ 187,972**	**N = A * M**
Investment Tax Credits								**O**
Miscellaneous Tax Credits								**P**
Total Tax Credits							**$ -**	**Q = O + P**
Corporate PILs/Income Tax Provision for Bridge Year							**$ 187,972**	**R = N - Q**

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.

Schedule 8 CCA - Test Year

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 9,643,296		-40,180	$ 9,603,116	$ -	$ 9,603,116	4%	$ 384,125	$ 9,218,991
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ -			$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 213,377	45,000		$ 258,377	$ 22,500	$ 235,877	20%	$ 47,175	$ 211,201
10	Computer Hardware/ Vehicles	$ 228,409	395,000	-190,067	$ 433,342	$ 102,467	$ 330,876	30%	$ 99,263	$ 334,080
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 54,300	10,000		$ 64,300	$ 5,000	$ 59,300	100%	$ 59,300	$ 5,000
13 1	Lease # 1	$ -			$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bl	$ -			$ -	$ -	$ -	8%	$ -	$ -
42	Fibre Optic Cable	$ 47,622			$ 47,622	$ -	$ 47,622	12%	$ 5,715	$ 41,907
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 738			$ 738	$ -	$ 738	45%	$ 332	$ 406
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -			$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 6,814,536	1,590,000	-51,852	$ 8,352,684	$ 769,074	$ 7,583,610	8%	$ 606,689	$ 7,745,995
50	Data Network Infrastructure Equipment - post Mar 2007	$ 10,317	10,000		$ 20,317	$ 5,000	$ 15,317	55%	$ 8,424	$ 11,893
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ -			$ -	$ -	$ -	0%	$ -	$ -
1	Valuation bump	$ 1,179,860			$ 1,179,860	$ -	$ 1,179,860	4%	$ 47,194	$ 1,132,666
6	Portable office	$ 39,239			$ 39,239	$ -	$ 39,239	10%	$ 3,924	$ 35,315
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 18,231,695	$ 2,050,000	-$ 282,099	$ 19,999,596	$ 904,041	$ 19,095,555		$ 1,262,141	$ 18,737,455

Income Tax/PILs Workform for 2013 Filers

Schedule 10 CEC - Test Year

Cumulative Eligible Capital				**0**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**0**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**0**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")		**0**	**x 7% =**	**0**
Cumulative Eligible Capital - Closing Balance				**0**

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

Description	Bridge Year	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	0		0			0	0	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Income Tax/PILs Workform for 2013 Filers

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Net Capital Loss Carry Forward Deduction	**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Income Tax/PILs Workform for 2013 Filers

Taxable Income - Test Year

	T2 S1 line #	Test Year Taxable Income
Net Income Before Taxes		743,125
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	1,019,001
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	93,546
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	0
Reserves from financial statements- balance at end of year	126	0
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	

Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
	296	
	297	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		
Total Additions		**1,112,547**
Deductions:		
Gain on disposal of assets per financial statements	401	15,000
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	1,262,141
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	0
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	0
Reserves from financial statements - balance at beginning of year	414	0
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	

Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
	395	
	396	
	397	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Total Deductions		**1,277,141**
NET INCOME FOR TAX PURPOSES		**578,531**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**578,531**

Income Tax/PILs
Workform for 2013 Filers

PILs Tax Provision - Test Year

							Wires Only	
Regulatory Taxable Income							$ 578,531	**A**
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$ 66,531	**C = A * B**			
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**					
	Rate reduction	-7.00%	**E**	-$ 35,000	**F = D * E**			
Ontario Income tax							$ 31,531	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			5.45%	**K = J / A**			
	Federal tax rate			15.00%	**L**			
	Combined tax rate						20.45%	**M = K + L**
Total Income Taxes							**$ 118,311**	**N = A * M**
Investment Tax Credits								**O**
Miscellaneous Tax Credits								**P**
Total Tax Credits							**$ -**	**Q = O + P**
Corporate PILs/Income Tax Provision for Test Year							**$ 118,311**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up [1]				79.55%	**S = 1 - M**		**$ 30,415**	**T = R / S - R**
Income Tax (grossed-up)							**$ 148,725**	**U = R + T**

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

A P P E N D I X D

2011 FEDERAL & ONTARIO TAX RETURNS

Canada Revenue Agency / Agence du revenu du Canada

200

T2 CORPORATION INCOME TAX RETURN

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, paragraphs, and subparagraphs mentioned on this return refer to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide.*

Identification

Business Number (BN) 001 89649 9613 RC0001

Corporation's name
002 LAKELAND POWER DISTRIBUTION LTD.

Address of head office
Has this address changed since the last time we were notified? .... 010 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 200-395 CENTRE STREET NORTH
012
City: 015 HUNTSVILLE
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal code/Zip code: 018 P1H 2M2

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? .... 020 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028.)
021 c/o
022
023
City: 025
Province, territory, or state: 026
Country (other than Canada): 027
Postal code/Zip code: 028

Location of books and records
Has the location of books and records changed since the last time we were notified .... 030 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
031 200-395 CENTRE STREET NORTH
032
City: 035 HUNTSVILLE
Province, territory, or state: 036 ON
Country (other than Canada): 037
Postal code/Zip code: 038 P1H 2M2

040 Type of corporation at the end of the tax year
1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. 043 ____ YYYY MM DD

To which tax year does this return apply?
Tax year start: 060 2011-01-01 (YYYY MM DD)
Tax year-end: 061 2011-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? .... 063 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired .... 065 ____ YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with:
subparagraph 88(2)(a)(iv)? .... 064 1 Yes [ ] 2 No [X]
subsection 249(3.1)? .... 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? .... 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? .... 070 1 Yes [ ] 2 No [X]
Amalgamation? .... 071 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? .... 072 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? .... 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? .... 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada?
080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? .... 082 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area
095 096

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Was the resident corporation the beneficiary of a non-resident discretionary trust or did it make a contribution to a non-resident discretionary trust at any time during the tax year?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210		10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265		55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

		1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution US

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	HYDRO POWER	285	100.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		
If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible (YYYY MM DD)	294		
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295		

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		788,333	A
Deduct: Charitable donations from Schedule 2	311			
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal				B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			788,333	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		788,333	
Income exempt under paragraph 149(1)(t)	370			
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			788,333	Z

* This amount is equal to 3.2 times the Part VI.1 tax payable at line 724 on page 8.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	788,333	A
Taxable income from line 360 on page 3, **minus** 10/3 of the amount on line 632* on page 7, **minus** 1/(0.38 - X**) 3.77358 times the amount on line 636*** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax	405	788,333	B
Business limit (see notes 1 and 2 below)	410	500,000	C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x 415 **** 48,559 / 11,250 D = 2,158,178 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") 425 ______ F

Small business deduction

Amount A, B, C, or F, whichever is the least ______ x 17 % = 430 ______ G

Enter amount G on line 1 on page 7.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** General rate reduction percentage for the tax year. It has to be pro-rated.

*** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

**** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3		788,333	A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27	B		
Amount QQ from Part 13 of Schedule 27	C		
Amount used to calculate the credit union deduction from Schedule 17	D		
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least	E		
Aggregate investment income from line 440 on page 6*	F		
Total of amounts B to F	▶		G
Amount A **minus** amount G (if negative, enter "0")		788,333	H

Amount H	788,333	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year 365	x	9 %	=	I
Amount H	788,333	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year 365	x	10 %	=	J
Amount H	788,333	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 365 / Number of days in the tax year 365	x	11.5 %	= 90,658	K
Amount H	788,333	x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year 365	x	13 %	=	L

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L . . . 90,658 M
Enter amount M on line 638 on page 7.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)			N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27	O		
Amount QQ from Part 13 of Schedule 27	P		
Amount used to calculate the credit union deduction from Schedule 17	Q		
Total of amounts O to Q	▶		R
Amount N **minus** amount R (if negative, enter "0")			S

Amount S		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year 365	x	9 %	=	T
Amount S		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year 365	x	10 %	=	U
Amount S		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 365 / Number of days in the tax year 365	x	11.5 %	=	V
Amount S		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year 365	x	13 %	=	W

General tax reduction – Total of amounts T to W . . . X
Enter amount X on line 639 on page 7.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7	440		x 26 2 / 3 % =		A
Foreign non-business income tax credit from line 632 on page 7					
Deduct: Foreign investment income from Schedule 7	445		x 9 1 / 3 % =		
			(if negative, enter "0")		B
Amount A **minus** amount B (if negative, enter "0")					C
Taxable income from line 360 on page 3			788,333		
Deduct:					
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least					
Foreign non-business income tax credit from line 632 on page 7		x 25 / 9 =			
Foreign business income tax credit from line 636 on page 7		x 1(0.38 - X*) / 3.77358 =			
			788,333		
			x 26 2 / 3 % =	210,222	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8)				130,076	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least	450				F

* General rate reduction percentage for the tax year. It has to be pro-rated.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	460			
Deduct: Dividend refund for the previous tax year	465			
				G
Add the total of:				
Refundable portion of Part I tax from line 450 above				
Total Part IV tax payable from Schedule 3				
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480			
				H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H	485			

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3		x 1 / 3		I
Refundable dividend tax on hand at the end of the tax year from line 485 above				J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 on page 8)				

Part I tax

Base amount of Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %			550	299,567	A
Recapture of investment tax credit from Schedule 31			602		B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			i
Taxable income from line 360 on page 3	788,333		
Deduct: Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			
Net amount	788,333 ▶	788,333	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii	604		C
Subtotal (**add** lines A to C)		299,567	D

Deduct:

Small business deduction from line 430 on page 4			1	
Federal tax abatement	608	78,833		
Manufacturing and processing profits deduction from Schedule 27	616			
Investment corporation deduction	620			
Taxed capital gains 624				
Additional deduction – credit unions from Schedule 17	628			
Federal foreign non-business income tax credit from Schedule 21	632			
Federal foreign business income tax credit from Schedule 21	636			
General tax reduction for CCPCs from amount M on page 5	638	90,658		
General tax reduction from amount X on page 5	639			
Federal logging tax credit from Schedule 21	640			
Federal qualifying environmental trust tax credit	648			
Investment tax credit from Schedule 31	652			
Subtotal		169,491 ▶	169,491	E

Part I tax payable – Line D **minus** line E	130,076	F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	130,076
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		130,076

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	56,373	
Provincial tax on large corporations (Nova Scotia Schedule 342)	765		
		56,373 ▶	56,373
Total tax payable	770		186,449 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from page 6	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld 801			
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	219,064	
Total credits	890	219,064 ▶	219,064 B

Refund code 894 1 Overpayment 32,615 ◀ Balance (line A **minus** line B) -32,615

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid ....

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 ______ Branch number

914 ______ Institution number 918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No [X]

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, 950 LITSCHKO (Last name in block letters) 951 CHRIS (First name in block letters) 954 PRESIDENT (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2012-04-25 Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (705) 789-5442 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below .... 957 1 Yes [X] 2 No ☐

958 ______ Name in block letters 959 ______ Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Privacy Act, Personal Information Bank number CRA PPU 047

Schedule of Instalment Remittances

Name of corporation contact
Telephone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	2011 instalments	219,064
	Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	219,064 A
	Total instalments credited to the taxation year per T9	219,064 B

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
LAKELAND POWER DISTRIBUTION LTD.	89649 9613 RC0001	2011-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	5,420,582	5,007,030
	Total tangible capital assets	2008	+	25,527,749	23,316,900
	Total accumulated amortization of tangible capital assets	2009	–	10,548,735	9,390,831
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	3,543,965	3,096,590
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	23,943,561	22,029,689
	Liabilities				
	Total current liabilities	3139	+	7,551,289	5,822,373
	Total long-term liabilities	3450	+	3,838,090	4,339,602
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	11,389,379	10,161,975
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	12,554,182	11,867,714
	Total liabilities and shareholder equity	3640	=	23,943,561	22,029,689
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	3,327,395	2,640,927

* Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
LAKELAND POWER DISTRIBUTION LTD.	89649 9613 RC0001	2011-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence Number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	23,155,055	21,711,431
	Cost of sales	8518	–	18,600,838	17,170,452
	Gross profit/loss	8519	=	4,554,217	4,540,979
	Cost of sales	8518	+	18,600,838	17,170,452
	Total operating expenses	9367	+	4,140,748	4,164,993
	Total expenses (mandatory field)	9368	=	22,741,586	21,335,445
	Total revenue (mandatory field)	8299	+	23,568,602	22,170,556
	Total expenses (mandatory field)	9368	–	22,741,586	21,335,445
	Net non-farming income	9369	=	827,016	835,111
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	827,016	835,111
	Total other comprehensive income	9998	=		
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	190,548	47,031
	Deferred income tax provision	9995	–	-50,000	
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	686,468	788,080

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency — Agence du revenu du Canada

SCHEDULE 141

NOTES CHECKLIST

Name of corporation	Business Number	Tax year-end Year Month Day
LAKELAND POWER DISTRIBUTION LTD.	89649 9613 RC0001	2011-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . . 095 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . . . 097 1 Yes [ ] 2 No [X]

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note: If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: 198

- Completed an auditor's report . . . . . 1 [X]
- Completed a review engagement report . . . . . 2 [ ]
- Conducted a compilation engagement . . . . . 3 [ ]

Part 3 – Reservations

If you selected option "1" or "2" under T**ype of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . 099 1 Yes [ ] 2 No [X]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: 110

- Prepared the tax return (financial statements prepared by client) . . . . . 1 [ ]
- Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 [ ]

Were notes to the financial statements prepared? . . . . . 101 1 Yes [X] 2 No [ ]

If **yes**, complete lines 104 to 107 below:

- Are subsequent events mentioned in the notes? . . . . . 104 1 Yes [ ] 2 No [X]
- Is re-evaluation of asset information mentioned in the notes? . . . . . 105 1 Yes [ ] 2 No [X]
- Is contingent liability information mentioned in the notes? . . . . . 106 1 Yes [X] 2 No [ ]
- Is information regarding commitments mentioned in the notes? . . . . . 107 1 Yes [ ] 2 No [X]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . 108 1 Yes [ ] 2 No [X]

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . 200 1 Yes ☐ 2 No ☒

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		In OCI Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year? . . . 250 1 Yes ☐ 2 No ☒

Did the corporation apply hedge accounting during the tax year? . . . 255 1 Yes ☐ 2 No ☒

Did the corporation discontinue hedge accounting during the tax year? . . . 260 1 Yes ☐ 2 No ☒

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . 265 1 Yes ☐ 2 No ☒

If **yes**, you have to maintain a separate reconciliation.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
LAKELAND POWER DISTRIBUTION LTD.	89649 9613 RC0001	2011-12-31

Assets – lines 1000 to 2599

1060	2,767,973	1062	2,262,158	1066	32,615
1120	184,199	1484	173,637	1599	5,420,582
1600	278,455	1601	516,004	1602	-15,147
1680	2,015,370	1681	-227,238	1740	22,083,072
1741	-9,800,574	1774	634,848	1775	-505,776
2008	25,527,749	2009	-10,548,735	2420	2,576,365
2421	967,600	2589	3,543,965	2599	23,943,561

Liabilities – lines 2600 to 3499

2600	1,338,359	2620	6,212,930	3139	7,551,289
3140	3,487,500	3320	350,590	3450	3,838,090
3499	11,389,379				

Shareholder equity – lines 3500 to 3640

3500	9,226,787	3600	3,327,395	3620	12,554,182
3640	23,943,561				

Retained earnings – lines 3660 to 3849

3660	2,640,927	3680	686,468	3849	3,327,395

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
LAKELAND POWER DISTRIBUTION LTD.	89649 9613 RC0001	2011-12-31

Description

Sequence number 0003 01

Revenue – lines 8000 to 8299

8000	23,155,055	8089	23,155,055	8090	48,188
8230	365,359	8299	23,568,602		

Cost of sales – lines 8300 to 8519

8450	18,600,838	8518	18,600,838	8519	4,554,217

Operating expenses – lines 8520 to 9369

8670	1,033,587	8710	266,615	8760	32
8762	9,773	9270	1,586,905	9284	1,243,836
9367	4,140,748	9368	22,741,586	9369	827,016

Farming revenue – lines 9370 to 9659

9659	0

Farming expenses – lines 9660 to 9899

9898	0

Extraordinary items and taxes – lines 9970 to 9999

9970	827,016	9990	190,548	9995	-50,000
9999	686,468				

Canada Revenue Agency / Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
LAKELAND POWER DISTRIBUTION LTD.	89649 9613 RC0001	2011-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125			686,468 A
Add:			
Provision for income taxes – current	101	190,548	
Provision for income taxes – deferred	102	-50,000	
Interest and penalties on taxes	103	19	
Amortization of tangible assets	104	1,105,776	
Non-deductible meals and entertainment expenses	121	7,836	
Subtotal of additions		1,254,179 ▶	1,254,179
Other additions:			
Miscellaneous other additions:			
600 Par. 12(1)(x) contributions capitalized on F/S	290	324,443	
604			
Total	294		
Subtotal of other additions	199	324,443 ▶	324,443
Total additions	500	1,578,622 ▶	1,578,622
Deduct:			
Capital cost allowance from Schedule 8	403	1,152,314	
Subtotal of deductions		1,152,314 ▶	1,152,314
Other deductions:			
Miscellaneous other deductions:			
700 Ss. 13(7.4) election re Contributions in aid of construction	390	324,443	
704			
Total	394		
Subtotal of other deductions	499	324,443 ▶	324,443
Total deductions	510	1,476,757 ▶	1,476,757
Net income (loss) for income tax purposes – enter on line 300 of the T2 return			788,333

T2 SCH 1 E (10)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
LAKELAND POWER DISTRIBUTION LTD.	89649 9613 RC0001	2011-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations*.
- For more information, see the *T2 Corporation – Income Tax Guide*.
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ______ Enter the regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☐	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
788,333		788,333	56,373

	Line	Amount		Total	
Ontario basic income tax (from Schedule 500)	270	92,613			
Deduct: Ontario small business deduction (from schedule 500)	402	36,240			
Subtotal		56,373	▶	56,373	A6
Add:					
Surtax re Ontario small business deduction (from Schedule 500)	272				
Ontario additional tax re Crown royalties (from Schedule 504)	274				
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal			▶		B6
Subtotal (amount A6 **plus** amount B6)				56,373	C6
Deduct:					
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario transitional tax credits (from Schedule 506)	414				
Ontario political contributions tax credit (from Schedule 525)	415				
Subtotal			▶		D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")				56,373	E6
Deduct: Ontario research and development tax credit (from Schedule 508)			416		
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")				56,373	F6
Deduct: Ontario corporate minimum tax credit (from schedule 510)			418		
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")				56,373	G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278				
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies)	282				
Subtotal			▶		H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)				56,373	I6
Deduct:					
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452				
Ontario apprenticeship training tax credit (from Schedule 552)	454				
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario sound recording tax credit (from Schedule 562)	464				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Other Ontario tax credits					
Subtotal			▶		J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.			290	56,373	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits	255	56,373

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

SCHEDULE 8

Canada Revenue Agency | Agence du revenu du Canada

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
LAKELAND POWER DISTRIBUTION LTD.	89649 9613 RC0001	2011-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? 101 1 Yes [ ] 2 No [X]

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1	Distribution	8,773,137			0		8,773,137	4	0	0	350,925	8,422,212
2.	1	Building	562,173	1,188,048		0	594,024	1,156,197	4	0	0	46,248	1,703,973
3.	10	Computers	17,480			0		17,480	30	0	0	5,244	12,236
4.	10	Automotive	381,585			0		381,585	30	0	0	114,476	267,109
5.	1	Valuation Bump	1,280,230			0		1,280,230	4	0	0	51,209	1,229,021
6.	8	Equipment	145,399	79,613		0	39,807	185,205	20	0	0	37,041	187,971
7.	12	Computer Software	16,508	66,105		0	33,053	49,560	100	0	0	49,560	33,053
8.	45	Computers	2,440			0		2,440	45	0	0	1,098	1,342
9.	50	Computers	5,739	5,839		0	2,920	8,658	55	0	0	4,762	6,816
10.	6	Portable Office	48,443			0		48,443	10	0	0	4,844	43,599
11.	47	Distribution System	5,468,225	1,051,739		0	525,870	5,994,094	8	0	0	479,528	6,040,436
12.	42	Fibre Optic Communication	61,495			0		61,495	12	0	0	7,379	54,116
13.	47	CONSTRUCTION IN PROCESS	255,271		-255,271	0			8	0	0		
		Totals	17,018,125	2,391,344	-255,271		1,195,674	17,958,524				1,152,314	18,001,884

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments.*

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (11)

Canada

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		2,391,344		
Additions for tax purposes – Schedule 8 leasehold improvements	+			
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+			
Construction in process transfered to other category	+	-255,271		
Total additions per books	=	2,136,073	▶	2,136,073
Proceeds up to original cost – Schedule 8 regular classes				
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
	+			
Total proceeds per books	=		▶ –	
Depreciation and amortization per accounts – Schedule 1			–	1,105,776
Loss on disposal of fixed assets per accounts			–	
Gain on disposal of fixed assets per accounts			+	
Net change per tax return			=	1,030,297

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		14,199,702
Opening net book value	–	13,169,405
Net change per financial statements	=	1,030,297

If the amounts from the tax return and the financial statements differ, explain why below.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
LAKELAND POWER DISTRIBUTION LTD.	89649 9613 RC0001	2011-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name	Country of residence (other than Canada)	Business number (see note 1)	Relationship code (see note 2)	Number of common shares you own	% of common shares you own	Number of preferred shares you own	% of preferred shares you own	Book value of capital stock
	100	200	300	400	500	550	600	650	700
1.	LAKELAND HOLDING LTD.	CA	86574 9568 RC0001	1					
2.	LAKELAND ENERGY LTD.	CA	89650 2416 RC0001	3					
3.	BRACEBRIDGE GENERATION LTD.	CA	89650 1210 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . 025 Year Month Day

Enter the calendar year to which the agreement applies . . . . . 050 Year 2011

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . 075 1 Yes [ ] 2 No [X]

	1 Names of associated corporations 100	2 Business Number of associated corporations 200	3 Association code 300	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400	
1	LAKELAND POWER DISTRIBUTION LTD.	89649 9613 RC0001	1	500,000	100.0000	500,000	
2	LAKELAND HOLDING LTD.	86574 9568 RC0001	1	500,000			
3	LAKELAND ENERGY LTD.	89650 2416 RC0001	1	500,000			
4	BRACEBRIDGE GENERATION LTD.	89650 1210 RC0001	1	500,000			
				Total	100.0000	500,000	A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
LAKELAND POWER DISTRIBUTION LTD.	89649 9613 RC0001	2011-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Provide only one number per shareholder: Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	LAKELAND HOLDING LTD	86574 9568 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
LAKELAND POWER DISTRIBUTION LTD.	89649 9613 RC0001	2011-12-31

On: 2011-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 — 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? ☒ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year				100	2,858,234 A
Taxable income for the year (DICs enter "0") *		110	788,333 B		
Income for the credit union deduction * (amount E in Part 3 of Schedule 17)	120				
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less *	130				
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income *	140				
Subtotal (**add** lines 120, 130, and 140)		►	C		
Income taxable at the general corporate rate (line B **minus** line C) (if negative enter "0")		150	788,333		
After-tax income (line 150 x general rate factor for the tax year ** 0.7)				190	551,833 D
Eligible dividends received in the tax year		200			
Dividends deductible under section 113 received in the tax year		210			
Subtotal (**add** lines 200 and 210)				►	E
GRIP addition:					
Becoming a CCPC (line PP from Part 4)		220			
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)		230			
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)		240			
Subtotal (**add** lines 220, 230, and 240)				► 290	F
Subtotal (**add** lines A, D, E, and F)					3,410,067 G
Eligible dividends paid in the previous tax year		300			
Excessive eligible dividend designations made in the previous tax year		310			
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.					
Subtotal (line 300 **minus** line 310)				►	H
GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative)				490	3,410,067
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)				560	
GRIP at the end of the tax year (line 490 **minus** line 560)				590	3,410,067

Enter this amount on line 160 of Schedule 55.

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2010-12-31

Taxable income before specified future tax consequences from the current tax year		790,677 J1	
Enter the following amounts before specified future tax consequences from the current tax year:			
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	L1		
Aggregate investment income (line 440 of the T2 return)	M1		
Subtotal (**add** lines K1, L1, and M1)	►	N1	
Subtotal (line J1 **minus** line N1) (if negative, enter "0")		790,677 ►	790,677 O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences . . . . ______ P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R1

Aggregate investment income (line 440 of the T2 return) . . . . ______ S1

Subtotal (**add** lines Q1, R1, and S1) ______ ▶ ______ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ______ ▶ ______ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") ______ V1

GRIP adjustment for specified future tax consequences to the first previous tax year

(line V1 **multiplied by** the general rate factor for the tax year 0.7) . . . . 500 ______

Second previous tax year 2009-12-31

Taxable income before specified future tax consequences from the current tax year 504,269 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L2

Aggregate investment income (line 440 of the T2 return) . . . . ______ M2

Subtotal (**add** lines K2, L2, and M2) ______ ▶ ______ N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") 504,269 ▶ 504,269 O2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences . . . . ______ P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R2

Aggregate investment income (line 440 of the T2 return) . . . . ______ S2

Subtotal (**add** lines Q2, R2, and S2) ______ ▶ ______ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ______ ▶ ______ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") ______ V2

GRIP adjustment for specified future tax consequences to the second previous tax year

(line V2 **multiplied by** the general rate factor for the tax year 0.7) . . . . 520 ______

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2008-12-31

Taxable income before specified future tax consequences from the current tax year 636,901 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L3

Aggregate investment income (line 440 of the T2 return) . . . . ______ M3

Subtotal (**add** lines K3, L3, and M3) ______ ▶ ______ N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") 636,901 ▶ 636,901 O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R3

Aggregate investment income (line 440 of the T2 return) . . . . ______ S3

Subtotal (**add** lines Q3, R3, and S3) ______ ▶ ______ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") ______ ▶ ______ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") ______ V3

GRIP adjustment for specified future tax consequences to the third previous tax year
(line V3 **multiplied by** the general rate factor for the tax year 0.7) . . . . 540 ______

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . ______ W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . ______ AA

Eligible dividends paid by the corporation in its last tax year . . . . ______ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . . ______ CC

Subtotal (line BB **minus** line CC) ______ ▶ ______ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)
(line AA **minus** line DD) . . . . ______ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . ☐ Post wind-up . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year . . . . ________ FF

The corporation's money on hand immediately before the end of its previous/last tax year . . . . ________ GG

Unused and unexpired losses at the end of the corporation's previous/last tax year:

- Non-capital losses . . . . ________
- Net capital losses . . . . ________
- Farm losses . . . . ________
- Restricted farm losses . . . . ________
- Limited partnership losses . . . . ________

Subtotal ________ ▶ ________ HH

Subtotal (**add** lines FF, GG, and HH) ________ II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year . . . . ________ JJ

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year . . . . ________ KK

All the corporation's reserves deducted in its previous/last tax year . . . . ________ LL

The corporation's capital dividend account immediately before the end of its previous/last tax year . . . . ________ MM

The corporation's low rate income pool immediately before the end of its previous/last tax year . . . . ________ NN

Subtotal (**add** lines JJ, KK, LL, MM, and NN) ________ ▶ ________ OO

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0") . . . . ________ PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 5 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year.

0.68	x	number of days in the tax year before January 1, 2010 / number of days in the tax year	/ 365	....	=		QQ
0.69	x	number of days in the tax year in 2010 / number of days in the tax year	/ 365	....	=		RR
0.7	x	number of days in the tax year in 2011 / number of days in the tax year	365 / 365	....	=	0.70000	SS
0.72	x	number of days in the tax year after December 31, 2011 / number of days in the tax year	/ 365	....	=		TT

General rate factor for the tax year (total of lines QQ to TT) .... 0.70000 UU

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SCHEDULE 500

ONTARIO CORPORATION TAX CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
LAKELAND POWER DISTRIBUTION LTD.	89649 9613 RC0001	2011-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references on this schedule are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only and does not have to be filed with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic rate of tax for the year

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	/ 365	x	14.00 %	=	%	A1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	181 / 365	x	12.00 %	=	5.95068 %	A2
Number of days in the tax year after June 30, 2011, and before July 1, 2012 / Number of days in the tax year	184 / 365	x	11.50 %	=	5.79726 %	A3
Number of days in the tax year after June 30, 2012, and before July 1, 2013 / Number of days in the tax year	/ 365	x	11.00 %	=	%	A4
Number of days in the tax year after June 30, 2013 / Number of days in the tax year	/ 365	x	10.00 %	=	%	A5

Ontario basic rate of tax for the year (total of rates A1 to A5) 11.74794 ▶ 11.74794 % A6

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . 788,333 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A6 from Part 1) . . . . 92,613 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit, in addition to Ontario basic income tax, or has Ontario corporate minimum tax, Ontario special additional tax on life insurance corporations or Ontario capital tax payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)	788,333	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)	788,333	2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return) 500,000 x 500,000 / 500,000 (line 4 on page 4 of the T2 return *) =	500,000	3
Enter the least of amounts 1, 2, and 3	500,000	D
Ontario domestic factor: Ontario taxable income ** / taxable income earned in all provinces and territories *** = 788,333.00 / 788,333 =	1.00000	E

Amount D x amount E	500,000	a
Ontario taxable income (amount B from Part 2)	788,333	b

Ontario small business income (lesser of amount a and amount b) 500,000 F

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	/ 365	x	8.50 %	=	%	G1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	181 / 365	x	7.50 %	=	3.71918 %	G2
Number of days in the tax year after June 30, 2011, and before July 1, 2012 / Number of days in the tax year	184 / 365	x	7.00 %	=	3.52877 %	G3
Number of days in the tax year after June 30, 2012, and before July 1, 2013 / Number of days in the tax year	/ 365	x	6.50 %	=	%	G4
Number of days in the tax year after June 30, 2013 / Number of days in the tax year	/ 365	x	5.50 %	=	%	G5

OSBD rate for the year (total of rates G1 to G5) 7.24795 % G6

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G6) 36,240 H

Enter amount H on line 402 of Schedule 5.

* For 2011 and later tax years, enter the amount from line 410 of the T2 return on line 3 of this schedule.

** Enter amount B from Part 2.

*** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Calculation of surtax re Ontario small business deduction

Complete this part if the corporation is claiming the OSBD and its adjusted taxable income, **plus** the adjusted taxable income of each corporation with which the corporation was associated during its tax year, is greater than $500,000. If the corporation is a member of an associated group, complete Schedule 501, *Ontario Adjusted Taxable Income of Associated Corporations to Determine Surtax re Ontario Small Business Deduction.*

Note: For days in the tax year after June 30, 2010, the small business surtax rate is 0%. You do not have to complete this part if the corporation's tax year begins after June 30, 2010.

Adjusted taxable income * .... ______ I

Adjusted taxable income of all associated corporations (amount from line 500 of Schedule 501) .... ______ J

Aggregate adjusted taxable income (amount I **plus** amount J) .... ______ ► ______ K

Deduct:

Ontario business limit 500,000

Subtotal (amount K **minus** Ontario business limit) (if negative, enter "0" on this line and on line P) .... ______ L

Small business surtax rate for the year:

Number of days in the tax year before July 1, 2010 ______ / Number of days in the tax year 365 x 4.25 % = ______ % M

Amount L x % on line M = ... ______ N

Amount N ______ x Ontario small business income (amount F from Part 3) ______ / 500,000 500,000 = ... ______ O

Surtax re Ontario small business deduction: lesser of amount O and OSBD (amount H from Part 3) .... ______ P

Enter amount P on line 272 of Schedule 5.

* Adjusted taxable income is equal to the corporation's taxable income or taxable income earned in Canada for the year **plus** the amount of the corporation's adjusted Crown royalties for the year **minus** the amount of the corporation's notional resource allowance for the year (from Schedule 504, *Ontario Resource Tax Credit and Ontario Additional Tax re Crown Royalties*).

If the tax year of the corporation is less than 51 weeks, **multiply** the adjusted taxable income of the corporation for the year by 365 and **divide** by the number of days in the tax year.

Part 5 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Lesser of amount D and amount b from Part 3 .... 500,000 Q

Surtax payable (amount P from Part 4) ______ / Ontario domestic factor (amount E from Part 3) x OSBD rate (rate G6 from Part 3) 7.24795 % 0.07248 = ______ R

Note: Enter "0" on line R for tax years beginning after June 30, 2010.

Ontario adjusted small business income (amount Q **minus** amount R) (if negative, enter "0") .... 500,000 S

Enter amount S on line U in Part 6 or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 6 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17			T
Deduct:			
Ontario adjusted small business income (amount S from Part 5)			U
Subtotal (amount T **minus** amount U) (if negative, enter "0")			V
OSBD rate for the year (rate G6 from Part 3)	7.24795 %		
Amount V **multiplied** by the OSBD rate for the year			W
Ontario domestic factor (amount E from Part 3)		1.00000	X
Ontario credit union tax reduction (amount W **multiplied** by amount X)			Y

Enter amount Y on line 410 of Schedule 5.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
LAKELAND POWER DISTRIBUTION LTD.	89649 9613 RC0001	2011-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record): LAKELAND POWER DISTRIBUTION LTD.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	110 Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	120 Ontario Corporation No.
Ontario	2001-09-01	1800128

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable):

210 Street number	220 Street name/Rural route/Lot and Concession number	230 Suite number
200-395	CENTRE STREET NORTH	

240 Additional address information if applicable (line 220 must be completed first):

250 Municipality (e.g., city, town)	260 Province/state	270 Country	280 Postal/zip code
HUNTSVILLE	ON	CA	P1H 2M2

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 [1] If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 LITSCHKO (Last name) **451** CHRIS (First name)

454 ________________, (Middle name(s))

460 [1] Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 ☐ Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)		
520 Street number	530 Street name/Rural route/Lot and Concession number	540 Suite number
550 Additional address information if applicable (line 530 must be completed first)		

560 Municipality (e.g., city, town)	570 Province/state	580 Country	590 Postal/zip code

Part 6 – Language of preference

600 ☐ Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

ATTACHEMENT

Lakeland Power Distribution Ltd.
December 31, 2011
Election under Subsection 13(7.4) of the Federal Income Tax Act

In accordance with the provisions of subsection 13(7.4) of the Federal Income Tax Act ("the Act"), the taxpayer hereby elects to include the receipt of $324,443 in contributions in aid of construction as a reduction to the original capital cost of the underlying property for which the assistance was received.

Adjustments to reflect this election have been made to reduce the undepreciated capital cost ("UCC") of the underlying property on Schedule 8 of the federal Income Tax Return.

<u>OVERVIEW:</u>

The purpose of this evidence is to summarize the method and cost of financing capital requirements for the 2009-2013 Test years.

Capital Structure

LPDL has a current deemed capital structure of 4% Short Term Debt with a return of 1.33%, 56% Long Term Debt with a return of 5.16% and 40% Equity with a return of 8.01% as approved in the 2009 rate decision (EB-2008-0234).

LPDL has prepared this rate application with a deemed capital structure of 56.00% Long Term Debt with a return of 5.16% , 4.00% Short Term Debt with a return of 2.08% and 40.00% Equity with a return of 9.12%.

Return on Equity

LPDL is requesting a return on equity ("ROE") for the 2013 Test year of 9.12% in accordance with the Cost of Capital Parameter Updates for 2012 Cost of Service Applications issued by the OEB on March 2, 2012. LPDL understands that the OEB will be finalizing the ROE for 2013 rates based on January 2013 market interest rate information. LPDL's use of an ROE of 9.12% is without prejudice to any revised ROE that may be adopted by the OEB in early 2013.

<u>COST OF DEBT:</u>

Long Term Debt

LPDL is requesting a return on Long Term Debt for the 2013 Test Year of 5.16% . LPDL is currently paying rates varying from 5.03% to 5.41% on existing Long Term loans negotiated with TD Bank.

Short Term Debt

LPDL is requesting a return on Short Term Debt for the 2013 Test year of 2.08% in accordance with the Cost of Capital Parameter Updates for 2012 Cost of Service Applications issued by the OEB on March 2, 2012. LPDL understands that the OEB will be finalizing the return on Short Term Debt for 2013 rates based on January 2013 market interest rate information. LPDL's use of a Return on Short Term Debt of 2.08% is without prejudice to any revised Short Term Debt rate that may be adopted by the OEB in early 2013.

Rate Base and Rate of Return

Table 5.1.1 of Exhibit 5, Tab 1, Schedule 2 details LPDL's rate base, deemed debt/equity ratios, deemed rate of return, actual debt/equity ratios and actual rates of returns for 2009 Board Approved, 2009 Actual, 2010 Actual, 2011 Actual, and 2012 Bridge (CGAAP & MIFRS) and 2013 Test Year Forecast (MIFRS).

CAPITAL STRUCTURE DEEMED & ACTUAL:

Table 5.1.1 – Deemed Capital Structure 2009 to 2013

Deemed Capital Structure for 2009 - Board Approved

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	8,406,326	52.70%	5.16%	433,766
Unfunded Short Term Debt	638,051	4.00%	1.33%	8,486
Total Debt	9,044,377	56.70%		442,253
Common Share Equity	6,906,906	43.30%	8.01%	553,243
Total equity	6,906,906	43.30%		553,243
Total Rate Base	15,951,283	100.00%	6.24%	995,496

Deemed Capital Structure for 2009 - Actual

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	8,128,883	52.70%	5.16%	419,179
Unfunded Short Term Debt	616,993	4.00%	1.33%	8,206
Total Debt	8,745,876	56.70%		427,385
Common Share Equity	6,678,949	43.30%	8.01%	534,984
Total equity	6,678,949	43.30%		534,984
Total Rate Base	15,424,825	100.00%	6.24%	962,369

Deemed Capital Structure for 2010

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	9,173,459	56.00%	5.16%	473,045
Unfunded Short Term Debt	655,247	4.00%	1.33%	8,715
Total Debt	9,828,706	60.00%		481,759
Common Share Equity	6,552,471	40.00%	8.01%	524,853
Total equity	6,552,471	40.00%		524,853
Total Rate Base	16,381,177	100.00%	6.14%	1,006,612

Deemed Capital Structure for 2011

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	10,204,359	56.00%	5.16%	526,205
Unfunded Short Term Debt	728,883	4.00%	1.33%	9,694
Total Debt	10,933,242	60.00%		535,899
Common Share Equity	7,288,828	40.00%	8.01%	583,835
Total equity	7,288,828	40.00%		583,835
Total Rate Base	18,222,070	100.00%	6.14%	1,119,734

Deemed Capital Structure for 2012 (CGAAP)

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	11,269,822	56.00%	5.16%	581,147
Unfunded Short Term Debt	804,987	4.00%	1.33%	10,706
Total Debt	12,074,810	60.00%		591,854
Common Share Equity	8,049,873	40.00%	8.01%	644,795
Total equity	8,049,873	40.00%		644,795
Total Rate Base	20,124,683	100.00%	6.14%	1,236,648

Deemed Capital Structure for 2012 (MIFRS)

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	11,335,453	56.00%	5.16%	584,532
Unfunded Short Term Debt	809,675	4.00%	1.33%	10,769
Total Debt	12,145,128	60.00%		595,300
Common Share Equity	8,096,752	40.00%	8.01%	648,550
Total equity	8,096,752	40.00%		648,550
Total Rate Base	20,241,880	100.00%	6.14%	1,243,850

Deemed Capital Structure for 2013 (MIFRS)

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	11,407,626	56.00%	5.16%	588,253
Unfunded Short Term Debt	814,830	4.00%	2.08%	16,948
Total Debt	12,222,456	60.00%		605,202
Common Share Equity	8,148,304	40.00%	9.12%	743,125
Total equity	8,148,304	40.00%		743,125
Total Rate Base	20,370,760	100.00%	6.62%	1,348,327

1 **Table 5.1.2 – Capital Structure Rate Base Calculations**

2009 BOARD APPROVED

Description	Deemed Portion	Effective Rate
Long-Term Debt	52.70%	5.16%
Short-Tern Debt	4.00%	1.33%
Return On Equity	43.30%	8.01%
Weighted Debt Rate		4.89%
Regulated Rate of Return		6.24%

2009

Description	Deemed Portion	Effective Rate
Long-Term Debt	52.70%	5.16%
Short-Tern Debt	4.00%	1.33%
Return On Equity	43.30%	8.01%
Weighted Debt Rate		4.89%
Regulated Rate of Return		6.24%

WORKING CAPITAL ALLOWANCE FOR 2009 (B.A.)

Distribution Expenses	$
Distribution Expenses - Operation	223,674
Distribution Expenses - Maintenance	927,043
Billing and Collecting	655,137
Community Relations	11,255
Administrative and General Expenses	1,028,905
Taxes Other than Income Taxes	10,972
Less: Capital Taxes within 6105	
Total Eligible Distribution Expenses	**2,856,986**
Power Supply Expenses	19,632,370
Total Working Capital Expenses	22,489,356
Working Capital Allowance rate of 15%	3,373,403

WORKING CAPITAL ALLOWANCE FOR 2009

Distribution Expenses	$
Distribution Expenses - Operation	196,371
Distribution Expenses - Maintenance	832,493
Billing and Collecting	644,517
Community Relations	25,980
Administrative and General Expenses	1,125,207
Taxes Other than Income Taxes	24,798
Less: Capital Taxes within 6105	14,733.00
Total Eligible Distribution Expenses	**2,834,633**
Power Supply Expenses	16,319,947
Total Working Capital Expenses	19,154,580
Working Capital Allowance rate of 15%	2,873,187

RATE BASE CALCULATION FOR 2009 (B.A.)

Fixed Assets Opening Balance 2009	
Fixed Assets Closing Balance 2009	
Average Fixed Asset Balance for 2009	12,577,880
Working Capital Allowance	3,373,403
Rate Base	15,951,283
Regulated Rate of Return	6.24%
Regulated Return on Capital	995,496
Deemed Interest Expense	442,253
Deemed Return on Equity	553,243

RATE BASE CALCULATION FOR 2009

Fixed Assets Opening Balance 2009	12,047,993
Fixed Assets Closing Balance 2009	13,055,283
Average Fixed Asset Balance for 2009	12,551,638
Working Capital Allowance	2,873,187
Rate Base	15,424,825
Regulated Rate of Return	6.24%
Regulated Return on Capital	962,369
Deemed Interest Expense	427,385
Deemed Return on Equity	534,984

Table 5.1.2 - Capital Structure Rate Base Calculations (CONTINUED)

2010

Description	Deemed Portion	Effective Rate
Long-Term Debt	56.00%	5.16%
Short-Tern Debt	4.00%	1.33%
Return On Equity	40.00%	8.01%
Weighted Debt Rate		4.90%
Regulated Rate of Return		6.14%

2011

Description	Deemed Portion	Effective Rate
Long-Term Debt	56.00%	5.16%
Short-Tern Debt	4.00%	1.33%
Return On Equity	40.00%	8.01%
Weighted Debt Rate		4.90%
Regulated Rate of Return		6.14%

WORKING CAPITAL ALLOWANCE FOR 2010

Distribution Expenses	
Distribution Expenses - Operation	164,974
Distribution Expenses - Maintenance	764,547
Billing and Collecting	798,870
Community Relations	32,988
Administrative and General Expenses	1,178,528
Taxes Other than Income Taxes	16,365
Less: Capital Taxes within 6105	5,816.00
Total Eligible Distribution Expenses	**2,950,457**
Power Supply Expenses	17,170,452
Total Working Capital Expenses	20,120,909
Working Capital Allowance rate of 15%	3,018,136

WORKING CAPITAL ALLOWANCE FOR 2011

Distribution Expenses	
Distribution Expenses - Operation	156,712
Distribution Expenses - Maintenance	808,995
Billing and Collecting	650,758
Community Relations	20,952
Administrative and General Expenses	1,175,441
Taxes Other than Income Taxes	9,805
Less: Capital Taxes within 6105	32
Total Eligible Distribution Expenses	**2,822,631**
Power Supply Expenses	18,600,838
Total Working Capital Expenses	21,423,469
Working Capital Allowance rate of 15%	3,213,520

RATE BASE CALCULATION FOR 2010

Fixed Assets Opening Balance 2010	13,055,283
Fixed Assets Closing Balance 2010	13,670,798
Average Fixed Asset Balance for 2010	13,363,040
Working Capital Allowance	3,018,136
Rate Base	16,381,177
Regulated Rate of Return	6.14%
Regulated Return on Capital	1,006,612
Deemed Interest Expense	481,759
Deemed Return on Equity	524,853

RATE BASE CALCULATION FOR 2011

Fixed Assets Opening Balance 2011	13,670,798
Fixed Assets Closing Balance 2011	16,346,301
Average Fixed Asset Balance for 2011	15,008,549
Working Capital Allowance	3,213,520
Rate Base	18,222,070
Regulated Rate of Return	6.14%
Regulated Return on Capital	1,119,734
Deemed Interest Expense	535,899
Deemed Return on Equity	583,835

1 **Table 5.1.2 – Capital Structure Rate Base Calculations (CONTINUED)**

2012 CGAAP

Description	Deemed Portion	Effective Rate
Long-Term Debt	56.00%	5.16%
Short-Tern Debt	4.00%	1.33%
Return On Equity	40.00%	8.01%
Weighted Debt Rate		4.90%
Regulated Rate of Return		6.14%

2012 MIFRS

Description	Deemed Portion	Effective Rate
Long-Term Debt	56.00%	5.16%
Short-Tern Debt	4.00%	1.33%
Return On Equity	40.00%	8.01%
Weighted Debt Rate		4.90%
Regulated Rate of Return		6.14%

WORKING CAPITAL ALLOWANCE FOR 2012 CGAAP

Distribution Expenses	
Distribution Expenses - Operation	207,888
Distribution Expenses - Maintenance	900,185
Billing and Collecting	783,034
Community Relations	21,000
Administrative and General Expenses	1,356,507
Taxes Other than Income Taxes	10,290
Less: Capital Taxes within 6105	-
Total Eligible Distribution Expenses	**3,278,904**
Power Supply Expenses	21,312,493
Total Working Capital Expenses	24,591,397
Working Capital Allowance rate of 15%	3,688,709

WORKING CAPITAL ALLOWANCE FOR 2012 MIFRS

Distribution Expenses	
Distribution Expenses - Operation	207,888
Distribution Expenses - Maintenance	900,185
Billing and Collecting	783,034
Community Relations	21,000
Administrative and General Expenses	1,356,507
Taxes Other than Income Taxes	10,290
Less: Capital Taxes within 6105	-
Total Eligible Distribution Expenses	**3,278,904**
Power Supply Expenses	21,312,493
Total Working Capital Expenses	24,591,397
Working Capital Allowance rate of 15%	3,688,709

RATE BASE CALCULATION FOR 2012 CGAAP

Fixed Assets Opening Balance 2012	16,346,301
Fixed Assets Closing Balance 2012	16,525,646
Average Fixed Asset Balance for 2012	16,435,973
Working Capital Allowance	3,688,709
Rate Base	20,124,683
Regulated Rate of Return	6.14%
Regulated Return on Capital	1,236,648
Deemed Interest Expense	591,854
Deemed Return on Equity	644,795

RATE BASE CALCULATION FOR 2012 MIFRS

Fixed Assets Opening Balance 2012	16,346,301
Fixed Assets Closing Balance 2012	16,760,041
Average Fixed Asset Balance for 2012	16,553,171
Working Capital Allowance	3,688,709
Rate Base	20,241,880
Regulated Rate of Return	6.14%
Regulated Return on Capital	1,243,850
Deemed Interest Expense	595,300
Deemed Return on Equity	648,550

1 **Table 5.1.2 – Capital Structure Rate Base Calculations (CONTINUED)**

2013 MIFRS

Description	Deemed Portion	Effective Rate
Long-Term Debt	56.00%	5.16%
Short-Tern Debt	4.00%	2.08%
Return On Equity	40.00%	9.12%
Weighted Debt Rate		4.95%
Regulated Rate of Return		6.62%

WORKING CAPITAL ALLOWANCE FOR 2013 MIFRS

Distribution Expenses	
Distribution Expenses - Operation	197,000
Distribution Expenses - Maintenance	921,046
Billing and Collecting	798,025
Community Relations	21,000
Administrative and General Expenses	1,379,756
Return on PP&E	
Taxes Other than Income Taxes	10,702
Less: Capital Taxes within 6105	-
Total Eligible Distribution Expenses	**3,327,529**
Power Supply Expenses	21,044,660
Total Working Capital Expenses	24,372,189
Working Capital Allowance rate of 13%	3,168,385

RATE BASE CALCULATION FOR 2013 MIFRS

Fixed Assets Opening Balance 2013	16,760,041
Fixed Assets Closing Balance 2013	17,644,710
Average Fixed Asset Balance for 2013	17,202,376
Working Capital Allowance	3,168,385
Rate Base	20,370,760
Regulated Rate of Return	6.62%
Regulated Return on Capital	1,348,327
Deemed Interest Expense	605,202
Deemed Return on Equity	743,125

1 # Table 5.1.3 – Actual Weighted Average Cost of Long Term Debt

Weighted Debt Cost

Description	Debt Holder	Affliated with LDC?	Date of Issuance	Principal	Term (Years)	Rate%	Year Applied to	Interest Cost
Bank Loan - 9520026-03	TD Bank	No	March 11, 2009	1,162,500	5	5.41%	2009	62,891
Bank Loan - 9520026-05	TD Bank	No	March 13, 2008	2,325,000	5	5.03%	2009	116,948
								0
Bank Loan - 9520026-03	TD Bank	No	March 11, 2009	1,162,500	5	5.41%	2010	62,891
Bank Loan - 9520026-05	TD Bank	No	March 13, 2008	2,325,000	5	5.03%	2010	116,948
								0
Bank Loan - 9520026-03	TD Bank	No	March 11, 2009	1,162,500	5	5.41%	2011	62,891
Bank Loan - 9520026-05	TD Bank	No	March 13, 2008	2,325,000	5	5.03%	2011	116,948
								0
Bank Loan - 9520026-03	TD Bank	No	March 11, 2009	1,162,500	5	5.41%	2012	62,891
Bank Loan - 9520026-05	TD Bank	No	March 13, 2008	2,325,000	5 - extended 1 yr	5.03%	2012	116,948
								0
Bank Loan - 9520026-03	TD Bank	No	March 11, 2009	1,162,500	5	5.41%	2013	62,891
Bank Loan - 9520026-05	TD Bank	No	March 13, 2008	2,325,000	5 - extended 1 yr	5.03%	2013	116,948
								0

2009 Total Long Term Debt	3,487,500	**Total Interest Cost for 2009**	179,839
		Weighted Debt Cost Rate for 2009	5.16%
2010 Total Long Term Debt	3,487,500	**Total Interest Cost for 2010**	179,839
		Weighted Debt Cost Rate for 2010	5.16%
2011 Total Long Term Debt	3,487,500	**Total Interest Cost for 2011**	179,839
		Weighted Debt Cost Rate for 2011	5.16%
2012 Total Long Term Debt	3,487,500	**Total Interest Cost for 2012**	179,839
		Weighted Debt Cost Rate for 2012	5.16%
2013 Total Long Term Debt	3,487,500	**Total Interest Cost for 2013**	179,839
		Weighted Debt Cost Rate for 2013	5.16%

Exhibit	Tab	Schedule	Appendix	Contents
6 – Calculation of Revenue Deficiency or Surplus				
	1	1		Revenue Deficiency - Overview
		2		Cost Drivers for Revenue Deficiency
			A	Revenue Requirement Workform

REVENUE DEFICIENCY - OVERVIEW:

Under Modified International Financial Reporting Standards (MIFRS), LPDL's net revenue deficiency is $288,786 and when grossed up for PILs, LPDL's revenue deficiency is $392,906 . This deficiency is calculated as the difference between the 2013 Test Year Service Revenue Requirement of $5,773,388 and the Forecast 2013 Test Year Service Revenue, based on the 2012 approved rates, at $5,380,482 . Table 6.1.1 on the following page provides the revenue deficiency calculations.

Revenue Requirement

LPDL's Revenue Requirement consists of the following:

- Administrative & General, Billing & Collecting Expense
- Operation & Maintenance Expense
- Depreciation Expense
- Property Taxes
- PILs
- Deemed Interest & Return on Equity

LPDL's revenue requirement is primarily received through electricity distribution rates and offset by revenue from OEB-approved specific service charges, late payment charges, interest, and other operating income.

Table 6.1.1 - Revenue Deficiency

Particulars	Initial Application: At Current Approved Rates		Initial Application: At Proposed Rates
Revenue Deficiency from Below			$392,906
Distribution Revenue	$5,066,854		$5,066,854
Other Operating Revenue Offsets - net	$313,628		$313,628
Total Revenue	$5,380,482		$5,773,388
Operating Expenses	$4,279,610		$4,279,610
Deemed Interest Expense	$605,202		$605,202
Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	($15,517)	**(2)**	($15,517)
Total Cost and Expenses	$4,869,295		$4,869,295
Utility Income Before Income Taxes	$511,187		$904,093
Tax Adjustments to Accounting Income per 2013 PILs model	($164,592)		($164,592)
Taxable Income	$346,595		$739,501
Income Tax Rate	26.50%		26.50%
Income Tax on Taxable Income	$91,848		$195,968
Income Tax Credits	($35,000)		($35,000)
Utility Net Income	$454,339		$743,125
Utility Rate Base	$20,370,760		$20,370,760
Deemed Equity Portion of Rate Base	$8,148,304		$8,148,304
Income/(Equity Portion of Rate Base)	5.58%		9.12%
Target Return - Equity on Rate Base	9.12%		9.12%
Deficiency/Sufficiency in Return on Equity	-3.54%		0.00%
Indicated Rate of Return	5.20%		6.62%
Requested Rate of Return on Rate Base	6.62%		6.62%
Deficiency/Sufficiency in Rate of Return	-1.42%		0.00%
Target Return on Equity	$743,125		$743,125
Revenue Deficiency/(Sufficiency)	$288,786		$ -
Gross Revenue Deficiency/(Sufficiency)	$392,906	**(1)**	

<u>COST DRIVERS FOR REVENUE DEFICIENCY:</u>

The Applicant notes there are several factors that contribute to the gross revenue deficiency of $392,906 for the 2013 Test Year. The following discussion highlights some significant items that contribute to this deficiency. The increase in OM&A over 2012 actual is approximately $290 K or 10% due primarily to the change in FTE with the filling of vacancies and $90 K for the revised load forecast to correct for 2009 load forecast error in billed kWh historical data (see Exhibit 3, Tab 3, Schedule 1).

Operating Expenses

LPDL's OM&A expenses have increased from the 2009 approved amount of $2,846,014 to $3,316,827 in the 2013 Test Year. The cost increases of over the 4 year period are discussed in Exhibit 4, Tab 2.

Rate Base

In this application, LPDL is applying for a rate base of $20,370,760 compared to a rate base of $15,951,283 which was approved during LPDL's 2009 Cost of Service application. $437,173 of this increase is the result of the change in financial reporting from CGAAP to MIFRS specifically regarding the change in useful lives. In addition, the working capital allowance has decreased by almost $205,000 from the 2009 Board Approved amount due to the change in the allowance rate from 15% down to 13%, a decrease impact of $449,787 offset by increases in the cost of power and increases in the LPDL's operating expenses. The most significant increase however is the increase in the net book value of fixed assets which has risen by $4,624,496 since the 2009 Board Approved amount. This increase has been primarily driven by the completion of Distribution Stations, the installation of smart meters, and capital improvements required to accommodate customer demand and to replace aging assets. The changes due to MIFRS, working capital and capital spending have been fully disclosed in Exhibit 2 of this application. These changes have resulted in an increase in deemed interest expense of $162,949 . Also the increased rate base, plus the increase in deemed return on equity from 8.01% to 9.12% has caused deemed return on equity to increase by $189,882 .

Table 6.1.2 – Summary of Revenue Deficiency Cost Drivers

	2009 Board Approved	2013 Test MIFRS	Difference
Rate base	$ 15,951,283	$ 20,370,760	$ 4,419,477
Rate of return	6.24%	6.62%	0.38%
Debt portion	56.70%	60.00%	3.30%
Deemed Interest Exp	$ 442,253	$ 605,202	$ 162,949
Deemed ROE	$ 553,243	$ 743,125	$ 189,882
Working Capital	$ 3,373,403	$ 3,168,385	-$ 205,019

APPENDIX A

REVENUE REQUIREMENT WORKFORM

Revenue Requirement Workform

Version 3.00

Utility Name	Lakeland Power Distribution Ltd.
Service Territory	*Bracebridge, Huntsville, Burks Falls, Sundridge, Ma*
Assigned EB Number	EB-2012-0XXX
Name and Title	Margaret Maw
Phone Number	705-789-5442
Email Address	mmaw@lakelandholdings.com

Revenue Requirement Workform

Notes:

(1) Pale green cells represent inputs

(2) Pale green boxes at the bottom of each page are for additional notes

(3) Pale yellow cells represent drop-down lists

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

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

Revenue Requirement Workform

Data Input [1]

		Initial Application	(2)	(6)		Per Board Decision	
1	**Rate Base**						
	Gross Fixed Assets (average)	$29,147,291		$ 29,147,291		$29,147,291	
	Accumulated Depreciation (average)	($11,944,915)	(5)	($11,944,915)		($11,944,915)	
	Allowance for Working Capital:						
	Controllable Expenses	$3,327,529		$ 3,327,529		$3,327,529	
	Cost of Power	$21,044,660		$ 21,044,660		$21,044,660	
	Working Capital Rate (%)	13.00%	(9)	13.00%	(9)	13.00%	(9)
2	**Utility Income**						
	Operating Revenues:						
	Distribution Revenue at Current Rates	$5,066,854					
	Distribution Revenue at Proposed Rates	$5,459,760					
	Other Revenue:						
	Specific Service Charges	$55,000					
	Late Payment Charges	$78,000					
	Other Distribution Revenue	$134,530					
	Other Income and Deductions	$46,098					
	Total Revenue Offsets	$313,628	(7)				
	Operating Expenses:						
	OM+A Expenses	$3,316,827		$ 3,316,827		$3,316,827	
	Depreciation/Amortization	$952,081	(10)	$ 952,081		$952,081	
	Property taxes	$10,702		$ 10,702		$10,702	
	Other expenses						
3	**Taxes/PILs**						
	Taxable Income:						
	Adjustments required to arrive at taxable income	($164,592)	(3)				
	Utility Income Taxes and Rates:						
	Income taxes (not grossed up)	$118,311					
	Income taxes (grossed up)	$160,968					
	Federal tax (%)	15.00%					
	Provincial tax (%)	11.50%					
	Income Tax Credits	($35,000)					
4	**Capitalization/Cost of Capital**						
	Capital Structure:						
	Long-term debt Capitalization Ratio (%)	56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		(8)		(8)
	Common Equity Capitalization Ratio (%)	40.0%					
	Prefered Shares Capitalization Ratio (%)						
		100.0%					
	Cost of Capital						
	Long-term debt Cost Rate (%)	5.16%					
	Short-term debt Cost Rate (%)	2.08%					
	Common Equity Cost Rate (%)	9.12%					
	Prefered Shares Cost Rate (%)						
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS ($)	($15,517)	(11)		(11)		(11)

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

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

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

(10) Depreciation Expense should include the adjustment resulting from the amortization of the deferred PP&E balance as shown on Appendix 2-EA or Appendix 2-EB of the Chapter 2 Appendices to the Filing Requirements.

(11) Adjustment should include the adjustment to the return on rate base associated with deferred PP&E balance as shown on Appendix 2-EA or Appendix 2-EB of the Chapter 2 Appendices to the Filing Requirements.

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(3)	$29,147,291	$ -	$29,147,291	$ -	$29,147,291
2	Accumulated Depreciation (average)	(3)	($11,944,915)	$ -	($11,944,915)	$ -	($11,944,915)
3	Net Fixed Assets (average)	(3)	$17,202,376	$ -	$17,202,376	$ -	$17,202,376
4	Allowance for Working Capital	(1)	$3,168,385	$ -	$3,168,385	$ -	$3,168,385
5	**Total Rate Base**		$20,370,760	$ -	$20,370,760	$ -	$20,370,760

Allowance for Working Capital - Derivation

(1)

Line No.	Particulars		Initial Application				Per Board Decision
6	Controllable Expenses		$3,327,529	$ -	$3,327,529	$ -	$3,327,529
7	Cost of Power		$21,044,660	$ -	$21,044,660	$ -	$21,044,660
8	Working Capital Base		$24,372,189	$ -	$24,372,189	$ -	$24,372,189
9	Working Capital Rate %	(2)	13.00%	0.00%	13.00%	0.00%	13.00%
10	Working Capital Allowance		$3,168,385	$ -	$3,168,385	$ -	$3,168,385

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. Default rate for 2013 cost of service applications is 13%.

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

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$5,459,760	($5,459,760)	$ -	$ -	$ -
2	Other Revenue	(1)	$313,628	($313,628)	$ -	$ -	$ -
3	Total Operating Revenues		$5,773,388	($5,773,388)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$3,316,827	$ -	$3,316,827	$ -	$3,316,827
5	Depreciation/Amortization		$952,081	$ -	$952,081	$ -	$952,081
6	Property taxes		$10,702	$ -	$10,702	$ -	$10,702
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$4,279,610	$ -	$4,279,610	$ -	$4,279,610
10	Deemed Interest Expense		$605,202	($605,202)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)		$4,884,812	($605,202)	$4,279,610	$ -	$4,279,610
12	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS		($15,517)	$15,517	$ -	$ -	$ -
13	**Utility income before income taxes**		$904,093	($5,183,703)	($4,279,610)	$ -	($4,279,610)
14	Income taxes (grossed-up)		$160,968	$ -	$160,968	$ -	$160,968
15	**Utility net income**		$743,125	($5,183,703)	($4,440,578)	$ -	($4,440,578)

Notes

Other Revenues / Revenue Offsets

(1)	Specific Service Charges	$55,000		$ -		$ -
	Late Payment Charges	$78,000		$ -		$ -
	Other Distribution Revenue	$134,530		$ -		$ -
	Other Income and Deductions	$46,098		$ -		$ -
	Total Revenue Offsets	$313,628	$ -	$ -	$ -	$ -

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$743,125	$ -	$ -
2	Adjustments required to arrive at taxable utility income	($164,592)	$ -	($164,592)
3	Taxable income	$578,533	$ -	($164,592)
	Calculation of Utility income Taxes			
4	Income taxes	$118,311	$118,311	$118,311
6	Total taxes	$118,311	$118,311	$118,311
7	Gross-up of Income Taxes	$42,656	$42,656	$42,656
8	Grossed-up Income Taxes	$160,968	$160,968	$160,968
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$160,968	$160,968	$160,968
10	Other tax Credits	($35,000)	($35,000)	($35,000)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Initial Application				
	Debt				
1	Long-term Debt	56.00%	$11,407,626	5.16%	$588,253
2	Short-term Debt	4.00%	$814,830	2.08%	$16,948
3	**Total Debt**	60.00%	$12,222,456	4.95%	$605,202
	Equity				
4	Common Equity	40.00%	$8,148,304	9.12%	$743,125
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$8,148,304	9.12%	$743,125
7	**Total**	100.00%	$20,370,760	6.62%	$1,348,327

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$ -
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
4	Common Equity	0.00%	$ -	0.00%	$ -
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	$ -
7	**Total**	0.00%	$20,370,760	0.00%	$ -

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Per Board Decision				
	Debt				
8	Long-term Debt	0.00%	$ -	5.16%	$ -
9	Short-term Debt	0.00%	$ -	2.08%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	9.12%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$20,370,760	0.00%	$ -

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	At Current Approved Rates	At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$392,906		($894,206)		$4,279,610
2	Distribution Revenue	$5,066,854	$5,066,854	$5,066,854	$6,353,966	$ -	($4,279,610)
3	Other Operating Revenue Offsets - net	$313,628	$313,628	$ -	$ -	$ -	$ -
4	**Total Revenue**	$5,380,482	$5,773,388	$5,066,854	$5,459,760	$ -	$ -
5	Operating Expenses	$4,279,610	$4,279,610	$4,279,610	$4,279,610	$4,279,610	$4,279,610
6	Deemed Interest Expense	$605,202	$605,202	$ -	$ -	$ -	$ -
7	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	($15,517) **(2)**	($15,517)	$ - **(2)**	$ -	$ - **(2)**	$ -
8	**Total Cost and Expenses**	$4,869,295	$4,869,295	$4,279,610	$4,279,610	$4,279,610	$4,279,610
9	**Utility Income Before Income Taxes**	$511,187	$904,093	$787,244	$1,180,150	($4,279,610)	($4,279,610)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($164,592)	($164,592)	($164,592)	($164,592)	$ -	$ -
11	**Taxable Income**	$346,595	$739,501	$622,651	$1,015,557	($4,279,610)	($4,279,610)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$91,848	$195,968	$165,003	$269,123	($1,134,097)	($1,134,097)
14	**Income Tax Credits**	($35,000)	($35,000)	($35,000)	($35,000)	$ -	$ -
15	**Utility Net Income**	$454,339	$743,125	$657,241	($4,440,578)	($3,145,514)	($4,440,578)
16	**Utility Rate Base**	$20,370,760	$20,370,760	$20,370,760	$20,370,760	$20,370,760	$20,370,760
17	Deemed Equity Portion of Rate Base	$8,148,304	$8,148,304	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	5.58%	9.12%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	9.12%	9.12%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-3.54%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	5.20%	6.62%	3.23%	0.00%	-15.44%	0.00%
22	Requested Rate of Return on Rate Base	6.62%	6.62%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-1.42%	0.00%	3.23%	0.00%	-15.44%	0.00%
24	Target Return on Equity	$743,125	$743,125	$ -	$ -	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$288,786	$ -	($657,241)	$ -	$3,145,514	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$392,906 **(1)**		($894,206) **(1)**		$4,279,610 **(1)**	

Notes:

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

(2) Treated as an adjustment pre-tax to avoid an impact on taxes/PILs and hence on revenue sufficiency deficiency

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$3,316,827		$3,316,827		$3,316,827	
2	Amortization/Depreciation	$952,081		$952,081		$952,081	
3	Property Taxes	$10,702		$10,702		$10,702	
5	Income Taxes (Grossed up)	$160,968		$160,968		$160,968	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$605,202		$ -		$ -	
	Return on Deemed Equity	$743,125		$ -		$ -	
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	($15,517)		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$5,773,388		$4,440,578		$4,440,578	
9	Revenue Offsets	$313,628		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$5,459,760		$4,440,578		$4,440,578	
11	Distribution revenue	$5,459,760		$ -		$ -	
12	Other revenue	$313,628		$ -		$ -	
13	**Total revenue**	$5,773,388		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	**(1)**	($4,440,578)	**(1)**	($4,440,578)	**(1)**

Notes

(1) Line 11 - Line 8

Exhibit	Tab	Schedule	Appendix	Contents
7 – Cost Allocation				
	1	1		Cost Allocation – Overview
		2		Summary of Results and Proposed Changes
			A	2013 Updated Cost Allocation Study

COST ALLOCATION OVERVIEW:

Introduction

On September 15, 2006, the OEB issued its directions on Cost Allocation Methodology for Electricity Distributors (the "Directions"). On November 15, 2006, the Board issued the Cost Allocation Information Filing Guidelines for Electricity Distributors ("the Guidelines"), the Cost Allocation Model (the "Model") and User Instructions (the "Instructions") for the Model. LPDL prepared and filed a cost allocation informational filing consistent with LPDL's understanding of the Directions, the Guidelines, the Model and the Instructions.

One of the main objectives of the filing was to provide information on any apparent cross-subsidization among a distributor's rate classifications. It was felt that this would give an indication of cross-subsidization from one class to another and this information would be useful as a tool in future rate applications.

In LPDL's 2009 Cost of Service rate application the results of the original cost allocation informational filing were used as a basis for LPDL to propose reallocations of distribution costs across customer classes to address the issue of cross-subsidization. The reallocations were based on the objective of moving the revenue to cost ratios to be within the Board's acceptable range as outlined in the "Report on Application of Cost Allocation for Electricity Distributors" (the "Cost Allocation Report") issued by the OEB on November 28, 2007

In the 2013 Cost of Service rate application LPDL has used the latest Board-approved Cost Allocation model and methodology and updated the values from the Hydro One Run 2 weather normalized load profiles from the original Cost Allocation Informational Filing using 2013 weather normalized forecasted data information.

SUMMARY OF RESULTS AND PROPOSED CHANGES:

Cost Allocation Study Results

The data used in the Cost Allocation Model for the 2009 Cost of Service filing was consistent with LPDL's Cost Allocation Informational filing. Consistent with the Guidelines, LPDL's assets were broken out into primary and secondary distribution functions. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to LPDL through its GIS system, its engineering records, and its customer and financial information systems.

The results of a cost allocation study are typically presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

The following Table 7.1.1 outlines the starting point (Cost Allocation Informational Filing) for revenue to cost ratios approved with LPDL's 2009 Cost of Service rate application.

Table 7.1.1 – 2009 Cost Allocation Filing Revenue to Cost Ratios

		1	2	3	7	8	9
	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Distribution Revenue (sale)	$3,865,824	$2,097,742	$852,652	$865,500	$33,395	$1,133	$15,402
Miscellaneous Revenue (mi)	$325,141	$185,463	$79,559	$48,455	$7,826	$204	$3,635
Total Revenue	$4,190,965	$2,283,205	$932,211	$913,955	$41,221	$1,337	$19,037
Expenses							
Distribution Costs (di)	$716,676	$381,832	$161,009	$95,263	$74,482	$1,592	$2,497
Customer Related Costs (cu)	$666,773	$435,992	$168,085	$48,300	$283	$178	$13,936
General and Administration (ad)	$637,624	$374,839	$151,400	$68,591	$34,683	$817	$7,294
Depreciation and Amortization (dep)	$778,314	$405,107	$177,760	$143,610	$49,099	$1,050	$1,687
PILs (INPUT)	$346,148	$178,945	$78,983	$66,003	$21,050	$450	$717
Interest	$342,436	$177,026	$78,136	$65,295	$20,824	$446	$710
Total Expenses	$3,487,971	$1,953,740	$815,373	$487,062	$200,420	$4,534	$26,842
Direct Allocation	$0	$0	$0	$0	$0	$0	$0
Allocated Net Income (NI)	$702,994	$363,420	$160,407	$134,046	$42,750	$915	$1,457
Revenue Requirement (includes NI)	$4,190,965	$2,317,160	$975,780	$621,108	$243,170	$5,448	$28,299
	Revenue Requirement Input equals Output						
Rate Base Calculation							
Net Assets							
Distribution Plant - Gross	$15,885,617	$8,246,415	$3,624,672	$2,966,456	$993,136	$21,246	$33,693
General Plant - Gross	$1,480,882	$768,144	$337,897	$277,350	$92,373	$1,976	$3,143
Accumulated Depreciation	($3,313,079)	($1,724,954)	($755,960)	($611,787)	($208,899)	($4,467)	($7,012)
Capital Contribution	($1,070,494)	($576,226)	($244,203)	($159,806)	($85,561)	($1,829)	($2,869)
Total Net Plant	$12,982,927	$6,713,378	$2,962,406	$2,472,213	$791,048	$16,926	$26,955
Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
Cost of Power (COP)	$14,974,633	$5,617,500	$3,288,498	$5,920,060	$125,777	$2,743	$20,055
OM&A Expenses	$2,021,073	$1,192,663	$480,494	$212,154	$109,448	$2,587	$23,728
Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
Subtotal	*$16,995,706*	*$6,810,162*	*$3,768,992*	*$6,132,214*	*$235,225*	*$5,330*	*$43,783*
Working Capital	$2,549,356	$1,021,524	$565,349	$919,832	$35,284	$799	$6,567
Total Rate Base	$15,532,283	$7,734,903	$3,527,755	$3,392,045	$826,332	$17,725	$33,523
	Rate Base Input equals Output						
Equity Component of Rate Base	$7,766,141	$3,867,451	$1,763,877	$1,696,023	$413,166	$8,863	$16,761
Net Income on Allocated Assets	$702,994	$329,465	$116,838	$426,893	($159,199)	($3,197)	($7,805)
Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
Net Income	$702,994	$329,465	$116,838	$426,893	($159,199)	($3,197)	($7,805)
RATIOS ANALYSIS							
REVENUE TO EXPENSES %	100.00%	98.53%	95.53%	147.15%	16.95%	24.54%	67.27%
EXISTING REVENUE MINUS ALLOCATED COSTS	($0)	($33,955)	($43,570)	$292,847	($201,949)	($4,111)	($9,262)
RETURN ON EQUITY COMPONENT OF RATE BASE	9.05%	8.52%	6.62%	25.17%	-38.53%	-36.07%	-46.57%

2013 Updated Cost Allocation Study Results

LPDL has used the updated Board-approved Cost Allocation Model and followed the instructions and guidelines issued by the Board to enter the 2013 data into this model. LPDL has made the changes according to the latest filing guidelines issued by the Board for the 2013 Cost of Service rate applications.

LPDL populated the information on Sheet I3, Trial Balance Data with the 2013 forecasted cost data, Target Net Income, PILs, deemed interest on long term debt, PP&E CGAAP to MIFRS adjustment, specific service charges information and the targeted Revenue Requirement and Rate Base.

On Sheet I4, Break-out of Assets, LPDL updated the allocation of the accounts based on 2013 values obtained from the Asset Management Plan. Updated information from LPDL's Asset Management Plan and GIS system has provided more accurate primary/secondary splits when breaking out the asset costs.

In Sheet I5.1, Miscellaneous Data, LPDL updated the deemed equity component of rate base, km of roads where distribution lines exist, working capital allowance, the proportion of pole rental revenue from secondary poles, and the monthly service charges.

In Sheet I5.2, Weighting Factors, LPDL has used LDC specific factors versus the use of default factors used on the Informational Filing. LPDL has applied service and billing and collecting weightings for each customer classification. These weightings are based upon costs incurred servicing these particular customer classifications and were weighted as a result of discussions with experienced LDC colleagues. For example:

- Residential: weighted for services and for billing and collecting as "1" as per the suggested methodology on the Cost Allocation instruction sheet.
- General Service < 50 kW: weighted "1" for billing and collecting as these customers are handled similarly to those in the residential class. Although the customers in this class are monitored to assess if their kVA demand will require reclassification to the General Service > 50kW class that effort was not seen to be enough to change the weighting from that used in the Residential customer class.

Weighting for services is “2.8” as the cost of installation usually requires after hours attendances to mitigate against interruptions during normal business hours.

- General Service > 50 kW: Weighted “1.2” for billing and collecting as each monthly bill is individually validated to ensure monthly consumption data corresponds to the third party energy monitoring system data (Utilismart). Weighting for services is “6.1” as the cost of installation usually requires after hours attendances to mitigate against interruptions during normal business hours as well as higher cost components. Additional time is also required to ensure the demand data is programmed and monitored appropriately. These installations require additional planning and preparation time due to the complexity of the metering equipment.
- Street Lighting: Weighted “1.2” for billing and collecting as each monthly bill is individually validated to ensure monthly consumption data corresponds to the third party energy monitoring system data (Utilismart). Street Lighting services rating is not applicable as services is related to the connection between the distribution system to the customer’s electrical panel.
- Sentinel Lighting: Weighted “0.6” for billing and collecting since the customers in this class require little to no oversight. Once the estimated load is calculated and entered into the billing system no further monthly changes are required. Sentinel Lighting services rating is not applicable as services is related to the connection between the distribution system to the customer’s electrical panel.
- Unmetered Scattered Load: Weighted “0.6” for billing and collecting as consumption remains static each month and RPP tier billing requires minimal monitoring and basic rate setups. Unmetered Scattered Load services rating is not applicable as services is related to the connection between the distribution system to the customer’s electrical panel.

In Sheet I6.1, Revenue, has been populated with the 2013 Test Year forecast data as well as existing rates.

Sheet I6.2, Customer Data, has been updated with the required Bad Debt and Late Payment revenue data as well as customer/connection number information. It should be noted that LPDL has an equal number of devices and connections in the street lighting customer class which is consistent to the way connections were handled in the Cost Allocation Informational Filing.

LPDL updated the capital meter cost information on Sheet I7.1 and the meter reading information on I7.2 in accordance with the recent update to smart meters.

Sheet I8, Demand Data, is based on the output of LPDL's load forecast model. The load profile from the 2004 data received from Hydro One, Run 2 and the weather normalized 2013 forecast data was used to calculate the 1 NCP, 4 NCP, 12 NCP, 1 CP, 4 CP and the 12CP demand data.

On Sheet I9, Direct Allocation, LPDL has chosen to allocate specific identifiable costs to the actual rate class responsible for those expenditures. LPDL utilizes a third party to electronically read and monitor meters in its General Service>50 kW customer class as well as the Street Light profile. The cost of that service has been directly allocated to those two customer classes. Additionally, collection costs directly attributable to the two General Service customer classes have been directly allocated. Amounts remaining in those accounts following direct allocation have been allocated to all customer classes in the model.

The revenue to cost ratios calculated on Sheet O1 of the Cost Allocation model for the 2013 updated study is provided in Table 7.1.2 below.

Table 7.1.2 - Revenue to Cost Ratios from LPDL's Updated 2013 Cost Allocation Model

	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Distribution Revenue at Existing Rates	**$5,066,854**	$2,891,083	$1,130,963	$833,019	$198,858	$4,421	$8,510
Miscellaneous Revenue (mi)	**$313,628**	$190,379	$63,956	$43,600	$14,788	$479	$426
	Miscellaneous Revenue Input equals Output						
Total Revenue at Existing Rates	**$5,380,482**	**$3,081,462**	**$1,194,920**	**$876,619**	**$213,646**	**$4,900**	**$8,936**
Factor required to recover deficiency (1 + D)	**1.0775**						
Distribution Revenue at Status Quo Rates	**$5,459,760**	$3,115,270	$1,218,663	$897,615	$214,279	$4,764	$9,169
Miscellaneous Revenue (mi)	**$313,628**	$190,379	$63,956	$43,600	$14,788	$479	$426
Total Revenue at Status Quo Rates	**$5,773,388**	**$3,305,649**	**$1,282,619**	**$941,215**	**$229,066**	**$5,243**	**$9,596**
Expenses							
Distribution Costs (di)	**$1,056,006**	$585,322	$275,881	$146,801	$46,287	$948	$767
Customer Related Costs (cu)	**$783,907**	$638,254	$129,427	$12,892	$487	$1,581	$1,266
General and Administration (ad)	**$1,388,958**	$919,174	$306,176	$124,183	$36,006	$1,894	$1,525
Depreciation and Amortization (dep)	**$952,081**	$516,796	$209,084	$181,199	$43,362	$888	$752
PILs (INPUT)	**$160,968**	$85,030	$36,305	$32,408	$6,959	$143	$123
Interest	**$605,202**	$319,693	$136,499	$121,845	$26,166	$536	$463
Total Expenses	**$4,947,122**	**$3,064,269**	**$1,093,372**	**$619,328**	**$159,268**	**$5,990**	**$4,896**
Direct Allocation	**$98,658**	**$0**	**$9,675**	**$84,180**	**$4,803**	**$0**	**$0**
Allocated Net Income (NI)	**$727,608**	$384,353	$164,107	$146,490	$31,458	$644	$557
Revenue Requirement (includes NI)	**$5,773,388**	$3,448,622	$1,267,154	$849,997	$195,528	$6,634	$5,453
	Revenue Requirement Input equals Output						
Rate Base Calculation							
Net Assets							
Distribution Plant - Gross	**$30,026,511**	$15,976,644	$6,781,100	$5,651,497	$1,558,657	$31,922	$26,691
General Plant - Gross	**$4,118,018**	$2,195,242	$933,978	$786,517	$194,898	$3,992	$3,391
Accumulated Depreciation	**($11,944,915)**	($6,303,424)	($2,667,929)	($2,266,764)	($681,345)	($13,953)	($11,499)
Capital Contribution	**($4,997,238)**	($2,772,923)	($1,165,053)	($726,097)	($321,264)	($6,578)	($5,322)
Total Net Plant	**$17,202,376**	**$9,095,538**	**$3,882,095**	**$3,445,153**	**$750,945**	**$15,383**	**$13,261**
Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cost of Power (COP)	**$21,044,660**	$8,003,679	$4,320,723	$8,514,674	$190,538	$4,053	$10,992
OM&A Expenses	**$3,228,871**	$2,142,750	$711,484	$283,875	$82,781	$4,423	$3,559
Directly Allocated Expenses	**$98,658**	$0	$9,675	$84,180	$4,803	$0	$0
Subtotal	***$24,372,189***	***$10,146,429***	***$5,041,882***	***$8,882,729***	***$278,122***	***$8,476***	***$14,551***
Working Capital	**$3,168,385**	**$1,319,036**	**$655,445**	**$1,154,755**	**$36,156**	**$1,102**	**$1,892**
Total Rate Base	**$20,370,760**	**$10,414,574**	**$4,537,540**	**$4,599,908**	**$787,101**	**$16,485**	**$15,153**
	Rate Base Input equals Output						
Equity Component of Rate Base	**$8,148,304**	**$4,165,829**	**$1,815,016**	**$1,839,963**	**$314,840**	**$6,594**	**$6,061**
Net Income on Allocated Assets	**$727,608**	**$241,380**	**$179,573**	**$237,708**	**$64,996**	**($747)**	**$4,699**
Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Net Income	**$727,608**	**$241,380**	**$179,573**	**$237,708**	**$64,996**	**($747)**	**$4,699**
RATIOS ANALYSIS							
REVENUE TO EXPENSES STATUS QUO%	**100.00%**	**95.85%**	**101.22%**	**110.73%**	**117.15%**	**79.03%**	**175.97%**
EXISTING REVENUE MINUS ALLOCATED COSTS	**($392,906)**	($367,160)	($72,234)	$26,622	$18,118	($1,734)	$3,483
	Deficiency Input equals Output						
STATUS QUO REVENUE MINUS ALLOCATED COSTS	**($0)**	($142,973)	$15,466	$91,218	$33,538	($1,391)	$4,143
RETURN ON EQUITY COMPONENT OF RATE BASE	8.93%	5.79%	9.89%	12.92%	20.64%	-11.33%	77.53%

Proposed Adjustment to Cost Allocation

On November 28, 2007, the OEB issued its "Report on Application of Cost Allocation for Electricity Distributors" (the "Cost Allocation Report"). In the Cost Allocation Report, the OEB established what it considered to be the appropriate ranges of revenue to cost ratios which are summarized in Table 7.1.3. Table 7.1.3 provides LPDL's proposed 2013 revenue to cost ratios. The proposed revenue to cost ratios reflect adjustments to revenue to address cross subsidization and to bring all classes within the recommended Board Target Ranges.

Table 7.1.3 - Proposed Revenue to Cost Ratios

Class	Revenue Cost Ratios from 2013 Cost Allocation Model	Proposed Revenue to Cost Ratio	Board Target Low	Board Target High
Residential	92.46%	95.24%	85%	115%
GS < 50 kW	102.42%	102.42%	80%	120%
GS >50 to 999 kW	120.29%	111.00%	80%	120%
Sentinel Lights	85.53%	95.24%	80%	120%
Street Lighting	127.07%	120.00%	70%	120%
Unmetered and Scattered	191.19%	120.00%	80%	120%

The three classes that were beyond the maximum ratio of 120% were reduced to 120% with a compensating adjustment in Residential and Sentinel Lighting classes to bring revenue neutrality. The result was that GS>50 kW class bill impact was higher than optional. For rate mitigation purposes, the ratio for GS>50 kW was lowered to 111%. The balance was then adjusted in both Residential and Sentinel Lighting. This resulted in acceptable bill impacts for all classes.

LPDL is proposing in this application to re-align its revenue to cost ratios by adjusting the allocations of revenue among rate classes in order to reduce some of the cross-subsidization that is occurring based on the results of the Cost Allocation study.

Table 7.1.4 outlines the revenue splits required to achieve the proposed revenue to cost ratios:

Table 7.1.4 - Revenue Split by Rate Class to Achieve Proposed R/C Ratios

Customer Class	Total Net Rev. Requirement	Rev Requirement %
Residential	3,094,202	56.67%
GS < 50 kW	1,233,858	22.60%
GS >50 to 999 kW	899,897	16.48%
Sentinel Lights	5,840	0.11%
Street Lighting	219,846	4.03%
Unmetered and Scattered	6,117	0.11%
TOTAL	**5,459,761**	**100.00%**

LPDL has also completed the Cost Allocation worksheet, Appendix 2-P, of the Board's Chapter 2 Appendices, a copy of which is provided below in Table 7.1.5.

Table 7.1.5 - Appendix 2-P

A) Allocated Costs

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 2,317,160	55.29%	$ 3,448,622	59.73%
GS < 50 kW	$ 975,780	23.28%	$ 1,267,154	21.95%
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	$ 621,108	14.82%	$ 849,997	14.72%
GS > xxx kW, if applicable		0.00%		0.00%
Large User, if applicable		0.00%		0.00%
Street Lighting	$ 243,170	5.80%	$ 195,528	3.39%
Sentinel Lighting	$ 5,448	0.13%	$ 6,634	0.11%
Unmetered Scattered Load (USL)	$ 28,299	0.68%	$ 5,453	0.09%
Other class, if applicable		0.00%		0.00%
		0.00%		0.00%
Embedded distributor class		0.00%		0.00%
Total	$ 4,190,965	100.00%	$ 5,773,388	100.00%

B) Calculated Class Revenues

Classes (same as previous table)	Column 7B Load Forecast (LF) X current	Column 7C L.F. X current approved rates X	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 2,891,083	$ 3,115,270	$ 3,094,202	$ 190,379
GS < 50 kW	$ 1,130,963	$ 1,218,663	$ 1,233,858	$ 63,956
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	$ 833,019	$ 897,615	$ 899,897	$ 43,600
GS > xxx kW, if applicable				
Large User, if applicable				
Street Lighting	$ 198,858	$ 214,279	$ 219,846	$ 14,788
Sentinel Lighting	$ 4,421	$ 4,764	$ 5,840	$ 479
Unmetered Scattered Load (USL)	$ 8,510	$ 9,169	$ 6,117	$ 426
Other class, if applicable				
Embedded distributor class				
Total	$ 5,066,854	$ 5,459,760	$ 5,459,761	$ 313,628

C) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios Most Recent Year: 2011	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	100.00	95.85	95.24	85 - 115
GS < 50 kW	99.99	101.22	102.42	80 - 120
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	114.33	110.73	111.00	80 - 120
GS > xxx kW, if applicable				80 - 120
Large User, if applicable				85 - 115
Street Lighting	70.00	117.15	120.00	70 - 120
Sentinel Lighting	70.00	79.03	95.24	80 - 120
Unmetered Scattered Load (USL)	47.11	175.97	120.00	80 - 120
Other class, if applicable				
Embedded distributor class				

The discussion and tables above support LPDL's proposed reallocation of distribution revenues across customer classes in accordance with Board directions, in order to begin moving toward revenue to cost ratios of 100% and to reduce cross-subsidization. Based on the proposed 2013 revenue to cost ratios, LPDL does not anticipate any changes in the ratios for 2014 and 2015 at this time. LPDL submits the proposed reallocation of distribution revenue is fair and reasonable and customer class revenues will more closely reflect the actual costs of providing distribution service to each class.

Attached as Appendix A is a copy of the 2013 Updated Cost Allocation Study.

APPENDIX A

LPDL 2013 UPDATED COST ALLOCATION STUDY

Sheet I6.1 Revenue Worksheet - First Run

Total kWhs from Load Forecast	203,143,087
Total kWs from Load Forecast	208,875
Deficiency from RRWF	- 392,906
Miscellaneous Revenue	313,628

			1	2	3	7	8	9
	ID	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Billing Data								
Forecast kWh	CEN	203,143,087	77,259,128	41,707,732	82,191,734	1,839,258	39,125	106,109
Forecast kW	CDEM	208,875			203,731	5,035	109	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		93,716			93,716			
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-						
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	203,143,087	77,259,128	41,707,732	82,191,734	1,839,258	39,125	106,109
kWh - 30 year weather normalized amount	Click here to	-	-	-	-	-	-	-
Existing Monthly Charge			$18.86	$40.89	$487.45	$4.83	$4.89	$18.08
Existing Distribution kWh Rate			$0.0138	$0.0084				$0.0082
Existing Distribution kW Rate					$1.4113	$14.7836	$16.9360	
Existing TFOA Rate					$0.60			
Additional Charges								
Distribution Revenue from Rates		$5,123,084	$2,891,083	$1,130,963	$889,249	$198,858	$4,421	$8,510
Transformer Ownership Allowance		$56,230	$0	$0	$56,230	$0	$0	$0
Net Class Revenue	CREV	$5,066,854	$2,891,083	$1,130,963	$833,019	$198,858	$4,421	$8,510
Data Mismatch Analysis								
Revenue with 30 year weather normalized kWh		-	-	-	-	-	-	-

Sheet I6.2 Customer Data Worksheet - First Run

	ID	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
Billing Data								
Bad Debt 3 Year Historical Average	BDHA	$26,564	$22,142	$4,422	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$80,061	$40,900	$19,385	$18,926	$808	$0	$42
Number of Bills	CNB	118,120	96,761	19,091	1,234	84	528	423
Number of Devices						2,147		
Number of Connections (Unmetered)	CCON	2,226				2,147	44	35
Total Number of Customers	CCA	11,983	8,063	1,591	103	2,147	44	35
Bulk Customer Base	CCB	-						
Primary Customer Base	CCP	11,983	8,063	1,591	103	2,147	44	35
Line Transformer Customer Base	CCLT	11,965	8,063	1,591	85	2,147	44	35
Secondary Customer Base	CCS	11,965	8,063	1,591	85	2,147	44	35
Weighted - Services	CWCS	13,036	8,063	4,454	519	-	-	-
Weighted Meter -Capital	CWMC	1,810,590	1,295,420	355,723	159,447	-	-	-
Weighted Meter Reading	CWMR	9,677	8,063	1,591	22	-	-	-
Weighted Bills	CWNB	118,023	96,761	19,091	1,481	101	327	262

Bad Debt Data

		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Historic Year:	2009	15,121	11,502	3,619	-	-	-	-
Historic Year:	2010	36,734	31,585	5,149	-	-	-	-
Historic Year:	2011	27,836	23,339	4,497	-	-	-	-
Three-year average		26,564	22,142	4,422	-	-	-	-

Late Payment Data

		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Historic Year:	2009	78,954	41,869	17,283	18,874	888	-	40
Historic Year:	2010	81,795	42,525	20,786	17,424	1,022	-	38
Historic Year:	2011	79,434	38,307	20,085	20,479	514	-	49
Three-year average		80,061	40,900	19,385	18,926	808	-	42

Sheet I8 Demand Data Worksheet - First Run

This is an input sheet for demand allocators.

CP TEST RESULTS	4 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	7	8	9
Customer Classes		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	38,788	17,445	9,342	11,664	313	7	17
Bulk Delivery CP	BCP1	38,788	17,445	9,342	11,664	313	7	17
Total Sytem CP	DCP1	38,788	17,445	9,342	11,664	313	7	17
4 CP								
Transformation CP	TCP4	145,036	70,347	31,818	42,280	522	11	59
Bulk Delivery CP	BCP4	145,036	70,347	31,818	42,280	522	11	59
Total Sytem CP	DCP4	145,036	70,347	31,818	42,280	522	11	59
12 CP								
Transformation CP	TCP12	372,251	149,205	94,653	127,501	731	16	145
Bulk Delivery CP	BCP12	372,251	149,205	94,653	127,501	731	16	145
Total Sytem CP	DCP12	372,251	149,205	94,653	127,501	731	16	145
NON CO_INCIDENT PEAK								
1 NCP								
Classification NCP from Load Data Provider	DNCP1	45,544	21,052	11,372	12,676	418	9	17
Primary NCP	PNCP1	45,544	21,052	11,372	12,676	418	9	17
Line Transformer NCP	LTNCP1	39,752	21,052	11,372	6,884	418	9	17
Secondary NCP	SNCP1	43,342	21,052	11,372	10,474	418	9	17
4 NCP								
Classification NCP from Load Data Provider	DNCP4	171,147	76,823	42,544	50,016	1,670	36	59
Primary NCP	PNCP4	171,147	76,823	42,544	50,016	1,670	36	59
Line Transformer NCP	LTNCP4	148,293	76,823	42,544	27,161	1,670	36	59
Secondary NCP	SNCP4	162,459	76,823	42,544	41,327	1,670	36	59
12 NCP								
Classification NCP from Load Data Provider	DNCP12	438,877	175,092	113,749	144,775	5,010	107	145
Primary NCP	PNCP12	438,877	175,092	113,749	144,775	5,010	107	145
Line Transformer NCP	LTNCP12	372,723	175,092	113,749	78,621	5,010	107	145
Secondary NCP	SNCP12	413,729	175,092	113,749	119,626	5,010	107	145

Sheet O1 Revenue to Cost Summary Worksheet

		1	2	3	7	8	9
	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Distribution Revenue at Existing Rates	**$5,066,854**	$2,891,083	$1,130,963	$833,019	$198,858	$4,421	$8,510
Miscellaneous Revenue (mi)	**$313,628**	$190,379	$63,956	$43,600	$14,788	$479	$426
	Miscellaneous Revenue Input equals Output						
Total Revenue at Existing Rates	**$5,380,482**	**$3,081,462**	**$1,194,920**	**$876,619**	**$213,646**	**$4,900**	**$8,936**
Factor required to recover deficiency (1 + D)	**1.0775**						
Distribution Revenue at Status Quo Rates	**$5,459,760**	$3,115,270	$1,218,663	$897,615	$214,279	$4,764	$9,169
Miscellaneous Revenue (mi)	**$313,628**	$190,379	$63,956	$43,600	$14,788	$479	$426
Total Revenue at Status Quo Rates	**$5,773,388**	**$3,305,649**	**$1,282,619**	**$941,215**	**$229,066**	**$5,243**	**$9,596**
Expenses							
Distribution Costs (di)	**$1,056,006**	$585,322	$275,881	$146,801	$46,287	$948	$767
Customer Related Costs (cu)	**$783,907**	$638,254	$129,427	$12,892	$487	$1,581	$1,266
General and Administration (ad)	**$1,388,958**	$919,174	$306,176	$124,183	$36,006	$1,894	$1,525
Depreciation and Amortization (dep)	**$952,081**	$516,796	$209,084	$181,199	$43,362	$888	$752
PILs (INPUT)	**$160,968**	$85,030	$36,305	$32,408	$6,959	$143	$123
Interest	**$605,202**	$319,693	$136,499	$121,845	$26,166	$536	$463
Total Expenses	**$4,947,122**	**$3,064,269**	**$1,093,372**	**$619,328**	**$159,268**	**$5,990**	**$4,896**
Direct Allocation	**$98,658**	**$0**	**$9,675**	**$84,180**	**$4,803**	**$0**	**$0**
Allocated Net Income (NI)	**$727,608**	$384,353	$164,107	$146,490	$31,458	$644	$557
Revenue Requirement (includes NI)	**$5,773,388**	$3,448,622	$1,267,154	$849,997	$195,528	$6,634	$5,453
	Revenue Requirement Input equals Output						
Rate Base Calculation							
Net Assets							
Distribution Plant - Gross	**$30,026,511**	$15,976,644	$6,781,100	$5,651,497	$1,558,657	$31,922	$26,691
General Plant - Gross	**$4,118,018**	$2,195,242	$933,978	$786,517	$194,898	$3,992	$3,391
Accumulated Depreciation	**($11,944,915)**	($6,303,424)	($2,667,929)	($2,266,764)	($681,345)	($13,953)	($11,499)
Capital Contribution	**($4,997,238)**	($2,772,923)	($1,165,053)	($726,097)	($321,264)	($6,578)	($5,322)
Total Net Plant	**$17,202,376**	**$9,095,538**	**$3,882,095**	**$3,445,153**	**$750,945**	**$15,383**	**$13,261**
Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cost of Power (COP)	**$21,044,660**	$8,003,679	$4,320,723	$8,514,674	$190,538	$4,053	$10,992
OM&A Expenses	**$3,228,871**	$2,142,750	$711,484	$283,875	$82,781	$4,423	$3,559
Directly Allocated Expenses	**$98,658**	$0	$9,675	$84,180	$4,803	$0	$0
Subtotal	***$24,372,189***	***$10,146,429***	***$5,041,882***	***$8,882,729***	***$278,122***	***$8,476***	***$14,551***
Working Capital	**$3,168,385**	**$1,319,036**	**$655,445**	**$1,154,755**	**$36,156**	**$1,102**	**$1,892**
Total Rate Base	**$20,370,760**	**$10,414,574**	**$4,537,540**	**$4,599,908**	**$787,101**	**$16,485**	**$15,153**
	Rate Base Input equals Output						
Equity Component of Rate Base	**$8,148,304**	**$4,165,829**	**$1,815,016**	**$1,839,963**	**$314,840**	**$6,594**	**$6,061**
Net Income on Allocated Assets	**$727,608**	**$241,380**	**$179,573**	**$237,708**	**$64,996**	**($747)**	**$4,699**
Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Net Income	**$727,608**	**$241,380**	**$179,573**	**$237,708**	**$64,996**	**($747)**	**$4,699**
RATIOS ANALYSIS							
REVENUE TO EXPENSES STATUS QUO%	**100.00%**	**95.85%**	**101.22%**	**110.73%**	**117.15%**	**79.03%**	**175.97%**
EXISTING REVENUE MINUS ALLOCATED COSTS	**($392,906)**	($367,160)	($72,234)	$26,622	$18,118	($1,734)	$3,483
	Deficiency Input equals Output						
STATUS QUO REVENUE MINUS ALLOCATED COSTS	**($0)**	($142,973)	$15,466	$91,218	$33,538	($1,391)	$4,143
RETURN ON EQUITY COMPONENT OF RATE BASE	8.93%	5.79%	9.89%	12.92%	20.64%	-11.33%	77.53%

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - First Run

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	3	7	8	9
Summary	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$7.06	$7.42	$13.25	-$0.01	$2.53	$2.43
Customer Unit Cost per month - Directly Related	$11.49	$12.11	$23.08	$0.00	$4.43	$4.33
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$23.28	$31.27	$42.29	$7.33	$12.53	$3.03
Existing Approved Fixed Charge	$18.86	$40.89	$487.45	$4.83	$4.89	$18.08

		1	2	3	7	8	9
Information to be Used to Allocate PILs, ROD, ROE and A&G	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
General Plant - Gross Assets	$4,118,018	$2,195,242	$933,978	$786,517	$194,898	$3,992	$3,391
General Plant - Accumulated Depreciation	($2,356,839)	($1,256,389)	($534,537)	($450,142)	($111,545)	($2,285)	($1,941)
General Plant - Net Fixed Assets	$1,761,179	$938,853	$399,440	$336,375	$83,353	$1,707	$1,450
General Plant - Depreciation	$218,598	$116,530	$49,579	$41,751	$10,346	$212	$180
Total Net Fixed Assets Excluding General Plant	$15,441,197	$8,156,685	$3,482,655	$3,108,779	$667,592	$13,676	$11,811
Total Administration and General Expense	$1,388,958	$919,174	$306,176	$124,183	$36,006	$1,894	$1,525
Total O&M	$1,839,913	$1,223,576	$405,308	$159,692	$46,774	$2,529	$2,034

RATE DESIGN OVERVIEW:

This Exhibit documents the calculation of LPDL's proposed distribution rates by rate class for the 2013 Test year, based on the rate design as proposed in this Exhibit.

LPDL has determined its total 2013 service revenue requirement to be $5,773,388 . The total revenue offsets in the amount of $313,628 reduce LPDL's total service revenue requirement to a base revenue requirement to $5,459,760 which is used to determine the proposed distribution rates. The base revenue requirement is derived from LPDL's 2013 capital and operating forecasts, weather normalized usage, forecasted customer counts and regulated return on rate base. The revenue requirement is summarized in Table 8.1.1 below:

Table 8.1.1 – Calculation of Base Revenue Requirement

Service Revenue Requirement

OM&A Expenses	3,327,529
Amortization Expenses	1,010,680
Amortization of PP&E Adjustment	-58,599
Total Distribution Expenses	**4,279,610**
Return on PP&E Adjustment	**-15,517**
Regulated Return On Capital	1,348,327
PILs	160,968
Service Revenue Requirement	**5,773,388**
Less: Revenue Offsets	**313,628**
Base Revenue Requirement	**5,459,760**

The outstanding base revenue requirement is allocated to the various rate classes using the proposed revenue to cost ratios outlined in Exhibit 7 – Cost Allocation. Table 8.1.2 below shows how the base revenue requirement has been allocated to the rate classes.

Table 8.1.2 – Rate Class Base Revenue Requirement

Class	Proposed Base Revenue
Residential	3,094,202
GS < 50 kW	1,233,858
GS >50 to 999 kW	899,897
Sentinel Lights	5,840
Street Lighting	219,846
Unmetered and Scattered	6,117
TOTAL	5,459,761

Determination of Monthly Fixed Charges

Based on applying the existing approved monthly service charges to the forecasted number of customers for 2013 and applying the existing approved distribution volumetric charge, excluding the adjustment for LV and transformation allowance, to 2013 forecasted volumes, the following Table 8.1.3 outlines LPDL's current split between fixed and variable distribution revenue.

Table 8.1.3 - Current Fixed/Variable Split

Customer Class	2013 Fixed Base Revenue with 2012 Approved rates	2013 Variable Base Revenue with 2012 Approved rates	2013 Toal Base Revenue with 2012 Approved Rates	Fixed Revenue Proportion	Variable Revenue Proportion
Residential	1,824,907	1,066,176	2,891,083	63.12%	36.88%
GS < 50 kW	780,618	350,345	1,130,963	69.02%	30.98%
GS >50 to 999 kW	601,723	231,296	833,019	72.23%	27.77%
Sentinel Lights	2,579	1,841	4,421	58.35%	41.65%
Street Lighting	124,429	74,430	198,858	62.57%	37.43%
Unmetered and Scattered	7,639	870	8,510	89.78%	10.22%
TOTAL	3,341,896	1,724,958	5,066,854	65.96%	34.04%

LPDL submits that it is appropriate for 2013 to maintain the same fixed/variable proportions assumed in the current rates to all customer classifications.

Table 8.1.4 – Monthly Service Charge Information from Cost Allocation Model

Class	2012 Approved Monthly Service Charge	Customer Unit Cost per month - Avoided Cost	Minimum System with PLCC Adj
Residential	$ 18.86	$ 7.06	$ 23.28
GS < 50 kW	$ 40.89	$ 7.42	$ 31.27
GS >50 to 999 kW	$ 487.45	$ 13.25	$ 42.29
Sentinel Lights	$ 4.89	$ 2.53	$ 12.53
Street Lighting	$ 4.83	-$ 0.01	$ 7.33
Unmetered and Sc	$ 18.08	$ 2.43	$ 3.03

Consistent with the recent Board Decision on 2011 Cost of Service rate applications for Hydro One Brampton, Kenora Hydro and Horizon Utilities, as well as Atikokan Hydro's 2012 Cost of Service rate application, this Application proposes to maintain the current fixed/variable proportions for all rate classes as shown in the following table 8.1.5.

Table 8.1.5 - Proposed Monthly Service Charge

Customer Class	Total Base Rev. Requirement	Fixed Revenue Proportion	Fixed Revenue	Annualized Customers or Connections	Proposed Fixed Rate
Residential	3,094,202	63.1%	1,953,120	96,761	20.19
GS < 50 kW	1,233,858	69.0%	851,639	19,091	44.61
GS >50 to 999 kW	899,897	72.2%	650,032	1,234	526.58
Sentinel Lights	5,840	58.3%	3,407	528	6.46
Street Lighting	219,846	62.6%	137,561	25,762	5.34
Unmetered and Scattered	6,117	89.8%	5,492	423	13.00
TOTAL	**5,459,761**	**66.0%**	**3,601,251**		

Proposed Volumetric Charges

The variable distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement by the appropriate 2013 Test Year usage, kWh or kW, as the class charge determinant.

The following Table 8.1.6 provides LPDL's calculations of its proposed variable distribution charges for the 2013 Test Year which maintains the same fixed/variable split used in designing the current approved rates.

Table 8.1.6 – Proposed Distribution Volumetric Charge without Transformer Allowance

Customer Class	Total Base Rev. Requirement	Fixed Revenue	Variable Revenue	Annualized kWh or kW	Unit of Measure	Proposed Variable Rate
Residential	3,094,202	1,953,120	1,141,082	77,259,128	kWh	0.0148
GS < 50 kW	1,233,858	851,639	382,219	41,707,732	kWh	0.0092
GS >50 to 999 kW	899,897	650,032	249,865	203,731	kW	1.2264
Sentinel Lights	5,840	3,407	2,432	109	kW	22.3710
Street Lighting	219,846	137,561	82,285	5,035	kW	16.3439
Unmetered and Scattered	6,117	5,492	625	106,109	kWh	0.0059
TOTAL	**5,459,761**	**3,601,251**	**1,858,510**			

Proposed Adjustment for Transformer Allowance

Currently, LPDL provides a Transformer Allowance to those customers that own their transformation facilities. LPDL proposes to maintain the current approved transformer ownership allowance of $0.60 per kW. The Transformer Allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the customer's utilization voltage level. Since the distributor provides electricity at utilization voltage, the cost of this transformation is captured in and recovered through the distribution rates. Therefore, when a customer provides its own step down transformation from primary to secondary, it should receive a credit of these costs already included in the distribution rates.

The amount of the Transformer Allowance expected to be provided to those GS > 50 kW customers that own their transformers is included in the GS > 50 kW volumetric charge. As a result, the proposed volumetric charge of $1.2264 per kW for the GS > 50 kW customer class is increased by $0.2760 per kW to include the amount of the Transformer Allowance in the GS > 50 kW class distribution volumetric rate. The total proposed distribution volumetric charge for the GS>50 kW class will be $1.5024 per kW.

Table 8.1.7 - Proposed Distribution Volumetric Charge with Transformer Allowance

Customer Class	Variable Revenue	Transformer Allowance	Total Variable Revenue	Annualized kWh or kW	Unit of Measure	Proposed Variable Rate
Residential	1,141,082	0	1,141,082	77,259,128	kWh	0.0148
GS < 50 kW	382,219	0	382,219	41,707,732	kWh	0.0092
GS >50 to 999 kW	249,865	56,230	306,095	203,731	kW	1.5024
Sentinel Lights	2,432	0	2,432	109	kW	22.3710
Street Lighting	82,285	0	82,285	5,035	kW	16.3439
Unmetered and Scattered	625	0	625	106,109	kWh	0.0059
TOTAL	**1,858,510**	**56,230**	**1,914,740**			

Recovery of Low Voltage (LV) Costs

Consistent with the approach in the Board's 2006 EDR model, LV costs of $ 677,259 have been allocated to each rate class based on the proportion of retail transmission connection revenue collected from each class. The amount of forecasted LV costs in 2013 is based on calculations shown in Table 8.1.8. These calculations are based on applying the appropriate Hydro One sub transmission charges to the forecasted units for 2013. The Hydro One sub transmission charges used in the calculations are from the Hydro One Approved Rate Schedule (EB-2010-0096). The forecasted units for 2013 are based on the trend in the level of sub transmission service (i.e kW) that Hydro One provided to LPDL from 2009 to 2011.

Table 8.1.8 – LV Costs

2013 Data for ST/LV Charges						
Number of Monthly Service Charges	14					
Number of Meter Points	14					
Common ST kW	31,470.2					
LVDS kW	12,754.3					
Hydro One Sub Transmission Charges based on				Units	Months	Total
Service charge		292.56	per month	14	12	$ 49,150
Meter Charge		466.14	per meter per mo	14	12	$ 78,312
Facility charge for connection to Specific ST lines		0.668	per kW	31,470.2	12	$ 252,265
Facility charge for connection to low voltage		1.944	per kW	12,754.3	12	$ 297,532
Total						**$ 677,259**

The calculation of proposed LV charges to recover the 2013 LV amount is outlined in the following Table 8.1.9:

Table 8.1.9 – Proposed LV Charges

	Retail Transmission Connection Rate ($)								
Customer Class	per KWh	per kW	Basis for Allocation ($)	LV Adj. Allocated	Calculated kWh	Calculated kW	Volumetric Rate Type	LV/ Adj. Rates/kWh	LV Adj. Rates/ kW
Residential	0.0047		363,118	261,528	77,259,128		kWh	0.0034	
GS < 50 kW	0.0042		175,172	126,164	41,707,732		kWh	0.0030	
GS >50 to 999 kW		1.9383	394,892	284,413	82,191,734	203,731	kW		1.3960
Sentinel Lights		1.3312	145	104	39,125	109	kW		0.9588
Street Lighting		1.3038	6,564	4,728	1,839,258	5,035	kW		0.9390
Unmetered and Scattered	0.0042		446	321	106,109		kWh	0.0030	
TOTALS			**940,337**	**677,259**	**203,143,087**	**208,875**			

Retail Transmission Service Rates

Electricity distributors are charged the Ontario Uniform Transmission Rates (UTRs) at the wholesale level and subsequently pass these charges on to their distribution customers through Retail Transmission Service Rates (RTSRs). For each distribution rate class there are two RTSRs, one for network and one for connection. The RTSR network charge recovers the UTR wholesale network service charge, and the RTSR connection charge recovers the UTR wholesale line and transformation connection charges. Deferral accounts capture timing and rate differences between the UTR's paid at the wholesale level and RTSR's billed to distribution customers.

The Board has provided a Microsoft Excel workbook "2013_RTSR_Adjustment_Work_Form" and instructions for distributors to complete as part of their 2013 electricity rate applications. LPDL has completed this workbook to determine the RTSR's and has filed the model as part of this application. Table 8.10 is reproduced from the Board model and indicates the new RTSR's**.**

Table 8.1.10 - Final 2013 RTS Rates

Rate Class	Unit	Proposed RTSR Network		Proposed RTSR Connection	
Residential	kWh	$	0.0052	$	0.0042
General Service Less Than 50 kW	kWh	$	0.0048	$	0.0039
General Service 50 to 4,999 kW	kW	$	2.0358	$	1.6356
Sentinel Lighting	kW	$	1.5212	$	1.2053
Street Lighting	kW	$	1.4829	$	1.1937
Unmetered Scattered Load	kWh	$	0.0048	$	0.0039

LPDL is embedded to Hydro One and as such was billed for transmission services from Hydro One only.

Loss Factor: Determination of Loss Adjustment Factors

Total Loss Factor

LPDL has calculated the total loss factor to be applied to customers' consumption based on the average wholesale and retail kWh for the years 2007 to 2011. The calculations are summarized in Table 8.1.11 below.

Table 8.1.11 - Line Loss Calculation

Appendix 2-R
Loss Factors

		Historical Years					5-Year Average
		2007	2008	2009	2010	2011	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	230,101,605	233,194,447	225,969,773	221,209,083	221,759,892	226,446,960
A(2)	"Wholesale" kWh delivered to distributor (lower value)	223,391,038	228,102,047	219,902,138	215,461,717	216,447,244	220,660,837
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	0	0	0	0	0	-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	223,391,038	228,102,047	219,902,138	215,461,717	216,447,244	220,660,837
D	"Retail" kWh delivered by distributor	218,579,500	219,166,243	210,190,317	206,701,676	205,943,133	212,116,174
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	0	0	0	0	0	-
F	Net "Retail" kWh delivered by distributor = **D - E**	218,579,500	219,166,243	210,190,317	206,701,676	205,943,133	212,116,174
G	Loss Factor in Distributor's system = **C / F**	1.0220	1.0408	1.0462	1.0424	1.0510	1.0403
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0340	1.0340	1.0340	1.0340	1.0340	1.0340
	Total Losses						
I	Total Loss Factor = **G x H**	1.0568	1.0762	1.0818	1.0778	1.0867	1.0757

The supply facility loss factor (the "SFLF") shown in the above table represents the losses on supply to LPDL. The SFLF is calculated on the measured quantities between the transformer stations and the wholesale meter points. The SFLF used in the calculations of the total loss factor above is based the 2012 forecast of purchases from Hydro One (1.0340).

Total Loss Factor by Class

Table 8.1.12 sets out the class-specific Loss Factors used by LPDL in the calculation of commodity and other non-distribution charges.

Table 8.1.12 Total Loss Factor by Class

Supply Facility Loss Factor	1.0340
Distribution Loss Factor	
Distribution Loss Factor - Secondary Metered Customer < 5,000 kW	1.0757
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0657
Total Loss Factor	
Distribution Loss Factor - Secondary Metered Customer < 5,000 kW	1.0757
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0657

Materiality Analysis on Distribution Losses

LPDL's Distribution Loss Adjustment factor, as can be seen in Table 8.1.11 above, is 4.03%. Pursuant to the Filing Requirements, as the Distribution Loss Adjustment factor is less than 5%, LPDL is not required to provide an explanation of, or justification for, its loss adjustment factor.

RATE MITIGATION:

In cost allocation, the three classes that were beyond the maximum ratio of 120% were reduced to 120% with a compensating adjustment in Residential and Sentinel Lighting classes. The result was that GS>50 kW class bill impact was higher than optional. In order to correct this, the ratio for GS>50 kW was lowered to 111%. The balance was then adjusted in both Residential and Sentinel Lighting. This resulted in acceptable bill impacts for all classes.

In addition, LPDL has applied for disposition of the Stranded Meters over a two year period instead of over one year to provide a greater offset to increasing rates.

EXISTING RATE CLASSES:

Residential

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

General Service Less Than 50kW

This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. This class includes small commercial services such as small stores, small service stations, restaurants, churches, small offices and other establishments with similar loads.

General Service Greater Than 50 kW

This classification refers to a non-residential account whose monthly average peak demand is greater than, or is forecast to be greater than, 50 kW but less than 5,000 kW. This class includes medium and large-size commercial buildings, apartment buildings, condominiums, trailer courts, industrial plants, as well as large stores, shopping centers, hospitals, manufacturing or processing plants, garages, storage buildings, restaurants, office buildings, hotels, motels, schools, colleges, arenas and other comparable premises.

Unmetered Scattered Load

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, private sentinel lighting, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/ consumption of the proposed unmetered load.

Sentinel Lighting

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

Street Lighting

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation or private roadway lighting operation, controlled by photocells. 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.

EXISTING RATE SCHEDULE:

LPDL has attached the Board's Decision and Order from its 2012 Rate Application and Smart Meter Cost Recovery Application (EB-2011-0180 and EB-2011-0413) in Appendix A, which contains a complete schedule of existing rates.

PROPOSED RATES AND CHARGES:

LPDL has attached a schedule of the proposed rates and charges effective May 1, 2013 in Appendix A.

RECONCILIATION OF RATE CLASS REVENUE:

The following Table 8.6.1 provides a reconciliation between the 2013 distribution rate calculations based on the 2013 Proposed Rates and the total base revenue required.

Table 8.6.1 - 2013 Test Year Distribution Revenue Reconciliation

Appendix 2-V
Revenue Reconciliation

Rate Class	Customers/ Connections	Number of			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric					
								kWh	kW				
Residential	Customers	8,063	8,063	8,063	77,259,128		$ 20.19	$ 0.0148		$ 3,094,681	$ 3,094,202		$ 3,094,202
GS < 50 kW	Customers	1,591	1,591	1,591	41,707,732		$ 44.61	$ 0.0092		$ 1,233,855	$ 1,233,858		$ 1,233,858
GS > 50 to 4,999 kW	Customers	103	103	103		203,731	$ 526.58		$ 1.5024	$ 956,122	$ 899,897	$ 56,230	$ 956,127
Large Use			-	-						$ -			$ -
Streetlighting	Connections	2,147	2,147	2,147		5,035	$ 5.34		$16.3439	$ 219,852	$ 219,846		$ 219,846
Sentinel Lighting	Connections	44	44	44		109	$ 6.46		$22.3710	$ 5,840	$ 5,840		$ 5,840
Unmetered Scattered Load	Connections	35	35	35	106,109		$ 13.00	$ 0.0059		$ 6,118	$ 6,117		$ 6,117
Standby Power				-						$ -			$ -
Embedded Distributor Class				-						$ -			$ -
etc.				-						$ -			$ -
				-						$ -			$ -
				-						$ -			$ -
				-						$ -			$ -
Total										$ 5,516,468	$ 5,459,761	$ 56,230	$ 5,515,990

RATE AND BILL IMPACTS:

Appendix A to 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 shown using the applicable current approved rates and the proposed 2013 distribution rates, including rate riders for the disposition of Deferral and Variance Accounts, as discussed in Exhibit 9.

The total bill impacts are calculated for each rate class at various levels of consumption. The rate impacts are assessed on the basis of moving to the proposed distribution rates.

APPENDIX A

2012 AND 2013 TABLE OF RATES AND BILL IMPACTS

Lakeland Power Distribution Ltd.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2012

Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0413

RESIDENTIAL SERVICE CLASSIFICATION

Tjis classification refers to the supply of electrical energy to residential customers residing in detached, semi detached, town house (freehold or condominium) dwelling units, duplexes or triplexes. Supply will be limited up to a maximum of 200 amp @ 240/120 volt. Further servicing details are available in our Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	15.35
SMDR	$	1.15
SMIRR	$	3.51
Distribution Volumetric Rate	$/kWh	0.0138
Low Voltage Service Rate - Effective Until	$/kWh	0.0024
Rate Rider for Tax Adjustments - Effective Until April 30, 2013	$/kWh	-0.0002
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery - Effective Until April 30, 2013	$/kWh	0.0007
Rate Rider for Deferral/Variance Account Disposition (2012)	$/kWh	0.0001
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Lakeland Power Distribution Ltd.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2012

Implementation Date May 1, 2012

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EB-2011-0413

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in our Conditions of Service

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	36.65
SMDR	$	2.86
SMIRR	$	4.24
Distribution Volumetric Rate	$/kWh	0.0084
Low Voltage Service Rate - Effective Until	$/kWh	0.0021
Rate Rider for Tax Adjustments - Effective Until April 30, 2013	$/kWh	-0.0002
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery - Effective Until April 30, 2013	$/kWh	0.0001
Rate Rider for Deferral/Variance Account Disposition (2012)	$/kWh	0.0001
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0037

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Lakeland Power Distribution Ltd.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2012

Implementation Date May 1, 2012

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EB-2011-0413

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in our Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	487.45
Distribution Volumetric Rate	$/kW	1.4113
Low Voltage Service Rate - Effective Until	$/kW	0.8393
Rate Rider for Tax Adjustments - Effective Until April 30, 2013	$/kW	-0.033
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery - Effective Until April 30, 2013	$/kW	0.0054
Rate Rider for Deferral/Variance Account Disposition (2012)	$/kW	0.0212
Retail Transmission Rate – Network Service Rate	$/kW	1.9996
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5659

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Lakeland Power Distribution Ltd.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2012

Implementation Date May 1, 2012

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EB-2011-0413

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 240/120 or 120 volts whose monthly peak demand is less than or expected to be less than 50 kW and is unmetered. A detailed calculation of the load will be calculated for billing purposes. Further servicing details are available in our Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	18.08
Distribution Volumetric Rate	$/kWh	0.0082
Low Voltage Service Rate - Effective Until	$/kWh	0.0021
Rate Rider for Tax Adjustments - Effective Until April 30, 2013	$/kWh	-0.0004
Rate Rider for Deferral/Variance Account Disposition (2012)	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0037

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Lakeland Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012
Implementation Date May 1, 2012

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EB-2011-0413

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in our Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	4.89
Distribution Volumetric Rate	$/kW	16.936
Low Voltage Service Rate - Effective Until	$/kW	0.6624
Rate Rider for Tax Adjustments - Effective Until April 30, 2013	$/kW	-0.307
Rate Rider for Deferral/Variance Account Disposition (2012)	$/kW	0.1002
Retail Transmission Rate – Network Service Rate	$/kW	1.4942
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.154

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Lakeland Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
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Implementation Date May 1, 2012

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EB-2011-0413

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in our Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	4.83
Distribution Volumetric Rate	$/kW	14.7836
Low Voltage Service Rate - Effective Until	$/kW	0.6488
Rate Rider for Tax Adjustments - Effective Until April 30, 2013	$/kW	-0.2972
Rate Rider for Deferral/Variance Account Disposition (2012)	$/kW	0.0971
Retail Transmission Rate – Network Service Rate	$/kW	1.4565
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1429

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Lakeland Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012
Implementation Date May 1, 2012

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EB-2011-0413

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's micoFIT program and connected to the distribuor's distribution system. Further servicing details are available in the distributor's Condition of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.25

Lakeland Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012
Implementation Date May 1, 2012

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EB-2011-0413

ALLOWANCES

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

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Request for other billing information	$	15.00
Income tax letter	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00

Non-Payment of Account

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

Temporary service install & remove - overhead - no transformer	$	500.00
Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00

Lakeland Power Distribution Ltd.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2012

Implementation Date May 1, 2012

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RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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

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

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factor will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0585
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0480

2013 Tariff Sheet of Rates and Charges

Lakeland Power Distribution Ltd.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2013

Implementation Date May 1, 2013

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EB-2012-0145

RESIDENTIAL SERVICE CLASSIFICATION

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	20.19
Rate Rider for Stranded Meters - Effective until April 30, 2015	$	1.70
Distribution Volumetric Rate	$/kWh	0.0148
Low Voltage Service Rate - Effective Until	$/kWh	0.0034
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery - Effective Until April 30, 2013	$/kWh	0
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until April 30, 2014	$/kWh	0.0037
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	-0.0035
Retail Transmission Rate – Network Service Rate	$/kWh	0.0052
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0042

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Lakeland Power Distribution Ltd.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2013

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EB-2012-0145

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	44.61
Rate Rider for Stranded Meters - Effective until April 30, 2015	$	3.09
Distribution Volumetric Rate	$/kWh	0.0092
Low Voltage Service Rate - Effective Until	$/kWh	0.003
Rate Rider for Tax Adjustments - Effective Until April 30, 2013	$/kWh	
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery - Effective Until April 30, 2013	$/kWh	0
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until April 30, 2014	$/kWh	0.0037
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	-0.0035
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Lakeland Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
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EB-2012-0145

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in our Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	526.58
Distribution Volumetric Rate	$/kW	3.0048
Low Voltage Service Rate - Effective Until	$/kW	1.3960
Rate Rider for Tax Adjustments - Effective Until April 30, 2013	$/kW	
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery - Effective Until April 30, 2013	$/kW	0
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until April 30, 2014	$/kW	1.5362
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014	$/kW	-1.4292
Applicable only for Non-RPP Customers		
Retail Transmission Rate – Network Service Rate	$/kW	2.0358
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6356

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Lakeland Power Distribution Ltd.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2013

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EB-2012-0145

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 240/120 or 120 volts whose monthly peak demand is less than or expected to be less than 50 kW and is unmetered. A detailed calculation of the load will be calculated for billing purposes. Further servicing details are available in our Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	13.00
Distribution Volumetric Rate	$/kWh	0.0059
Low Voltage Service Rate - Effective Until	$/kWh	0.0030
Rate Rider for Tax Adjustments - Effective Until April 30, 2013	$/kWh	
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until April 30, 2014	$/kWh	0.0037
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014	$/kWh	-0.0035
Applicable only for Non-RPP Customers		
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Lakeland Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2013
Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0145

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in our Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	6.46
Distribution Volumetric Rate	$/kW	22.3710
Low Voltage Service Rate - Effective Until	$/kW	0.9588
Rate Rider for Tax Adjustments - Effective Until April 30, 2013	$/kW	
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until April 30, 2014	$/kW	1.3280
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	-1.2355
Retail Transmission Rate – Network Service Rate	$/kW	1.5212
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2053

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Lakeland Power Distribution Ltd.
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Effective Date May 1, 2013
Implementation Date May 1, 2013

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EB-2012-0145

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times and the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in our Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	5.34
Distribution Volumetric Rate	$/kW	16.3439
Low Voltage Service Rate - Effective Until	$/kW	0.9390
Rate Rider for Tax Adjustments - Effective Until April 30, 2013	$/kW	
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until April 30, 2014	$/kW	1.3712
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014	$/kW	-1.2756
Applicable only for Non-RPP Customers		
Retail Transmission Rate – Network Service Rate	$/kW	1.4829
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1937

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Lakeland Power Distribution Ltd.

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Effective Date May 1, 2013

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microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's micoFIT program and connected to the distribuor's distribution system. Further servicing details are available in the distributor's Condition of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule unless required by the Distributor's Licence or a Code or Order ofthe Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Programs, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.25

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ALLOWANCES

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

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Request for other billing information	$	15.00
Income tax letter	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00

Non-Payment of Account

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

Temporary service install & remove - overhead - no transformer	$	500.00
Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00

Lakeland Power Distribution Ltd.
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RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

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

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

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factor will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0757
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0650

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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption 100 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 15.3500	1	$ 15.35	$ 20.1900	1	$ 20.19	$ 4.84	31.53%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly	$ 3.5100	1	$ 3.51		1	$ -	-$ 3.51	-100.00%
Smart Meter Disposition Rider	Monthly	$ 1.1500	1	$ 1.15		1	$ -	-$ 1.15	-100.00%
Stranded Meter Disposition	Monthly		1	$ -	$ 1.70	1	$ 1.70	$ 1.70	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0138	100	$ 1.38	$ 0.0148	100	$ 1.48	$ 0.10	7.25%
Smart Meter Disposition Rider			100	$ -		100	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0007	100	$ 0.07		100	$ -	-$ 0.07	-100.00%
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Sub-Total A				$ 21.46			$ 23.37	**$ 1.91**	**8.88%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0001	100	$ 0.01	$ 0.0037	100	$ 0.37	$ 0.36	3621.49%
Tax Adjustment	per kWh	-$ 0.0002	100	-$ 0.02		100	$ -	$ 0.02	-100.00%
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0024	100	$ 0.24	$ 0.0034	100	$ 0.34	$ 0.10	41.67%
Smart Meter Entity Charge						100	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 21.69**			**$ 24.08**	**$ 2.39**	**11.01%**
RTSR - Network	per kWh	$ 0.0051	106	$ 0.54	$ 0.0052	108	$ 0.56	$ 0.02	3.46%
RTSR - Line and Transformation Connection	per kWh	$ 0.0040	106	$ 0.42	$ 0.0042	108	$ 0.45	$ 0.03	6.15%
Sub-Total C - Delivery (including Sub-Total B)				**$ 22.65**			**$ 25.09**	**$ 2.43**	**10.74%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	106	$ 0.55	$ 0.0052	108	$ 0.56	$ 0.01	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	106	$ 0.12	$ 0.0011	108	$ 0.12	$ 0.00	1.62%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	106	$ 0.74	$ 0.0070	108	$ 0.75	$ 0.01	1.62%
Energy - RPP - Tier 1		$ 0.0750	106	$ 7.94	$ 0.0750	108	$ 8.07	$ 0.13	1.62%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	68	$ 4.40	$ 0.0650	69	$ 4.47	$ 0.07	1.62%
TOU - Mid Peak		$ 0.1000	19	$ 1.91	$ 0.1000	19	$ 1.94	$ 0.03	1.62%
TOU - On Peak		$ 0.1170	19	$ 2.23	$ 0.1170	19	$ 2.27	$ 0.04	1.62%
Total Bill on RPP (before Taxes)				**$ 32.25**			**$ 34.84**	**$ 2.59**	**8.02%**
HST		13%		$ 4.19	13%		$ 4.53	$ 0.34	8.02%
Total Bill (including HST)				$ 36.44			$ 39.36	$ 2.92	8.02%
Ontario Clean Energy Benefit [1]				-$ 3.64			-$ 3.94	-$ 0.30	8.24%
Total Bill on RPP (including OCEB)				**$ 32.80**			**$ 35.42**	**$ 2.62**	**7.99%**
Total Bill on TOU (before Taxes)				**$ 32.85**			**$ 35.44**	**$ 2.60**	**7.90%**
HST		13%		$ 4.27	13%		$ 4.61	$ 0.34	7.90%
Total Bill (including HST)				$ 37.12			$ 40.05	$ 2.93	7.90%
Ontario Clean Energy Benefit [1]				-$ 3.71			-$ 4.01	-$ 0.30	8.09%
Total Bill on TOU (including OCEB)				**$ 33.41**			**$ 36.04**	**$ 2.63**	**7.88%**

Loss Factor (%) Current: 5.85% Proposed: 7.57%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption 250 **kWh** ○ May 1 - October 31

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 15.3500	1	$ 15.35	$ 20.1900	1	$ 20.19	$ 4.84	31.53%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly	$ 3.5100	1	$ 3.51	$ -	1	$ -	-$ 3.51	-100.00%
Smart Meter Disposition Rider	Monthly	$ 1.1500	1	$ 1.15	$ -	1	$ -	-$ 1.15	-100.00%
Stranded Meter Disposition	Monthly	$ -	1	$ -	$ 1.70	1	$ 1.70	$ 1.70	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0138	250	$ 3.45	$ 0.0148	250	$ 3.70	$ 0.25	7.25%
Smart Meter Disposition Rider		$ -	250	$ -	$ -	250	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0007	250	$ 0.18	$ -	250	$ -	-$ 0.18	-100.00%
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
Sub-Total A				$ 23.64			$ 25.59	**$ 1.95**	**8.26%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0001	250	$ 0.03	$ 0.0037	250	$ 0.93	$ 0.91	3621.49%
Tax Adjustment		-$ 0.0002	0	$ -	$ -	0	$ -	$ -	
		$ -	250	$ -	$ -	250	$ -	$ -	
		$ -	0	$ -	$ -	0	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0024	250	$ 0.60	$ 0.0034	250	$ 0.85	$ 0.25	41.67%
Smart Meter Entity Charge						0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 24.26**			**$ 27.37**	**$ 3.11**	**12.81%**
RTSR - Network	per kWh	$ 0.0051	265	$ 1.35	$ 0.0052	269	$ 1.40	$ 0.05	3.46%
RTSR - Line and Transformation Connection	per kWh	$ 0.0040	265	$ 1.06	$ 0.0042	269	$ 1.12	$ 0.07	6.15%
Sub-Total C - Delivery (including Sub-Total B)				**$ 26.67**			**$ 29.89**	**$ 3.22**	**12.07%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	265	$ 1.38	$ 0.0052	269	$ 1.40	$ 0.02	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	265	$ 0.29	$ 0.0011	269	$ 0.30	$ 0.00	1.62%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	265	$ 1.85	$ 0.0070	269	$ 1.88	$ 0.03	1.62%
Energy - RPP - Tier 1		$ 0.0750	265	$ 19.85	$ 0.0750	269	$ 20.17	$ 0.32	1.62%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	169	$ 11.01	$ 0.0650	172	$ 11.19	$ 0.18	1.62%
TOU - Mid Peak		$ 0.1000	48	$ 4.76	$ 0.1000	48	$ 4.84	$ 0.08	1.62%
TOU - On Peak		$ 0.1170	48	$ 5.57	$ 0.1170	48	$ 5.66	$ 0.09	1.62%
Total Bill on RPP (before Taxes)				**$ 50.28**			**$ 53.88**	**$ 3.60**	**7.16%**
HST		13%		$ 6.54	13%		$ 7.00	$ 0.47	7.16%
Total Bill (including HST)				$ 56.82			$ 60.89	$ 4.07	7.16%
Ontario Clean Energy Benefit [1]				-$ 5.68			-$ 6.09	-$ 0.41	7.22%
Total Bill on RPP (including OCEB)				**$ 51.14**			**$ 54.80**	**$ 3.66**	**7.15%**
Total Bill on TOU (before Taxes)				**$ 51.78**			**$ 55.41**	**$ 3.62**	**7.00%**
HST		13%		$ 6.73	13%		$ 7.20	$ 0.47	7.00%
Total Bill (including HST)				$ 58.51			$ 62.61	$ 4.09	7.00%
Ontario Clean Energy Benefit [1]				-$ 5.85			-$ 6.26	-$ 0.41	7.01%
Total Bill on TOU (including OCEB)				**$ 52.66**			**$ 56.35**	**$ 3.68**	**7.00%**

Loss Factor (%) 5.85% 7.57%

Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

lote that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced onsumption level at existing and proposed rates.

pplicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant ɔ their service territory, class by class. A general guideline of consumption levels follows:

tesidential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
S<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
S>50kW (kW) - 60, 100, 500, 1000
arge User - range appropriate for utility
ighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption 500 **kWh** ○ May 1 - October 31

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 15.3500	1	$ 15.35	$ 20.1900	1	$ 20.19	$ 4.84	31.53%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly	$ 3.5100	1	$ 3.51	$ -	1	$ -	-$ 3.51	-100.00%
Smart Meter Disposition Rider	Monthly	$ 1.1500	1	$ 1.15	$ -	1	$ -	-$ 1.15	-100.00%
Stranded Meter Disposition	Monthly	$ -	1	$ -	$ 1.6967	1	$ 1.70	$ 1.70	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0138	500	$ 6.90	$ 0.0148	500	$ 7.40	$ 0.50	7.25%
Smart Meter Disposition Rider		$ -	500	$ -	$ -	500	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0007	500	$ 0.35	$ -	500	$ -	-$ 0.35	-100.00%
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Sub-Total A				$ 27.26			$ 29.29	**$ 2.03**	**7.43%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0001	500	$ 0.05	$ 0.0037	500	$ 1.86	$ 1.81	3621.49%
Tax Adjustment		-$ 0.0002	0	$ -	$ -	0	$ -	$ -	
		$ -	500	$ -	$ -	500	$ -	$ -	
		$ -	0	$ -	$ -	0	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0024	500	$ 1.20	$ 0.0034	500	$ 1.70	$ 0.50	41.67%
Smart Meter Entity Charge						0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 28.51**			**$ 32.85**	**$ 4.34**	**15.21%**
RTSR - Network	per kWh	$ 0.0051	529	$ 2.70	$ 0.0052	538	$ 2.79	$ 0.09	3.46%
RTSR - Line and Transformation Connection	per kWh	$ 0.0040	529	$ 2.12	$ 0.0042	538	$ 2.25	$ 0.13	6.15%
Sub-Total C - Delivery (including Sub-Total B)				**$ 33.33**			**$ 37.89**	**$ 4.56**	**13.69%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	529	$ 2.75	$ 0.0052	538	$ 2.80	$ 0.04	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	529	$ 0.58	$ 0.0011	538	$ 0.59	$ 0.01	1.62%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	529	$ 3.70	$ 0.0070	538	$ 3.76	$ 0.06	1.62%
Energy - RPP - Tier 1		$ 0.0750	529	$ 39.69	$ 0.0750	538	$ 40.34	$ 0.64	1.62%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	339	$ 22.02	$ 0.0650	344	$ 22.37	$ 0.36	1.62%
TOU - Mid Peak		$ 0.1000	95	$ 9.53	$ 0.1000	97	$ 9.68	$ 0.15	1.62%
TOU - On Peak		$ 0.1170	95	$ 11.15	$ 0.1170	97	$ 11.33	$ 0.18	1.62%
Total Bill on RPP (before Taxes)				**$ 80.31**			**$ 85.63**	**$ 5.32**	**6.62%**
HST		13%		$ 10.44	13%		$ 11.13	$ 0.69	6.62%
Total Bill (including HST)				$ 90.75			$ 96.76	$ 6.01	6.62%
***Ontario Clean Energy Benefit* [1]**				-$ 9.07			-$ 9.68	-$ 0.61	6.73%
Total Bill on RPP (including OCEB)				**$ 81.68**			**$ 87.08**	**$ 5.40**	**6.61%**
Total Bill on TOU (before Taxes)				**$ 83.30**			**$ 88.67**	**$ 5.37**	**6.45%**
HST		13%		$ 10.83	13%		$ 11.53	$ 0.70	6.45%
Total Bill (including HST)				$ 94.13			$ 100.20	$ 6.07	6.45%
***Ontario Clean Energy Benefit* [1]**				-$ 9.41			-$ 10.02	-$ 0.61	6.48%
Total Bill on TOU (including OCEB)				**$ 84.72**			**$ 90.18**	**$ 5.46**	**6.44%**

Loss Factor (%) 5.85% 7.57%

Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

lote that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced onsumption level at existing and proposed rates.

ıpplicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant › their service territory, class by class. A general guideline of consumption levels follows:

ɛesidential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
ɜS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
ɜS>50kW (kW) - 60, 100, 500, 1000
arge User - range appropriate for utility
ighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption 800 **kWh** ○ May 1 - October 31

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 15.3500	1	$ 15.35	$ 20.1900	1	$ 20.19	$ 4.84	31.53%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly	$ 3.5100	1	$ 3.51	$ -	1	$ -	-$ 3.51	-100.00%
Smart Meter Disposition Rider	Monthly	$ 1.1500	1	$ 1.15	$ -	1	$ -	-$ 1.15	-100.00%
Stranded Meter Disposition	Monthly	$ -	1	$ -	$ 1.6967	1	$ 1.70	$ 1.70	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0138	800	$ 11.04	$ 0.0148	800	$ 11.84	$ 0.80	7.25%
Smart Meter Disposition Rider		$ -	800	$ -	$ -	800	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0007	800	$ 0.56	$ -	800	$ -	-$ 0.56	-100.00%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A				$ 31.61			$ 33.73	**$ 2.12**	**6.70%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0001	800	$ 0.08	$ 0.0037	800	$ 2.98	$ 2.90	3621.49%
Tax Adjustment		-$ 0.0002	0	$ -	$ -	0	$ -	$ -	
		$ -	800	$ -	$ -	800	$ -	$ -	
		$ -	0	$ -	$ -	0	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0024	800	$ 1.92	$ 0.0034	800	$ 2.72	$ 0.80	41.67%
Smart Meter Entity Charge						0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 33.61**			**$ 39.42**	**$ 5.81**	**17.30%**
RTSR - Network	per kWh	$ 0.0051	847	$ 4.32	$ 0.0052	861	$ 4.47	$ 0.15	3.46%
RTSR - Line and Transformation Connection	per kWh	$ 0.0040	847	$ 3.39	$ 0.0042	861	$ 3.60	$ 0.21	6.15%
Sub-Total C - Delivery (including Sub-Total B)				**$ 41.32**			**$ 47.49**	**$ 6.17**	**14.94%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	847	$ 4.40	$ 0.0052	861	$ 4.47	$ 0.07	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	847	$ 0.93	$ 0.0011	861	$ 0.95	$ 0.02	1.62%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	847	$ 5.93	$ 0.0070	861	$ 6.02	$ 0.10	1.62%
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	247	$ 21.72	$ 0.0880	261	$ 22.93	$ 1.21	5.58%
TOU - Off Peak		$ 0.0650	542	$ 35.23	$ 0.0650	551	$ 35.80	$ 0.57	1.62%
TOU - Mid Peak		$ 0.1000	152	$ 15.24	$ 0.1000	155	$ 15.49	$ 0.25	1.62%
TOU - On Peak		$ 0.1170	152	$ 17.83	$ 0.1170	155	$ 18.12	$ 0.29	1.62%
Total Bill on RPP (before Taxes)				**$ 119.55**			**$ 127.11**	**$ 7.57**	**6.33%**
HST		13%		$ 15.54	13%		$ 16.52	$ 0.98	6.33%
Total Bill (including HST)				$ 135.09			$ 143.64	$ 8.55	6.33%
Ontario Clean Energy Benefit [1]				-$ 13.51			-$ 14.36	-$ 0.85	6.29%
Total Bill on RPP (including OCEB)				**$ 121.58**			**$ 129.28**	**$ 7.70**	**6.33%**
Total Bill on TOU (before Taxes)				**$ 121.13**			**$ 128.60**	**$ 7.46**	**6.16%**
HST		13%		$ 15.75	13%		$ 16.72	$ 0.97	6.16%
Total Bill (including HST)				$ 136.88			$ 145.31	$ 8.43	6.16%
Ontario Clean Energy Benefit [1]				-$ 13.69			-$ 14.53	-$ 0.84	6.14%
Total Bill on TOU (including OCEB)				**$ 123.19**			**$ 130.78**	**$ 7.59**	**6.17%**

Loss Factor (%) — Current: 5.85% — Proposed: 7.57%

Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

lote that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced onsumption level at existing and proposed rates.

.pplicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant › their service territory, class by class. A general guideline of consumption levels follows:

:esidential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
;S<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
;S>50kW (kW) - 60, 100, 500, 1000
arge User - range appropriate for utility
ighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption 1000 **kWh** ○ May 1 - October 31

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 15.3500	1	$ 15.35	$ 20.1900	1	$ 20.19	$ 4.84	31.53%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly	$ 3.5100	1	$ 3.51	$ -	1	$ -	-$ 3.51	-100.00%
Smart Meter Disposition Rider	Monthly	$ 1.1500	1	$ 1.15	$ -	1	$ -	-$ 1.15	-100.00%
Stranded Meter Disposition	Monthly	$ -	1	$ -	$ 1.6967	1	$ 1.70	$ 1.70	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0138	1000	$ 13.80	$ 0.0148	1000	$ 14.80	$ 1.00	7.25%
Smart Meter Disposition Rider		$ -	1000	$ -	$ -	1000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0007	1000	$ 0.70	$ -	1000	$ -	-$ 0.70	-100.00%
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
Sub-Total A				$ 34.51			$ 36.69	**$ 2.18**	**6.31%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0001	1000	$ 0.10	$ 0.0037	1000	$ 3.72	$ 3.62	3621.49%
Tax Adjustment		-$ 0.0002	0	$ -	$ -	0	$ -	$ -	
		$ -	1000	$ -	$ -	1000	$ -	$ -	
		$ -	0	$ -	$ -	0	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0024	1000	$ 2.40	$ 0.0034	1000	$ 3.40	$ 1.00	41.67%
Smart Meter Entity Charge						0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 37.01**			**$ 43.81**	**$ 6.80**	**18.37%**
RTSR - Network	per kWh	$ 0.0051	1059	$ 5.40	$ 0.0052	1076	$ 5.59	$ 0.19	3.46%
RTSR - Line and Transformation Connection	per kWh	$ 0.0040	1059	$ 4.23	$ 0.0042	1076	$ 4.49	$ 0.26	6.15%
Sub-Total C - Delivery (including Sub-Total B)				**$ 46.64**			**$ 53.89**	**$ 7.25**	**15.53%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	1059	$ 5.50	$ 0.0052	1076	$ 5.59	$ 0.09	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	1059	$ 1.16	$ 0.0011	1076	$ 1.18	$ 0.02	1.62%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1059	$ 7.41	$ 0.0070	1076	$ 7.53	$ 0.12	1.62%
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	459	$ 40.35	$ 0.0880	476	$ 41.86	$ 1.51	3.75%
TOU - Off Peak		$ 0.0650	677	$ 44.03	$ 0.0650	688	$ 44.75	$ 0.72	1.62%
TOU - Mid Peak		$ 0.1000	191	$ 19.05	$ 0.1000	194	$ 19.36	$ 0.31	1.62%
TOU - On Peak		$ 0.1170	191	$ 22.29	$ 0.1170	194	$ 22.65	$ 0.36	1.62%
Total Bill on RPP (before Taxes)				**$ 146.32**			**$ 155.31**	**$ 8.99**	**6.14%**
HST		13%		$ 19.02	13%		$ 20.19	$ 1.17	6.14%
Total Bill (including HST)				$ 165.34			$ 175.50	$ 10.16	6.14%
Ontario Clean Energy Benefit [1]				-$ 16.53			-$ 17.55	-$ 1.02	6.17%
Total Bill on RPP (including OCEB)				**$ 148.81**			**$ 157.95**	**$ 9.14**	**6.14%**
Total Bill on TOU (before Taxes)				**$ 146.35**			**$ 155.21**	**$ 8.86**	**6.06%**
HST		13%		$ 19.03	13%		$ 20.18	$ 1.15	6.06%
Total Bill (including HST)				$ 165.37			$ 175.39	$ 10.01	6.06%
Ontario Clean Energy Benefit [1]				-$ 16.54			-$ 17.54	-$ 1.00	6.05%
Total Bill on TOU (including OCEB)				**$ 148.83**			**$ 157.85**	**$ 9.01**	**6.06%**

Loss Factor (%) 5.85% 7.57%

Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.* ¹

lote that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced N
onsumption level at existing and proposed rates. c

pplicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant A
› their service territory, class by class. A general guideline of consumption levels follows: tc

esidential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000 R
S<50kW (kWh) - 1000, 2000, 5000, 10000, 15000 G
S>50kW (kW) - 60, 100, 500, 1000 G
arge User - range appropriate for utility L
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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption **1500** **kWh** ○ May 1 - October 31

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 15.3500	1	$ 15.35	$ 20.1900	1	$ 20.19	$ 4.84	31.53%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly	$ 3.5100	1	$ 3.51	$ -	1	$ -	-$ 3.51	-100.00%
Smart Meter Disposition Rider	Monthly	$ 1.1500	1	$ 1.15	$ -	1	$ -	-$ 1.15	-100.00%
Stranded Meter Disposition	Monthly	$ -	1	$ -	$ 1.6967	1	$ 1.70	$ 1.70	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0138	1500	$ 20.70	$ 0.0148	1500	$ 22.20	$ 1.50	7.25%
Smart Meter Disposition Rider		$ -	1500	$ -	$ -	1500	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0007	1500	$ 1.05	$ -	1500	$ -	-$ 1.05	-100.00%
			1500	$ -		1500	$ -	$ -	
			1500	$ -		1500	$ -	$ -	
			1500	$ -		1500	$ -	$ -	
			1500	$ -		1500	$ -	$ -	
			1500	$ -		1500	$ -	$ -	
			1500	$ -		1500	$ -	$ -	
			1500	$ -		1500	$ -	$ -	
Sub-Total A				$ 41.76			$ 44.09	**$ 2.33**	**5.57%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0001	1500	$ 0.15	$ 0.0037	1500	$ 5.58	$ 5.43	3621.49%
Tax Adjustment		-$ 0.0002	0	$ -	$ -	0	$ -	$ -	
		$ -	1500	$ -	$ -	1500	$ -	$ -	
		$ -	0	$ -	$ -	0	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0024	1500	$ 3.60	$ 0.0034	1500	$ 5.10	$ 1.50	41.67%
Smart Meter Entity Charge						0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 45.51**			**$ 54.77**	**$ 9.26**	**20.34%**
RTSR - Network	per kWh	$ 0.0051	1588	$ 8.10	$ 0.0052	1614	$ 8.38	$ 0.28	3.46%
RTSR - Line and Transformation Connection	per kWh	$ 0.0040	1588	$ 6.35	$ 0.0042	1614	$ 6.74	$ 0.39	6.15%
Sub-Total C - Delivery (including Sub-Total B)				**$ 59.96**			**$ 69.89**	**$ 9.93**	**16.56%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	1588	$ 8.26	$ 0.0052	1614	$ 8.39	$ 0.13	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	1588	$ 1.75	$ 0.0011	1614	$ 1.77	$ 0.03	1.62%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1588	$ 11.11	$ 0.0070	1614	$ 11.29	$ 0.18	1.62%
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	988	$ 86.92	$ 0.0880	1014	$ 89.19	$ 2.27	2.61%
TOU - Off Peak		$ 0.0650	1016	$ 66.05	$ 0.0650	1033	$ 67.12	$ 1.07	1.62%
TOU - Mid Peak		$ 0.1000	286	$ 28.58	$ 0.1000	290	$ 29.04	$ 0.46	1.62%
TOU - On Peak		$ 0.1170	286	$ 33.44	$ 0.1170	290	$ 33.98	$ 0.54	1.62%
Total Bill on RPP (before Taxes)				**$ 213.25**			**$ 225.79**	**$ 12.54**	**5.88%**
HST		13%		$ 27.72	13%		$ 29.35	$ 1.63	5.88%
Total Bill (including HST)				$ 240.97			$ 255.14	$ 14.17	5.88%
Ontario Clean Energy Benefit [1]				-$ 24.10			-$ 25.51	-$ 1.41	5.85%
Total Bill on RPP (including OCEB)				**$ 216.87**			**$ 229.63**	**$ 12.76**	**5.89%**
Total Bill on TOU (before Taxes)				**$ 209.39**			**$ 221.75**	**$ 12.35**	**5.90%**
HST		13%		$ 27.22	13%		$ 28.83	$ 1.61	5.90%
Total Bill (including HST)				$ 236.61			$ 250.57	$ 13.96	5.90%
Ontario Clean Energy Benefit [1]				-$ 23.66			-$ 25.06	-$ 1.40	5.92%
Total Bill on TOU (including OCEB)				**$ 212.95**			**$ 225.51**	**$ 12.56**	**5.90%**

Loss Factor (%) 5.85% 7.57%

Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

lote that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced onsumption level at existing and proposed rates.

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{esidential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
;S<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
;S>50kW (kW) - 60, 100, 500, 1000
arge User - range appropriate for utility
ighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption 2000 **kWh** ○ May 1 - October 31

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 15.3500	1	$ 15.35	$ 20.1900	1	$ 20.19	$ 4.84	31.53%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly	$ 3.5100	1	$ 3.51	$ -	1	$ -	-$ 3.51	-100.00%
Smart Meter Disposition Rider	Monthly	$ 1.1500	1	$ 1.15	$ -	1	$ -	-$ 1.15	-100.00%
Stranded Meter Disposition	Monthly	$ -	1	$ -	$ 1.6967	1	$ 1.70	$ 1.70	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0138	2000	$ 27.60	$ 0.0148	2000	$ 29.60	$ 2.00	7.25%
Smart Meter Disposition Rider		$ -	2000	$ -	$ -	2000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0007	2000	$ 1.40	$ -	2000	$ -	-$ 1.40	-100.00%
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Sub-Total A				$ 49.01			$ 51.49	**$ 2.48**	**5.05%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0001	2000	$ 0.20	$ 0.0037	2000	$ 7.44	$ 7.24	3621.49%
Tax Adjustment		-$ 0.0002	0	$ -	$ -	0	$ -	$ -	
		$ -	2000	$ -	$ -	2000	$ -	$ -	
		$ -	0	$ -	$ -	0	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0024	2000	$ 4.80	$ 0.0034	2000	$ 6.80	$ 2.00	41.67%
Smart Meter Entity Charge						0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 54.01**			**$ 65.73**	**$ 11.72**	**21.70%**
RTSR - Network	per kWh	$ 0.0051	2117	$ 10.80	$ 0.0052	2151	$ 11.17	$ 0.37	3.46%
RTSR - Line and Transformation Connection	per kWh	$ 0.0040	2117	$ 8.47	$ 0.0042	2151	$ 8.99	$ 0.52	6.15%
Sub-Total C - Delivery (including Sub-Total B)				**$ 73.27**			**$ 85.89**	**$ 12.61**	**17.21%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2117	$ 11.01	$ 0.0052	2151	$ 11.19	$ 0.18	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2117	$ 2.33	$ 0.0011	2151	$ 2.37	$ 0.04	1.62%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2117	$ 14.82	$ 0.0070	2151	$ 15.06	$ 0.24	1.62%
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	1517	$ 133.50	$ 0.0880	1551	$ 136.52	$ 3.03	2.27%
TOU - Off Peak		$ 0.0650	1355	$ 88.07	$ 0.0650	1377	$ 89.50	$ 1.43	1.62%
TOU - Mid Peak		$ 0.1000	381	$ 38.11	$ 0.1000	387	$ 38.73	$ 0.62	1.62%
TOU - On Peak		$ 0.1170	381	$ 44.58	$ 0.1170	387	$ 45.31	$ 0.72	1.62%
Total Bill on RPP (before Taxes)				**$ 280.18**			**$ 296.28**	**$ 16.10**	**5.75%**
HST		13%		$ 36.42	13%		$ 38.52	$ 2.09	5.75%
Total Bill (including HST)				$ 316.60			$ 334.79	$ 18.19	5.75%
Ontario Clean Energy Benefit [1]				-$ 31.66			-$ 33.48	-$ 1.82	5.75%
Total Bill on RPP (including OCEB)				**$ 284.94**			**$ 301.31**	**$ 16.37**	**5.75%**
Total Bill on TOU (before Taxes)				**$ 272.44**			**$ 288.28**	**$ 15.85**	**5.82%**
HST		13%		$ 35.42	13%		$ 37.48	$ 2.06	5.82%
Total Bill (including HST)				$ 307.85			$ 325.76	$ 17.91	5.82%
Ontario Clean Energy Benefit [1]				-$ 30.79			-$ 32.58	-$ 1.79	5.81%
Total Bill on TOU (including OCEB)				**$ 277.06**			**$ 293.18**	**$ 16.12**	**5.82%**

	Current	Proposed
Loss Factor (%)	5.85%	7.57%

Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

lote that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced onsumption level at existing and proposed rates.

pplicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant › their service territory, class by class. A general guideline of consumption levels follows:

esidential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
S<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
S>50kW (kW) - 60, 100, 500, 1000
arge User - range appropriate for utility
ighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **GS <50 kW**

Consumption 1000 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 36.6500	1	$ 36.65	$ 44.6100	1	$ 44.61	$ 7.96	21.72%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly	$ 4.2400	1	$ 4.24		1	$ -	-$ 4.24	-100.00%
Smart Meter Disposition Rider	Monthly	$ 2.8600	1	$ 2.86		1	$ -	-$ 2.86	-100.00%
Stranded Meter Disposition	Monthly		1	$ -	$ 3.09	1	$ 3.09	$ 3.09	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0084	1000	$ 8.40	$ 0.0092	1000	$ 9.20	$ 0.80	9.52%
Smart Meter Disposition Rider			1000	$ -		1000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0001	1000	$ 0.10		1000	$ -	-$ 0.10	-100.00%
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
Sub-Total A				$ 52.25			$ 56.90	**$ 4.65**	**8.90%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0001	1000	$ 0.10	$ 0.0037	1000	$ 3.72	$ 3.62	3621.49%
Tax Adjustments	per kWh	-$ 0.0002	1000	-$ 0.20		1000	$ -	$ 0.20	-100.00%
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0021	1000	$ 2.10	$ 0.0030	1000	$ 3.00	$ 0.90	42.86%
Smart Meter Entity Charge						1000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 54.25**			**$ 63.62**	**$ 9.37**	**17.28%**
RTSR - Network	per kWh	$ 0.0047	1059	$ 4.97	$ 0.0048	1076	$ 5.15	$ 0.17	3.46%
RTSR - Line and Transformation Connection	per kWh	$ 0.0037	1059	$ 3.92	$ 0.0039	1076	$ 4.16	$ 0.24	6.15%
Sub-Total C - Delivery (including Sub-Total B)				**$ 63.14**			**$ 72.93**	**$ 9.79**	**15.50%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	1059	$ 5.50	$ 0.0052	1076	$ 5.59	$ 0.09	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	1059	$ 1.16	$ 0.0011	1076	$ 1.18	$ 0.02	1.62%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1059	$ 7.41	$ 0.0070	1076	$ 7.53	$ 0.12	1.62%
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	459	$ 40.35	$ 0.0880	476	$ 41.86	$ 1.51	3.75%
TOU - Off Peak		$ 0.0650	677	$ 44.03	$ 0.0650	688	$ 44.75	$ 0.72	1.62%
TOU - Mid Peak		$ 0.1000	191	$ 19.05	$ 0.1000	194	$ 19.36	$ 0.31	1.62%
TOU - On Peak		$ 0.1170	191	$ 22.29	$ 0.1170	194	$ 22.65	$ 0.36	1.62%
Total Bill on RPP (before Taxes)				**$ 162.82**			**$ 174.35**	**$ 11.53**	**7.08%**
HST		13%		$ 21.17	13%		$ 22.67	$ 1.50	7.08%
Total Bill (including HST)				$ 183.98			$ 197.01	$ 13.03	7.08%
Ontario Clean Energy Benefit [1]				-$ 18.40			-$ 19.70	-$ 1.30	7.07%
Total Bill on RPP (including OCEB)				**$ 165.58**			**$ 177.31**	**$ 11.73**	**7.08%**
Total Bill on TOU (before Taxes)				**$ 162.85**			**$ 174.25**	**$ 11.40**	**7.00%**
HST		13%		$ 21.17	13%		$ 22.65	$ 1.48	7.00%
Total Bill (including HST)				$ 184.02			$ 196.90	$ 12.89	7.00%
Ontario Clean Energy Benefit [1]				-$ 18.40			-$ 19.69	-$ 1.29	7.01%
Total Bill on TOU (including OCEB)				**$ 165.62**			**$ 177.21**	**$ 11.60**	**7.00%**
Loss Factor (%)		5.85%			7.57%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **GS <50 kW**

Consumption 2000 **kWh** ○ May 1 - October 31

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 36.6500	1	$ 36.65	$ 44.6100	1	$ 44.61	$ 7.96	21.72%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly	$ 4.2400	1	$ 4.24	$ -	1	$ -	-$ 4.24	-100.00%
Smart Meter Disposition Rider	Monthly	$ 2.8600	1	$ 2.86	$ -	1	$ -	-$ 2.86	-100.00%
Stranded Meter Disposition	Monthly	$ -	1	$ -	$ 3.0924	1	$ 3.09	$ 3.09	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0084	2000	$ 16.80	$ 0.0092	2000	$ 18.40	$ 1.60	9.52%
Smart Meter Disposition Rider		$ -	2000	$ -	$ -	2000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0001	2000	$ 0.20	$ -	2000	$ -	-$ 0.20	-100.00%
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Sub-Total A				$ 60.75			$ 66.10	**$ 5.35**	**8.81%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0001	2000	$ 0.20	$ 0.0037	2000	$ 7.44	$ 7.24	3621.49%
Tax Adjustment		-$ 0.0002	0	$ -	$ -	0	$ -	$ -	
		$ -	2000	$ -	$ -	2000	$ -	$ -	
		$ -	0	$ -	$ -	0	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0021	2000	$ 4.20	$ 0.0030	2000	$ 6.00	$ 1.80	42.86%
Smart Meter Entity Charge						0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 65.15**			**$ 79.55**	**$ 14.40**	**22.10%**
RTSR - Network	per kWh	$ 0.0047	2117	$ 9.95	$ 0.0048	2151	$ 10.29	$ 0.34	3.46%
RTSR - Line and Transformation Connection	per kWh	$ 0.0037	2117	$ 7.83	$ 0.0039	2151	$ 8.31	$ 0.48	6.15%
Sub-Total C - Delivery (including Sub-Total B)				**$ 82.93**			**$ 98.15**	**$ 15.22**	**18.35%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2117	$ 11.01	$ 0.0052	2151	$ 11.19	$ 0.18	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2117	$ 2.33	$ 0.0011	2151	$ 2.37	$ 0.04	1.62%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2117	$ 14.82	$ 0.0070	2151	$ 15.06	$ 0.24	1.62%
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	1517	$ 133.50	$ 0.0880	1551	$ 136.52	$ 3.03	2.27%
TOU - Off Peak		$ 0.0650	1355	$ 88.07	$ 0.0650	1377	$ 89.50	$ 1.43	1.62%
TOU - Mid Peak		$ 0.1000	381	$ 38.11	$ 0.1000	387	$ 38.73	$ 0.62	1.62%
TOU - On Peak		$ 0.1170	381	$ 44.58	$ 0.1170	387	$ 45.31	$ 0.72	1.62%
Total Bill on RPP (before Taxes)				**$ 289.83**			**$ 308.54**	**$ 18.71**	**6.45%**
HST		13%		$ 37.68	13%		$ 40.11	$ 2.43	6.45%
Total Bill (including HST)				$ 327.51			$ 348.65	$ 21.14	6.45%
Ontario Clean Energy Benefit [1]				-$ 32.75			-$ 34.87	-$ 2.12	6.47%
Total Bill on RPP (including OCEB)				**$ 294.76**			**$ 313.78**	**$ 19.02**	**6.45%**
Total Bill on TOU (before Taxes)				**$ 282.10**			**$ 300.55**	**$ 18.45**	**6.54%**
HST		13%		$ 36.67	13%		$ 39.07	$ 2.40	6.54%
Total Bill (including HST)				$ 318.77			$ 339.62	$ 20.85	6.54%
Ontario Clean Energy Benefit [1]				-$ 31.88			-$ 33.96	-$ 2.08	6.52%
Total Bill on TOU (including OCEB)				**$ 286.89**			**$ 305.66**	**$ 18.77**	**6.54%**
Loss Factor (%)		5.85%			7.57%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **GS <50 kW**

Consumption 5000 **kWh** ○ May 1 - October 31

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 36.6500	1	$ 36.65	$ 44.6100	1	$ 44.61	$ 7.96	21.72%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly	$ 4.2400	1	$ 4.24	$ -	1	$ -	-$ 4.24	-100.00%
Smart Meter Disposition Rider	Monthly	$ 2.8600	1	$ 2.86	$ -	1	$ -	-$ 2.86	-100.00%
Stranded Meter Disposition	Monthly	$ -	1	$ -	$ 3.0924	1	$ 3.09	$ 3.09	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0084	5000	$ 42.00	$ 0.0092	5000	$ 46.00	$ 4.00	9.52%
Smart Meter Disposition Rider		$ -	5000	$ -	$ -	5000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0001	5000	$ 0.50	$ -	5000	$ -	-$ 0.50	-100.00%
			5000	$ -		5000	$ -	$ -	
			5000	$ -		5000	$ -	$ -	
			5000	$ -		5000	$ -	$ -	
			5000	$ -		5000	$ -	$ -	
			5000	$ -		5000	$ -	$ -	
			5000	$ -		5000	$ -	$ -	
			5000	$ -		5000	$ -	$ -	
Sub-Total A				$ 86.25			$ 93.70	**$ 7.45**	**8.64%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0001	5000	$ 0.50	$ 0.0037	5000	$ 18.61	$ 18.11	3621.49%
Tax Adjustment		-$ 0.0002	0	$ -	$ -	0	$ -	$ -	
		$ -	5000	$ -	$ -	5000	$ -	$ -	
		$ -	0	$ -	$ -	0	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0021	5000	$ 10.50	$ 0.0030	5000	$ 15.00	$ 4.50	42.86%
Smart Meter Entity Charge						0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 97.25**			**$ 127.31**	**$ 30.06**	**30.91%**
RTSR - Network	per kWh	$ 0.0047	5293	$ 24.87	$ 0.0048	5379	$ 25.74	$ 0.86	3.46%
RTSR - Line and Transformation Connection	per kWh	$ 0.0037	5293	$ 19.58	$ 0.0039	5379	$ 20.79	$ 1.20	6.15%
Sub-Total C - Delivery (including Sub-Total B)				**$ 141.71**			**$ 173.83**	**$ 32.13**	**22.67%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	5293	$ 27.52	$ 0.0052	5379	$ 27.97	$ 0.45	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	5293	$ 5.82	$ 0.0011	5379	$ 5.92	$ 0.09	1.62%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	5293	$ 37.05	$ 0.0070	5379	$ 37.65	$ 0.60	1.62%
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	4693	$ 412.94	$ 0.0880	4779	$ 420.51	$ 7.57	1.83%
TOU - Off Peak		$ 0.0650	3387	$ 220.17	$ 0.0650	3442	$ 223.75	$ 3.58	1.62%
TOU - Mid Peak		$ 0.1000	953	$ 95.27	$ 0.1000	968	$ 96.81	$ 1.55	1.62%
TOU - On Peak		$ 0.1170	953	$ 111.46	$ 0.1170	968	$ 113.27	$ 1.81	1.62%
Total Bill on RPP (before Taxes)				**$ 670.29**			**$ 711.12**	**$ 40.84**	**6.09%**
HST		13%		$ 87.14	13%		$ 92.45	$ 5.31	6.09%
Total Bill (including HST)				$ 757.42			$ 803.57	$ 46.15	6.09%
Ontario Clean Energy Benefit [1]				-$ 75.74			-$ 80.36	-$ 4.62	6.10%
Total Bill on RPP (including OCEB)				**$ 681.68**			**$ 723.21**	**$ 41.53**	**6.09%**
Total Bill on TOU (before Taxes)				**$ 639.24**			**$ 679.45**	**$ 40.21**	**6.29%**
HST		13%		$ 83.10	13%		$ 88.33	$ 5.23	6.29%
Total Bill (including HST)				$ 722.34			$ 767.77	$ 45.43	6.29%
Ontario Clean Energy Benefit [1]				-$ 72.23			-$ 76.78	-$ 4.55	6.30%
Total Bill on TOU (including OCEB)				**$ 650.11**			**$ 690.99**	**$ 40.88**	**6.29%**
Loss Factor (%)		5.85%			7.57%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **GS <50 kW**

Consumption 10000 **kWh** ○ May 1 - October 31

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 36.6500	1	$ 36.65	$ 44.6100	1	$ 44.61	$ 7.96	21.72%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly	$ 4.2400	1	$ 4.24	$ -	1	$ -	-$ 4.24	-100.00%
Smart Meter Disposition Rider	Monthly	$ 2.8600	1	$ 2.86	$ -	1	$ -	-$ 2.86	-100.00%
Stranded Meter Disposition	Monthly	$ -	1	$ -	$ 3.0924	1	$ 3.09	$ 3.09	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0084	10000	$ 84.00	$ 0.0092	10000	$ 92.00	$ 8.00	9.52%
Smart Meter Disposition Rider		$ -	10000	$ -	$ -	10000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0001	10000	$ 1.00	$ -	10000	$ -	-$ 1.00	-100.00%
			10000	$ -		10000	$ -	$ -	
			10000	$ -		10000	$ -	$ -	
			10000	$ -		10000	$ -	$ -	
			10000	$ -		10000	$ -	$ -	
			10000	$ -		10000	$ -	$ -	
			10000	$ -		10000	$ -	$ -	
			10000	$ -		10000	$ -	$ -	
Sub-Total A				$ 128.75			$ 139.70	**$ 10.95**	**8.51%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0001	10000	$ 1.00	$ 0.0037	10000	$ 37.21	$ 36.21	3621.49%
Tax Adjustment		-$ 0.0002	0	$ -	$ -	0	$ -	$ -	
		$ -	10000	$ -	$ -	10000	$ -	$ -	
		$ -	0	$ -	$ -	0	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0021	10000	$ 21.00	$ 0.0030	10000	$ 30.00	$ 9.00	42.86%
Smart Meter Entity Charge						0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 150.75**			**$ 206.92**	**$ 56.17**	**37.26%**
RTSR - Network	per kWh	$ 0.0047	10585	$ 49.75	$ 0.0048	10757	$ 51.47	$ 1.72	3.46%
RTSR - Line and Transformation Connection	per kWh	$ 0.0037	10585	$ 39.16	$ 0.0039	10757	$ 41.57	$ 2.41	6.15%
Sub-Total C - Delivery (including Sub-Total B)				**$ 239.66**			**$ 299.96**	**$ 60.30**	**25.16%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	10585	$ 55.04	$ 0.0052	10757	$ 55.94	$ 0.89	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	10585	$ 11.64	$ 0.0011	10757	$ 11.83	$ 0.19	1.62%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	10585	$ 74.10	$ 0.0070	10757	$ 75.30	$ 1.20	1.62%
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	9985	$ 878.68	$ 0.0880	10157	$ 893.82	$ 15.14	1.72%
TOU - Off Peak		$ 0.0650	6774	$ 440.34	$ 0.0650	6884	$ 447.49	$ 7.16	1.62%
TOU - Mid Peak		$ 0.1000	1905	$ 190.53	$ 0.1000	1936	$ 193.63	$ 3.10	1.62%
TOU - On Peak		$ 0.1170	1905	$ 222.92	$ 0.1170	1936	$ 226.54	$ 3.62	1.62%
Total Bill on RPP (before Taxes)				**$ 1,304.37**			**$ 1,382.10**	**$ 77.72**	**5.96%**
HST		13%		$ 169.57	13%		$ 179.67	$ 10.10	5.96%
Total Bill (including HST)				$ 1,473.94			$ 1,561.77	$ 87.83	5.96%
Ontario Clean Energy Benefit [1]				-$ 147.39			-$ 156.18	-$ 8.79	5.96%
Total Bill on RPP (including OCEB)				**$ 1,326.55**			**$ 1,405.59**	**$ 79.04**	**5.96%**
Total Bill on TOU (before Taxes)				**$ 1,234.48**			**$ 1,310.94**	**$ 76.46**	**6.19%**
HST		13%		$ 160.48	13%		$ 170.42	$ 9.94	6.19%
Total Bill (including HST)				$ 1,394.96			$ 1,481.36	$ 86.40	6.19%
Ontario Clean Energy Benefit [1]				-$ 139.50			-$ 148.14	-$ 8.64	6.19%
Total Bill on TOU (including OCEB)				**$ 1,255.46**			**$ 1,333.22**	**$ 77.76**	**6.19%**
Loss Factor (%)		5.85%			7.57%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **GS <50 kW**

Consumption 15000 **kWh** ○ May 1 - October 31

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 36.6500	1	$ 36.65	$ 44.6100	1	$ 44.61	$ 7.96	21.72%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly	$ 4.2400	1	$ 4.24	$ -	1	$ -	-$ 4.24	-100.00%
Smart Meter Disposition Rider	Monthly	$ 2.8600	1	$ 2.86	$ -	1	$ -	-$ 2.86	-100.00%
Stranded Meter Disposition	Monthly	$ -	1	$ -	$ 3.0924	1	$ 3.09	$ 3.09	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0084	15000	$ 126.00	$ 0.0092	15000	$ 138.00	$ 12.00	9.52%
Smart Meter Disposition Rider		$ -	15000	$ -	$ -	15000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0001	15000	$ 1.50	$ -	15000	$ -	-$ 1.50	-100.00%
			15000	$ -		15000	$ -	$ -	
			15000	$ -		15000	$ -	$ -	
			15000	$ -		15000	$ -	$ -	
			15000	$ -		15000	$ -	$ -	
			15000	$ -		15000	$ -	$ -	
			15000	$ -		15000	$ -	$ -	
			15000	$ -		15000	$ -	$ -	
Sub-Total A				$ 171.25			$ 185.70	**$ 14.45**	**8.44%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0001	15000	$ 1.50	$ 0.0037	15000	$ 55.82	$ 54.32	3621.49%
Tax Adjustment		-$ 0.0002	0	$ -	$ -	0	$ -	$ -	
		$ -	15000	$ -	$ -	15000	$ -	$ -	
		$ -	0	$ -	$ -	0	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0021	15000	$ 31.50	$ 0.0030	15000	$ 45.00	$ 13.50	42.86%
Smart Meter Entity Charge						0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 204.25**			**$ 286.52**	**$ 82.27**	**40.28%**
RTSR - Network	per kWh	$ 0.0047	15878	$ 74.62	$ 0.0048	16136	$ 77.21	$ 2.59	3.46%
RTSR - Line and Transformation Connection	per kWh	$ 0.0037	15878	$ 58.75	$ 0.0039	16136	$ 62.36	$ 3.61	6.15%
Sub-Total C - Delivery (including Sub-Total B)				**$ 337.62**			**$ 426.09**	**$ 88.47**	**26.20%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	15878	$ 82.56	$ 0.0052	16136	$ 83.90	$ 1.34	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	15878	$ 17.47	$ 0.0011	16136	$ 17.75	$ 0.28	1.62%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	15878	$ 111.14	$ 0.0070	16136	$ 112.95	$ 1.81	1.62%
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	15278	$ 1,344.42	$ 0.0880	15536	$ 1,367.12	$ 22.70	1.69%
TOU - Off Peak		$ 0.0650	10162	$ 660.50	$ 0.0650	10327	$ 671.24	$ 10.73	1.62%
TOU - Mid Peak		$ 0.1000	2858	$ 285.80	$ 0.1000	2904	$ 290.44	$ 4.64	1.62%
TOU - On Peak		$ 0.1170	2858	$ 334.38	$ 0.1170	2904	$ 339.81	$ 5.43	1.62%
Total Bill on RPP (before Taxes)				**$ 1,938.46**			**$ 2,053.07**	**$ 114.61**	**5.91%**
HST		13%		$ 252.00	13%		$ 266.90	$ 14.90	5.91%
Total Bill (including HST)				$ 2,190.46			$ 2,319.97	$ 129.50	5.91%
Ontario Clean Energy Benefit [1]				-$ 219.05			-$ 232.00	-$ 12.95	5.91%
Total Bill on RPP (including OCEB)				**$ 1,971.41**			**$ 2,087.97**	**$ 116.55**	**5.91%**
Total Bill on TOU (before Taxes)				**$ 1,829.72**			**$ 1,942.43**	**$ 112.71**	**6.16%**
HST		13%		$ 237.86	13%		$ 252.52	$ 14.65	6.16%
Total Bill (including HST)				$ 2,067.58			$ 2,194.95	$ 127.36	6.16%
Ontario Clean Energy Benefit [1]				-$ 206.76			-$ 219.49	-$ 12.73	6.16%
Total Bill on TOU (including OCEB)				**$ 1,860.82**			**$ 1,975.46**	**$ 114.63**	**6.16%**

Loss Factor (%) 5.85% 7.57%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **GS >50 kW**

Consumption 60 kW ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

21600 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 487.4500	1	$ 487.45	$ 526.5800	1	$ 526.58	$ 39.13	8.03%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly	$ -	1	$ -		1	$ -	$ -	
Smart Meter Disposition Rider	Monthly	$ -	1	$ -		1	$ -	$ -	
Stranded Meter Disposition	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 1.4113	60	$ 84.68	$ 3.0048	60	$ 180.29	$ 95.61	112.91%
Smart Meter Disposition Rider			60	$ -		60	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ 0.0054	60	$ 0.32		60	$ -	-$ 0.32	-100.00%
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
Sub-Total A				$ 572.45			$ 706.87	**$ 134.42**	**23.48%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ 0.0212	60	$ 1.27	$ 1.5362	60	$ 92.17	$ 90.90	7146.23%
Tax Adjustment	per kW	-$ 0.0330	60	-$ 1.98		60	$ -	$ 1.98	-100.00%
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.8393	60	$ 50.36	$ 1.3960	60	$ 83.76	$ 33.40	66.33%
Smart Meter Entity Charge						60	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 622.10**			**$ 882.80**	**$ 260.70**	**41.91%**
RTSR - Network	per kW	$ 1.9960	60	$ 119.76	$ 2.0358	60	$ 122.15	$ 2.39	1.99%
RTSR - Line and Transformation Connection	per kW	$ 1.5659	60	$ 93.95	$ 1.6356	60	$ 98.13	$ 4.18	4.45%
Sub-Total C - Delivery (including Sub-Total B)				**$ 835.82**			**$ 1,103.08**	**$ 267.27**	**31.98%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	22864	$ 118.89	$ 0.0052	23235	$ 120.82	$ 1.93	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	22864	$ 25.15	$ 0.0011	23235	$ 25.56	$ 0.41	1.62%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	22864	$ 160.05	$ 0.0070	23235	$ 162.65	$ 2.60	1.62%
Energy - RPP - Tier 1		$ 0.0750	0	$ -	$ 0.0750	0	$ -	$ -	
Energy - RPP - Tier 2		$ 0.0880	22864	$ 2,012.00	$ 0.0880	23235	$ 2,044.69	$ 32.69	1.62%
TOU - Off Peak		$ 0.0650	14633	$ 951.13	$ 0.0650	14870	$ 966.58	$ 15.46	1.62%
TOU - Mid Peak		$ 0.1000	4115	$ 411.54	$ 0.1000	4182	$ 418.23	$ 6.69	1.62%
TOU - On Peak		$ 0.1170	4115	$ 481.51	$ 0.1170	4182	$ 489.33	$ 7.82	1.62%
Total Bill on RPP (before Taxes)				**$ 3,152.15**			**$ 3,457.05**	**$ 304.90**	**9.67%**
HST		13%		$ 409.78	13%		$ 449.42	$ 39.64	9.67%
Total Bill (including HST)				$ 3,561.93			$ 3,906.47	$ 344.54	9.67%
Ontario Clean Energy Benefit [1]				-$ 356.19			-$ 390.65	-$ 34.46	9.67%
Total Bill on RPP (including OCEB)				**$ 3,205.74**			**$ 3,515.82**	**$ 310.08**	**9.67%**
Total Bill on TOU (before Taxes)				**$ 2,984.33**			**$ 3,286.50**	**$ 302.17**	**10.13%**
HST		13%		$ 387.96	13%		$ 427.25	$ 39.28	10.13%
Total Bill (including HST)				$ 3,372.29			$ 3,713.75	$ 341.46	10.13%
Ontario Clean Energy Benefit [1]				-$ 337.23			-$ 371.37	-$ 34.14	10.12%
Total Bill on TOU (including OCEB)				**$ 3,035.06**			**$ 3,342.38**	**$ 307.32**	**10.13%**

Loss Factor (%) 5.85% 7.57%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **GS >50 kW**

Consumption 100 kW ○ May 1 - October 31

36000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 487.4500	1	$ 487.45	$ 526.5800	1	$ 526.58	$ 39.13	8.03%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Smart Meter Disposition Rider	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Stranded Meter Disposition	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 1.4113	100	$ 141.13	$ 3.0048	100	$ 300.48	$ 159.35	112.91%
Smart Meter Disposition Rider		$ -	100	$ -	$ -	100	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ 0.0054	100	$ 0.54	$ -	100	$ -	-$ 0.54	-100.00%
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Sub-Total A				$ 629.12			$ 827.06	**$ 197.94**	**31.46%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ 0.0212	100	$ 2.12	$ 1.5362	100	$ 153.62	$ 151.50	7146.23%
Tax Adjustment	per kW	-$ 0.0330	100	-$ 3.30	$ -	100	$ -	$ 3.30	-100.00%
		$ -	100	$ -	$ -	100	$ -	$ -	
		$ -	100	$ -	$ -	100	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.8393	100	$ 83.93	$ 1.3960	100	$ 139.60	$ 55.67	66.33%
Smart Meter Entity Charge						60	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 711.87**			**$ 1,120.28**	**$ 408.41**	**57.37%**
RTSR - Network	per kW	$ 1.9960	106	$ 211.28	$ 2.0358	108	$ 218.99	$ 7.71	3.65%
RTSR - Line and Transformation Connection	per kW	$ 1.5659	106	$ 165.75	$ 1.6356	108	$ 175.94	$ 10.19	6.15%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,088.90**			**$ 1,515.21**	**$ 426.31**	**39.15%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	38106	$ 198.15	$ 0.0052	38725	$ 201.37	$ 3.22	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	38106	$ 41.92	$ 0.0011	38725	$ 42.60	$ 0.68	1.62%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	38106	$ 266.74	$ 0.0070	38725	$ 271.08	$ 4.33	1.62%
Energy - RPP - Tier 1		$ 0.0750	0	$ -	$ 0.0750	0	$ -	$ -	
Energy - RPP - Tier 2		$ 0.0880	38106	$ 3,353.33	$ 0.0880	38725	$ 3,407.82	$ 54.49	1.62%
TOU - Off Peak		$ 0.0650	24388	$ 1,585.21	$ 0.0650	24784	$ 1,610.97	$ 25.76	1.62%
TOU - Mid Peak		$ 0.1000	6859	$ 685.91	$ 0.1000	6971	$ 697.05	$ 11.15	1.62%
TOU - On Peak		$ 0.1170	6859	$ 802.51	$ 0.1170	6971	$ 815.55	$ 13.04	1.62%
Total Bill on RPP (before Taxes)				**$ 4,949.28**			**$ 5,438.32**	**$ 489.04**	**9.88%**
HST		13%		$ 643.41	13%		$ 706.98	$ 63.57	9.88%
Total Bill (including HST)				$ 5,592.69			$ 6,145.30	$ 552.61	9.88%
Ontario Clean Energy Benefit [1]				-$ 559.27			-$ 614.53	-$ 55.26	9.88%
Total Bill on RPP (including OCEB)				**$ 5,033.42**			**$ 5,530.77**	**$ 497.35**	**9.88%**
Total Bill on TOU (before Taxes)				**$ 4,669.59**			**$ 5,154.08**	**$ 484.49**	**10.38%**
HST		13%		$ 607.05	13%		$ 670.03	$ 62.98	10.38%
Total Bill (including HST)				$ 5,276.63			$ 5,824.11	$ 547.47	10.38%
Ontario Clean Energy Benefit [1]				-$ 527.66			-$ 582.41	-$ 54.75	10.38%
Total Bill on TOU (including OCEB)				**$ 4,748.97**			**$ 5,241.70**	**$ 492.72**	**10.38%**

Loss Factor (%) 5.85% 7.57%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **GS >50 kW**

Consumption 500 kW ○ May 1 - October 31
180000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 487.4500	1	$ 487.45	$ 526.5800	1	$ 526.58	$ 39.13	8.03%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Smart Meter Disposition Rider	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Stranded Meter Disposition	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 1.4113	500	$ 705.65	$ 3.0048	500	$ 1,502.40	$ 796.75	112.91%
Smart Meter Disposition Rider		$ -	500	$ -	$ -	500	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ 0.0054	500	$ 2.70	$ -	500	$ -	-$ 2.70	-100.00%
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Sub-Total A				$ 1,195.80			$ 2,028.98	**$ 833.18**	**69.68%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ 0.0212	500	$ 10.60	$ 1.5362	500	$ 768.10	$ 757.50	7146.23%
Tax Adjustment	per kW	-$ 0.0330	500	-$ 16.50	$ -	500	$ -	$ 16.50	-100.00%
		$ -	500	$ -	$ -	500	$ -	$ -	
		$ -	500	$ -	$ -	500	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.8393	500	$ 419.65	$ 1.3960	500	$ 698.00	$ 278.35	66.33%
Smart Meter Entity Charge						60	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,609.55**			**$ 3,495.08**	**$ 1,885.53**	**117.15%**
RTSR - Network	per kW	$ 1.9960	529	$ 1,056.38	$ 2.0358	538	$ 1,094.95	$ 38.57	3.65%
RTSR - Line and Transformation Connection	per kW	$ 1.5659	529	$ 828.75	$ 1.6356	538	$ 879.69	$ 50.93	6.15%
Sub-Total C - Delivery (including Sub-Total B)				**$ 3,494.69**			**$ 5,469.72**	**$ 1,975.03**	**56.52%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	190530	$ 990.76	$ 0.0052	193626	$ 1,006.86	$ 16.10	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	190530	$ 209.58	$ 0.0011	193626	$ 212.99	$ 3.41	1.62%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	190530	$ 1,333.71	$ 0.0070	193626	$ 1,355.38	$ 21.67	1.62%
Energy - RPP - Tier 1		$ 0.0750	0	$ -	$ 0.0750	0	$ -	$ -	
Energy - RPP - Tier 2		$ 0.0880	190530	$ 16,766.64	$ 0.0880	193626	$ 17,039.09	$ 272.45	1.62%
TOU - Off Peak		$ 0.0650	121939	$ 7,926.05	$ 0.0650	123921	$ 8,054.84	$ 128.79	1.62%
TOU - Mid Peak		$ 0.1000	34295	$ 3,429.54	$ 0.1000	34853	$ 3,485.27	$ 55.73	1.62%
TOU - On Peak		$ 0.1170	34295	$ 4,012.56	$ 0.1170	34853	$ 4,077.76	$ 65.20	1.62%
Total Bill on RPP (before Taxes)				**$ 22,795.62**			**$ 25,084.28**	**$ 2,288.66**	**10.04%**
HST		13%		$ 2,963.43	13%		$ 3,260.96	$ 297.53	10.04%
Total Bill (including HST)				$ 25,759.06			$ 28,345.24	$ 2,586.18	10.04%
Ontario Clean Energy Benefit [1]				-$ 2,575.91			-$ 2,834.52	-$ 258.61	10.04%
Total Bill on RPP (including OCEB)				**$ 23,183.15**			**$ 25,510.72**	**$ 2,327.57**	**10.04%**
Total Bill on TOU (before Taxes)				**$ 21,397.13**			**$ 23,663.07**	**$ 2,265.93**	**10.59%**
HST		13%		$ 2,781.63	13%		$ 3,076.20	$ 294.57	10.59%
Total Bill (including HST)				$ 24,178.76			$ 26,739.26	$ 2,560.50	10.59%
Ontario Clean Energy Benefit [1]				-$ 2,417.88			-$ 2,673.93	-$ 256.05	10.59%
Total Bill on TOU (including OCEB)				**$ 21,760.88**			**$ 24,065.33**	**$ 2,304.45**	**10.59%**
Loss Factor (%)		5.85%			7.57%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **GS >50 kW**

Consumption 1000 kW ○ May 1 - October 31
360000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 487.4500	1	$ 487.45	$ 526.5800	1	$ 526.58	$ 39.13	8.03%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Smart Meter Disposition Rider	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Stranded Meter Disposition	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 1.4113	1000	$ 1,411.30	$ 3.0048	1000	$ 3,004.80	$ 1,593.50	112.91%
Smart Meter Disposition Rider		$ -	1000	$ -	$ -	1000	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ 0.0054	1000	$ 5.40	$ -	1000	$ -	-$ 5.40	-100.00%
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
			1000	$ -		1000	$ -	$ -	
Sub-Total A				$ 1,904.15			$ 3,531.38	**$ 1,627.23**	**85.46%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ 0.0212	1000	$ 21.20	$ 1.5362	1000	$ 1,536.20	$ 1,515.00	7146.23%
Tax Adjustment	per kW	-$ 0.0330	1000	-$ 33.00	$ -	1000	$ -	$ 33.00	-100.00%
		$ -	1000	$ -	$ -	1000	$ -	$ -	
		$ -	1000	$ -	$ -	1000	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.8393	1000	$ 839.30	$ 1.3960	1000	$ 1,396.00	$ 556.70	66.33%
Smart Meter Entity Charge						60	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 2,731.65**			**$ 6,463.58**	**$ 3,731.93**	**136.62%**
RTSR - Network	per kW	$ 1.9960	1059	$ 2,112.77	$ 2.0358	1076	$ 2,189.90	$ 77.14	3.65%
RTSR - Line and Transformation Connection	per kW	$ 1.5659	1059	$ 1,657.51	$ 1.6356	1076	$ 1,759.37	$ 101.87	6.15%
Sub-Total C - Delivery (including Sub-Total B)				**$ 6,501.92**			**$ 10,412.85**	**$ 3,910.93**	**60.15%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	381060	$ 1,981.51	$ 0.0052	387252	$ 2,013.71	$ 32.20	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	381060	$ 419.17	$ 0.0011	387252	$ 425.98	$ 6.81	1.62%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	381060	$ 2,667.42	$ 0.0070	387252	$ 2,710.76	$ 43.34	1.62%
Energy - RPP - Tier 1		$ 0.0750	0	$ -	$ 0.0750	0	$ -	$ -	
Energy - RPP - Tier 2		$ 0.0880	381060	$ 33,533.28	$ 0.0880	387252	$ 34,078.18	$ 544.90	1.62%
TOU - Off Peak		$ 0.0650	243878	$ 15,852.10	$ 0.0650	247841	$ 16,109.68	$ 257.59	1.62%
TOU - Mid Peak		$ 0.1000	68591	$ 6,859.08	$ 0.1000	69705	$ 6,970.54	$ 111.46	1.62%
TOU - On Peak		$ 0.1170	68591	$ 8,025.12	$ 0.1170	69705	$ 8,155.53	$ 130.40	1.62%
Total Bill on RPP (before Taxes)				**$ 45,103.55**			**$ 49,641.73**	**$ 4,538.18**	**10.06%**
HST		13%		$ 5,863.46	13%		$ 6,453.43	$ 589.96	10.06%
Total Bill (including HST)				$ 50,967.01			$ 56,095.16	$ 5,128.15	10.06%
Ontario Clean Energy Benefit [1]				-$ 5,096.70			-$ 5,609.52	-$ 512.82	10.06%
Total Bill on RPP (including OCEB)				**$ 45,870.31**			**$ 50,485.64**	**$ 4,615.33**	**10.06%**
Total Bill on TOU (before Taxes)				**$ 42,306.57**			**$ 46,799.30**	**$ 4,492.73**	**10.62%**
HST		13%		$ 5,499.85	13%		$ 6,083.91	$ 584.06	10.62%
Total Bill (including HST)				$ 47,806.42			$ 52,883.21	$ 5,076.79	10.62%
Ontario Clean Energy Benefit [1]				-$ 4,780.64			-$ 5,288.32	-$ 507.68	10.62%
Total Bill on TOU (including OCEB)				**$ 43,025.78**			**$ 47,594.89**	**$ 4,569.11**	**10.62%**

Loss Factor (%) 5.85% 7.57%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **Sentinel Lighting**

Consumption 1 kW ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

360 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 4.8900	1	$ 4.89	$ 6.4593	1	$ 6.46	$ 1.57	32.09%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly		1	$ -		1	$ -	$ -	
Smart Meter Disposition Rider	Monthly	$ -	1	$ -		1	$ -	$ -	
Stranded Meter Disposition	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 16.9360	1	$ 16.94	$ 22.3710	1	$ 22.37	$ 5.44	32.09%
Smart Meter Disposition Rider			1	$ -		1	$ -	$ -	
LRAM & SSM Rate Rider	per kW		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Sub-Total A				$ 21.83			$ 28.83	**$ 7.00**	**32.09%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ 0.1002	1	$ 0.10	$ 1.3280	1	$ 1.33	$ 1.23	1225.37%
Tax Adjustment	per kW	-$ 0.3070	1	-$ 0.31		1	$ -	$ 0.31	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.6624	1	$ 0.66	$ 0.9588	1	$ 0.96	$ 0.30	44.75%
Smart Meter Entity Charge						1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 22.28**			**$ 31.12**	**$ 8.84**	**39.65%**
RTSR - Network	per kW	$ 1.4942	1	$ 1.49	$ 1.5212	1	$ 1.52	$ 0.03	1.81%
RTSR - Line and Transformation Connection	per kW	$ 1.1540	1	$ 1.15	$ 1.2053	1	$ 1.21	$ 0.05	4.45%
Sub-Total C - Delivery (including Sub-Total B)				**$ 24.93**			**$ 33.84**	**$ 8.91**	**35.76%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	381	$ 1.98	$ 0.0052	387	$ 2.01	$ 0.03	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	381	$ 0.42	$ 0.0011	387	$ 0.43	$ 0.01	1.62%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	381	$ 2.67	$ 0.0070	387	$ 2.71	$ 0.04	1.62%
Energy - RPP - Tier 1		$ 0.0750	381	$ 28.58	$ 0.0750	387	$ 29.04	$ 0.46	1.62%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	244	$ 15.85	$ 0.0650	248	$ 16.11	$ 0.26	1.62%
TOU - Mid Peak		$ 0.1000	69	$ 6.86	$ 0.1000	70	$ 6.97	$ 0.11	1.62%
TOU - On Peak		$ 0.1170	69	$ 8.03	$ 0.1170	70	$ 8.16	$ 0.13	1.62%
Total Bill on RPP (before Taxes)				**$ 58.83**			**$ 68.29**	**$ 9.46**	**16.08%**
HST		13%		$ 7.65	13%		$ 8.88	$ 1.23	16.08%
Total Bill (including HST)				$ 66.47			$ 77.17	$ 10.69	16.08%
Ontario Clean Energy Benefit [1]				-$ 6.65			-$ 7.72	-$ 1.07	16.09%
Total Bill on RPP (including OCEB)				**$ 59.82**			**$ 69.45**	**$ 9.62**	**16.08%**
Total Bill on TOU (before Taxes)				**$ 60.98**			**$ 70.48**	**$ 9.50**	**15.57%**
HST		13%		$ 7.93	13%		$ 9.16	$ 1.23	15.57%
Total Bill (including HST)				$ 68.91			$ 79.64	$ 10.73	15.57%
Ontario Clean Energy Benefit [1]				-$ 6.89			-$ 7.96	-$ 1.07	15.53%
Total Bill on TOU (including OCEB)				**$ 62.02**			**$ 71.68**	**$ 9.66**	**15.58%**

Loss Factor (%) 5.85% 7.57%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **Street Lighting**

Consumption 1 kW ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

360 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 4.8300	1	$ 4.83	$ 5.3398	1	$ 5.34	$ 0.51	10.55%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly		1	$ -		1	$ -	$ -	
Smart Meter Disposition Rider	Monthly	$ -	1	$ -		1	$ -	$ -	
Stranded Meter Disposition	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 14.7836	1	$ 14.78	$ 16.3439	1	$ 16.34	$ 1.56	10.55%
Smart Meter Disposition Rider			1	$ -		1	$ -	$ -	
LRAM & SSM Rate Rider	per kW		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Sub-Total A				$ 19.61			$ 21.68	**$ 2.07**	**10.55%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ 0.0971	1	$ 0.10	$ 1.3712	1	$ 1.37	$ 1.27	1312.12%
Tax Adjustment	per kW	-$ 0.2972	1	-$ 0.30		1	$ -	$ 0.30	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.6488	1	$ 0.65	$ 0.9390	1	$ 0.94	$ 0.29	44.73%
Smart Meter Entity Charge						1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 20.06**			**$ 23.99**	**$ 3.93**	**19.60%**
RTSR - Network	per kW	$ 1.4565	1	$ 1.46	$ 1.4829	1	$ 1.48	$ 0.03	1.81%
RTSR - Line and Transformation Connection	per kW	$ 1.1429	1	$ 1.14	$ 1.1937	1	$ 1.19	$ 0.05	4.45%
Sub-Total C - Delivery (including Sub-Total B)				**$ 22.66**			**$ 26.67**	**$ 4.01**	**17.69%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	381	$ 1.98	$ 0.0052	387	$ 2.01	$ 0.03	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	381	$ 0.42	$ 0.0011	387	$ 0.43	$ 0.01	1.62%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	381	$ 2.67	$ 0.0070	387	$ 2.71	$ 0.04	1.62%
Energy - RPP - Tier 1		$ 0.0750	381	$ 28.58	$ 0.0750	387	$ 29.04	$ 0.46	1.62%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	244	$ 15.85	$ 0.0650	248	$ 16.11	$ 0.26	1.62%
TOU - Mid Peak		$ 0.1000	69	$ 6.86	$ 0.1000	70	$ 6.97	$ 0.11	1.62%
TOU - On Peak		$ 0.1170	69	$ 8.03	$ 0.1170	70	$ 8.16	$ 0.13	1.62%
Total Bill on RPP (before Taxes)				**$ 56.56**			**$ 61.11**	**$ 4.56**	**8.05%**
HST		13%		$ 7.35	13%		$ 7.94	$ 0.59	8.05%
Total Bill (including HST)				$ 63.91			$ 69.06	$ 5.15	8.05%
Ontario Clean Energy Benefit [1]				-$ 6.39			-$ 6.91	-$ 0.52	8.14%
Total Bill on RPP (including OCEB)				**$ 57.52**			**$ 62.15**	**$ 4.63**	**8.05%**
Total Bill on TOU (before Taxes)				**$ 58.72**			**$ 63.31**	**$ 4.59**	**7.82%**
HST		13%		$ 7.63	13%		$ 8.23	$ 0.60	7.82%
Total Bill (including HST)				$ 66.35			$ 71.54	$ 5.19	7.82%
Ontario Clean Energy Benefit [1]				-$ 6.63			-$ 7.15	-$ 0.52	7.84%
Total Bill on TOU (including OCEB)				**$ 59.72**			**$ 64.39**	**$ 4.67**	**7.82%**

Loss Factor (%) 5.85% 7.57%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **Unmetered Scattered Load**

Consumption 150 **kWh** ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31) ○ May 1 -

	Charge Unit	**Current Board-Approved Rate ($)**	**Current Board-Approved Volume**	**Current Board-Approved Charge ($)**	**Proposed Rate ($)**	**Proposed Volume**	**Proposed Charge ($)**	**Impact $ Change**	**Impact % Change**
Monthly Service Charge	Monthly	$ 18.0800	1	$ 18.08	$ 12.9974	1	$ 13.00	-$ 5.08	-28.11%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Smart Meter Inc Rev Req Rider	Monthly		1	$ -		1	$ -	$ -	
Smart Meter Disposition Rider	Monthly		1	$ -		1	$ -	$ -	
Stranded Meter Disposition	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0082	150	$ 1.23	$ 0.0059	150	$ 0.89	-$ 0.35	-28.05%
Smart Meter Disposition Rider			150	$ -		150	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		150	$ -		150	$ -	$ -	
			150	$ -		150	$ -	$ -	
			150	$ -		150	$ -	$ -	
			150	$ -		150	$ -	$ -	
			150	$ -		150	$ -	$ -	
			150	$ -		150	$ -	$ -	
			150	$ -		150	$ -	$ -	
			150	$ -		150	$ -	$ -	
Sub-Total A				$ 19.31			$ 13.88	**-$ 5.43**	**-28.11%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ 0.0003	150	$ 0.05	$ 0.0037	150	$ 0.56	$ 0.51	1140.50%
Tax Adjustment	per kWh	-$ 0.0004	150	-$ 0.06		150	$ -	$ 0.06	-100.00%
			150	$ -		150	$ -	$ -	
			150	$ -		150	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0021	150	$ 0.32	$ 0.0030	150	$ 0.45	$ 0.14	42.86%
Smart Meter Entity Charge						150	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 19.61**			**$ 14.89**	**-$ 4.72**	**-24.07%**
RTSR - Network	per kWh	$ 0.0047	159	$ 0.75	$ 0.0048	161	$ 0.77	$ 0.03	3.46%
RTSR - Line and Transformation Connection	per kWh	$ 0.0037	159	$ 0.59	$ 0.0039	161	$ 0.62	$ 0.04	6.15%
Sub-Total C - Delivery (including Sub-Total B)				**$ 20.94**			**$ 16.29**	**-$ 4.66**	**-22.24%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	159	$ 0.83	$ 0.0052	161	$ 0.84	$ 0.01	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	159	$ 0.17	$ 0.0011	161	$ 0.18	$ 0.00	1.62%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	159	$ 1.11	$ 0.0070	161	$ 1.13	$ 0.02	1.62%
Energy - RPP - Tier 1		$ 0.0750	159	$ 11.91	$ 0.0750	161	$ 12.10	$ 0.19	1.62%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	102	$ 6.61	$ 0.0650	103	$ 6.71	$ 0.11	1.62%
TOU - Mid Peak		$ 0.1000	29	$ 2.86	$ 0.1000	29	$ 2.90	$ 0.05	1.62%
TOU - On Peak		$ 0.1170	29	$ 3.34	$ 0.1170	29	$ 3.40	$ 0.05	1.62%
Total Bill on RPP (before Taxes)				**$ 35.21**			**$ 30.78**	**-$ 4.43**	**-12.58%**
HST		13%		$ 4.58	13%		$ 4.00	-$ 0.58	-12.58%
Total Bill (including HST)				$ 39.79			$ 34.79	-$ 5.01	-12.58%
Ontario Clean Energy Benefit [1]				-$ 3.98			-$ 3.48	$ 0.50	-12.56%
Total Bill on RPP (including OCEB)				**$ 35.81**			**$ 31.31**	**-$ 4.51**	**-12.58%**
Total Bill on TOU (before Taxes)				**$ 36.11**			**$ 31.70**	**-$ 4.42**	**-12.23%**
HST		13%		$ 4.69	13%		$ 4.12	-$ 0.57	-12.23%
Total Bill (including HST)				$ 40.81			$ 35.82	-$ 4.99	-12.23%
Ontario Clean Energy Benefit [1]				-$ 4.08			-$ 3.58	$ 0.50	-12.25%
Total Bill on TOU (including OCEB)				**$ 36.73**			**$ 32.24**	**-$ 4.49**	**-12.22%**
Loss Factor (%)		5.85%			7.57%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

APPENDIX B

RTSR MODEL

v 3.0

RTSR Workform for Electricity Distributors (2013 Filers)

Utility Name	Lakeland Power Distribution Ltd.
Assigned EB Number	EB-2012-0145
Name and Title	Margaret Maw, Chief Financial Officer
Phone Number	705-789-5442
Email Address	mmaw@lakelandholding.com
Date	31-Aug-12
Last COS Re-based Year	**2009**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

RTSR Workform for Electricity Distributors (2013 Filers)

RTSR Workform for Electricity Distributors (2013 Filers)

1. Select the appropriate rate classes that appear on your most recent Board-Approved Tariff of Rates and Charges.
2. Enter the RTS Network and Connection Rate as it appears on the Tariff of Rates and Charges

Rate Class	Unit	RTSR-Network	RTSR-Connectior
Residential	kWh	$ 0.0051	$ 0.0040
General Service Less Than 50 kW	kWh	$ 0.0047	$ 0.0037
General Service 50 to 4,999 kW	kW	$ 1.9996	$ 1.5659
Sentinel Lighting	kW	$ 1.4942	$ 1.1540
Street Lighting	kW	$ 1.4565	$ 1.1429
Unmetered Scattered Load	kWh	$ 0.0047	$ 0.0037
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			

RTSR Workform for Electricity Distributors (2013 Filers)

In the green shaded cells, enter the most recent reported RRR billing determinants. Please ensure that billing determinants are non-loss adjusted.

Rate Class	Unit	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor	Load Factor	Loss Adjusted Billed kWh	Billed kW
Residential	**kWh**	77,905,420		1.0585		82,462,887	-
General Service Less Than 50 kW	**kWh**	42,698,322		1.0585		45,196,174	-
General Service 50 to 4,999 kW	**kW**	83,774,463	202,946		**56.58%**	83,774,463	202,946
Sentinel Lighting	**kW**	40,324	113		**48.91%**	40,324	113
Street Lighting	**kW**	1,874,274	5,087		**50.50%**	1,874,274	5,087
Unmetered Scattered Load	**kWh**	131,903		1.0585		139,619	-

RTSR Workform for Electricity Distributors (2013 Filers)

Uniform Transmission Rates	Unit	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.22	$ 3.57	$ 3.57
Line Connection Service Rate	kW	$ 0.79	$ 0.80	$ 0.80
Transformation Connection Service Rate	kW	$ 1.77	$ 1.86	$ 1.86

Hydro One Sub-Transmission Rates	Unit	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 2.65	$ 2.65	$ 2.65
Line Connection Service Rate	kW	$ 0.64	$ 0.64	$ 0.64
Transformation Connection Service Rate	kW	$ 1.50	$ 1.50	$ 1.50
Both Line and Transformation Connection Service Rate	kW	$ 2.14	$ 2.14	$ 2.14

Hydro One Sub-Transmission Rate Rider 6A	Unit	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate Description		**Rate**	**Rate**	**Rate**
RSVA Transmission network – 4714 – which affects 1584	kW	$ 0.0470	$ -	$ -
RSVA Transmission connection – 4716 – which affects 1586	kW	-$ 0.0250	$ -	$ -
RSVA LV – 4750 – which affects 1550	kW	$ 0.0580	$ -	$ -
RARA 1 – 2252 – which affects 1590	kW	-$ 0.0750	$ -	$ -
Hydro One Sub-Transmission Rate Rider 6A	kW	$ 0.0050	$ -	$ -

RTSR Workform for Electricity Distributors (2013 Filers)

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	39,802	$2.65	$ 105,475	39,802	$0.64	$ 25,473	39,802	$1.50	$ 59,703	$ 85,176
February	36,706	$2.65	$ 97,271	36,706	$0.64	$ 23,492	36,706	$1.50	$ 55,059	$ 78,551
March	31,660	$2.65	$ 83,899	31,660	$0.64	$ 20,262	31,660	$1.50	$ 47,490	$ 67,752
April	28,753	$2.65	$ 76,195	28,753	$0.64	$ 18,402	28,753	$1.50	$ 43,130	$ 61,531
May	27,928	$2.65	$ 74,009	27,928	$0.64	$ 17,874	27,928	$1.50	$ 41,892	$ 59,766
June	28,230	$2.65	$ 74,810	28,230	$0.64	$ 18,067	28,230	$1.50	$ 42,345	$ 60,412
July	35,121	$2.65	$ 93,071	35,121	$0.64	$ 22,477	35,121	$1.50	$ 52,682	$ 75,159
August	30,556	$2.65	$ 80,973	30,556	$0.64	$ 19,556	30,556	$1.50	$ 45,834	$ 65,390
September	30,279	$2.65	$ 80,240	29,334	$0.64	$ 18,774	29,334	$1.50	$ 44,001	$ 62,774
October	29,477	$2.65	$ 78,113	29,039	$0.64	$ 18,585	29,039	$1.50	$ 43,559	$ 62,144
November	47,169	$2.65	$ 124,999	47,169	$0.64	$ 30,188	47,169	$1.50	$ 70,754	$ 100,942
December	36,575	$2.65	$ 96,924	36,575	$0.64	$ 23,408	36,575	$1.50	$ 54,863	$ 78,271
Total	402,256	$ 2.65	$ 1,065,979	400,873	$ 0.64	$ 256,559	400,873	$ 1.50	$ 601,310	$ 857,869

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	39,802	$2.65	$ 105,475	39,802	$0.64	$ 25,473	39,802	$1.50	$ 59,703	$ 85,176
February	36,706	$2.65	$ 97,271	36,706	$0.64	$ 23,492	36,706	$1.50	$ 55,059	$ 78,551
March	31,660	$2.65	$ 83,899	31,660	$0.64	$ 20,262	31,660	$1.50	$ 47,490	$ 67,752
April	28,753	$2.65	$ 76,195	28,753	$0.64	$ 18,402	28,753	$1.50	$ 43,130	$ 61,531
May	27,928	$2.65	$ 74,009	27,928	$0.64	$ 17,874	27,928	$1.50	$ 41,892	$ 59,766
June	28,230	$2.65	$ 74,810	28,230	$0.64	$ 18,067	28,230	$1.50	$ 42,345	$ 60,412
July	35,121	$2.65	$ 93,071	35,121	$0.64	$ 22,477	35,121	$1.50	$ 52,682	$ 75,159
August	30,556	$2.65	$ 80,973	30,556	$0.64	$ 19,556	30,556	$1.50	$ 45,834	$ 65,390
September	30,279	$2.65	$ 80,240	29,334	$0.64	$ 18,774	29,334	$1.50	$ 44,001	$ 62,774
October	29,477	$2.65	$ 78,113	29,039	$0.64	$ 18,585	29,039	$1.50	$ 43,559	$ 62,144
November	47,169	$2.65	$ 124,999	47,169	$0.64	$ 30,188	47,169	$1.50	$ 70,754	$ 100,942
December	36,575	$2.65	$ 96,924	36,575	$0.64	$ 23,408	36,575	$1.50	$ 54,863	$ 78,271
Total	402,256	$ 2.65	$ 1,065,979	400,873	$ 0.64	$ 256,559	400,873	$ 1.50	$ 601,310	$ 857,869

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to calculate the expected billing when current 2012 Uniform Transmission Rates are applied against historical 2011 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
February	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
March	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
April	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
May	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
June	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
July	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
August	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
September	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
October	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
November	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
December	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	39,802	$ 2.6500	$ 105,475	39,802	$ 0.6400	$ 25,473	39,802	$ 1.5000	$ 59,703	$ 85,176
February	36,706	$ 2.6500	$ 97,271	36,706	$ 0.6400	$ 23,492	36,706	$ 1.5000	$ 55,059	$ 78,551
March	31,660	$ 2.6500	$ 83,899	31,660	$ 0.6400	$ 20,262	31,660	$ 1.5000	$ 47,490	$ 67,752
April	28,753	$ 2.6500	$ 76,195	28,753	$ 0.6400	$ 18,402	28,753	$ 1.5000	$ 43,130	$ 61,531
May	27,928	$ 2.6500	$ 74,009	27,928	$ 0.6400	$ 17,874	27,928	$ 1.5000	$ 41,892	$ 59,766
June	28,230	$ 2.6500	$ 74,810	28,230	$ 0.6400	$ 18,067	28,230	$ 1.5000	$ 42,345	$ 60,412
July	35,121	$ 2.6500	$ 93,071	35,121	$ 0.6400	$ 22,477	35,121	$ 1.5000	$ 52,682	$ 75,159
August	30,556	$ 2.6500	$ 80,973	30,556	$ 0.6400	$ 19,556	30,556	$ 1.5000	$ 45,834	$ 65,390
September	30,279	$ 2.6500	$ 80,240	29,334	$ 0.6400	$ 18,774	29,334	$ 1.5000	$ 44,001	$ 62,774
October	29,477	$ 2.6500	$ 78,113	29,039	$ 0.6400	$ 18,585	29,039	$ 1.5000	$ 43,559	$ 62,144
November	47,169	$ 2.6500	$ 124,999	47,169	$ 0.6400	$ 30,188	47,169	$ 1.5000	$ 70,754	$ 100,942
December	36,575	$ 2.6500	$ 96,924	36,575	$ 0.6400	$ 23,408	36,575	$ 1.5000	$ 54,863	$ 78,271
Total	402,256	$ 2.65	$ 1,065,979	400,873	$ 0.64	$ 256,559	400,873	$ 1.50	$ 601,310	$ 857,869

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	39,802	$ 2.65	$ 105,475	39,802	$ 0.64	$ 25,473	39,802	$ 1.50	$ 59,703	$ 85,176
February	36,706	$ 2.65	$ 97,271	36,706	$ 0.64	$ 23,492	36,706	$ 1.50	$ 55,059	$ 78,551
March	31,660	$ 2.65	$ 83,899	31,660	$ 0.64	$ 20,262	31,660	$ 1.50	$ 47,490	$ 67,752
April	28,753	$ 2.65	$ 76,195	28,753	$ 0.64	$ 18,402	28,753	$ 1.50	$ 43,130	$ 61,531
May	27,928	$ 2.65	$ 74,009	27,928	$ 0.64	$ 17,874	27,928	$ 1.50	$ 41,892	$ 59,766
June	28,230	$ 2.65	$ 74,810	28,230	$ 0.64	$ 18,067	28,230	$ 1.50	$ 42,345	$ 60,412
July	35,121	$ 2.65	$ 93,071	35,121	$ 0.64	$ 22,477	35,121	$ 1.50	$ 52,682	$ 75,159
August	30,556	$ 2.65	$ 80,973	30,556	$ 0.64	$ 19,556	30,556	$ 1.50	$ 45,834	$ 65,390
September	30,279	$ 2.65	$ 80,240	29,334	$ 0.64	$ 18,774	29,334	$ 1.50	$ 44,001	$ 62,774
October	29,477	$ 2.65	$ 78,113	29,039	$ 0.64	$ 18,585	29,039	$ 1.50	$ 43,559	$ 62,144
November	47,169	$ 2.65	$ 124,999	47,169	$ 0.64	$ 30,188	47,169	$ 1.50	$ 70,754	$ 100,942
December	36,575	$ 2.65	$ 96,924	36,575	$ 0.64	$ 23,408	36,575	$ 1.50	$ 54,863	$ 78,271
Total	402,256	$ 2.65	$ 1,065,979	400,873	$ 0.64	$ 256,559	400,873	$ 1.50	$ 601,310	$ 857,869

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to calculate the expected billing when forecasted 2013 Uniform Transmission Rates are applied against historical 2011 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
February	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
March	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
April	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
May	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
June	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
July	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
August	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
September	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
October	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
November	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
December	-	$ 3.5700	$ -	-	$ 0.8000	$ -	-	$ 1.8600	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	39,802	$ 2.6500	$ 105,475	39,802	$ 0.6400	$ 25,473	39,802	$ 1.5000	$ 59,703	$ 85,176
February	36,706	$ 2.6500	$ 97,271	36,706	$ 0.6400	$ 23,492	36,706	$ 1.5000	$ 55,059	$ 78,551
March	31,660	$ 2.6500	$ 83,899	31,660	$ 0.6400	$ 20,262	31,660	$ 1.5000	$ 47,490	$ 67,752
April	28,753	$ 2.6500	$ 76,195	28,753	$ 0.6400	$ 18,402	28,753	$ 1.5000	$ 43,130	$ 61,531
May	27,928	$ 2.6500	$ 74,009	27,928	$ 0.6400	$ 17,874	27,928	$ 1.5000	$ 41,892	$ 59,766
June	28,230	$ 2.6500	$ 74,810	28,230	$ 0.6400	$ 18,067	28,230	$ 1.5000	$ 42,345	$ 60,412
July	35,121	$ 2.6500	$ 93,071	35,121	$ 0.6400	$ 22,477	35,121	$ 1.5000	$ 52,682	$ 75,159
August	30,556	$ 2.6500	$ 80,973	30,556	$ 0.6400	$ 19,556	30,556	$ 1.5000	$ 45,834	$ 65,390
September	30,279	$ 2.6500	$ 80,240	29,334	$ 0.6400	$ 18,774	29,334	$ 1.5000	$ 44,001	$ 62,774
October	29,477	$ 2.6500	$ 78,113	29,039	$ 0.6400	$ 18,585	29,039	$ 1.5000	$ 43,559	$ 62,144
November	47,169	$ 2.6500	$ 124,999	47,169	$ 0.6400	$ 30,188	47,169	$ 1.5000	$ 70,754	$ 100,942
December	36,575	$ 2.6500	$ 96,924	36,575	$ 0.6400	$ 23,408	36,575	$ 1.5000	$ 54,863	$ 78,271
Total	402,256	$ 2.65	$ 1,065,979	400,873	$ 0.64	$ 256,559	400,873	$ 1.50	$ 601,310	$ 857,869

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	39,802	$ 2.65	$ 105,475	39,802	$ 0.64	$ 25,473	39,802	$ 1.50	$ 59,703	$ 85,176
February	36,706	$ 2.65	$ 97,271	36,706	$ 0.64	$ 23,492	36,706	$ 1.50	$ 55,059	$ 78,551
March	31,660	$ 2.65	$ 83,899	31,660	$ 0.64	$ 20,262	31,660	$ 1.50	$ 47,490	$ 67,752
April	28,753	$ 2.65	$ 76,195	28,753	$ 0.64	$ 18,402	28,753	$ 1.50	$ 43,130	$ 61,531
May	27,928	$ 2.65	$ 74,009	27,928	$ 0.64	$ 17,874	27,928	$ 1.50	$ 41,892	$ 59,766
June	28,230	$ 2.65	$ 74,810	28,230	$ 0.64	$ 18,067	28,230	$ 1.50	$ 42,345	$ 60,412
July	35,121	$ 2.65	$ 93,071	35,121	$ 0.64	$ 22,477	35,121	$ 1.50	$ 52,682	$ 75,159
August	30,556	$ 2.65	$ 80,973	30,556	$ 0.64	$ 19,556	30,556	$ 1.50	$ 45,834	$ 65,390
September	30,279	$ 2.65	$ 80,240	29,334	$ 0.64	$ 18,774	29,334	$ 1.50	$ 44,001	$ 62,774
October	29,477	$ 2.65	$ 78,113	29,039	$ 0.64	$ 18,585	29,039	$ 1.50	$ 43,559	$ 62,144
November	47,169	$ 2.65	$ 124,999	47,169	$ 0.64	$ 30,188	47,169	$ 1.50	$ 70,754	$ 100,942
December	36,575	$ 2.65	$ 96,924	36,575	$ 0.64	$ 23,408	36,575	$ 1.50	$ 54,863	$ 78,271
Total	402,256	$ 2.65	$ 1,065,979	400,873	$ 0.64	$ 256,559	400,873	$ 1.50	$ 601,310	$ 857,869

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to re-align the current RTS Network Rates to recover current wholesale network costs.

Rate Class	Unit	Current RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Network
Residential	kWh	$ 0.0051	82,462,887	-	$ 420,561	40.2%	$ 428,173	$ 0.0052
General Service Less Than 50 kW	kWh	$ 0.0047	45,196,174	-	$ 212,422	20.3%	$ 216,267	$ 0.0048
General Service 50 to 4,999 kW	kW	$ 1.9996	83,774,463	202,946	$ 405,811	38.8%	$ 413,156	$ 2.0358
Sentinel Lighting	kW	$ 1.4942	40,324	113	$ 169	0.0%	$ 172	$ 1.5212
Street Lighting	kW	$ 1.4565	1,874,274	5,087	$ 7,409	0.7%	$ 7,543	$ 1.4829
Unmetered Scattered Load	kWh	$ 0.0047	139,619	-	$ 656	0.1%	$ 668	$ 0.0048
					$ 1,047,028			

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to re-align the current RTS Connection Rates to recover current wholesale connection costs.

Rate Class	Unit	Current RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Connection
Residential	kWh	$ 0.0040	82,462,887	-	$ 329,852	40.2%	$ 344,525	$ 0.0042
General Service Less Than 50 kW	kWh	$ 0.0037	45,196,174	-	$ 167,226	20.4%	$ 174,665	$ 0.0039
General Service 50 to 4,999 kW	kW	$ 1.5659	83,774,463	202,946	$ 317,793	38.7%	$ 331,930	$ 1.6356
Sentinel Lighting	kW	$ 1.1540	40,324	113	$ 130	0.0%	$ 136	$ 1.2053
Street Lighting	kW	$ 1.1429	1,874,274	5,087	$ 5,814	0.7%	$ 6,073	$ 1.1937
Unmetered Scattered Load	kWh	$ 0.0037	139,619	-	$ 517	0.1%	$ 540	$ 0.0039
					$ 821,331			

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to update the re-align RTS Network Rates to recover forecast wholesale network costs.

Rate Class	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Network
Residential	kWh	$ 0.0052	82,462,887	-	$ 428,173	40.2%	$ 428,173	$ 0.0052
General Service Less Than 50 kW	kWh	$ 0.0048	45,196,174	-	$ 216,267	20.3%	$ 216,267	$ 0.0048
General Service 50 to 4,999 kW	kW	$ 2.0358	83,774,463	202,946	$ 413,156	38.8%	$ 413,156	$ 2.0358
Sentinel Lighting	kW	$ 1.5212	40,324	113	$ 172	0.0%	$ 172	$ 1.5212
Street Lighting	kW	$ 1.4829	1,874,274	5,087	$ 7,543	0.7%	$ 7,543	$ 1.4829
Unmetered Scattered Load	kWh	$ 0.0048	139,619	-	$ 668	0.1%	$ 668	$ 0.0048
					$ 1,065,979			

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to update the re-aligned RTS Connection Rates to recover forecast wholesale connection costs.

Rate Class	Unit	Adjusted RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Connection
Residential	kWh	$ 0.0042	82,462,887	-	$ 344,525	40.2%	$ 344,525	$ 0.0042
General Service Less Than 50 kW	kWh	$ 0.0039	45,196,174	-	$ 174,665	20.4%	$ 174,665	$ 0.0039
General Service 50 to 4,999 kW	kW	$ 1.6356	83,774,463	202,946	$ 331,930	38.7%	$ 331,930	$ 1.6356
Sentinel Lighting	kW	$ 1.2053	40,324	113	$ 136	0.0%	$ 136	$ 1.2053
Street Lighting	kW	$ 1.1937	1,874,274	5,087	$ 6,073	0.7%	$ 6,073	$ 1.1937
Unmetered Scattered Load	kWh	$ 0.0039	139,619	-	$ 540	0.1%	$ 540	$ 0.0039
					$ 857,869			

RTSR Workform for Electricity Distributors (2013 Filers)

For Cost of Service Applicants, please enter the following Proposed RTS rates into your rates model.

For IRM applicants, please enter these rates into the 2013 IRM Rate Generator, Sheet 11 "Proposed Rates", column I. Please note that the rate description for the RTSRs has been transfered to Sheet 11, Column A from Sheet 4.

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0052	$ 0.0042
General Service Less Than 50 kW	kWh	$ 0.0048	$ 0.0039
General Service 50 to 4,999 kW	kW	$ 2.0358	$ 1.6356
Sentinel Lighting	kW	$ 1.5212	$ 1.2053
Street Lighting	kW	$ 1.4829	$ 1.1937
Unmetered Scattered Load	kWh	$ 0.0048	$ 0.0039

OVERVIEW - DEFERRAL AND VARIANCE ACCOUNTS:

The information contained in this exhibit includes the status and description of LPDL's deferral and variance accounts, the proposed disposition of certain account balances, and the rate riders required for recovery or refund of the account balances.

<u>PREVIOUS DEFERRAL AND VARIANCE ACCOUNT DISPOSITION:</u>

2012 IRM

On March 22, 2012 the Ontario Energy Board's Decision and Order EB-2011-0180 indicated LPDL's Group 1 account balances did not exceed the preset disposition threshold and that no disposition was required at that time. In addition, the following accounts were approved for disposition over a one year period:

- 1592 – Shared Tax Savings Adjustment - $38,129
- 1521 – Special Purpose Charge - $3,836.99
- 1562 – PILs - $15,091
- LRAM claim for 2006-2009 programs - $57,639

2012 Smart Meter Cost Recovery Application

On April 19, 2012 the Ontario Energy Board's Decision and Order EB-2011-0413 allowed for a Smart Meter Disposition Rider (SMDR) from May 1, 2012, effective for a one year period.

- 1555/1556 Smart Meter disposition (not including stranded meters)

In addition, this application approved a Smart Meter Incremental Revenue Requirement Rate Rider (SMIRR), May 1, 2012 to April 30, 2013, that will effectively be absorbed into rates effective with the first Cost of Service application (May 2013).

STATUS OF DEFERRAL AND VARIANCE ACCOUNTS:

This Schedule contains the status of Deferral and Variance Accounts ("DVAs") currently used by LPDL. The balances as at December 31, 2011 and the proposed recovery amounts are summarized in Table 9.2.3 following the descriptions of each account:

GROUP 1 Accounts

1550 LV Variance Account

This Account is used to record the net of the low voltage transactions, which are not part of the electricity wholesale market. Monthly, this account is used to record the net amounts charged by host distributor(s) to an embedded distributor for transmission or low voltage services (USoA 4750) and the amount billed to the embedded distributor's customers based on approved LV rate(s) (USoA 4075).The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, LPDL is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1550. The requested amount is a debit of $176,676 .

1580 Retail Settlement Variance Account - Wholesale Market Service Charges

This account is used to record the net of the amount charged by Hydro One based on the settlement invoice for the operation of the IESO-administered markets and the operation of the IESO-controlled grid, and the amount billed to customers using the OEB-approved Wholesale Market Service Rate. LPDL uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, LPDL is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1580. The requested amount is a credit of -$655,531 .

1584 Retail Settlement Variance Account - Retail Transmission Network Charges

This account is used to record the net of the amount charged by Hydro One, based on the settlement invoice for transmission network services, and the amount billed to customers using the OEB-approved Retail Transmission Rate for network services. LPDL uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, LPDL is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1584. The requested amount is a debit of $44,825 .

1586 Retail Settlement Variance Account - Retail Transmission Connection Charges

This account is used to record the net of the amount charged by Hydro One, based on the settlement invoice for transmission connection services, and the amount billed to customers using the OEB-approved Retail Transmission Rate for connection services. LPDL uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, LPDL is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1586. The requested amount is a debit of $19,527 .

1588 Retail Settlement Variance Account – Power (excluding Global Adjustment)

This account is used to recover the net difference between the energy amount billed to customers and the energy charge to LPDL using the settlement invoice from Hydro One.

LPDL uses the accrual method. The variance between Board-approved and actual line losses is reflected in Account 1588 for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, LPDL is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1588 - Power. The requested amount is a debit of $938,993 .

1588 Retail Settlement Variance Account - Power, Sub-account Global Adjustment

This account is used to recover the net difference between the provincial benefit amount billed to customers and the global adjustment charge to LPDL using the settlement invoice from Hydro One. LPDL uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, LPDL is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1588 sub-account Global Adjustment through a separate non-RPP rate rider. The requested amount is a credit of -$115,709 .

1590 Recovery of Regulatory Balances

This account is used to recover the approved principal account balances on the transfer to Account 1590 of the Board-approved deferral or variance account balances based on LPDL’s 2006 Cost of Service application. LPDL uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, LPDL is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1590. The requested amount is a debit of $219,150 .

1595 Recovery of Regulatory Balances

This account is used to recover the approved principal account balances on the transfer to Account 1595 of the Board-approved deferral or variance account balances based on LPDL's 2009 Cost of Service application and subsequent IRM applications. LPDL uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, LPDL is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1595. The requested amount is a debit of for 2008 balances and a credit of -$72,555 for 2009 balances. Both of these accounts had a disposition period until April 30, 2011 and as such, stopped prior to the end of 2011 and are in the audited balances for 2011. The 2009 balance includes a portion specifically related to Non-RPP customers and as such the rate rider will be determined for only those classes of customers for -$51,597 . LPDL is not seeking disposition for a credit of -$290,763 for 2010 balances as the disposition continues until May 2012.

GROUP 2 Accounts

1508 Other Regulatory Assets – Sub-account IFRS Transition Costs

This account includes amounts paid for one-time incremental costs for the transition to International Financial Reporting Standards (IFRS). The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

LPDL has established account 1508 – sub-account IFRS Transition Costs in accordance with the Board Requirements. The balance as of December 31, 2011 is -$10,056 however, the majority of expenses for the transition of IFRS will not occur until 2012 and 2013. LPDL is not requesting disposition of this account until the transition to IFRS is complete in 2012/2013.

Table 9.2.1 - One-Time Incremental IFRS Transition Costs

Nature of One-Time Incremental IFRS Transition Costs [1]	Audited Actual Costs Incurred 2009	Audited Actual Costs Incurred 2010	Audited Actual Costs Incurred 2011	Audited Carrying Charges to Dec 31, 2011	Total Audited Actual Costs to Dec 31, 2011
professional accounting fees		$ 10,000	$ 15,000		$ 25,000
professional legal fees					$ -
salaries, wages and benefits of staff added to support the transition to IFRS					$ -
associated staff training and development costs	$ 2,021	$ 1,791	$ 905		$ 4,716
costs related to system upgrades, or replacements or changes where IFRS was the major reason for conversion					$ -
professional valuation fees & componentization	$ 15,000		$ 26,000		$ 41,000
recovery in 2009 Cost of Service application	-$ 20,000	-$ 30,000	-$ 30,000		-$ 80,000
carrying charges on IFRS transition costs				-$ 590	-$ 590
Insert description of additional item(s) and new rows if needed.					$ -
Total	-$ 2,979	-$ 18,209	$ 11,905	-$ 590	-$ 9,874

1508 Other Regulatory Assets – Sub-account Incremental Capital Charges

This account contains the incremental capital charges from Hydro One. The requested amount is a debit of $7,254 .

1508 Other Regulatory Assets – Late Payment Penalty Litigation Costs

This account includes amounts paid for one-time incremental costs for the Late Payment Penalty Litigation Costs. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

LPDL has established account 1508 – sub-account Late Payment Penalty Litigation in accordance with the Board Requirements. The balance as of December 31, 2011 is $9,201, however the rate continues to April 30, 2013 and at such time the balance should be near zero. LPDL is not requesting disposition of this account at this time.

1518 Retail Settlement Variance Account – Retail

This account is used to recover the net differences between the revenues recovered from Retailer Service Agreements and Billing options and the cost of managing the retailer contracts. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, LPDL is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1518 – RCVA Retail. The requested amount is a credit of -$72,664 .

1548 Retail Settlement Variance Account – Service Transaction Request

This account is used to recover the net differences between the revenues recovered from Service Transaction Requests (as described in the 2000 EDRH) and the incremental costs of providing these services. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, LPDL is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1548 – RCVA STR. The requested amount is a debit of $95,095 .

1592 PILs and Tax Variances for 2006 and Subsequent Years

Sub-account HST/OVAT Input Tax credits

LPDL uses account 1592 to record the incremental ITCs received on the distribution revenue requirement items that were previously subject to PST and which became subject to HST on July 1, 2010. The balance in this account on December 31, 2011 was a credit of -$25,556 and LPDL requests disposition of this amount, with 50% or -$12,778 being allocated to customers and the remainder to LPDL.

Table 9.2.2 – Account 1592 Balance

Appendix 2-T
Deferred PILs Account 1592 Balances

The following table should be completed based on the information requested below, in accordance with the notes following the table. An explanation should be provided for any blank entries.

Tax Item	Principal as of December 31, 2011
Large Corporation Tax grossed-up proxy from 2006 EDR application PILs model for the period from May 1, 2006 to April 30, 2007	N/A
Large Corporation Tax grossed-up proxy from 2006 EDR application PILs model for the period from January 1, 2006 to April 30, 2006 (4/12ths of the approved grossed-up proxy), if not recorded in PILs account 1562	N/A
Ontario Capital Tax rate decrease and increase in capital deduction for 2007	N/A
Ontario Capital Tax rate decrease and increase in capital deduction for 2008	N/A
Ontario Capital Tax rate decrease and increase in capital deduction for 2009	N/A
Ontario Capital Tax rate decrease and increase in capital deduction for 2010	N/A
Capital Cost Allowance class changes from 2006 EDR application for 2006	N/A
Capital Cost Allowance class changes from 2006 EDR application for 2007	N/A
Capital Cost Allowance class changes from 2006 EDR application for 2008	N/A
Capital Cost Allowance class changes from 2006 EDR application for 2009	N/A
Capital Cost Allowance class changes from 2006 EDR application for 2010	N/A
Capital Cost Allowance class changes from 2006 EDR application for 2011	N/A
Capital Cost Allowance class changes from any prior application not recorded above. Please provide details and explanation separately.	
Sub-account - HST/OVAT Input Tax Credits	
PST on OM&A items - 2010	-$ 2,028
PST on Capital Items - savings in dep'n - 2010	-$ 3,871
PST on OM&A items - 2011	-$ 13,023
PST on Capital Items - savings in dep'n - 2010 (con't)	-$ 3,871
PST on Capital Items - savings in dep'n - 2011	-$ 2,764
Total	-$ 25,556

Notes:

DEFERRAL AND VARIANCE ACCOUNT BALANCES:

The following Table 9.2.3 contains account balances from the 2011 Audited Financial Statements as at December 31, 2011 and agrees to the 2011 year end balances for RRR filing E2.1.7 Trial Balance as filed April 30, 2012 with the OEB.

Table 9.2.3 - December 31, 2011 Audited Balances – Deferral and Variance Accounts

		Projected Interest on Dec-31-11 Balances		
Account Descriptions	**Account Number**	**Projected Interest from Jan 1, 2012 to December 31, 2012 on**	**Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 -11**	**Total Claim**
Group 1 Accounts				
LV Variance Account	1550	$ 173,670	$ 3,006	$ 176,676
RSVA - Wholesale Market Service Charge	1580	-$ 632,336	-$ 23,196	-$ 655,531
RSVA - Retail Transmission Network Charge	1584	$ 44,990	-$ 165	$ 44,825
RSVA - Retail Transmission Connection Charge	1586	$ 20,666	-$ 1,139	$ 19,527
RSVA - Power (excluding Global Adjustment)	1588	$ 906,939	$ 32,054	$ 938,993
RSVA - Power - Sub-account - Global Adjustment	1588	-$ 111,307	-$ 4,402	-$ 115,709
Recovery of Regulatory Asset Balances	1590	$ 208,185	$ 10,965	$ 219,150
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	-$ 34,075	$ 62,694	$ 28,619
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	-$ 490,537	$ 469,579	-$ 20,958
Disposition and Recovery/Refund of Regulatory Balances (2009)[7 - GA related]	1595	-$ 34,710	-$ 16,887	-$ 51,597
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	-$ 698,644	-$ 43,810	no disposition
Disposition and Recovery/Refund of Regulatory Balances (2010)[7 - GA Related]	1595	$ 405,216	$ 27,709	no disposition
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-$ 241,941	$ 516,407	$ 274,466
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-$ 130,635	$ 520,810	$ 390,175
RSVA - Power - Sub-account - Global Adjustment	**1588**	-$ 111,307	-$ 4,402	-$ 115,709
Group 2 Accounts				
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	-$ 9,284	-$ 772	no disposition
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ 6,956	$ 298	$ 7,254
Other Regulatory Assets - Sub-Account - Late Payment Penalty Litigation	1508	$ 9,025	$ 177	no disposition
Retail Cost Variance Account - Retail	1518	-$ 69,638	-$ 3,026	-$ 72,664
Renewable Generation Connection Capital Deferral Account	1531	$ 249,798	$ 4,896	no disposition
Retail Cost Variance Account - STR	1548	$ 91,127	$ 3,968	$ 95,095
Group 2 Sub-Total		$ 277,985	$ 5,541	$ 283,525
Deferred Payments in Lieu of Taxes	1562	$ 1	-$ 0	$ 0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$ 25,556	$ -	-$ 25,556
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ 10,488	$ 521,947	$ 532,435
Total including Account 1521 and Account 1568		$ 10,488	$ 521,947	$ 532,435
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -	$ 0	$ 0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ 0	-$ 0	$ 0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ 446,409	$ -	$ 446,409
Smart Meter OM&A Variance[11]	1556	$ -	-$ 0	-$ 0

Table 9.2.4 provides the interest rates that have been used to calculate actual and forecast carrying charges on the accounts in accordance with the methodology approved by the Board in

EB-2006-0117 on November 28, 2006.

Table 9.2.4 - Interest Rates Applied to Deferral and Variance Accounts

Quarter	Interest Rate Utilized
Q1 2005	7.25%
Q2 2005	7.25%
Q3 2005	7.25%
Q4 2005	7.25%
Q1 2006	7.25%
Q2 2006	4.14%
Q3 2006	4.59%
Q4 2006	4.59%
Q1 2007	4.59%
Q2 2007	4.59%
Q3 2007	4.59%
Q4 2007	5.14%
Q1 2008	5.14%
Q2 2008	4.08%
Q3 2008	3.35%
Q4 2008	0.03%
Q1 2009	2.45%
Q2 2009	1.00%
Q3 2009	0.55%
Q4 2009	0.55%
Q1 2010	0.55%
Q2 2010	0.55%
Q3 2010	0.89%
Q4 2010	1.20%
Q1 2011	1.47%
Q2 2011	1.47%
Q3 2011	1.47%
Q4 2011	1.47%
Q1 2012	1.47%
Q2 2012	1.47%
Q3 2012	1.47%
Q4 2012	1.47%
Q1 2013	1.47%
Q2 2013	1.47%

ACCOUNTS REQUESTED FOR DISPOSITION BY WAY OF A DEFERRAL AND VARIANCE ACCOUNT RATE RIDER:

LPDL is requesting disposition of the variance accounts noted below according to the Report of the Board EB-2009-0046, which states that “at the time of rebasing, all Account balances should be disposed of unless otherwise justified by the distributor or as required by a specific Board decision or guideline”.

LPDL has followed the guidelines in the Report of the Board and requests disposition over a one-year period. LPDL has provided a continuity schedule of the accounts listed below in Appendix A of this exhibit.

LPDL is requesting the disposition of the following Group 1 and Group 2 Accounts shown in Table 9.2.6. These amounts are comprised of the audited balances as of December 31, 2011 and the forecasted interest through April 30, 2013.

LPDL is proposing that the following accounts, as shown in Table 9.2.5 below, be included in the non-RPP global adjustment rate rider by class. LPDL tracked the previous rate riders specific to non-RPP customers and is able to determine the portion of account 1595 that pertains to non-RPP customers. This would ensure that there would be no cross-subsidization of the disposition.

Table 9.2.5 - Account Balances for Disposition – Non-RPP specific

		Projected Interest on Dec-31-11 Balances		
Account Descriptions	**Account Number**	**Projected Interest from Jan 1, 2012 to December 31,**	**Projected Interest from January 1, 2013 to April 30,**	**Total Claim**
Group 1 Accounts				
RSVA - Power - Sub-account - Global Adjustment	1588	-$ 111,307	-$ 4,402	-$ 115,709
Disposition and Recovery/Refund of Regulatory Balances (2009)[7 - GA related]	1595	-$ 34,710	-$ 16,887	-$ 51,597
Non-RPP Global Adjustment claim		-$ 146,017	-$ 21,289	-$ 167,306

Table 9.2.6 - Group 1 and Group 2 Deferral and Variance Accounts

		Amounts from Sheet 2	Allocator
LV Variance Account	1550	176,676	kWh
RSVA - Wholesale Market Service Charge	1580	(655,531)	kWh
RSVA - Retail Transmission Network Charge	1584	44,825	kWh
RSVA - Retail Transmission Connection Charge	1586	19,527	kWh
RSVA - Power (excluding Global Adjustment)	1588	938,993	kWh
RSVA - Power - Sub-account - Global Adjustment	1588	(115,709)	Non-RPP kWh
Recovery of Regulatory Asset Balances	1590	219,150	kWh
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	28,619	kWh
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	(20,958)	kWh
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	(51,597)	Non-RPP kWh
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	0	kWh
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	0	Non-RPP kWh
Total of Group 1 Accounts (excluding 1588 sub-account)		**751,300**	
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	0	
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	0	
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	0	kWh
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	7,254	kWh
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	0	kWh
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	0	
Other Regulatory Assets - Sub-Account - Other	1508	0	
Retail Cost Variance Account - Retail	1518	(72,664)	kWh
Misc. Deferred Debits	1525	0	
Renewable Generation Connection Capital Deferral Account	1531	0	
Renewable Generation Connection OM&A Deferral Account	1532	0	
Renewable Generation Connection Funding Adder Deferral Account	1533	0	
Smart Grid Capital Deferral Account	1534	0	
Smart Grid OM&A Deferral Account	1535	0	
Smart Grid Funding Adder Deferral Account	1536	0	
Retail Cost Variance Account - STR	1548	95,095	kWh
Board-Approved CDM Variance Account	1567	0	
Extra-Ordinary Event Costs	1572	0	
Deferred Rate Impact Amounts	1574	0	
RSVA - One-time	1582	0	
Other Deferred Credits	2425	0	
Total of Group 2 Accounts		**29,685**	
Deferred Payments in Lieu of Taxes	1562	0	
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	0	
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	(12,778)	kWh
Total of Account 1562 and Account 1592		**(12,778)**	
Special Purpose Charge Assessment Variance Account	1521	0	
LRAM Variance Account **(Enter dollar amount for each class)**	1568	0	
(Account 1568 - total amount allocated to classes)		0	
Variance		0	
Total Balance Allocated to each class (excluding 1588 sub-account)		**768,208**	
Total Balance in Account 1588 - sub account		**(167,306)**	
Total Balance Allocated to each class (including 1588 sub-account)		**600,902**	

METHOD OF DISPOSITION:

Allocators

LPDL submits the following Allocators in Table 9.2.7. Table 9.2.8 used these determinants to assign the Group 1 and Group 2 balances to rate each class. Table 9.2.7 summarizes the variables used to determine the proposed regulatory asset rate rider by rate class for the Group 1 and Group 2 accounts, excluding the Non-RPP rate rider for the 1588 Sub-Account Global Adjustment. The billing determinants are based on the 2011 Annual RRR filing (2.1.5) and calculated for a one-year disposition period.

Table 9.2.7 – Billing Determinants by Customer Class

Rate Class (Enter Rate Classes in cells below)	Units	# of Customers	Metered kWh	Metered kW	Billed kWh for Non-RPP Customers	Estimated kW for Non-RPP Customers
Residential	kWh	7,930	77,905,420		9,879,218	-
General Service <50 kW	kWh	1,567	42,698,322		9,112,556	-
General Service >50 kW	kW	101	83,774,463	202,946	28,916,248	70,050
Sentinel Lighting	kW	45	40,324	113	1,059	3
Street Lighting	kW	2,130	1,874,274	5,087	411,364	1,116
USL	kWh	38	131,903		3,036	-
						-
						-
						-
						-
Total		**11,811**	**206,424,706**	**208,146**	**48,323,481**	**71,170**

Table 9.2.8 - 2013 Deferral and Variance Account Rate Rider by Class (Group 1 & 2 Accounts)

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1588 sub-account)	Rate Rider for Deferral/Variance Accounts	
Residential	kWh	77,905,420	$ 289,924	**0.0037**	$/kWh
General Service <50 kW	kWh	42,698,322	$ 158,901	**0.0037**	$/kWh
General Service >50 kW	**kW**	202,946	$ 311,766	**1.5362**	**$/kW**
Sentinel Lighting	**kW**	113	$ 150	**1.3280**	**$/kW**
Street Lighting	**kW**	5,087	$ 6,975	**1.3712**	**$/kW**
USL	kWh	131,903	$ 491	**0.0037**	$/kWh
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
Total			**$ 768,208**		

Table 9.2.9 summarizes the variables used to determine the proposed non-RPP global adjustment rate rider by rate class. The billing determinants are based on the 2013 Test Year forecast load data and calculated for a one-year disposition period.

Table 9.2.9 - 2013 Non-RPP Global Adjustment Rate Rider by Class

Rate Rider Calculation for RSVA - Power - Sub-account - Global Adjustment

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of RSVA - Power - Sub-	Rate Rider for RSVA - Power -	
Residential	kWh	9,879,218	-$ 34,204	- **0.0035**	$/kWh
General Service <50 kW	kWh	9,112,556	-$ 31,550	- **0.0035**	$/kWh
General Service >50 kW	**kW**	70,050	-$ 100,114	- **1.4292**	**$/kW**
Sentinel Lighting	**kW**	3	-$ 4	- **1.2355**	**$/kW**
Street Lighting	**kW**	1,116	-$ 1,424	- **1.2756**	**$/kW**
USL	kWh	3,036	-$ 11	- **0.0035**	$/kWh
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
Total			**-$ 167,306**		

STRANDED ASSETS:

LPDL is also seeking disposition of its stranded meter costs. LPDL has continued to record the costs of the stranded meters in Account 1860 and has continued to depreciate these assets over a 25 year period. By the end of 2011, following completion of the smart meter deployment, 9,497 stranded meters had been removed from service and were disposed of. Table 9.3.1 contains the asset and accumulated depreciation balances under both CGAAP and MIFRS for 2012.

Table 9.3.1 - Stranded Asset Values

Appendix 2-S
Stranded Meter Treatment

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006		$ 922,697	$ 281,559		$ 641,138	$ -	$ 641,138
2007		$ 998,307	$ 326,367		$ 671,940	$ -	$ 671,940
2008		$ 1,006,849	$ 373,036		$ 633,813	$ -	$ 633,813
2009		$ 1,006,849	$ 419,887		$ 586,962	$ -	$ 586,962
2010		$ 1,006,849	$ 466,738		$ 540,111	$ -	$ 540,111
2011		$ 1,006,849	$ 513,589		$ 493,260	$ -	$ 493,260
2012	(1)	$ 1,006,849	$ 560,440		$ 446,409	$ -	$ 446,409

As this application is prepared under MIFRS, LPDL is requesting recovery of the $446,409 the residual net book value of the assets.

Smart Meter/Stranded Asset Rate Rider Calculation

As detailed in this Exhibit, LPDL is requesting recovery of a Stranded Asset amount of $446,409 LPDL proposes to recover these amounts through a fixed monthly rider from smart metered customers. Based on LPDL's 2013 customer forecast, a rate rider of $1.70 per month per Residential metered customer and $3.09 per GS<50 kW per month per metered customer would be required to recover these amounts in two years. Table 9.3.2 summarizes the calculation of this rate using the split of costs related to the meters of each class.

1 **Table 9.3.2 – Stranded Meter Asset Rate Rider Calculation**

Stranded Meter Cost Recovery Rate Rider	Number of Meters	2012 NBV	Monthly Rate Rider - 2 yr Recovery
Number of meters replaced with Smart Meters			
Residential - single phase	7087	$ 221,880.38	
Residential - single phase radio read	172	$ 5,384.99	
Residential - three phase	532	$ 101,065.08	
GS<50 kW - single phase	1132	$ 35,440.75	
GS<50 kW - three phase	435	$ 82,637.80	
Total	**9358**	**$ 446,409.00**	
Number of metered customers - 2013 Forecast			
Residential	8063	$ 328,330.45	**$ 1.70**
GS< 50 kW	1591	$ 118,078.55	**$ 3.09**
	9654	**$ 446,409.00**	

2
3

PP&E DEFFERAL ACCOUNT AND DISPOSITION:

In Exhibit 2, Tab 5, Schedule 3 of this application LPDL identified a change that will occur to the 2012 Net Book Value of its property, plant and equipment, as a result of the transition from financial reporting under CGAAP to MIFRS. The net book value of the assets is expected to increase by $234,395 .

Based on the *Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment* (EB-2009-0408) dated June 13, 2012, LPDL requests this amount be moved to a PP&E deferral account for disposition to customers. LPDL requests a four year disposition period to match with the period until next rebasing. As directed, this amount will not attract carrying charges but will attract the same level of return LPDL has used in determining revenue requirement for this cost of service application. This return is calculated at 6.62%. The disposition has been included in the determination of distribution revenue rates and the reduction of revenue requirement. The calculation of the above PP&E deferral account requested for disposition is shown in Table 9.4.1 below.

Table 9.4.1 Calculation of NBV Change and Return applied to PPE Deferral Account

Appendix 2-EB
IFRS-CGAAP Transitional PP&E Amounts
2013 Adopters of IFRS for Financial Reporting Purposes

For applicants that adopt IFRS on January 1, 2013 for financial reporting purposes

Note: this sheet should be filled out if the applicant adopts IFRS for its financial reporting purpose as of January 1, 2013.

	2009 Rebasing Year	2010	2011	2012	2013 Rebasing Year	2014	2015	2016
Reporting Basis	CGAAP	IRM	IRM	IRM	MIFRS	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast			
			$	$	$	$	$	$
PP&E Values under CGAAP								
Opening net PP&E - Note 1				16,346,300				
Additions				1,587,268				
Depreciation (amounts should be negative)				-1,407,922				
Closing net PP&E (1)				16,525,647				
PP&E Values under MIFRS (Starts from 2012, the transition year)								
Opening net PP&E - Note 1				16,346,300				
Additions				1,460,907				
Depreciation (amounts should be negative)				-1,047,166				
Closing net PP&E (2)				16,760,042				
Difference in Closing net PP&E, CGAAP vs. MIFRS (Shown as adjustment to rate base on rebasing)				-234,395				
Account 1575 - IFRS-CGAAP Transitional PP&E Amounts								
Opening balance				0	-234395	-175796	-117198	-58599
Amounts added in the year				-234395				
Sub-total				-234395	-234395	-175796	-117198	-58599
Amount of amortization, included in depreciation expense - Note 2					58599	58599	58599	58599
Closing balance in deferral account				-234395	-175796	-117198	-58599	0

Effect on Revenue Requirement

Amortization of deferred balance as above - Note 2	-58599	**WACC**	6.62%
Return on Rate Base Associated with deferred PP&E balance at WACC - Note 3	-15517	**Disposition Period - Note 4**	4
Amount included in Revenue Requirement on rebasing	-74116		

APPENDIX A

LPDL 2013 EDDVAR MODEL

Deferral/Variance Account Workform for 2013 Filers

Version 2.0

Utility Name	Lakeland Power Distribution Ltd
Service Territory	*Bracebridge, Huntsville, Magnetawan, Burk's Falls,*
Assigned EB Number	EB-2012-0145
Name of Contact and Title	Margaret Maw, Chief Financial Officer
Phone Number	705-789-5442
Email Address	mmaw@lakelandholding.com

General Notes

1. Please ensure that your macros have been enabled. (Tools -> Macro -> Security)

2. Due to the time lag of deferral/variance account dispositions, this model assumes that all opening balances include previously disposed of amounts. Accordingly, all "Board Approved Dispositions" are deducted from the opening balance.

3. Please provide information in this model since the last time your balances were disposed.

4. For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-05	Transactions Debit / (Credit) during 2005 excluding interest and adjustments [3]	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec-31-05	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Interest Amounts as of Dec-31-05
		2005									
Group 1 Accounts											
LV Variance Account	1550					$ -					$ -
RSVA - Wholesale Market Service Charge	1580		$ 53,859			$ 53,859					$ -
RSVA - Retail Transmission Network Charge	1584		$ 14,636		-$ 52,285	-$ 37,649		$ 2,891			$ 2,891
RSVA - Retail Transmission Connection Charge	1586		-$ 1,210,713		$ 941,193	-$ 269,520		$ 199,550			$ 199,550
RSVA - Power (excluding Global Adjustment)	1588		$ 678,583			$ 678,583		$ 19,546			$ 19,546
RSVA - Power - Sub-account - Global Adjustment	1588		-$ 317,482			-$ 317,482		$ 3,707			$ 3,707
Recovery of Regulatory Asset Balances	1590					$ -		-$ 50,221			-$ 50,221
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595					$ -					$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595					$ -					$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7] - GA related	1595					$ -					$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595					$ -					$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7] - GA Related	1595					$ -					$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	-$ 781,117	$ -	$ 888,908	$ 107,791	$ -	$ 175,473	$ -	$ -	$ 175,473
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	-$ 463,635	$ -	$ 888,908	$ 425,273	$ -	$ 171,766	$ -	$ -	$ 171,766
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	-$ 317,482	$ -	$ -	-$ 317,482	$ -	$ 3,707	$ -	$ -	$ 3,707
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508		$ 19,840			$ 19,840		$ 303			$ 303
Other Regulatory Assets - Sub-Account - Pension Contributions	1508		$ 75,939			$ 75,939		$ 1,308			$ 1,308
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508					$ -					$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Late Payment Penalty Litigation	1508					$ -					$ -
Retail Cost Variance Account - Retail	1518		-$ 11,664			-$ 11,664		-$ 391			-$ 391
Misc. Deferred Debits	1525					$ -					$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -					$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -					$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -					$ -
Smart Grid Capital Deferral Account	1534					$ -					$ -
Smart Grid OM&A Deferral Account	1535					$ -					$ -
Smart Grid Funding Adder Deferral Account	1536					$ -					$ -
Retail Cost Variance Account - STR	1548		$ 18,704			$ 18,704		$ 617			$ 617
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572					$ -					$ -
Deferred Rate Impact Amounts	1574					$ -					$ -
RSVA - One-time	1582					$ -					$ -
Other Deferred Credits	2425					$ -					$ -
Group 2 Sub-Total		$ -	$ 102,819	$ -	$ -	$ 102,819	$ -	$ 1,837	$ -	$ -	$ 1,837
Deferred Payments in Lieu of Taxes	1562					$ -					$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592					$ -					$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592					$ -					$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ -	-$ 678,298	$ -	$ 888,908	$ 210,610	$ -	$ 177,310	$ -	$ -	$ 177,310

Account Descriptions	Account Number	2005 Opening Principal Amounts as of Jan-1-05	Transactions Debit / (Credit) during 2005 excluding interest and adjustments [3]	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec-31-05	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Interest Amounts as of Dec-31-05
Special Purpose Charge Assessment Variance Account[9]	**1521**										
LRAM Variance Account	**1568**										
Total including Account 1521 and Account 1568		$ -	-$ 678,298	$ -	$ 888,908	$ 210,610	$ -	$ 177,310	$ -	$ -	$ 177,310
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555					$ -					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555					$ -					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555					$ -					$ -
Smart Meter OM&A Variance[11]	1556					$ -					$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563					$ -					$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575					$ -					$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592					$ -					$ -
Disposition and Recovery of Regulatory Balances[7]	1595					$ -					$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

1 Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, etc.

1A Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the 2006 EDR and account 1595 during the 2008 EDR and subsequent years as ordered by the Board.

2 Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

3 For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

4 Please describe "other" components of 1508 and add more component lines if necessary.

5 1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligation to the ratepayer.

6 If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

7 Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, include the balances in Account 1595 on a memo basis only (line 85).

8 As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January 1, 2011 will require a variance account for OCEB purposes... The Board expects that any principal balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be addressed through the monthly settlement process with the IESO or the host distributor, as applicable.

9 The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would have resulted in non-compliance with the timeline set out in section 8 of the SPC regulation.

10 Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall be cleared as an adjustment to the distributor's revenue requirement.

11 Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance Account rate rider. For details on how to dispose of balances in Smart Meter accounts see the Board's Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Account Descriptions	Account Number	2006 Opening Principal Amounts as of Jan-1-06	Transactions Debit / (Credit) during 2006 excluding interest and adjustments [3]	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec-31-06	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Interest Amounts as of Dec-31-06
Group 1 Accounts											
LV Variance Account	1550	$ -	-$ 8,026			-$ 8,026	$ -	-$ 91			-$ 91
RSVA - Wholesale Market Service Charge	1580	$ 53,859	-$ 146,058		$ 5,002	-$ 87,197	$ -	$ 1,260			$ 1,260
RSVA - Retail Transmission Network Charge	1584	-$ 37,649	-$ 224,510		-$ 67,320	-$ 329,479	$ 2,891	-$ 15,766			-$ 12,875
RSVA - Retail Transmission Connection Charge	1586	-$ 269,520	-$ 1,196,268		$ 1,114,981	-$ 350,807	$ 199,550	-$ 213,915			-$ 14,365
RSVA - Power (excluding Global Adjustment)	1588	$ 678,583	-$ 165,602			$ 512,981	$ 19,546	$ 56,253			$ 75,799
RSVA - Power - Sub-account - Global Adjustment	1588	-$ 317,482	$ 606,059			$ 288,577	$ 3,707	-$ 10,601			-$ 6,894
Recovery of Regulatory Asset Balances	1590	$ -	-$ 672,044	-$ 2,204,920		$ 1,532,876	-$ 50,221	$ 17,382	-$ 488,225		$ 455,386
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7 - GA related]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7 - GA Related]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ 107,791	-$ 1,806,449	-$ 2,204,920	$ 1,052,663	$ 1,558,925	$ 175,473	-$ 165,478	-$ 488,225	$ -	$ 498,220
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ 425,273	-$ 2,412,508	-$ 2,204,920	$ 1,052,663	$ 1,270,348	$ 171,766	-$ 154,877	-$ 488,225	$ -	$ 505,114
RSVA - Power - Sub-account - Global Adjustment	**1588**	-$ 317,482	$ 606,059	$ -	$ -	$ 288,577	$ 3,707	-$ 10,601	$ -	$ -	-$ 6,894
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 19,840	$ 14,054			$ 33,894	$ 303	$ 1,471			$ 1,773
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 75,939	$ 16,003			$ 91,943	$ 1,308	$ 3,802			$ 5,110
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Late Payment Penalty Litigation	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	-$ 11,664	-$ 16,082			-$ 27,747	-$ 391	-$ 912			-$ 1,303
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -	$ -				$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -	$ -				$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -	$ -				$ -
Smart Grid Capital Deferral Account	1534					$ -	$ -				$ -
Smart Grid OM&A Deferral Account	1535					$ -	$ -				$ -
Smart Grid Funding Adder Deferral Account	1536					$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	$ 18,704	$ 26,007			$ 44,711	$ 617	$ 1,465			$ 2,082
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ -				$ -	$ -				$ -
Other Deferred Credits	2425	$ -				$ -	$ -				$ -
Group 2 Sub-Total		$ 102,819	$ 39,982	$ -	$ -	$ 142,801	$ 1,837	$ 5,826	$ -	$ -	$ 7,663
Deferred Payments in Lieu of Taxes	1562	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ 210,610	-$ 1,766,467	-$ 2,204,920	$ 1,052,663	$ 1,701,726	$ 177,310	-$ 159,652	-$ 488,225	$ -	$ 505,883

Account Descriptions	Account Number	2006 Opening Principal Amounts as of Jan-1-06	Transactions Debit / (Credit) during 2006 excluding interest and adjustments [3]	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec-31-06	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Interest Amounts as of Dec-31-06
Special Purpose Charge Assessment Variance Account[9]	**1521**										
LRAM Variance Account	**1568**										
Total including Account 1521 and Account 1568		$ 210,610	-$ 1,766,467	-$ 2,204,920	$ 1,052,663	$ 1,701,726	$ 177,310	-$ 159,652	-$ 488,225	$ -	$ 505,883
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -	-$ 15,772			-$ 15,772	$ -	-$ 182			-$ 182
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -				$ -	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -				$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig have a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs v

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of th

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved dis

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transa

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the ol
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to Decembe
the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded fro
disposed balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refu
balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will

The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the pr
non-compliance with the timeline set out in section 8 of the SPC regulation.

Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall b

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Account Descriptions	Account Number	2007 Opening Principal Amounts as of Jan-1-07	Transactions Debit / (Credit) during 2007 excluding interest and adjustments [3]	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec-31-07	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Interest Amounts as of Dec-31-07
Group 1 Accounts											
LV Variance Account	1550	-$ 8,026	-$ 20,741			-$ 28,767	-$ 91	-$ 608			-$ 699
RSVA - Wholesale Market Service Charge	1580	-$ 87,197	-$ 92,175			-$ 179,372	$ 1,260	-$ 5,954			-$ 4,694
RSVA - Retail Transmission Network Charge	1584	-$ 329,479	-$ 169,902			-$ 499,381	-$ 12,875	-$ 19,344			-$ 32,219
RSVA - Retail Transmission Connection Charge	1586	-$ 350,807	-$ 192,658			-$ 543,465	-$ 14,365	-$ 20,882			-$ 35,247
RSVA - Power (excluding Global Adjustment)	1588	$ 512,981	$ 396,289			$ 909,270	$ 75,799	$ 35,958			$ 111,757
RSVA - Power - Sub-account - Global Adjustment	1588	$ 288,577	-$ 8,317			$ 280,260	-$ 6,894	$ 12,143			$ 5,249
Recovery of Regulatory Asset Balances	1590	$ 1,532,876	-$ 1,343,501			$ 189,375	$ 455,386	$ 40,836			$ 496,222
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7 - GA related]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7 - GA Related]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ 1,558,925	-$ 1,431,005	$ -	$ -	$ 127,920	$ 498,220	$ 42,149	$ -	$ -	$ 540,369
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ 1,270,348	-$ 1,422,688	$ -	$ -	-$ 152,340	$ 505,114	$ 30,006	$ -	$ -	$ 535,120
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ 288,577	-$ 8,317	$ -	$ -	$ 280,260	-$ 6,894	$ 12,143	$ -	$ -	$ 5,249
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 33,894				$ 33,894	$ 1,773	$ 1,602			$ 3,376
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 91,943				$ 91,943	$ 5,110	$ 4,347			$ 9,457
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Late Payment Penalty Litigation	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	-$ 27,747	-$ 17,361			-$ 45,108	-$ 1,303	-$ 1,708			-$ 3,012
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -					$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -					$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -					$ -
Smart Grid Capital Deferral Account	1534					$ -					$ -
Smart Grid OM&A Deferral Account	1535					$ -					$ -
Smart Grid Funding Adder Deferral Account	1536					$ -					$ -
Retail Cost Variance Account - STR	1548	$ 44,711	$ 24,927			$ 69,638	$ 2,082	$ 2,655			$ 4,737
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ -				$ -	$ -				$ -
Other Deferred Credits	2425	$ -				$ -	$ -				$ -
Group 2 Sub-Total		$ 142,801	$ 7,566	$ -	$ -	$ 150,367	$ 7,663	$ 6,895	$ -	$ -	$ 14,558
Deferred Payments in Lieu of Taxes	1562	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ 1,701,726	-$ 1,423,439	$ -	$ -	$ 278,287	$ 505,883	$ 49,044	$ -	$ -	$ 554,927

Account Descriptions	Account Number	2007 Opening Principal Amounts as of Jan-1-07	Transactions Debit / (Credit) during 2007 excluding interest and adjustments [3]	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec-31-07	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Interest Amounts as of Dec-31-07
Special Purpose Charge Assessment Variance Account[9]	**1521**										
LRAM Variance Account	**1568**										
Total including Account 1521 and Account 1568		$ 1,701,726	-$ 1,423,439	$ -	$ -	$ 278,287	$ 505,883	$ 49,044	$ -	$ -	$ 554,927
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -	$ 41,990			$ 41,990	$ -	$ 651			$ 651
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	-$ 15,772	-$ 27,109			-$ 42,881	-$ 182	-$ 1,347			-$ 1,529
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -				$ -	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -				$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig
have a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs v

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of th

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Please describe "other" components of 1508 and add more component lines if necessary.

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If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to Decembe
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"By way of exception... The Board does acicipate that licensed distributors that cannot adapt their invoices as of January
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will

The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the pr
non-compliance with the timeline set out in section 8 of the SPC regulation.

Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall b

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-08	Transactions Debit / (Credit) during 2008 excluding interest and adjustments [3]	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec-31-08	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Interest Amounts as of Dec-31-08
		2008									
Group 1 Accounts											
LV Variance Account	1550	-$ 28,767	$ 11,828			-$ 16,939	-$ 699	-$ 1,112			-$ 1,811
RSVA - Wholesale Market Service Charge	1580	-$ 179,372	-$ 119,931			-$ 299,303	-$ 4,694	-$ 9,284			-$ 13,978
RSVA - Retail Transmission Network Charge	1584	-$ 499,381	-$ 205,967			-$ 705,348	-$ 32,219	-$ 23,435			-$ 55,654
RSVA - Retail Transmission Connection Charge	1586	-$ 543,465	-$ 244,661			-$ 788,126	-$ 35,247	-$ 25,654			-$ 60,901
RSVA - Power (excluding Global Adjustment)	1588	$ 909,270	$ 461,693			$ 1,370,963	$ 111,757	$ 55,426			$ 167,183
RSVA - Power - Sub-account - Global Adjustment	1588	$ 280,260	-$ 47,064			$ 233,196	$ 5,249	-$ 2,448			$ 2,801
Recovery of Regulatory Asset Balances	1590	$ 189,375		$ 646,928		-$ 457,553	$ 496,222	-$ 10,394			$ 485,828
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7 - GA related]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7 - GA Related]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ 127,920	-$ 144,102	$ 646,928	$ -	-$ 663,110	$ 540,369	-$ 16,901	$ -	$ -	$ 523,468
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-$ 152,340	-$ 97,038	$ 646,928	$ -	-$ 896,306	$ 535,120	-$ 14,453	$ -	$ -	$ 520,667
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ 280,260	-$ 47,064	$ -	$ -	$ 233,196	$ 5,249	-$ 2,448	$ -	$ -	$ 2,801
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 33,894				$ 33,894	$ 3,376	$ 1,349			$ 4,725
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 91,943				$ 91,943	$ 9,457	$ 3,659			$ 13,116
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Late Payment Penalty Litigation	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	-$ 45,108	-$ 17,620			-$ 62,728	-$ 3,012	-$ 2,082			-$ 5,093
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -					$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -					$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -					$ -
Smart Grid Capital Deferral Account	1534					$ -					$ -
Smart Grid OM&A Deferral Account	1535					$ -					$ -
Smart Grid Funding Adder Deferral Account	1536					$ -					$ -
Retail Cost Variance Account - STR	1548	$ 69,638	$ 19,992			$ 89,630	$ 4,737	$ 3,095			$ 7,832
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ -				$ -	$ -				$ -
Other Deferred Credits	2425	$ -				$ -	$ -				$ -
Group 2 Sub-Total		$ 150,367	$ 2,372	$ -	$ -	$ 152,739	$ 14,558	$ 6,022	$ -	$ -	$ 20,580
Deferred Payments in Lieu of Taxes	1562	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ 278,287	-$ 141,730	$ 646,928	$ -	-$ 510,371	$ 554,927	-$ 10,879	$ -	$ -	$ 544,048

Account Descriptions	Account Number	2008 Opening Principal Amounts as of Jan-1-08	Transactions Debit / (Credit) during 2008 excluding interest and adjustments [3]	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec-31-08	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Interest Amounts as of Dec-31-08
Special Purpose Charge Assessment Variance Account[9]	**1521**										
LRAM Variance Account	**1568**										
Total including Account 1521 and Account 1568		$ 278,287	-$ 141,730	$ 646,928	$ -	-$ 510,371	$ 554,927	-$ 10,879	$ -	$ -	$ 544,048
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ 41,990	$ 60,851			$ 102,842	$ 651	$ 2,109			$ 2,760
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	-$ 42,881	-$ 27,532			-$ 70,413	-$ 1,529	-$ 2,155			-$ 3,684
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -	$ 3,874			$ 3,874	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -				$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig have a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs v

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of th

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Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall b

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

2009

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-09	Transactions Debit / (Credit) during 2009 excluding interest and adjustments [3]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Interest Amounts as of Dec-31-09
Group 1 Accounts											
LV Variance Account	1550	-$ 16,939	-$ 226,254	-$ 28,767		-$ 214,426	-$ 1,811	-$ 1,047	-$ 2,164		-$ 694
RSVA - Wholesale Market Service Charge	1580	-$ 299,303	-$ 351,885	-$ 179,372		-$ 471,816	-$ 13,978	-$ 3,974	-$ 13,836		-$ 4,116
RSVA - Retail Transmission Network Charge	1584	-$ 705,348	-$ 122,344	-$ 499,381		-$ 328,311	-$ 55,654	-$ 6,728	-$ 57,671		-$ 4,711
RSVA - Retail Transmission Connection Charge	1586	-$ 788,126	-$ 149,009	-$ 543,465		-$ 393,670	-$ 60,901	-$ 7,685	-$ 62,946		-$ 5,640
RSVA - Power (excluding Global Adjustment)	1588	$ 1,370,963	-$ 613,393	$ 909,269		-$ 151,699	$ 167,183	$ 10,317	$ 158,100		$ 19,400
RSVA - Power - Sub-account - Global Adjustment	1588	$ 233,196	$ 965,336	$ 280,260		$ 918,272	$ 2,801	$ 5,030	$ 19,533		-$ 11,702
Recovery of Regulatory Asset Balances	1590	-$ 457,553	$ 256,121			-$ 201,432	$ 485,828	-$ 3,271			$ 482,557
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -	-$ 24,288	-$ 88,912		$ 64,625	$ -	$ 297	-$ 63,238		$ 63,536
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7 - GA related]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7 - GA Related]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-$ 663,110	-$ 265,716	-$ 150,368	$ -	-$ 778,457	$ 523,468	-$ 7,061	-$ 22,222	$ -	$ 538,630
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-$ 896,306	-$ 1,231,052	-$ 430,628	$ -	-$ 1,696,729	$ 520,667	-$ 12,091	-$ 41,755	$ -	$ 550,332
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ 233,196	$ 965,336	$ 280,260	$ -	$ 918,272	$ 2,801	$ 5,030	$ 19,533	$ -	-$ 11,702
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 33,894		$ 33,894		$ -	$ 4,725		$ 5,103	$ 378	$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 91,943		$ 91,943		$ -	$ 13,116		$ 14,143	$ 1,027	$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -	-$ 2,979			-$ 2,979	$ -	-$ 0			-$ 0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ -	$ 4,457			$ 4,457	$ -	$ 6			$ 6
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508					$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508					$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Late Payment Penalty Litigation	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	-$ 62,728	-$ 18,252	-$ 45,108		-$ 35,872	-$ 5,093	-$ 611	-$ 5,311		-$ 394
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -	$ -				$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -	$ -				$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -	$ -				$ -
Smart Grid Capital Deferral Account	1534					$ -	$ -				$ -
Smart Grid OM&A Deferral Account	1535					$ -	$ -				$ -
Smart Grid Funding Adder Deferral Account	1536					$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	$ 89,630	$ 38,422	$ 69,638		$ 58,414	$ 7,832	$ 907	$ 8,286		$ 453
Board-Approved CDM Variance Account	1567										$ -
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ -				$ -	$ -				$ -
Other Deferred Credits	2425	$ -				$ -	$ -				$ -
Group 2 Sub-Total		$ 152,739	$ 21,648	$ 150,367	$ -	$ 24,020	$ 20,580	$ 302	$ 22,222	$ 1,405	$ 65
Deferred Payments in Lieu of Taxes	1562	$ -	-$ 398,373			-$ 398,373	$ -	-$ 66,798			-$ 66,798
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$ 510,371	-$ 642,440	-$ 1	$ -	-$ 1,152,810	$ 544,048	-$ 73,557	-$ 0	$ 1,405	$ 471,897

Account Descriptions	Account Number	2009 Opening Principal Amounts as of Jan-1-09	Transactions Debit / (Credit) during 2009 excluding interest and adjustments [3]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Interest Amounts as of Dec-31-09
Special Purpose Charge Assessment Variance Account[9]	**1521**										
LRAM Variance Account	**1568**										
Total including Account 1521 and Account 1568		-$ 510,371	-$ 642,440	-$ 1	$ -	-$ 1,152,810	$ 544,048	-$ 73,557	-$ 0	$ 1,405	$ 471,897
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ 102,842	$ 1,571,302			$ 1,674,144	$ 2,760	$ 4,651			$ 7,411
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	-$ 70,413	-$ 69,222			-$ 139,635	-$ 3,684	-$ 930			-$ 4,614
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ 3,874	$ 95,447			$ 99,321	$ -	$ 255			$ 255
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -	$ 398,373			$ 398,373	$ -	$ 66,798			$ 66,798
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig
have a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs v

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of th

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For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transa

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Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refu
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The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the pr
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Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall b

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Account Descriptions	Account Number	2010 Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [3]	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Interest Amounts as of Dec-31-10
Group 1 Accounts											
LV Variance Account	1550	-$ 214,426	-$ 16,855	$ 11,828		-$ 243,109	-$ 694	-$ 1,994	$ 311		-$ 2,999
RSVA - Wholesale Market Service Charge	1580	-$ 471,816	-$ 375,524	-$ 119,931		-$ 727,409	-$ 4,116	-$ 4,596	-$ 2,946		-$ 5,766
RSVA - Retail Transmission Network Charge	1584	-$ 328,311	-$ 5,204	-$ 205,967		-$ 127,548	-$ 4,711	-$ 1,496	-$ 4,112		-$ 2,095
RSVA - Retail Transmission Connection Charge	1586	-$ 393,670	-$ 19,030	-$ 244,661		-$ 168,039	-$ 5,640	-$ 1,839	-$ 4,894		-$ 2,585
RSVA - Power (excluding Global Adjustment)	1588	-$ 151,699	$ 851,528	$ 461,694		$ 238,135	$ 19,400	-$ 1,622	$ 21,379		-$ 3,601
RSVA - Power - Sub-account - Global Adjustment	1588	$ 918,272	-$ 565,660	-$ 47,064		$ 399,676	-$ 11,702	$ 6,813	-$ 15,425		$ 10,536
Recovery of Regulatory Asset Balances	1590	-$ 201,432	-$ 19,219	-$ 457,553		$ 236,902	$ 482,557	$ 867	$ 479,827		$ 3,597
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ 64,625	-$ 66,013			-$ 1,388	$ 63,536	$ 212			$ 63,748
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -	$ 34,699	$ 554,590		-$ 519,891	$ -	-$ 3,057	-$ 489,566		$ 486,509
Disposition and Recovery/Refund of Regulatory Balances (2009)[7 - GA related]	1595	$ -	$ 6,522	$ 47,064		-$ 40,542	$ -	-$ 250	$ 15,426		-$ 15,676
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7 - GA Related]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-$ 778,457	-$ 174,754	$ -	$ -	-$ 953,211	$ 538,630	-$ 6,962	$ -	$ -	$ 531,668
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-$ 1,696,729	$ 390,906	$ 47,064	$ -	-$ 1,352,887	$ 550,332	-$ 13,775	$ 15,425	$ -	$ 521,131
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ 918,272	-$ 565,660	-$ 47,064	$ -	$ 399,676	-$ 11,702	$ 6,813	-$ 15,425	$ -	$ 10,536
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	-$ 2,979	-$ 18,209			-$ 21,188	-$ 0	-$ 123			-$ 123
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ 4,457	$ 2,499			$ 6,956	$ 6	$ 53			$ 59
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Late Payment Penalty Litigation	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	-$ 35,872	-$ 17,845			-$ 53,717	-$ 394	-$ 366			-$ 759
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531	$ -	-$ 2,801			-$ 2,801	$ -				$ -
Renewable Generation Connection OM&A Deferral Account	1532	$ -				$ -	$ -				$ -
Renewable Generation Connection Funding Adder Deferral Account	1533	$ -				$ -	$ -				$ -
Smart Grid Capital Deferral Account	1534	$ -				$ -	$ -				$ -
Smart Grid OM&A Deferral Account	1535	$ -				$ -	$ -				$ -
Smart Grid Funding Adder Deferral Account	1536	$ -				$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	$ 58,414	$ 16,418			$ 74,832	$ 453	$ 542			$ 995
Board-Approved CDM Variance Account	1567					$ -	$ -				$ -
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ -				$ -	$ -				$ -
Other Deferred Credits	2425	$ -				$ -	$ -				$ -
Group 2 Sub-Total		$ 24,020	-$ 19,937	$ -	$ -	$ 4,082	$ 65	$ 106	$ -	$ -	$ 171
Deferred Payments in Lieu of Taxes	1562	-$ 398,373	$ -			-$ 398,373	-$ 66,798	-$ 2,726			-$ 69,523
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -	-$ 5,899			-$ 5,899	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$ 1,152,810	-$ 200,590	$ -	$ -	-$ 1,353,401	$ 471,897	-$ 9,581	$ -	$ -	$ 462,315

Account Descriptions	Account Number	2010 Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [3]	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Interest Amounts as of Dec-31-10
Special Purpose Charge Assessment Variance Account[9]	**1521**		$ 41,406			$ 41,406		$ 366			$ 366
LRAM Variance Account	**1568**					$ -					$ -
Total including Account 1521 and Account 1568		-$ 1,152,810	-$ 159,184	$ -	$ -	-$ 1,311,995	$ 471,897	-$ 9,215	$ -	$ -	$ 462,681
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ 1,674,144	$ 235,009			$ 1,909,152	$ 7,411	$ 14,621			$ 22,033
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	-$ 139,635	-$ 185,482			-$ 325,116	-$ 4,614	-$ 1,834			-$ 6,447
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ 99,321	$ 265,088			$ 364,409	$ 255	$ 1,445			$ 1,699
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ 398,373	$ -			$ 398,373	$ 66,798	$ 2,726			$ 69,523
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -	$ 5,899			$ 5,899	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

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Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Account Descriptions	Account Number	2011 Opening Principal Amounts as of Jan-1-11	Transactions Debit / (Credit) during 2011 excluding interest and adjustments [3]	Board-Approved Disposition during 2011	Other [2] Adjustments during Q1 2011	Other [2] Adjustments during Q2 2011	Other [2] Adjustments during Q3 2011	Other [2] Adjustments during Q4 2011	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Adjustments during 2011 - other [2]	Closing Interest Amounts as of Dec-31-11
Group 1 Accounts														
LV Variance Account	1550	-$ 243,109	$ 190,524	-$ 226,254					$ 173,670	-$ 2,999	-$ 699	-$ 3,300		-$ 398
RSVA - Wholesale Market Service Charge	1580	-$ 727,409	-$ 256,812	-$ 351,885					-$ 632,336	-$ 5,766	-$ 9,773	-$ 4,737		-$ 10,802
RSVA - Retail Transmission Network Charge	1584	-$ 127,548	$ 50,194	-$ 122,344					$ 44,990	-$ 2,095	-$ 791	-$ 1,839		-$ 1,047
RSVA - Retail Transmission Connection Charge	1586	-$ 168,039	$ 39,696	-$ 149,009					$ 20,666	-$ 2,585	-$ 1,216	-$ 2,256		-$ 1,544
RSVA - Power (excluding Global Adjustment)	1588	$ 238,135	$ 55,411	-$ 613,393					$ 906,939	-$ 3,601	$ 9,681	-$ 8,198		$ 14,278
RSVA - Power - Sub-account - Global Adjustment	1588	$ 399,676	$ 454,353	$ 965,336					-$ 111,307	$ 10,536	$ 755	$ 13,512		-$ 2,221
Recovery of Regulatory Asset Balances	1590	$ 236,902	-$ 28,717						$ 208,185	$ 3,597	$ 3,287			$ 6,884
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	-$ 1,388	-$ 32,687						-$ 34,075	$ 63,748	-$ 386			$ 63,362
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	-$ 519,891	$ 29,354						-$ 490,537	$ 486,509	-$ 7,315			$ 479,193
Disposition and Recovery/Refund of Regulatory Balances (2009)[7 - GA related]	1595	-$ 40,542	$ 5,831						-$ 34,710	-$ 15,676	-$ 531			-$ 16,206
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -	$ 764,241	$ 1,462,885					-$ 698,644	$ -	-$ 9,787	$ 20,330		-$ 30,117
Disposition and Recovery/Refund of Regulatory Balances (2010)[7 - GA Related]	1595	$ -	-$ 560,120	-$ 965,336					$ 405,216	$ -	$ 6,255	-$ 13,512		$ 19,767
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-$ 953,211	$ 711,270	$ -	$ -	$ -	$ -	$ -	-$ 241,941	$ 531,668	-$ 10,518	$ -	$ -	$ 521,149
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-$ 1,352,887	$ 256,917	-$ 965,336	$ -	$ -	$ -	$ -	-$ 130,635	$ 521,131	-$ 11,273	-$ 13,512	$ -	$ 523,370
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ 399,676	$ 454,353	$ 965,336	$ -	$ -	$ -	$ -	-$ 111,307	$ 10,536	$ 755	$ 13,512	$ -	-$ 2,221
Group 2 Accounts														
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -							$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -							$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	-$ 21,188	$ 11,905						-$ 9,284	-$ 123	-$ 467			-$ 590
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ 6,956							$ 6,956	$ 59	$ 102			$ 161
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508	$ -							$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	$ -							$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Late Payment Penalty Litigation	1508	$ -	$ 9,025						$ 9,025	$ -				$ -
Retail Cost Variance Account - Retail	1518	-$ 53,717	-$ 15,921						-$ 69,638	-$ 759	-$ 901			-$ 1,661
Misc. Deferred Debits	1525	$ -							$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531	-$ 2,801	$ 252,599						$ 249,798	$ -				$ -
Renewable Generation Connection OM&A Deferral Account	1532	$ -							$ -	$ -				$ -
Renewable Generation Connection Funding Adder Deferral Account	1533	$ -							$ -	$ -				$ -
Smart Grid Capital Deferral Account	1534	$ -							$ -	$ -				$ -
Smart Grid OM&A Deferral Account	1535	$ -							$ -	$ -				$ -
Smart Grid Funding Adder Deferral Account	1536	$ -							$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	$ 74,832	$ 16,295						$ 91,127	$ 995	$ 1,187			$ 2,182
Board-Approved CDM Variance Account	1567	$ -							$ -	$ -				$ -
Extra-Ordinary Event Costs	1572	$ -							$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -							$ -	$ -				$ -
RSVA - One-time	1582	$ -							$ -	$ -				$ -
Other Deferred Credits	2425	$ -							$ -	$ -				$ -
Group 2 Sub-Total		$ 4,082	$ 273,902	$ -	$ -	$ -	$ -	$ -	$ 277,985	$ 171	-$ 79	$ -	$ -	$ 92
Deferred Payments in Lieu of Taxes	1562	-$ 398,373							-$ 398,373	-$ 69,523	-$ 5,856			-$ 75,379
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ -							$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$ 5,899	-$ 19,658						-$ 25,556	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$ 1,353,401	$ 965,515	$ -	$ -	$ -	$ -	$ -	-$ 387,886	$ 462,315	-$ 16,453	$ -	$ -	$ 445,862

Account Descriptions	Account Number	2011 Opening Principal Amounts as of Jan-1-11	Transactions Debit / (Credit) during 2011 excluding interest and adjustments [3]	Board-Approved Disposition during 2011	Other [2] Adjustments during Q1 2011	Other [2] Adjustments during Q2 2011	Other [2] Adjustments during Q3 2011	Other [2] Adjustments during Q4 2011	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Adjustments during 2011 - other [2]	Closing Interest Amounts as of Dec-31-11
Special Purpose Charge Assessment Variance Account[9]	**1521**	$ 41,406	-$ 38,135						$ 3,271	$ 366	$ 184			$ 550
LRAM Variance Account	**1568**	$ -							$ -	$ -				$ -
Total including Account 1521 and Account 1568		-$ 1,311,995	$ 927,380	$ -	$ -	$ -	$ -	$ -	-$ 384,615	$ 462,681	-$ 16,270	$ -	$ -	$ 446,412
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ 1,909,152	$ 45,103						$ 1,954,256	$ 22,033	$ 28,792			$ 50,824
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	-$ 325,116	-$ 262,714						-$ 587,831	-$ 6,447	-$ 6,441			-$ 12,888
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -						$ 446,409	$ 446,409	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ 364,409	$ 116,686						$ 481,094	$ 1,699	$ 5,941			$ 7,640
The following is not included in the total claim but are included on a memo basis:														
Deferred PILs Contra Account [5]	1563	$ 398,373	$ -					$ -	$ 398,373	$ 69,523	$ 5,856		$ -	$ 75,379
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -							$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ 5,899	$ 19,658						$ 25,556	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -							$ -	$ -				$ -

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Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Account Descriptions	Account Number	2012				Projected Interest on Dec-31-11 Balances			2.1.7 RRR	
		Principal Disposition during 2012 - instructed by Board	Interest Disposition during 2012 - instructed by Board	Closing Principal Balances as of Dec 31-11 Adjusted for Dispositions during 2012	Closing Interest Balances as of Dec 31-11 Adjusted for Dispositions during 2012	Projected Interest from Jan 1, 2012 to December 31, 2012 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Total Claim	As of Dec 31-11	Variance RRR vs. 2011 Balance *(Principal + Interest)*
Group 1 Accounts										
LV Variance Account	1550			$ 173,670	-$ 398	$ 2,553	$ 851	$ 176,676	$ 173,272	$ -
RSVA - Wholesale Market Service Charge	1580			-$ 632,336	-$ 10,802	-$ 9,295	-$ 3,098	-$ 655,531	-$ 643,138	$ -
RSVA - Retail Transmission Network Charge	1584			$ 44,990	-$ 1,047	$ 661	$ 220	$ 44,825	$ 43,943	$ -
RSVA - Retail Transmission Connection Charge	1586			$ 20,666	-$ 1,544	$ 304	$ 101	$ 19,527	$ 19,122	$ -
RSVA - Power (excluding Global Adjustment)	1588			$ 906,939	$ 14,278	$ 13,332	$ 4,444	$ 938,993	$ 921,217	$ -
RSVA - Power - Sub-account - Global Adjustment	1588			-$ 111,307	-$ 2,221	-$ 1,636	-$ 545	-$ 115,709	-$ 113,527	$ -
Recovery of Regulatory Asset Balances	1590			$ 208,185	$ 6,884	$ 3,060	$ 1,020	$ 219,150	$ 215,069	$ -
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595			-$ 34,075	$ 63,362	-$ 501	-$ 167	$ 28,619	$ 29,287	$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595			-$ 490,537	$ 479,193	-$ 7,211	-$ 2,404	-$ 20,958	-$ 11,344	$ 0
Disposition and Recovery/Refund of Regulatory Balances (2009)[7 - GA related]	1595			-$ 34,710	-$ 16,206	-$ 510	-$ 170	-$ 51,597	-$ 50,916	$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595			-$ 698,644	-$ 30,117	-$ 10,270	-$ 3,423	no disp	-$ 728,762	-$ 1
Disposition and Recovery/Refund of Regulatory Balances (2010)[7 - GA Related]	1595			$ 405,216	$ 19,767	$ 5,957	$ 1,986	no disp	$ 424,984	$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	-$ 241,941	$ 521,149	-$ 3,557	-$ 1,186	$ 583,995	$ 279,208	-$ 1
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	-$ 130,635	$ 523,370	-$ 1,920	-$ 640	$ 390,175	$ 392,735	-$ 1
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	$ -	-$ 111,307	-$ 2,221	-$ 1,636	-$ 545	-$ 115,709	-$ 113,527	$ -
Group 2 Accounts										
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508			$ -	$ -	$ -	$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508			$ -	$ -	$ -	$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508			-$ 9,284	-$ 590	-$ 136	-$ 45	no disp	-$ 9,874	$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508			$ 6,956	$ 161	$ 102	$ 34	$ 7,254	$ 7,118	$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508			$ -	$ -	$ -	$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508			$ -	$ -	$ -	$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Late Payment Penalty Litigation	1508			$ 9,025	$ -	$ 133	$ 44	no disp	$ 9,025	$ -
Retail Cost Variance Account - Retail	1518			-$ 69,638	-$ 1,661	-$ 1,024	-$ 341	-$ 72,664	-$ 71,299	-$ 0
Misc. Deferred Debits	1525			$ -	$ -	$ -	$ -	$ -		$ -
Renewable Generation Connection Capital Deferral Account	1531			$ 249,798	$ -	$ 3,672	$ 1,224	no disp	$ 249,798	$ -
Renewable Generation Connection OM&A Deferral Account	1532			$ -	$ -	$ -	$ -	$ -		$ -
Renewable Generation Connection Funding Adder Deferral Account	1533			$ -	$ -	$ -	$ -	$ -		$ -
Smart Grid Capital Deferral Account	1534			$ -	$ -	$ -	$ -	$ -		$ -
Smart Grid OM&A Deferral Account	1535			$ -	$ -	$ -	$ -	$ -		$ -
Smart Grid Funding Adder Deferral Account	1536			$ -	$ -	$ -	$ -	$ -		$ -
Retail Cost Variance Account - STR	1548			$ 91,127	$ 2,182	$ 1,340	$ 447	$ 95,095	$ 93,309	$ -
Board-Approved CDM Variance Account	1567			$ -	$ -	$ -	$ -	$ -		$ -
Extra-Ordinary Event Costs	1572			$ -	$ -	$ -	$ -	$ -		$ -
Deferred Rate Impact Amounts	1574			$ -	$ -	$ -	$ -	$ -		$ -
RSVA - One-time	1582			$ -	$ -	$ -	$ -	$ -		$ -
Other Deferred Credits	2425			$ -	$ -	$ -	$ -	$ -		$ -
Group 2 Sub-Total		$ -	$ -	$ 277,985	$ 92	$ 4,086	$ 1,362	$ 283,525	$ 278,077	-$ 0
Deferred Payments in Lieu of Taxes	1562	-$ 398,374	-$ 75,379	$ 1	-$ 0			$ 0	-$ 473,752	$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592			$ -	$ -			$ -		$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592			-$ 25,556	$ -			-$ 12,778	-$ 25,556	$ -
										$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$ 398,374	-$ 75,379	$ 10,488	$ 521,241	$ 530	$ 177	$ 854,742	$ 57,976	-$ 1

Account Descriptions	Account Number	2012: Principal Disposition during 2012 - instructed by Board	2012: Interest Disposition during 2012 - instructed by Board	2012: Closing Principal Balances as of Dec 31-11 Adjusted for Dispositions during 2012	2012: Closing Interest Balances as of Dec 31-11 Adjusted for Dispositions during 2012	Projected Interest on Dec-31-11 Balances: Projected Interest from Jan 1, 2012 to December 31, 2012 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Projected Interest on Dec-31-11 Balances: Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Total Claim	2.1.7 RRR: As of Dec 31-11	Variance RRR vs. 2011 Balance *(Principal + Interest)*
Special Purpose Charge Assessment Variance Account[9]	**1521**	$ 3,271	$ 550	$ -	-$ 0			-$ 0	$ 3,821	$ -
										$ -
LRAM Variance Account	**1568**			$ -	$ -			$ -		$ -
Total including Account 1521 and Account 1568		-$ 395,102	-$ 74,829	$ 10,488	$ 521,241	$ 530	$ 177	$ 854,742	$ 61,797	-$ 1
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ 1,954,256	$ 50,824	$ -	$ 0			$ 0	$ 2,005,080	$ 0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	-$ 587,831	-$ 12,888	$ 0	-$ 0			$ 0	-$ 600,719	-$ 0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555			$ 446,409	$ -			$ 446,409		-$ 446,409
Smart Meter OM&A Variance[11]	1556	$ 481,094	$ 7,640	$ -	-$ 0			-$ 0	$ 488,734	$ -
The following is not included in the total claim but are included on a memo basis:										
Deferred PILs Contra Account [5]	1563	$ 398,374	$ 75,379	-$ 1	$ 0			-$ 0	$ 473,752	$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575			$ -	$ -			$ -		$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592			$ 25,556	$ -			$ -	$ 25,556	$ -
Disposition and Recovery of Regulatory Balances[7]	1595			$ -	$ -			$ -		$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig
have a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs v

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of th

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved dis

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transa

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the ol
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to Decembe
the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded fro
disposed balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refu

balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acicipate that licensed distributors that cannot adapt their invoices as of January
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will

The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the pr
non-compliance with the timeline set out in section 8 of the SPC regulation.

Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall b

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Accounts that produced a variance on the 2013 continuity schedule are listed below.
Please provide a detailed explanation for each variance below.

Account Descriptions	Account Number	Variance RRR vs. 2011 Balance *(Principal + Interest)*	Explanation
Group 1 Accounts			
Group 2 Accounts			
Retail Cost Variance Account - Retail	1518	$ (0.01)	rounding
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ 0.29	rounding
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ (0.29)	rounding
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ (446,409.21)	Adjustment to reclass Stranded Meters from Account 1860 to 1555 for disposition - $1,006,848.74 Gross, $560,439.54 Accum Dep

In the green shaded cells, enter the most recent Board Approved volumetric forecast. If there is a ma
forecast and the most recent 12-month actual volumetric data, use the most recent 12-month actual c

Rate Class (Enter Rate Classes in cells below)	Units	# of Customers	Metered kWh	Metered kW
Residential	kWh	7,930	77,905,420	
General Service <50 kW	kWh	1,567	42,698,322	
General Service >50 kW	kW	101	83,774,463	202,946
Sentinel Lighting	kW	45	40,324	113
Street Lighting	kW	2,130	1,874,274	5,087
USL	kWh	38	131,903	
Total		**11,811**	**206,424,706**	**208,146**

[1] For Account 1562, the allocation to customer classes should be performed on the basis of the test year distribu
found in the Applicant's Cost of Service application that was most recently approved at the time of disposition of t

[2] Residual Account balance to be allocated to rate classes in proportion to the recovery share as established whe

ce Account Workform
013 Filers

aterial difference between the latest Board-approved volumetric
data. Do not enter data for the MicroFit class.

Billed kWh for Non-RPP Customers	Estimated kW for Non-RPP Customers	Distribution Revenue [1]	1590 Recovery Share Proportion
9,879,218	-	$ 2,509,429	47.2%
9,112,556	-	$ 1,030,400	20.5%
28,916,248	70,050	$ 809,433	31.6%
1,059	3	$ 4,558	0.0%
411,364	1,116	$ 190,874	0.4%
3,036	-	$ 9,183	0.3%
	-		
	-		
	-		
	-		
48,323,481	**71,170**	**$ 4,553,877**	**100%**

tion revenue allocation to customer classes
the 1562 account balances

en rate riders were implemented.

1595 Recovery Share Proportion (2008) [2]	1595 Recovery Share Proportion (2009) [2]	1595 Recovery Share Proportion (2010) [2]	1568 LRAM Variance Account Class Allocation ($ amounts)
37.2%	38.7%	38.3%	
20.3%	20.9%	20.5%	
41.5%	39.4%	40.3%	
0.0%	0.0%	0.2%	
0.9%	0.9%	0.9%	
0.1%	0.1%	0.1%	
100%	**100%**	**100%**	**$ -**
		Balance as per Sheet 2	$ -
		Variance	$ -

		Amounts from Sheet 2	Allocator	Residential	General Service <50 kW	General Service >50 kW	Sentinel Lighting	Street Lighting	USL	
LV Variance Account	1550	176,676	kWh	66,678	36,545	71,701	35	1,604	113	0
RSVA - Wholesale Market Service Charge	1580	(655,531)	kWh	(247,400)	(135,595)	(266,038)	(128)	(5,952)	(419)	0
RSVA - Retail Transmission Network Charge	1584	44,825	kWh	16,917	9,272	18,192	9	407	29	0
RSVA - Retail Transmission Connection Charge	1586	19,527	kWh	7,370	4,039	7,925	4	177	12	0
RSVA - Power (excluding Global Adjustment)	1588	938,993	kWh	354,379	194,228	381,077	183	8,526	600	0
RSVA - Power - Sub-account - Global Adjustment	1588	(115,709)	Non-RPP kWh	(23,655)	(21,820)	(69,239)	(3)	(985)	(7)	0
Recovery of Regulatory Asset Balances	1590	219,150	kWh	82,708	45,330	88,939	43	1,990	140	0
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	28,619	kWh	10,801	5,920	11,615	6	260	18	0
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	(20,958)	kWh	(7,910)	(4,335)	(8,506)	(4)	(190)	(13)	0
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	(51,597)	Non-RPP kWh	(10,548)	(9,730)	(30,875)	(1)	(439)	(3)	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	0	kWh	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	0	Non-RPP kWh	0	0	0	0	0	0	0
Total of Group 1 Accounts (excluding 1588 sub-account)		**751,300**		**283,543**	**155,404**	**304,904**	**147**	**6,822**	**480**	**0**
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	0		0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	0		0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	0	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	7,254	kWh	2,738	1,500	2,944	1	66	5	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	0	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	0		0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Other	1508	0		0	0	0	0	0	0	0
Retail Cost Variance Account - Retail	1518	(72,664)	kWh	(27,424)	(15,030)	(29,490)	(14)	(660)	(46)	0
Misc. Deferred Debits	1525	0		0	0	0	0	0	0	0
Renewable Generation Connection Capital Deferral Account	1531	0		0	0	0	0	0	0	0
Renewable Generation Connection OM&A Deferral Account	1532	0		0	0	0	0	0	0	0
Renewable Generation Connection Funding Adder Deferral Account	1533	0		0	0	0	0	0	0	0
Smart Grid Capital Deferral Account	1534	0		0	0	0	0	0	0	0
Smart Grid OM&A Deferral Account	1535	0		0	0	0	0	0	0	0
Smart Grid Funding Adder Deferral Account	1536	0		0	0	0	0	0	0	0
Retail Cost Variance Account - STR	1548	95,095	kWh	35,889	19,670	38,593	19	863	61	0
Board-Approved CDM Variance Account	1567	0		0	0	0	0	0	0	0
Extra-Ordinary Event Costs	1572	0		0	0	0	0	0	0	0
Deferred Rate Impact Amounts	1574	0		0	0	0	0	0	0	0
RSVA - One-time	1582	0		0	0	0	0	0	0	0
Other Deferred Credits	2425	0		0	0	0	0	0	0	0
Total of Group 2 Accounts		**29,685**		**11,203**	**6,140**	**12,047**	**6**	**270**	**19**	**0**
Deferred Payments in Lieu of Taxes	1562	0		0	0	0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	0		0	0	0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	(12,778)	kWh	(4,823)	(2,643)	(5,186)	(2)	(116)	(8)	0
Total of Account 1562 and Account 1592		**(12,778)**		**(4,822)**	**(2,643)**	**(5,186)**	**(2)**	**(116)**	**(8)**	**0**
Special Purpose Charge Assessment Variance Account	1521	0		0	0	0	0	0	0	0
LRAM Variance Account **(Enter dollar amount for each class)**	1568	0								
(Account 1568 - total amount allocated to classes)		0								
Variance		0								
Total Balance Allocated to each class (excluding 1588 sub-account)		**768,208**		**289,924**	**158,901**	**311,766**	**150**	**6,975**	**491**	**0**
Total Balance in Account 1588 - sub account		**(167,306)**		**(34,204)**	**(31,550)**	**(100,114)**	**(4)**	**(1,424)**	**(11)**	**0**
Total Balance Allocated to each class (including 1588 sub-account)		**600,902**		**255,721**	**127,352**	**211,652**	**146**	**5,551**	**480**	**0**

Deferral/Variance Account for 2013 Filers

		Amounts from Sheet 2	Allocator			
LV Variance Account	1550	176,676	kWh	0	0	0
RSVA - Wholesale Market Service Charge	1580	(655,531)	kWh	0	0	0
RSVA - Retail Transmission Network Charge	1584	44,825	kWh	0	0	0
RSVA - Retail Transmission Connection Charge	1586	19,527	kWh	0	0	0
RSVA - Power (excluding Global Adjustment)	1588	938,993	kWh	0	0	0
RSVA - Power - Sub-account - Global Adjustment	1588	(115,709)	Non-RPP kWh	0	0	0
Recovery of Regulatory Asset Balances	1590	219,150	kWh	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	28,619	kWh	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	(20,958)	kWh	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	(51,597)	Non-RPP kWh	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	0	kWh	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	0	Non-RPP kWh	0	0	0
Total of Group 1 Accounts (excluding 1588 sub-account)		**751,300**		**0**	**0**	**0**
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	0		0	0	0
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	0		0	0	0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	0	kWh	0	0	0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	7,254	kWh	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	0	kWh	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	0		0	0	0
Other Regulatory Assets - Sub-Account - Other	1508	0		0	0	0
Retail Cost Variance Account - Retail	1518	(72,664)	kWh	0	0	0
Misc. Deferred Debits	1525	0		0	0	0
Renewable Generation Connection Capital Deferral Account	1531	0		0	0	0
Renewable Generation Connection OM&A Deferral Account	1532	0		0	0	0
Renewable Generation Connection Funding Adder Deferral Account	1533	0		0	0	0
Smart Grid Capital Deferral Account	1534	0		0	0	0
Smart Grid OM&A Deferral Account	1535	0		0	0	0
Smart Grid Funding Adder Deferral Account	1536	0		0	0	0
Retail Cost Variance Account - STR	1548	95,095	kWh	0	0	0
Board-Approved CDM Variance Account	1567	0		0	0	0
Extra-Ordinary Event Costs	1572	0		0	0	0
Deferred Rate Impact Amounts	1574	0		0	0	0
RSVA - One-time	1582	0		0	0	0
Other Deferred Credits	2425	0		0	0	0
Total of Group 2 Accounts		**29,685**		**0**	**0**	**0**
Deferred Payments in Lieu of Taxes	1562	0		0	0	0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	0		0	0	0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	(12,778)	kWh	0	0	0
Total of Account 1562 and Account 1592		**(12,778)**		**0**	**0**	**0**
Special Purpose Charge Assessment Variance Account	1521	0		0	0	0
LRAM Variance Account **(Enter dollar amount for each class)**	1568	0				
(Account 1568 - total amount allocated to classes)		0				
Variance		0				
Total Balance Allocated to each class (excluding 1588 sub-account)		**768,208**		**0**	**0**	**0**
Total Balance in Account 1588 - sub account		**(167,306)**		**0**	**0**	**0**
Total Balance Allocated to each class (including 1588 sub-account)		**600,902**		**0**	**0**	**0**

Deferral/Variance Account Workform for 2013 Filers

Please indicate the Rate Rider Recovery Period (in years) | 1

Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.)

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1588 sub-account)	Rate Rider for Deferral/Variance Accounts	
Residential	kWh	77,905,420	$ 289,924	**0.0037**	$/kWh
General Service <50 kW	kWh	42,698,322	$ 158,901	**0.0037**	$/kWh
General Service >50 kW	**kW**	202,946	$ 311,766	**1.5362**	**$/kW**
Sentinel Lighting	**kW**	113	$ 150	**1.3280**	**$/kW**
Street Lighting	**kW**	5,087	$ 6,975	**1.3712**	**$/kW**
USL	kWh	131,903	$ 491	**0.0037**	$/kWh
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
Total			**$ 768,208**		